Decision 25-08-032 August 28, 2025

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities.	Rulemaking 20-07-013

PHASE 4 DECISION

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PHASE 4 DECISION

Summary

This decision adopts refinements to the Risk-Based Decision-Making Framework to:

- Require the representation of Consequence of Risk Event as a probability distribution;
- Incorporate Overall Residual Risk reporting into the Risk-Based Decision-Making Framework;
- Require the presentation of optimized risk mitigation portfolios with Risk Assessment Mitigation Phase filings, including budget scenarios which will be based on the forecasted costs of Mitigations and Controls that the utility has proposed in its RAMP or current GRC. We call these forecasted costs the Baseline Cost Forecast. The four required budget scenarios are: 1) 85% of the Baseline Cost Forecast, 2) 90% of the Baseline Cost Forecast, 3) 95% of the Baseline Cost Forecast, and 4) 100% of the Baseline Cost Forecast;
- Incorporate the Risk Reporting Unit into the Risk-Based Decision-Making Framework;
- Provide guidelines for the Risk Mitigation Accountability Report;
- Provide minor key refinements to the Risk-Based Decision-Making Framework; and
- Provide the Risk Assessment Mitigation Phase Data Template and Guidelines.

This proceeding is closed.

1. Background

The Commission opened Rulemaking (R.) 20-07-013 on July 16, 2020, to consider ways to strengthen the risk-based decision-making framework that regulated energy utilities use to assess, manage, mitigate, and minimize safety risks. The Risk-Based Decision-Making Framework[1] (RDF) refines and enhances some of the analytical tools and concepts available to the Commission and to parties to help evaluate the reasonableness of proposed safety investments. As California ratepayers face growing challenges in affording utility rates, it is imperative that the records of general rate cases have the best information possible. California ratepayers deserve operational excellence from their utility systems and this requires safety investments that are effective and strategic in getting the most value for their dollar.

The RDF rulemaking builds on requirements for a utility risk framework adopted in the Safety Model Assessment Proceeding (S-MAP), Application (A.) 15-05-002 et al, and in R.13-11-006, which was opened to address the requirements of Pub. Util. Code Sections 963(b)(3) and 750. The purpose of this rulemaking is to further the prioritization of safety by gas and electric utilities in alignment with the requirement of Section 451 of just and reasonable rates.

The Commission adopted two decisions in Phase 1 of this proceeding, Decision (D.) 21-11-009, Decision Addressing Phase 1, Tracks 1 and 2 Issues, and D.22-10-002, Decision Addressing Phase 1, Tracks 3 and 4 Issues. In Phase 2 of

[1] The most recent RDF can be found as Appendix A of D.24-05-064, currently available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K206/533206241.PD, and is updated by the appendices in this Decision.

this proceeding, the Commission adopted D.22-12-027, Phase 2 Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots. In Phase 3 of this proceeding, the Commission adopted D.24-05-064, which resolved several outstanding issues by:

- Modifying the RDF included in Appendix A to Decision 22-12-027;
- Modifying the Transparency Pilot Guidelines appended to D.21-11-009;
- Identifying best practices for tranche granularity when implementing the RDF;
- Identifying the truncated power law distribution model as the best practice for wildfire tail risk modeling when implementing the RDF, while allowing other modeling approaches if justified;
- Directing IOUs to each prepare a Climate Pilot White Paper testing the quantitative integration of climate hazard data into the RDF;
- Modifying the risk scaling requirements of the RDF;
- Modifying the Benefit-Cost Ratio (BCR) calculation; and
- Authorizing continuation of the Technical Working Group (TWG) established in D.21-11-009.

1.1. Phase 4 Procedural Background

The assigned Commissioner's Phase 4 Scoping Memo and Ruling (Phase 4 Scoping Memo) was issued on September 3, 2024. The Phase 4 Scoping Memo outlined a detailed schedule for three workshops between October 30, 2024, and December 18, 2024.

Workshop #1, held October 30, 2024, addressed the definition of scoped work and the risk reporting unit with Safety Policy Division (SPD) staff leading discussions on the SPD staff proposal on this topic. On November 8, 2024, the assigned Administrative Law Judge (ALJ) issued a ruling entering Workshop #1 slides and the SPD definition of scoped work and the risk reporting unit proposal (Staff Scoped Work Proposal) (together, Workshop #1 Materials) into the record and inviting comment on Workshop #1 Materials. On November 8, 2024, San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E) jointly filed their definition of scoped work proposal (Joint Investor Owned Utilities (IOUs) Scoped Work Proposal). Opening comments on both the Workshop #1 Materials and the Joint IOU Scoped Work Proposal were filed[2] by Mussey Grade Road Alliance (MGRA), the Protect Our Communities Foundation (PCF), PG&E, SCE, jointly by SDG&E and Southern California Gas Company (SoCalGas) (together, the Sempra Companies), and jointly by the Public Advocate's Office at the California Public Utilities Commission (Cal Advocates), The Utility Reform Network (TURN), and Energy Producers and Users Coalition (EPUC), Indicated Shippers (IS) (together, EPUC/IS). Reply comments were timely filed by PG&E, SCE, the Sempra Companies, PCF, and jointly by Cal Advocates, EPUC/IS, and TURN.

[2] PCF moved to have its late-filed opening comments accepted, which was granted in the November 26, 2024, ALJ email ruling accepting PCF's late-filed comments on the scoped work proposals. All other party opening comments were timely filed.

Workshop #2, held over November 20, November 21, and November 22, 2024, addressed overall residual risk, risk tolerance, and simple optimization. On December 10, 2024, the assigned ALJ issued a ruling entering Workshop #2 slides and the SPD staff proposal on overall residual risk, risk tolerance, and simple optimization (Staff Risk Tolerance Proposal) (together, Workshop #2 Materials) into the record and inviting comment on Workshop #2 Materials. MGRA filed its Proposal for a Commission-led Deliberative Risk Tolerance Process (MGRA Risk Tolerance Proposal) on December 3, 2024. Opening comments on Workshop #2 Materials and the MGRA Risk Tolerance Proposal were timely filed by MGRA, Cal Advocates, EPUC/IS, PG&E, SCE, the Sempra Companies, SCE, and TURN. Reply comments were timely filed by EPUC/IS, MGRA, Cal Advocates, PG&E, SCE, the Sempra Companies, and TURN.

Workshop #3, held December 18, 2024, addressed Risk Mitigation Accountability Reports (RMARs). On January 2, 2025, the assigned ALJ issued a ruling entering Workshop #3 slides and the Staff RMAR Proposal (together, Workshop #3 Materials) into the record and inviting comment on Workshop #3 Materials. Opening comments were timely filed by EPUC/IS, Cal Advocates, PG&E, SCE, the Sempra Companies, and TURN. Reply comments were timely filed by Cal Advocates, EPUC/IS, PG&E, SCE, the Sempra Companies, and TURN.

The **Technical Working Group** (TWG)**,** established in D.21-11-009, was convened by SPD staff on January 24, January 27, January 28, January 29, and January 30, 2025, to address Risk Assessment Mitigation Phase (RAMP) and General Rate Case (GRC) Data Templates. On February 11, 2025, the assigned

ALJ issued a ruling (TWG Ruling) entering the TWG slides, SPD Staff's Data Template Guideline, and SPD Staff Data Template into the record. The TWG Ruling also directed PG&E, SCE, and the Sempra Companies (together, Joint IOUs) to jointly file a summary report of the TWG by February 18, 2025. The TWG Ruling allowed Cal Advocates, PG&E, SCE, and the Sempra Companies to each file a data template guideline and data template by February 18, 2025. Finally, the TWG Ruling invited opening and reply comments on SPD Staff's Data Template Guideline, SPD Staff's Data Template, the TWG summary report, and the respective data template guidelines and data templates (collectively, TWG Materials), by March 4, 2025, and March 10, 2025, respectively.

1.2. Submission Date

Phase 4 of this proceeding was submitted on March 10, 2025, upon filing of reply comments on the TWG Materials.

2. Jurisdiction

Sections 451 and 454 of the Public Utilities Code require electric and gas utilities to "promote the safety, health, comfort, and convenience of their patrons, employees, and the public," while offering "just and reasonable" rates.

Section 963(b)(3) states "it is the policy of the state that the Commission and each gas corporation place safety of public and gas corporation employees as the top priority," and that "the Commission shall take all reasonable and appropriate actions necessary to carry out a safety priority policy consistent with the principle of just and reasonable cost-based rates." Section 961(b)(1) requires gas corporations to develop plans for the safe and reliable operation of facilities that implement Section 963(b)(3) requirements.

Section 750 requires the Commission to develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation. Section 321.1(b) requires the Commission to "take all necessary and appropriate actions to assess the economic effects of its decisions and to assess and mitigate the impacts of its decisions on customer, public, and employee safety."

3. Issues Before the Commission

This decision addresses both Track 1 and Track 2 issues. The Phase 4 issues resolved in this decision are:

1. How should the utilities be required to report on their progress in reducing overall residual risk remaining after their respective mitigations have been implemented?
2. How should "scoped work" and "project" be defined for the purposes of the RDF?
3. What approach or procedure for determining an acceptable amount of overall residual risk that remains on the system after incrementally reducing risk, weighed against the cost of incremental risk reduction, should be adopted for use by the utilities, if any? How should this approach be integrated into the RDF?
4. Given the key constraints affecting the selection of mitigations or the portfolio of mitigations adopted by the utilities, how should the utilities optimize the reduction of risk through their prioritization of mitigations?
5. What reporting procedure, if any, should be adopted for use by the utilities that can compare a utility's projections of the benefits and costs of the risk mitigation programs? How can such a reporting procedure be integrated into the RDF?

6. Should minor clarifications and corrections be considered for certain key terms (for example: renaming Cost Benefit Ratio to Benefit Cost Ratio, clarifications of the definition of risk, clarifications to the GRC Forecast Cost Thresholds for Supplemental Analysis to account for 4-year rate cases)?
7. Should the Commission adopt required templates for data presentation for use in the RAMPs as proposed by Cal Advocates? If so, what should be the information requirements and format of the templates?
8. What structured method, if any, for collecting and consolidating the more granular project-level data necessary to support the utilities' proposed risk mitigation projects and show how the utilities determine specific targets and forecasts be integrated into the RDF should be adopted for use by the utilities?

Issue 3 is deferred to a successor proceeding, which may also address other Risk-Based Decision-Making issues. All other issues are resolved. It is reasonable to close this proceeding.

4. Risk Tolerance

Risk tolerance is the maximum amount of overall residual risk remaining in a system managed by the utilities that is deemed acceptable to ratepayers after implementation of Controls and Mitigations, weighed against the costs needed for that incremental risk reduction. The RDF tracks residual risk compared to the estimated GRC Test Year Baseline Risk presented in a given RAMP or GRC filing. Overall residual risk is the total risk managed by the utility, not merely the residual risk presented in a single RAMP or GRC filing. As things stand, risk tolerance is implied by the set of mitigations proposed by the utilities, is not made explicit, and does not reflect the preferences of ratepayers or Californians

more broadly. The development of a risk tolerance standard will allow the Commission to answer the question of how much risk reduction is sufficient, given the cost of that risk reduction, and allow the Commission to appropriately weigh safety and affordability.

4.1. SPD Staff Recommendations on Risk Tolerance

SPD Staff's Risk Tolerance Proposal, which also discusses overall residual risk and simple optimization, provides a conceptual overview of the issues related to risk tolerance and provides a number of recommendations. On the topic of risk tolerance, SPD staff recommends the following. First, SPD staff recommends requiring the use of probability distributions in risk modeling, including in the presentation in the RDF of Likelihood of Risk Events (LoRE), Consequence of Risk Events (CoRE), and Risk.[3] SPD staff provide examples of how single-number risk scores lead to systematic errors in reasoning.[4]

SPD staff recommends updates to the following component definitions of LoRE and CoRE in the RDF to better incorporate the use of probability distributions (language additions in *italics*, deletions in ~~strikethrough~~):

- Consequence (or Impact): the effect of the occurrence of a Risk Event. Consequences affect Attributes of a Cost-Benefit Approach *and can be presented in the natural units of the attribute or monetized. Consequence is represented as a probability distribution.*
- Likelihood or Probability: the chance that an event will occur, quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates

[3] SPD Staff Risk Tolerance Proposal at 52 – 54.

[4] *Id*. at 17.

certainty). The higher the Probability of an event, the more certain we are that the event will occur. *Likelihood of an event will be represented in simulation models as a distribution of zeros and ones whose average is the chance that the event will occur.*

- *Probability Distribution: the range and chance that a set of outcomes occurs, as used within datasets and model results.*
- Risk: the potential for the occurrence of an event that would be desirable to avoid, ~~often~~ expressed in terms of a combination of various Outcomes of an adverse event and their associated Probabilities. *Risk is the product of LoRE and CoRE and represented as a probability distribution.*

SPD staff also recommends the following changes to Rows 10, 11, and 13 of the RDF[5] (language additions in *italics*, deletions in ~~strikethrough~~):

10.	Identification of Potential Consequences of Risk Event	The identified potential Consequences of a Risk Event should reflect the unique characteristics of the utility *and will be represented as a probability distribution*. For each enterprise risk, the utility will use actual results, available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data), and/or Subject Matter Experts (SMEs) to identify potential Consequences of the Risk Event, consistent with the Cost-Benefit Approach developed in Step 1A. The utility should use utility-specific data, if available. If data that is specific to the utility is not available, the utility must supplement its analysis with subject matter expertise. Similarly, if data reflecting past results are used, that data must be supplemented by SME judgment that considers the Benefits of any Mitigations that are expected to be implemented prior to the GRC period under review in the RAMP submission. *For each enterprise risk, the utility must explain how they derived the probability distribution for Consequence of a Risk Event.*
11.	Identity of the ~~Frequency~~	The identified ~~Frequency~~ Likelihood of a Risk Event should reflect the unique characteristics of the utility and will be

[5] The most up-to-date RDF can be found as Appendix A of D.24-05-064, currently available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M533/K206/533206241.PDF

	Likelihood of the Risk Event	represented in simulation models as a distribution of zeros and ones. Likelihood of a Risk Event is the average of the distribution of the ones and zeroes. Frequency is the number of risk events over a defined period based on likelihood and can be presented for readability. For each enterprise risk, the utility will use actual results and/or SME input to determine the annual Frequency of the Risk Event. The utility should use utility- specific data, if available. If data that is specific to the utility is not available, the utility must supplement its analysis with subject matter expertise. In addition, if data reflecting past results are used, that data must be supplemented by SME judgment that considers the Benefits of any Mitigations that are expected to be implemented prior to the GRC period under review in the RAMP submission. *For each enterprise risk, the utility must explain how they derived the probability distribution for Likelihood of a Risk Event*. The utility will consider all known relevant Drivers when specifying the ~~Frequency~~ *Likelihood* of a Risk Event. Drivers should reflect current and/or forecasted conditions and may include both external actions as well as characteristics inherent to the asset. For example, where applicable, Drivers may include the presence of corrosion, vegetation, dig-ins, earthquakes, windstorms, or the location of a pipe in an area with a higher likelihood of dig-ins.
13.	Calculation of Risk	For purposes of the Step 3 analysis *for each enterprise risk assessed in the RAMP*, pre- and post-mitigation risk will be calculated by multiplying the *probability distribution representing* Likelihood of a Risk Event (LoRE) by the *probability distribution of* Consequences of a Risk Event (CoRE) *and be represented as a probability distribution*. The CoRE is the sum of each of the ~~Risk-Adjusted~~ Attribute Values *probability distributions monetized* using the utility's full Cost-Benefit Approach.

Second, SPD staff recommends the defining and inclusion of tail risk as a risk measure in the RDF. SPD staff recommends that the measure of tail risk be the average of the tail of the risk distribution above a percentile to be determined

by the Commission in consultation with stakeholders. SPD staff argue that the tail average captures the entire tail of the distribution, is stable, and can be optimized using linear programming or other methods. For these reasons, SPD staff prefers the tail average over other measures.[6] Relatedly, SPD staff recommends adding definitions for Expected Value, Tail Average, and Tail Risk to the RDF and making modifications to Row 5 of the RDF to incorporate Expected Value and tail average into the Cost-Benefit Approach.

Third, SPD staff recommends that risk tolerance should be modeled as an exceedance curve and calculated by applying the risk neutral or risk averse scaling function to a constant risk exceedance curve. SPD staff notes that in the context of the RDF, exceedance curves depict the maximum acceptable Consequence[7] for a given probability of a risk event. SPD staff further notes that after the application of a scaling function to reflect risk attitudes (e.g., risk neutrality, risk aversion, etc.), an exceedance curve is the probabilistic representation of risk tolerance. SPD staff also defines the constant risk exceedance curve as the curve that results in the same Expected Value of Risk for every probability. SPD staff recommends adding definitions for Constant Risk Exceedance Curve and Exceedance Curve to the RDF as well as modifying the definition of Risk Tolerance currently in the RDF. To incorporate Exceedance Curves into the RDF, SPD staff propose the addition of Rows 6.1 and 13.1 to the RDF as well as modifications to Row 7.

[6] *Id*. at 54.

[7] RDF at A-3.

SPD staff's final recommendation related to risk tolerance is to develop a phased process for the establishment of a risk tolerance representing the residents of California. SPD proposes to establish a forum of key stakeholders whose consensus on risk tolerance would represent the residents of California, the California Utility Risk Tolerance Stakeholder (CURTS) Forum. SPD staff proposes developing a timeline for the implementation of a risk tolerance standard, with initial implementation in the SCE 2026 RAMP, PG&E 2028 RAMP, and Sempra 2029 RAMP and utilities determining the interim tolerances. The long-term vision for a risk tolerance process is to transition to other, more complicated frameworks such as As Low As Reasonably Practicable (ALARP) after each utility has completed one GRC cycle. SPD staff recommend the addition of Row 13.2 to the RDF to incorporate a risk tolerance selection process into the RDF. [8]

4.2. MGRA's Risk Tolerance Recommendations

The MGRA Risk Tolerance Proposal focuses on the process around the development of a risk tolerance framework. MGRA does not take a position on the technical portions of the SPD Staff Risk Tolerance Proposal but argues that the process for establishing a risk tolerance framework proposed by SPD staff is impractical and unlikely to achieve the end results SPD staff envisions.[9] MGRA proposes creating a rulemaking specifically to address the topic of risk tolerance or, alternatively, adding an additional track to the present proceeding.

[8] *Id.* at 57 – 58.

[9] MGRA Risk Tolerance Proposal at 2; see also Section 3 of the MGRA Risk Tolerance Proposal.

4.3. Party Comments

Cal Advocates notes that the Commission may consider here whether to: a) forgo adoption of a specific risk tolerance framework at this time and focus instead on assessing the performance of the RDF budget constraint requirements to optimize risk reduction; b) adopt a version of the CURTS Working Group risk tolerance framework; or c) adopt a version of the MGRA Risk Tolerance Proposal. Cal Advocates recommends that, if the Commission adopts a), b), or c), the Commission require the utilities to submit optimized risk mitigation portfolios based only on RDF budget constraints. Cal Advocates also recommends that, beginning with SCE's 2026 RAMP, utilities be required to submit two sets of optimized risk mitigation portfolios, one based on a set of budget constraints and one based on the adopted risk tolerance framework, if applicable. Alternatively, if a risk tolerance framework is not adopted, the second set of optimized risk mitigation portfolios could be based on the utility's own process for assessing risk tolerance.[10]

EPUC/IS is generally supportive of the SPD Staff Risk Tolerance Proposal, though it notes the divergent risk tolerances of the members that would comprise the CURTS Forum and the need for the Commission to determine the allowable Overall Residual Risk levels. [11] As such, EPUC/IS characterizes the CURTS Forum as non-optimal.[12]

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[10] Cal Advocates Opening Comments on Workshop #2 at 10 – 11.

[11] EPUC/IS Opening Comments on Workshop #2 at 21 – 22.

[12] *Id.*

The utilities generally support the MGRA Risk Tolerance Proposal. PG&E supports the MGRA Risk Tolerance Proposal to assign risk tolerance to a separate track of the present proceeding or move it to a successor proceeding. PG&E highlights the importance and impact of a risk tolerance standard, the need for the risk tolerance issue to be adequately scoped at the outset of a successor proceeding, and the due process concerns resulting from the quick pace of the Phase 4 timeline that would be ameliorated by moving risk tolerance to a separate track or successor proceeding. PG&E also highlights the need to incorporate the experience and expertise of other industries and agencies, including the Federal Energy Regulatory Commission (FERC); U.S. Army Corps of Engineers (for Dam and Levee Safety); U.S. Department of Defense; U.S. Nuclear Regulatory Commission (NRC); U.K. Health and Safety Executive (HSE); aviation; construction; healthcare; oil and gas; and chemical process safety.[13] SCE supports the timeline and approach of the MGRA Risk Tolerance Proposal, namely, moving the risk tolerance issue to a separate proceeding, given its complexity and importance.[14] Like PG&E and SCE, the Sempra Companies recommend a process and schedule consistent with the MGRA Risk Tolerance Proposal.[15] All of the utilities argue that the schedule for Phase 4 is too short relative to the import of the issues in Phase 4.[16]

[13] PG&E Opening Comments on Workshop #2 at 11.

[14] SCE Opening Comments on Workshop #2 at 5.

[15] Sempra Companies Opening Comments on Workshop #2 at 4.

[16] PG&E Opening Comments on Workshop #2 at 6 – 8; SCE Opening Comments on Workshop #2 at 5 – 7; Sempra Companies Opening Comments on Workshop #2 at 4 – 5.

In comments, MGRA provides context to its risk tolerance proposal and how it differs from the SPD Staff Risk Tolerance Proposal. MGRA notes again that it does not address the technical merits of the SPD Staff Risk Tolerance Proposal.[17]

TURN opposes addressing risk tolerance at all, either in Phase 4 of the present proceeding or in a successor proceeding, as it believes that the other proposed changes to the RDF of tracking overall residual risk over time and portfolio optimization can better achieve the goals of a risk tolerance framework.[18]

Regarding SPD Staff's first recommendation on the use of probability distributions in the RDF, parties are generally supportive of using probability distributions in the RDF where feasible but not making it a requirement. TURN supports representing CoRE as a probability distribution but argues that LoRE cannot and should not be represented by a probability distribution because it conceptually makes no sense to discuss the probability of a probability. TURN is also opposed to the language modifications proposed by SPD staff to Row 11 of the RDF because it mistakenly implies the necessity of one potential computation method, simulation, for how Likelihood is calculated. Similarly, TURN objects to requiring Risk to be represented by a probability distribution as, they argue, Risk is a single number that is the product of the LoRE and the expected value of the

[17] MGRA Opening Comments on Workshop #2 at 1 – 3.

[18] TURN Opening Comments on Workshop #2 at 2.

probability distribution of the CoRE.[19] TURN proposes a definition for Probability Distribution, namely, that a probability distribution is the assignment of a probability to each of the possible events that can occur as the outcome of an uncertain situation.[20] MGRA supports the incorporation of probability distributions where they are available, reliable, and useful. As such, MGRA appears to be opposed to requiring their use in the way proposed by SPD staff. [21] PG&E opposes the required use of probability distributions in the RDF, noting that existing guidance in the RDF on how to model CoRE is sufficient and that the changes to LoRE's definition proposed by SPD staff is mathematically incorrect.[22] The Sempra Companies note that in most cases it is beneficial to use distributions for CoRE and in some cases may be computationally feasible for LoRE. [23] SCE does not see the need for the required use of probability distributions, preferring instead a flexible approach, but notes that there are certain cases in which probability distributions can illuminate the expected value and tail value for CoRE.[24] EPUC/IS supports the required use of probability distributions for LoRE, CoRE, and Risk wherever feasible. EPUC/IS notes that there was much less contention in Workshop #2 regarding the use of probability

[19] *Id*. at 38 – 40.

[20] *Id*. at 2.

[21] MGRA Opening Comments on Workshop #2 at 4 – 5.

[22] PG&E Opening Comments on Workshop #2 at 37 – 38.

[23] Sempra Companies Opening Comments on Workshop #2 at 14 – 16.

[24] SCE Opening Comments on Workshop #2 at 21.

distributions for representing CoRE.[25] Cal Advocates provides no position on the required use of probability distributions in the RDF.

There is near universal opposition to the CURTS Working Group and Forum proposed by SPD staff, with TURN, MGRA, PG&E, Sempra Companies, SCE, and EPUC/IS being opposed and Cal Advocates providing no position. The reasons given for opposing the CURTS Working Group include concerns about the proposed participants in the CURTS Working Group[26], their inability to sufficiently represent the interests of Californians[27], the inability of the CURTS Working Group to come to a consensus because of divergent opinions[28], and the CURTS Working Group being generally ill-defined, ill-conceived, or impractical[29].

Parties are split on the question of whether to incorporate exceedance curves into the RDF, though some parties provide no position[30] on this SPD staff recommendation. PG&E strongly opposes the use of constant risk exceedance curves and argues that they are ill-conceived, serve no practical purpose, and

[25] EPUC/IS Opening Comments on Workshop #2 at 13 – 14.

[26] MGRA Opening Comments on Workshop #2 at 2 – 3; TURN Opening Comments on Workshop #2 at 14.

[27] TURN Opening Comments on Workshop #2 at 15; EPUC/IS Opening Comments on Workshop #2 at 21.

[28] TURN Opening Comments on Workshop #2 at 15 – 16; MGRA Reply Comments on Workshop #2 at 10.

[29] Sempra Companies Opening Comments on Workshop #2 at 9 – 10; PG&E Opening Comments at 8 – 9; SCE Opening Comments on Workshop #2 at 25.

[30] MGRA, Cal Advocates, and SCE.

cause harm by allowing tolerance of events with large tail risks.[31] TURN also opposes the use of exceedance curves and argues that they are complex, opaque, and manipulable by the utilities, noting that SPD staff does not explain the mechanics of how the exceedance curves would be derived.[32] EPUC/IS supports the use of exceedance curves but provides little rationale as to why.[33]

Support for SPD staff's recommendation on the use of tail risk average in the RDF is unclear, with TURN and PG&E opposing this recommendation, [34] EPUC/IS supporting it,[35] and MGRA, the Sempra Companies, and SCE seeming to neither support nor oppose the recommendation.[36] TURN argues that SPD staff overstates the usefulness of the concept of tail risk for the RDF and that tail risk only considers a small portion of the probability distribution of CoRE while the expected value considers the full probability distribution.[37]

4.4. Discussion

Risk tolerance and its cognate ideas are an important component in the continued development of the RDF, as evidenced by the depth and breadth of engagement by parties on this topic. However, several issues related to the

[31] PG&E Opening Comments on Workshop #2 at 12 – 20.

[32] TURN Opening Comments on Workshop #2 at 20 – 22.

[33] EPUC/IS Opening Comments on Workshop #2 at 3.

[34] TURN Opening Comments on Workshop #2 at 40 – 42; PG&E Opening Comments on Workshop #2 at 12 – 20.

[35] EPUC/IS Opening Comments on Workshop #2 at 16 – 17.

[36] MGRA Opening Comments on Workshop #2 at 5 – 7; Sempra Companies Opening Comments on Workshop #2 at 15 – 16; SCE Opening Comments on Workshop #2 at 23 – 24.

[37] TURN Opening Comments on Workshop #2 at 40 – 41.

incorporation of risk tolerance into the RDF, both practical and substantive, are in need of further development and refinement. We are persuaded that risk tolerance should be saved for a successor proceeding, with the exception of representing CoRE as a probability distribution, which we adopt here. We also order the utilities to jointly draft a survey report on approaches to risk tolerance in related industries and serve it on the service list of this proceeding. The survey report shall include the following information: whether a regulator sets the baseline risk tolerance, or, if not or if only partially, how industries or private companies set, implement, and modify risk tolerance thresholds. The survey report shall include, but is not limited to, the following industries: aviation, chemical, mining, oil and gas, nuclear, autonomous vehicles, spaceflight, investor-owned utilities in other jurisdictions, and large California investor-owned electric and/or gas utilities. For the section on large California investor-owned electric and/or gas utilities, the utilities shall include a description of the status quo, explaining the internal process of how each company currently sets the amount of risk they accept in safety, operations, and decision-making.

We agree that representing CoRE as a probability distribution is beneficial in most cases, as noted by the Sempra Companies. Requiring the representation of CoRE as a probability distribution is relatively uncontroversial and provides the Commission with additional, useful information in assessing RAMP filings. We adopt here (language additions in *italics*, deletions in ~~strikethrough~~):

- SPD staff's recommended changes to Row 10 of the RDF:

10.	Identification of Potential	The identified potential Consequences of a Risk Event should reflect the unique characteristics of the utility *and will be*

	Consequences of Risk Event	*represented as a probability distribution, from which an expected value or tail risk value can be calculated*. For each enterprise risk, the utility will use actual results, available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data), and/or Subject Matter Experts (SMEs) to identify potential Consequences of the Risk Event, consistent with the Cost-Benefit Approach developed in Step 1A. The utility should use utility-specific data, if available. If data that is specific to the utility is not available, the utility must supplement its analysis with subject matter expertise. Similarly, if data reflecting past results are used, that data must be supplemented by SME judgment that considers the Benefits of any Mitigations that are expected to be implemented prior to the GRC period under review in the RAMP* submission. *For each enterprise risk, the utility must explain how it derived the probability distribution for Consequence of a Risk Event.*

- SPD staff's recommended modifications to the definitions of Consequence and Risk in the RDF:
- Consequence (or Impact): The effect of the occurrence of a Risk Event. Consequences affect Attributes of a Cost-Benefit Approach *and can be presented in the natural units of the Attribute and monetized. Consequence is represented as a probability distribution, from which an expected value or tail risk value can be calculated. The probability distribution of the CoRE is the probability distribution of the sum of the monetized Attributes.*
- Risk: The potential for the occurrence of an event that would be desirable to avoid, ~~often~~ expressed in terms of a combination of various Outcomes of an adverse event and their associated Probabilities. *Risk is the product of LoRE and CoRE and represented as a probability distribution, from which an expected value or tail risk value can be calculated.*
- The following definition for Probability Distribution provided by TURN for the RDF: *The assignment of a*

probability to each of the possible events that can occur as the outcome of an uncertain situation.

- The following modifications to Row 13 of the RDF:

13.	Calculation of Risk	For the purposes of the Step 3 analysis *for each enterprise risk assessed in the RAMP*, pre- and post-mitigation risk will be calculated by multiplying the Likelihood of a Risk Event (LoRE) by the *probability distribution of* Consequences of a Risk Event (CoRE) *and be represented as a probability distribution, from which an expected value or tail risk value can be calcuated*. The CoRE is the sum of each of the ~~Risk-Adjusted~~ Attribute Values' *probability distributions monetized* using the utility's full Cost-Benefit Approach.

We do not at this time adopt any of the other recommended changes to the RDF related to risk tolerance.

5. Overall Residual Risk Reporting

The concept of 'residual risk' provides a tool to answer the question: how much risk on the utility system remains in a GRC or RAMP filing? Within RAMP and GRC filings, the utilities develop mitigation programs based on the estimated GRC Test Year Baseline Risk. The amount of risk remaining after implementing the mitigation programs authorized by a GRC decision that reduces the GRC Test Year Baseline Risk is the residual risk but only within the scope of that GRC application. Currently, the RDF does not require the utilities to report on the overall residual risk associated with each enterprise risk submitted in a RAMP or GRC filing. To better contextualize the proposed safety investments in RAMPs and GRCs, and to better understand utility progress made on risk reduction over time, the Commission must be able to track overall

residual risk for each enterprise risk and include the historical progress of risk reduction for every RAMP cycle to date.

In this context, the SPD Staff Risk Tolerance Proposal argues that overall residual risk can be presented in easily understandable graphs and spreadsheet tables. SPD staff provides the example graph below (Figure 1) showing hypothetical overall residual risk remaining after mitigations.

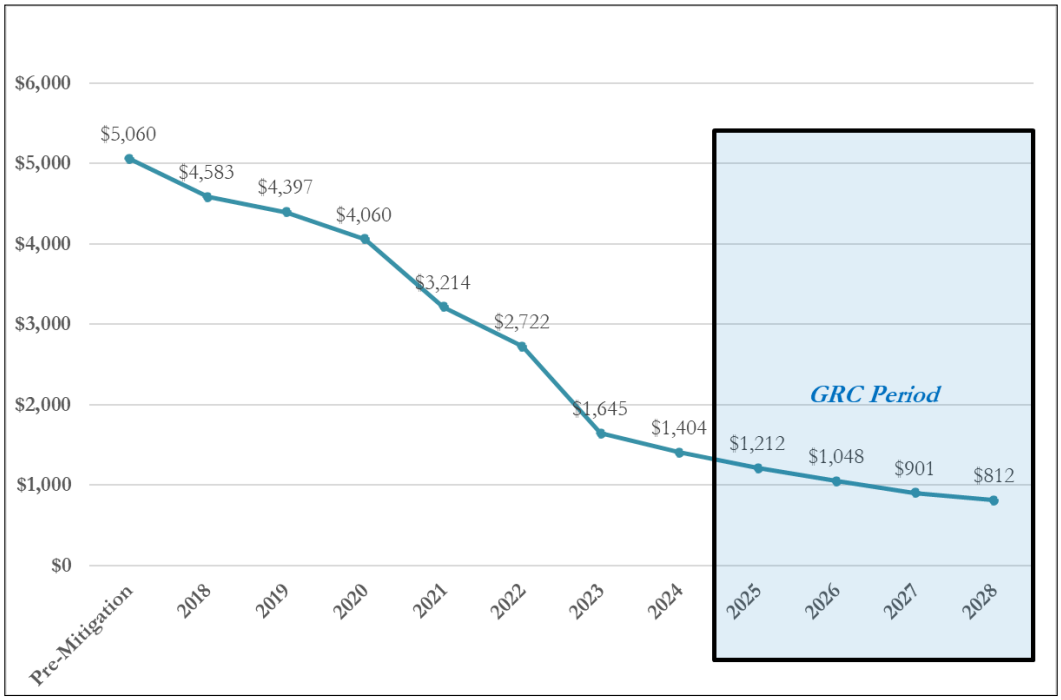

Figure 1. Hypothetical Overall Residual Risk Remaining After Mitigations [38]

SPD staff envisions that the Commission require the utilities to submit similar diagrams and spreadsheet tables for every risk included with each RAMP and GRC filing.[39] SPD staff recommend that the Commission require the utilities to report on their progress of reducing overall residual risk for each enterprise

[38] SPD Staff Risk Tolerance Proposal at 9.

[39] *Id*.

risk addressed in a RAMP or GRC filing. SPD staff recommends that the first time a utility presents its progress of reducing overall residual risk, it should include a narrative section that describes the level of overall residual risk between January 1, 2006, and the time it filed its first RAMP, and the total amount of money spent on mitigation investments between January 1, 2006, and the time if filed its first RAMP. SPD staff recommends updates to, or additions of, the following definitions in the RDF to better incorporate the concept of overall residual risk (language additions in *italics*, deletions in ~~strikethrough~~):

- *Overall Residual Risk: all the risk on the utility's assets or systems after taking account of the historical progress of risk reduction since the utility's first RAMP filing.*
- Residual Risk: Risk remaining after application of Mitigations, including Mitigations classified as Controls *for a given GRC cycle*.

SPD staff also recommend the following updates to Row 9 of the RDF (language additions in *italics*):

9.	Risk Assessment	Using the Cost-Benefit Approach developed in accordance with Step 1A, for each Risk included in the Enterprise Risk Register, the utility will compute a monetized Safety Risk Value using only the Safety Attribute. The utility will sort its ERR Risks in descending order by the monetized Safety Risk Value. For the top 40% of ERR risks with a Safety Risk Value greater than zero dollars, the utility will compute a monetized Risk Value using at least the Safety, Reliability and Financial Attributes to determine the output for Step 2A. The output of Step 2A, along with the input from stakeholders described in Row 12 below, will be used to decide which risks will be addressed in the RAMP. *The output of Step 2A must include a calculation of Overall Residual Risk, along with a diagram and supporting workpapers*

		demonstrating the change of Overall Residual Risk since the utility's first RAMP filing. The Risk Assessment in preparation for RAMP will follow the steps in Rows 10 and 11.

5.1. Party Comments

Parties are split on SPD staff's recommendations regarding overall residual risk, with the utilities questioning the usefulness of the overall residual risk diagrams and workpapers and intervenor parties supporting SPD staff's overall residual risk recommendations.

PG&E argues that, while it is not opposed to showing diagrams and workpapers of the overall residual risk trend, these may not be needed nor able to answer the questions SPD staff raise. On the former, PG&E states that historical graphs are not needed to show how close a utility is to achieving an acceptable amount of risk on its assets and systems. The only information needed is the current risk value and the risk tolerance target. On the latter, PG&E states that the diagrams proposed by SPD staff are deficient as a direct outcome of the foundational weakness of the Staff Risk Tolerance Proposal.[40]

The Sempra Companies argue that it is difficult, if not impossible, to measure overall residual risk in absolute terms because the Commission has never measured risk in absolute terms in the RDF. The Sempra Companies raise the issue that overall residual risk diagrams and workpapers may be contingent on the availability of data and subject-matter inputs based on hypotheticals of

[40] PG&E Opening Comments on Workshop #2 at 34 – 35.

what risk events could have occurred, yielding conjectural, low-fidelity, and potentially misleading results.[41]

SCE argues that no part of the Staff Risk Tolerance Proposal should be adopted by the Commission, including changes related to overall residual risk, but should instead be addressed in a successor proceeding or separate track of the present proceeding as suggested in the MGRA Risk Tolerance Proposal. SCE argues that any backcast would be extremely hypothetical and accompanied by a high degree of uncertainty.[42]

TURN supports SPD staff's recommendations on overall residual risk. In particular, TURN notes that utilities do not present the progress made in reducing risk in their GRCs and that graphs and charts of the trajectory of residual risk put utility spending requests for risk reduction in perspective.[43] TURN recommends reporting overall residual risk in both dollars and natural units and for each enterprise risk.[44]

Cal Advocates states that ratepayer risk diagrams and workpapers would be useful to help assess and compare past performance and effectiveness of risk mitigation programs compared to forecasts.[45]

MGRA states that the addition of a definition for overall residual risk to the RDF would be beneficial but recommends that any changes to the definitions

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[41] Sempra Companies Opening Comments on Workshop #2 at 11 – 12.

[42] SCE Opening Comments on Workshop #2 at 16 – 19.

[43] TURN Opening Comments on Workshop #2 at 5.

[44] *Id.* at 6 – 7.

[45] Cal Advocates Opening Comments on Workshop #2 at 9.

or lexicon of the RDF be saved for a successor proceeding or separate track of the present proceeding such as that recommended in the MGRA Risk Tolerance Proposal.[46]

EPUC/IS supports SPD staff's recommendation to require utilities to present diagrams and work papers of the trend of overall residual risk for each risk event as well as the addition of the definition of overall residual risk to the RDF. EPUC/IS recommends that overall residual risk be reported both in natural units and dollars and that the diagrams show both actual and forecasted risk reductions and allow for independent verification of graphical data.[47]

5.2. Discussion

While the broader issue of a risk tolerance standard is saved for a future proceeding, we are persuaded that an accounting and presentation of overall residual risk is a useful development in the RDF. Though opposed by PG&E and the Sempra Companies on the grounds that an accounting and presentation of overall residual risk is unnecessary or conjectural, Cal Advocates, EPUC/IS, and TURN persuasively argue that the presentation of overall residual risk will allow the Commission and stakeholders to take stock of the progress to date in reducing risk, albeit, as argued by SCE and the Sempra Companies, with uncertainty around backcasted values. As such, we add the following definition of overall residual risk to the RDF and modify the definition of residual risk to further distinguish the two concepts (language additions in *italics*):

[46] MGRA Opening Comments at 3.

[47] EPUC/IS Opening Comments on Workshop #2 at 9 – 10.

- *Overall Residual Risk: All the risk on the utility's assets or systems for a given enterprise risk presented in the RAMP filing after taking account of the historical progress of risk reduction since the utility's first RAMP filing.*
- Residual Risk: Risk remaining after application of Mitigations, including Mitigations classified as Controls *for a given GRC cycle*.

Additionally, we modify Rows 9 and 26 of the RDF as follows (language additions in *italics*):

9.	Risk Assessment	Using the Cost-Benefit Approach developed in accordance with Step 1A, for each Risk included in the Enterprise Risk Register, the utility will compute a monetized Safety Risk Value using only the Safety Attribute. The utility will sort its ERR Risks in descending order by the monetized Safety Risk Value. For the top 40% of ERR risks with a Safety Risk Value greater than zero dollars, the utility will compute a monetized Risk Value using at least the Safety, Reliability and Financial Attributes to determine the output for Step 2A. The output of Step 2A, along with the input from stakeholders described in Row 12 below, will be used to decide which risks will be addressed in the RAMP. *The output of Step 2A must include a calculation of Overall Residual Risk for a given risk presented in the RAMP filing, along with a diagram and supporting workpapers demonstrating the change of Overall Residual Risk since the utility's first RAMP filing. Diagrams and supporting workpapers must also include a disaggregation of the Overall Residual Risk values based on the Consequence Attributes, both in natural units and dollar values, as well as display the Likelihood of those Consequence Attributes.* The Risk Assessment in preparation for RAMP will follow the steps in Rows 10 and 11.
26.	Mitigation Strategy Presentation in the RAMP and GRC	The utility's RAMP filing will provide a ranking of all RAMP Mitigation by ~~Cost~~ Benefit-*Cost* ~~r~~*R*atios.

		In the GRC, the utility will provide a ranking of Mitigations by ~~Cost~~-Benefit-*Cost* Ratios, as follows: (1) For Mitigations addressed in the RAMP, the utility will use risk reduction estimates, including any updates, and updated costs to calculate ~~Cost~~-Benefit-*Cost* Ratios and explain any differences from its RAMP filing; (2) For Mitigations that require Step 3 analysis under and consistent with Row 28, the utility will include the ~~Cost~~-Benefit-*Cost* Ratios, calculated in accordance with Step 3, in the ranking of Mitigations by ~~Cost~~-Benefit-*Cost* Ratios. *In the GRC, the utility will provide an update of the calculations of Overall Residual Risk and associated diagrams and workpapers previously provided in the RAMP in accordance with Row 9.* In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigations for each risk and for its selection of its overall portfolio of Mitigations. The utility is not bound to select its Mitigation strategy based solely on the ~~Cost~~-Benefit-*Cost* Ratios produced by the Cost-Benefit Approach. Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In GRC, the utility will explain whether and how any such factors affected the utility's Mitigation selections. GRC Post-Test Year Reporting: All Controls and Mitigation programs must include *Benefit-Cost Ratios* in each of the GRC post-test years as well as aggregate *Benefit-Cost Ratios* for the entire post-test year period and the entire GRC period, by Tranche.

6. Mitigation Portfolio Optimization

Another topic closely related to risk tolerance is optimizing portfolios of mitigations. Currently, the RDF requires ranking of mitigations based on the Benefit-Cost Ratio (BCR), which can lead to optimal decisions if the mitigations are independent in their effectiveness (i.e., mutually exclusive). However, mitigations are often interrelated and may be synergistic, where they work together to decrease the amount of risk, or provide diminishing returns, in which mitigations together reduce risk but as investment in one increases, the need for the other mitigation is reduced. The solution that SPD staff proposes to evaluate interrelated mitigations is to construct portfolios of mitigations that can be compared and ranked.[48]

SPD staff shows how BCRs are helpful in ranking mitigations or portfolios by cost-effectiveness and how this is different from minimizing overall residual risk within affordability constraints. That is, a portfolio could have a high BCR but provide a small risk reduction, which would mean it is ranked highly for BCR but does not greatly reduce overall residual risk. If one is optimizing on cost-effectiveness (i.e., maximizing BCR), the selected portfolios will not necessarily minimize overall residual risk.[49] SPD staff proposes applying Markowitz's efficient frontier of optimal portfolios in the context of mitigation portfolio selection.[50] Additionally, SPD staff show how efficient frontiers can be

[48] SPD Staff Risk Tolerance Proposal at 27.

[49] *Id*. at 29.

[50] *Id*. at 30.

used to optimize in multiple dimensions and uses an example herringbone diagram to demonstrate how trade-offs can be visualized in three dimensions, in this case, safety, reliability, and budget.[51]

SPD staff makes two recommendations regarding mitigation portfolio optimization. First, SPD staff recommends that evaluations be based on portfolios of mitigations to account for the interrelationships between mitigations, as described above. To incorporate the use of portfolios of mitigations into the RDF, SPD proposes adding the following definitions to the RDF (additions in *italics*):

- *Mitigation Portfolio: a collection of one or more risk mitigations with a specified budget constraint for reducing the risk of a given enterprise risk. Costs, benefits, and benefit-cost ratios can be calculated for each portfolio, and portfolios can be compared to one another.*
- *Mitigation Group: the combining of two or more mitigations that exhibit either synergy, meaning the mitigations result in mutually reinforcing risk reduction efficiency, or diminishing returns, meaning as one mitigation reduces risk it limits the efficiency of the other mitigation to reduce risk.*

Additionally, SPD staff recommends the following changes to the RDF related to portfolios of mitigations (additions in *italics*, deletions in ~~strikethrough~~:

25.1	*Portfolios of Risk Mitigations*	*Utilities must construct portfolios of risk mitigations for each Risk as identified in Row 8 with a specified budget constraint. Mitigations in each portfolio should account for interrelationships between them, such as mutual exclusivity, synergies, and diminishing returns.* • *Mutually exclusive mitigations must be avoided, only one or the other can exist in the same portfolio.*

[51] *Id*. at 34.

		• *Synergies and diminishing returns can be captured by combining two or more mitigations, called a mitigation group. Synergies or diminishing returns can be calculated for the mitigation group.* *For example, a wildfire mitigation portfolio could include for a given circuit segment: covered conductor as mitigation, vegetation management as a mitigation, or covered conductor with vegetation management as a mitigation—but not covered conductor and vegetation management as separate mitigations since their benefits are not additive (re: may exhibit diminishing returns*).
26	Mitigation Strategy Presentation in the RAMP and GRC	The utility's RAMP filing will provide a ranking of all RAMP Mitigation by ~~Cost~~ Benefit-*Cost* ~~r~~Ratios. *Additionally, the utility must present a set of optimal portfolios for reducing each enterprise risk. Mitigation Groups defined in Row 25.1 can also be ranked within each portfolio. The utility must justify the portfolio selection, optimization, budget constraint, and structure of Mitigation Groups.* In the GRC, the utility will provide a ranking of Mitigations by ~~Cost~~ Benefit-*Cost* Ratios, as follows: (1) For Mitigations addressed in the RAMP, the utility will use risk reduction estimates, including any updates, and updated costs to calculate ~~Cost~~ Benefit-*Cost* Ratios and explain any differences from its RAMP filing; (2) For Mitigations that require Step 3 analysis under and consistent with Row 28, the utility will include the ~~Cost~~ Benefit-*Cost* Ratios, calculated in accordance with Step 3, in the ranking of Mitigations by ~~Cost~~ Benefit-*Cost* Ratios. *In the GRC, the utility will provide an updated presentation of a set of optimal portfolios for reducing each enterprise risk if an update is necessary. Any differences in the set of optimal portfolios from the RAMP filing must be clearly explained by the utility in its GRC filing.*

		In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigations for each *enterprise* risk and for its selection *and optimization* of its ~~overall~~ portfolio of Mitigations *for each enterprise risk. The utility must explain how the budget constraint and other constraints factored into the utility's portfolio selection.* ~~The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach.~~ Mitigation selection *and Mitigation Portfolio optimization* can be influenced by *Benefit-Cost Ratios and* other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In *the RAMP and* GRC, the utility will explain whether and how any such factors affected the utility's Mitigation selections. *In the RAMP and GRC, the utility must also implement and justify a transparent and systematic way to integrate these other factors into the optimization of its Mitigation Portfolios.* GRC Post-Test Year Reporting: All Controls and Mitigation programs must include *Benefit-Cost Ratios* in each of the GRC post-test years as well as aggregate *Benefit-Cost Ratios* for the entire post-test year period and the entire GRC period, by Tranche.

Second, SPD staff recommend that portfolio selection be based on simple optimization instead of ranking and note that optimization can be a complex, computationally intensive, and time-consuming process. In particular, SPD staff recommends the use of stochastic optimization using entire probability distributions, the use of efficient frontiers to enable trade-off and alternatives analysis, and the use of both an average overall residual risk minimization and a

tail average overall residual risk minimization scenario. SPD staff does not recommend any additional text changes to the RDF for this recommendation.

6.1. Party Comments

Parties are split on the question of whether the utilities should be required to construct optimized portfolios of risk mitigations, with the utilities generally being opposed and intervenor parties generally being supportive.

PG&E is opposed to requiring the utilities to construct optimized portfolios of risk mitigations on the grounds that the theoretical foundation supporting SPD's mitigation portfolio optimization recommendation, Markowitz's Portfolio Optimization, is misapplied because SPD's portrayal of Markowitz's work is inaccurate. PG&E argues that, because the Staff Risk Tolerance Proposal does not appear to be based on any decision-theoretic foundation, it is an incomplete framework that does nothing more than trade off expected benefits against costs without any consideration of risk, such as standard deviation or tail average.[52] PG&E also argues that there are practical difficulties with implementing an optimization approach similar to Markowitz's Portfolio Optimization because portfolio selection in finance is a continuous problem, whereas mitigations are a discrete problem (i.e., it does not make sense to include fractions of a mitigation to optimize a portfolio of mitigations as would be the case in a continuous problem). PG&E notes that discrete

[52] PG&E Opening Comments on Workshop #2 at 22 – 24.

optimization problems are considerably more computationally intensive than continuous optimization problems. [53]

SCE opposes a requirement for the utilities to present a set of optimal portfolios for reducing overall residual risk of each risk event addressed in a RAMP or GRC filing. SCE argues that each of its RAMP filings includes three mitigation portfolios, SCE's preferred portfolio of mitigations and two separate and realistic alternative portfolios of mitigations. As such, SCE argues that additional requirements are not necessary. SCE also recommends removing the word "optimal" from the Staff Risk Tolerance Proposal since different parties will have differing views on what constitutes an "optimal" portfolio.[54]

The Sempra Companies are opposed to requiring the utilities to construct portfolios of safety risk mitigations and note the differences between safety risk mitigations and financial markets, particularly that different aspects of risk impacting safety are not fungible. The Sempra Companies argue that what they currently do is effectively construct portfolios of risk mitigations but where each mitigation addresses different aspects of risk impacting safety. They also note that activities mandated by law or regulation provide less optionality than found in financial markets. The Sempra Companies additionally argue that utility risk data is less frequent and less granular than financial data, making it challenging to directly apply financial analysis techniques.[55]

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[53] *Id*. at 25 – 26.

[54] SCE Opening Comments on Workshop #2 at 31.

[55] Sempra Companies Opening Comments on Workshop #2 at 18 – 19.

Cal Advocates recommends utilities be required to submit optimized risk mitigation portfolios based solely on RDF budget constraints.[56]

TURN supports most aspects of SPD staff's recommendation requiring utilities to present budget-constrained, optimized portfolios of mitigations. TURN notes that the output of a budget-constrained optimization process would be a set of portfolios optimized to provide the maximum residual risk reduction for each required budget constraint. That is, the objective function of the optimization process is to minimize residual risk given budget constraints chosen by the Commission with the decision variable being whether or not a given mitigation is included in a portfolio of mitigations for implementation. TURN also notes that the relationship between risk reduction and budget level can be graphed to support decision-makers' reasoning about the trade-off between residual risk reduction and budget level. TURN reiterates its position that budget-constrained optimization is a practical and preferred alternative to SPD staff's risk tolerance proposal because it allows the Commission and parties to see the impact of different budget choices on achievable risk reduction while still focusing on the key determinants of risk tolerance.[57] In its reply comments on Workshop #2, TURN provides a heuristic approach to optimization in which optimized portfolios can be approximated. In this approach, the utility would first identify all mandatory programs and include those in all candidate portfolios. Then the utility would rank all discretionary programs by BCR at the

[56] Cal Advocates Opening Comments on Workshop #2 at 10 – 11.

[57] TURN Opening Comments on Workshop #2 at 28 – 29.

tranche level. Starting with the highest ranked discretionary tranche-based programs, discretionary tranche-based programs would be added to the portfolio until the budget constraint is reached.[58]

EPUC/IS supports SPD staff's recommendations to require the utilities to construct portfolios of risk mitigations for each risk event addressed in a RAMP or GRC filing. EPUC/IS recommends that the portfolios be evaluated and compared assuming a suite of budget constraints, for example, a range of percentage changes from the utility's current non-fuel GRC revenue requirement.[59]

MGRA provides no comment on mitigation portfolios and optimization other than to note their technical nature and recommend that they be reserved for future development.[60]

6.2. Discussion

We are persuaded that an optimization framework for mitigation portfolios is a worthwhile endeavor that will help the Commission reason about the relationship between risk reduction and mitigation spending. SCE argues that the mitigation portfolios currently required in RAMPs are sufficient. We disagree, as these portfolios are not produced through any optimizing criteria. While we agree with PG&E that Markowitz's Portfolio Optimization is not directly, literally applicable to mitigation portfolios, it does provide a helpful

[58] TURN Reply Comments on Workshop #2 at 8.

[59] EPUC/IS Opening Comments on Workshop #2 at 26 – 28.

[60] MGRA Opening Comments on Workshop #2 at 9.

heuristic for reasoning about mitigation portfolios. Similarly, we agree with the Sempra Companies that directly applying financial analysis techniques to utility risk data can be challenging. However, we are not persuaded that these techniques are necessary for mitigation portfolio optimization. TURN provides a compelling description of an optimization model where the objective function (i.e., the value to be maximized) is risk reduction, the constraint is a given budget level in dollars, and the decision variable (i.e., the value that is selected by the optimization algorithm to maximize the objective function) is whether a given mitigation is included in the portfolio or not. We adopt this approach here.

Instead of selecting a single budget level, we opt instead for several budget scenarios as suggested by TURN and EPUC/IS. By setting the constraint in the optimization model described above at each of the budget scenario values, a visual can be produced that shows the maximum possible risk reduction for each budget scenario, with each budget scenario having a corresponding optimal mitigation portfolio that produces that optimal risk reduction. These budget scenarios will be based on the forecasted costs of Mitigations and Controls that the utility has proposed in its RAMP or current GRC. We call these forecasted costs the Baseline Cost Forecast. The four required budget scenarios are: 1) 85% of the Baseline Cost Forecast, 2) 90% of the Baseline Cost Forecast, 3) 95% of the Baseline Cost Forecast, and 4) 100% of the Baseline Cost Forecast.

To provide clarity and support the implementation of budget scenario-informed mitigation portfolio optimization, we add the following definitions to the RDF developed in response to party comments on Workshop #2 (additions in *italics*):

- *Baseline Cost Forecast: An estimate of the expenditures for all RAMP-related Mitigation and Control Programs for which an IOU is seeking approval and/or funding in its RAMP or current GRC application. The Baseline Forecast is used to estimate the Budget Scenario for the Enterprise Portfolios.*
- *Budget Scenario: A scenario of expenditures for RAMP-related Mitigation and Control Programs to be used for portfolio optimization.*
- *Enterprise Portfolio: A collection of activities within a specified Budget Scenario reflecting all of the RAMP-related Mitigation and Control Programs to be funded in the utility's General Rate Case. The Enterprise Portfolio will include a Risk Mitigation Portfolio for every Enterprise Risk presented in a RAMP. Costs, Benefits, and Benefit-Cost Ratios can be calculated for each Enterprise Portfolio created for a Budget Scenario sensitivity analysis, and Enterprise Portfolios can be compared to one another.*
- *Risk Mitigation Portfolio: A collection of one or more risk Mitigations/Control Programs with a specified Budget Scenario for reducing the risk of a given enterprise risk. Costs, Benefits, and Benefit-Cost Ratios can be calculated for each Risk Mitigation Portfolio created for a Budget Scenario sensitivity analysis, and Risk Mitigation Portfolios can be compared to one another.*
- *Optimized (Enterprise or Risk Mitigation) Portfolio: A portfolio that is optimized using an optimization model where the objective to be maximized is risk reduction, the constraint is a given budget level in dollars, and the decision variable (i.e., what is selected by the optimization algorithm to maximize the objective function) is whether a given mitigation is included in the portfolio or not.*

Additionally, the following changes are made to the RDF (additions in *italics* and deletions in ~~strikethrough~~):

25.1	*Optimized Enterprise Portfolio*	*The utility will construct four Optimized Enterprise Portfolios with differing Budget Scenarios. The Budget Scenario for the Enterprise Portfolios will be based on the Baseline Cost Forecast. The specified four Budget Scenarios will be based on the Baseline Cost Forecast according to the following structure:* *Scenario 1: eighty-five percent of the Baseline Cost Forecast,* *Scenario 2: ninety percent of the Baseline Cost Forecast,* *Scenario 3: ninety-five percent of the Baseline Cost Forecast and,* *Scenario 4: the Baseline Cost Forecast.* *Optimized Enterprise Portfolios shall show the Risk Mitigation Portfolios that result for each enterprise risk presented in the RAMP based on the enterprise-level optimization.* *Optimized Enterprise Portfolios shall account for the interrelationships among mitigations and controls, as described in Row 25.2.*
25.2	*Optimized Risk Mitigations Portfolios*	*In addition to the Optimized Enterprise Portfolios required by Row 25.1, utilities may construct Optimized Risk Mitigation Portfolios for each Risk as identified in Row 8 with a specified Budget Scenario based on a different allocation of costs among risks than result under the corresponding Optimized Enterprise Portfolio. For each of Scenarios 1 through 4 in Row 25.1, the Budget Scenario for each Optimized Risk Mitigation Portfolio will be some proportion chosen by the utility of the Enterprise Portfolio Budget Scenario. The utility shall justify why the proportion of the Enterprise Portfolio Budget Scenario was chosen for each Optimized Risk Mitigation Portfolio.* *Mitigations and Controls in each Optimized Risk Mitigation Portfolio shall account for interrelationships between them, such as mutual exclusivity, synergies, and diminishing returns. Mutually exclusive Mitigations and Controls must be avoided, only one or the other can address the same asset or system that exhibits risk in the same portfolio.* *Synergies and diminishing returns can be captured by combining two or more mitigations to address risk on a given asset or system, called a Mitigation Group. Synergies or diminishing returns can be calculated for the Mitigation Group.*

		For example, a wildfire mitigation portfolio could include for a given circuit segment: covered conductor as a mitigation, vegetation management as a mitigation, or covered conductor with vegetation management as a mitigation—but not covered conductor and vegetation management as separate mitigations since their benefits are not additive (re: may exhibit diminishing returns).
26	*Portfolio and* Mitigation Strategy Presentation in the RAMP and GRC	The utility's RAMP filing will provide a ranking of all RAMP Mitigations *and Control Programs* by ~~Cost-~~Benefit-*Cost* ~~r~~Ratios. *The utility's RAMP filing will include a dataset of Risk Reporting Units for each Mitigation and Control Program and rank each Risk Reporting Unit by Benefit-Cost Ratio. Additionally, the utility must present the set of Optimized Enterprise Portfolios required by Row 25.1 and may present an alternative set of Optimized Risk Mitigation Portfolios within each Enterprise Portfolio in accordance with Row 25.2. Mitigation/Control Groups defined in Row 25.2 can also be ranked within each portfolio. The utility must justify the portfolio selection, optimization, and structure of Mitigation/Control Groups.* In the GRC, the utility will provide a ranking of Mitigations *and Control Programs* by ~~Cost-~~Benefit-*Cost* Ratios, as follows: *(1) For any dataset of Risk Reporting Units submitted with the RAMP, the utility will provide an update of the dataset, if any is required, and provide an explanation of any differences from its RAMP filing and a justification for why the dataset from the RAMP filing required to be updated;* (~~1~~2) For Mitigations *and Control Programs* addressed in the RAMP, the utility will use risk reduction estimates, including any updates, and updated costs to calculate ~~Cost-~~Benefit-*Cost* Ratios and explain any differences from its RAMP filing; (~~2~~3) For Mitigations *and Control Programs* that require Step 3 analysis under and consistent with Row 28, the utility will include the ~~Cost-~~Benefit-*Cost* Ratios, calculated in accordance with Step 3, in the ranking of Mitigations by ~~Cost-~~Benefit-*Cost* Ratios. *In the GRC, the utility will provide an updated presentation of the set of Optimized Enterprise Portfolios required by Row 25.1 and the optional set of Optimized Risk Mitigation*

		Portfolios within each Enterprise Portfolio in accordance with Row 25.2 if an update is necessary. Any differences in these Optimized Portfolios from the RAMP filing must be clearly explained by the utility in its GRC filing. In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigation~~s~~ *and Control Programs* for each *enterprise* risk *presented in the RAMP* and for its selection *and optimization* of its ~~overall~~ portfolio of Mitigation~~s~~ *and Control Programs for each enterprise risk presented in the RAMP. The utility must explain how the budget scenario and other constraints factored into the utility's portfolio selection. In the RAMP and GRC, the utility will clearly and transparently explain its rationale for prioritizing Risk Reporting Units for each Mitigation and Control Program.* ~~The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach.~~ *The utility's proposed Enterprise Portfolio, including its* Mitigation~~s~~ *and Control Programs* selection, *Risk Reporting Unit prioritization, and Risk Mitigation Portfolio optimization* can be influenced by *Benefit-Cost Ratios and* other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the *RAMP and* GRC, the utility will explain whether and how any such factors affected *the utility's proposed Enterprise Portfolio, including its* Mitigation *and Control Program* selections *and Risk Reporting Unit prioritization*. GRC Post-Test Year Reporting: All Controls and Mitigation programs must include ~~CBRs~~*Benefit-Cost Ratios* in each of the GRC post-test years as well as an aggregate ~~CBRs~~*Benefit-Cost Ratio* for the entire post-test year period and the entire GRC period, by Tranche.

The requirements described in Row 25.1 above would require the utilities to establish four Optimized Enterprise Portfolios (one for each Budget Scenario) as part of its RAMP and GRC Application. Row 25.2 provides the utilities the option to optimize on its Risk Mitigation Portfolios, thereby creating four alternative Enterprise Portfolios (one for each Budget Scenario). Each Enterprise Portfolio would include a Risk Mitigation Portfolio for each Risk submitted in a RAMP or GRC Application.

7. Risk Reporting Unit

At issue in Phase 3 was how to encourage a utility to maintain the same level of granularity and ensure the possibility of "apples-to-apples" comparisons of data and metrics between GRC cycles. When a utility changes the organization of its risk mitigation work and reporting of such data, this can lead to confusion and difficulty in analysis and tracking over time.

In Phase 3, Cal Advocates submitted a proposal for data templates that would require utilities to present data for each mitigation project in its RAMP and GRC application. Cal Advocates provided a definition of a project as a set of tasks with a defined timeline, for which there are a specific set of goals, and which include "scoping, estimating, planning, scheduling, tracking, unit cost, budget, and assessment". [61] In comments on the Cal Advocates proposal, there was contention among parties regarding the need to define "project" in the

[61] The Public Advocates Office's Recommendation to Develop Risk Mitigation Project Templates in Rulemaking 20-07-013 Workshop 5, October 31 2023, at 15.

context of the RDF. The Commission determined that robust discussion during a workshop would be needed to develop a definition of "project" that addresses the concerns of SPD staff, intervenors, and the utilities.[62]

7.1. SPD Staff Scoped Work Proposal

7.1.1. Review of Scoped Work

Although mitigation project has yet to be defined, the concept of "mitigation program" is well defined within the RDF:

> a. CPUC jurisdictional effort within Electric Operations or Gas Operations consisting of projects, activities, and/or functions with a defined scope that is intended to meet a specific objective.[63]

The Staff Scoped Work Proposal states that the term "program" is a high-level aggregation of projects with a defined scope. The Staff Scoped Work Proposal notes that tranches are a disaggregation of the risk associated with a given risk event and the assets and systems within each tranche share the same LoRE and CoRE profile.[64] It is through the risk reduction achieved by scoped work that a utility can then properly determine how to manage the risk found within tranches.

The Staff Scoped Work Proposal presents a number of examples of project-level data submitted to RAMP and GRC proceedings as well as responses to data

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[62] D.24-05-064 at 110.

[63] D.24-05-064, Appendix A, Row 28 at A-19. All three IOUs have a different alphanumeric naming convention for their programs. For details see D.24-05-064, Appendix A, Row 28 at A-19 – A-20

[64] The granularity of tranches has been addressed by the Commission in the Phase 3 Decision. See D.24-05-064 at 26 and D.24-05-064 Appendix A, Row 14 at A-13 for details.

requests.[65] SPD staff argue that it would be beneficial to decision-makers, SPD staff, and parties to have access to a set of projects submitted with the RAMP application for evaluation that is then updated in the utility's GRC. The Staff Scoped Work Proposal defines "scoped work" in the following way:

> A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates a group of assets or systems that exhibit a certain level of risk. Scoped work is traceable through all stages of a lifecycle, including, but not limited to, scoping, designing, permitting, construction/implementation, and post-construction. Scoped work must be forecastable to at least the third post-test year of a GRC cycle. Scoped work must be auditable in terms of timing, location, work units, cost, and risk reduction.[66]

The proposal also provides the following explanation of the terms within this definition:

- Exhibit a certain level of risk: This refers to the level of risk that is estimated by the utility's risk model.
- Scoping: Identifying the size and timeline of the scoped work. Scoping is the first step to providing visibility to the construction feasibility and possible execution timing.
- Designing: Delineation of a plan for implementing the scoped work including determining the scoped work's integration within existing infrastructure or operations and need for materials, training, or permitting. The costs for completing the scoped work, including for permitting, labor and materials, are forecasted at this stage.

[65] Staff Proposal at 5-8.

[66] Staff Proposal at 9.

- Permitting: The process of obtaining the rights and permits from relevant stakeholders to implement the scoped work. This stage of the lifecycle also includes negotiating of contracts to implement the scoped work as well as final estimation of the costs associated with implementing the scoped work.
- 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.
- Post-Construction: For capital investments, there can be final paperwork and updates to asset registries after the scoped work is used and useful.
- Forecastable: Scoped work is a unit of analysis that is forward-looking, which means the utility must be able to estimate the risk reduction, units of work to be completed and expenses of scoped work implemented in the future. Parties must also be able to verify the accuracy of the risk reduction estimates provided by utilities.
- Auditable: Scoped work is a unit of analysis that is backward-looking. Specifically, once a scoped work is implemented, parties, the Commission, or an independent auditor must be able to determine if the risk reduction and units of work estimate was realized by scoped work implemented in the past. It must also be possible to determine if the expenses of scoped work implemented in the past are incremental to expenses authorized in other rate-making proceedings.

7.1.2. SPD Staff Proposal Introduces the Risk Reporting Unit

The Staff Scoped Work Proposal argues that the term "scoped work" is not ideal because it could be confused with the concept "a scope of work".

Additionally, the term "scoped work" contains an uncountable noun (i.e., work), which makes phrases like "each scoped work," "the number of scoped work," or even "five scoped work" awkward. SPD staff recommends the Commission adopt the term Risk Reporting Unit (RRU).

The Staff Scoped Work Proposal presents Figure 2 below to show the minimal features of an RRU. The Staff Scoped Work Proposal explains that the first category of data is unique identifiers. Unique identifiers form the foundation for the utility's risk reporting hierarchy and enable aggregation. The second category is the actual risk data, which can be aggregated based on unique identifiers, which the Staff Scoped Work Proposal calls roll-up points within the risk reporting hierarchy.

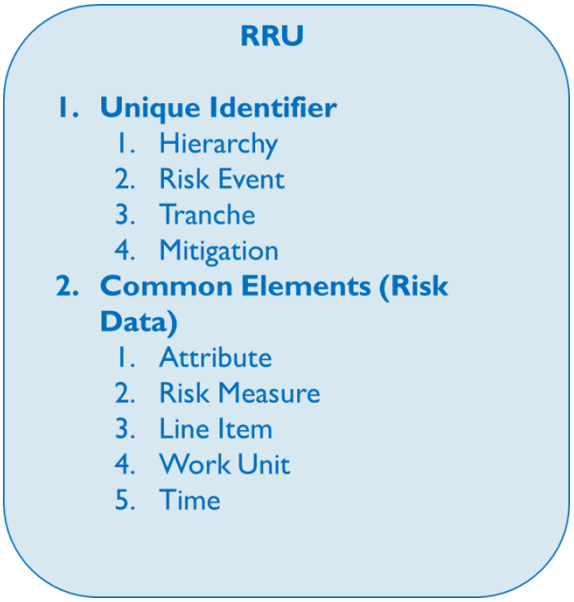

Figure 2. How an RRU is organized.[67]

[67] 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.). Unique identifiers could also include features

Footnote continued on next page.

Since each RRU contains risk information for each attribute, RRUs can be aggregated to total Safety, Reliability, and Financial attributes according to those three roll-up points.

The Staff Scoped Work Proposal notes that a key question about the RRU is the appropriate level of granularity for disaggregating a particular mitigation program. If RRUs are overly granular, mitigation programs may be broken down into thousands of RRUs. If RRUs are overly aggregated, they become easier to manage because they are fewer in number but the RRUs may be insufficiently flexible and not aggregable to the mitigation program level (e.g., if the RRU includes multiple mitigations or multiple tranches). The Staff Scoped Work Proposal argues that a reasonable starting point for determining the granularity of an RRU is scoped work. SPD staff argues that the principles discussed in the definition of scoped work above are directly relevant to determining the characteristics of an RRU.

The Staff Scoped Work Proposal presents several diagrams to assist parties in deciding how to define the granularity of an RRU. The Staff Scoped Work Proposal argues that a one-to-one relationship between a portion or segment of a mitigation and RRUs ensures a level of granularity that allows for proper aggregation to the mitigation program level while also being auditable. The Staff Scoped Work Proposal does allow that there may be scenarios in which an RRU can reduce risk for more than one Risk Event. In these scenarios, SPD staff note

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that were discussed further in the RMAR Staff Proposal, such as Scenario, which refers to actuals, plan or forecast, and Version, which refers to a risk model version.

that cost allocation needs to be carefully considered. Finally, the Staff Scoped Work Proposal emphasizes that consistency across time is an important principle of the RRU. Once the granularity for the RRU is determined, RRU granularity should not change from one GRC cycle to the next. The Staff Scoped Work Proposal argues if a utility wishes to update an RRU's granularity level, it must clearly explain the method it chose to update the granularity and how the granularity of the new RRU differs from the granularity of the prior RRU. Additionally, the utility must provide a Backcast of post-mitigated risk, risk reduction and BCRs submitted to the previous cycles of RAMPs and GRCs that are impacted by an update to the RRU's level of granularity. That is, the utility must demonstrate the implications for previous risk assessments of changing the RRU granularity. The Staff Proposal argues that requiring an RRU Backcast will encourage the utility to maintain the same level of granularity and ensure an "apples-to-apples" comparison of data and metrics between GRC Cycles.

7.1.3. SPD Staff Recommendations on the Risk Reporting Unit

On the topic of defining scoped work, SPD staff recommends the following. First, SPD staff recommend avoiding the term scoped work and instead integrating the term Risk Reporting Unit (RRU) into the RDF. The Commission should require utilities to present workpapers in RAMP and GRC filings at the RRU scale beginning with the SCE 2026 RAMP and Sempra 2028 GRC filings. Additionally, all data templates discussed in Track 2 of Phase 4 should be structured on the RRU.

Second, SPD staff recommends adding the following definitions to the RDF for clarity related to the RRU (language additions in *italics*):

- *Asset: A retirement unit as defined by Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) that exhibits risk.*[68]
- *Backcast: Use updated inputs (e.g., new RRUs, new risk models) to recalculate Benefit-Cost Ratios, pre-mitigated risk, post-mitigated risk or other data points as required by the RDF, Commission Ruling or Commission Decision. The goal of a Backcast is to establish a bridge between the prior inputs and the new inputs, which ensure an "apples-to-apples" comparison.*
- *Mitigation/Control Program: A CPUC jurisdictional effort within Electric Operations or Gas Operations consisting of multiple risk reporting units with a defined scope that is intended to meet a specific objective.*
- *Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates a group of 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, work units and time. The RRU can be aggregated based on unique identifiers that should include, but are not limited to, hierarchy*[69]*, risk event, tranche and mitigation type.*

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

[69] 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.).

- *System: A regularly interacting or interdependent group of items forming a unified whole that exhibits risk and cannot be classified as a retirement unit.*

Third, SPD staff recommends adding the following row to the RDF, between Rows 15 and 16, to ensure the RRU is properly defined, integrated, and consistently used in RAMP and GRC applications (additions in *italics*):

15.1	*Define the Mitigation Risk Reporting Unit*	*A Risk Reporting Unit (RRU) will be defined for each mitigation. The RRU must be:* *(a) traceable through all stages of a lifecycle, including but not limited to, scoping, designing, permitting, construction/implementation, post-construction.* *(b) forecastable to at least the third post-test year of a GRC cycle.* *(c) auditable in terms of timing, location, work units, cost, and risk reduction.* *(d) able to aggregate up to the Mitigation Program or Control Program.* *Once the level of granularity of an RRU for each risk is established, beginning with SCE's 2026 RAMP and SDG&E's 2028 GRC filings, that level of granularity for the RRU should be maintained for all future filings which include that risk. If a utility wishes to update an RRU's level of granularity it must clearly explain the method it chose to update the granularity and how the granularity of the new RRU differs from the granularity of the prior RRU. Additionally, the utility must provide a Backcast of post-mitigated risk, risk reduction and Benefit-Cost Ratios submitted to the previous cycles of RAMPs and GRCs that are impacted by an update to the RRU's level of granularity.*

Finally, SPD staff recommends the following changes to the RDF to ensure the RRU is properly integrated with all relevant aspects of RAMP and GRC applications (language additions in *italics* and deletions in ~~strikethrough~~):

4.	1 Definition of Risk Events and Tranches	Detailed pre- and post-mitigation analysis of Mitigations *and Controls* will be performed for each risk selected for inclusion in the RAMP. The utility will endeavor to identify all asset groups or systems subject to the risk and each Risk Event associated with the risk. For example, if Steps 2A and 2B identify wildfires associated with utility facilities as a RAMP Risk Event, the utility will identify

		all Drivers that could cause a wildfire and each group of assets or systems that could be associated with the wildfire risk, such as overhead wires and transformers. For each Risk Event, the utility will subdivide the group of assets or the system associated with the risk into Tranches. Risk reductions from Mitigation *and Control Programs* and ~~Cost~~ Benefit-*Cost* Ratios will be determined at the Tranche level, which gives a more granular view of how Mitigations *and Control Programs* will reduce Risk. *The utility will identify which Risk Reporting Units are responsible for reducing risk in each tranche.* The determination of Tranches will generally be based on how the risks, as a product of LoRE and CoRE, and assets are managed by each utility, data availability and model maturity, and strive to achieve as deep a level of granularity as reasonably possible. The rationale for the determination of Tranches, or for a utility's judgment that no Tranches are appropriate for a given Risk Event, will be presented in the utility's RAMP submission. For the purposes of the risk analysis, all of the elements (i.e., assets or system) that are scoped for a given RAMP and GRC Application and contained within the identified Tranche would be considered to have homogeneous risk profiles, meaning they should have the same LoRE and CoRE. The best practice for determining the homogeneity of risk profiles in reporting Tranches is the use of quintiles of LoRE and quintiles of CoRE, resulting in 25 reporting tranches. The utility can and should submit more granular data in workbooks included with RAMP and GRC filings if it is available. If the assets or system associated with a given risk are less than 25 in number, the utility may use an alternative means of determining homogeneity of risk profiles, including quartiles or other smaller divisions of LoRE and CoRE, but this alternative means must be described in detail in the RAMP filing. If a utility desires to use an alternative determination of Tranches not reflecting 25 homogenous risk profiles based on LoRE and CoRE, or they wish to use a percentile ranking approach that would result in more than 25 reporting Tranches, the utility must

		submit a White Paper describing their preferred method for determining Tranches and relevant workpapers to SPD no later than 45 days before their first pre-RAMP workshop and must serve the White Paper to the service list of R.20-07-013 or a successor proceeding as well as the service list of the utility's most recent RAMP application no later than 45 days before their first pre-RAMP workshop. Staff and parties may provide input on the IOU's White Paper within the 21 days of the submittal. The utility must also include the White Paper in its RAMP filing, clearly indicating any changes to the previously served version. An IOU may submit this White Paper without prejudice to the right of parties to the RAMP or GRC to challenge such alternative determination of tranches.

16.	Expressing Effects of a Mitigation	The effects of a Mitigation on a Tranche will be expressed as a change to the Tranche-specific pre-mitigation values for LoRE and/or CoRE. The utility will provide the pre- and post-mitigation values for LoRE and CoRE determined in accordance with this Step 3 for all Mitigations subject to this Step 3 analysis. *Additionally, the utility must provide pre- and post-mitigation values for LoRE, CoRE, Monetized Risk Value, Risk Reduction, and Benefit-Cost Ratios for all Risk Reporting Units that aggregate up to the Mitigation Program subject to this Step 3 analysis.*

26.	Mitigation Strategy Presentation in the RAMP and GRC	The utility's RAMP filing will provide a ranking of all RAMP Mitigations ~~Programs~~ *Programs* by ~~Cost~~ Benefit-*Cost* ~~r~~Ratios. *The utility's RAMP filing will include a dataset of Risk Reporting Units for each Mitigation and Control Program and rank each Risk Reporting Unit by Benefit-Cost Ratio.* In the GRC, the utility will provide a ranking of Mitigations ~~Programs~~ *Programs* by ~~Cost~~ Benefit-*Cost* Ratios, as follows: *(1) For any dataset of Risk Reporting Units submitted with the RAMP, the utility will provide an update of the dataset, if any is required, and provide an explanation of any differences from its RAMP filing and a justification for why the dataset from the RAMP filing required to be updated;* (~~1~~2) For Mitigations ~~Programs~~ *and Control Programs* addressed in the RAMP, the utility will use risk reduction estimates, including any updates, and updated costs to calculate ~~Cost~~ Benefit-*Cost* Ratios and explain any differences from its RAMP filing; (~~2~~3) For Mitigations

		and Control Programs that require Step 3 analysis under and consistent with Row 28, the utility will include the ~~Cost~~ Benefit-*Cost* Ratios, calculated in accordance with Step 3, in the ranking of Mitigations by ~~Cost~~ Benefit-*Cost* Ratios. In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigation~~s~~ *and Control Programs* for each risk and for its selection of its overall portfolio of Mitigations. *In the RAMP and GRC, the utility will clearly and transparently explain its rationale for prioritizing Risk Reporting Units for each Mitigation and Control Program.* The utility is not bound to select its Mitigation~~s~~ *and Control Programs* strategy based solely on the ~~Cost~~ Benefit-*Cost* Ratios produced by the Cost-Benefit Approach~~.~~ Mitigation~~s~~ *and Control Programs* selection *and Risk Reporting Unit prioritization* can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis. In the *RAMP and* GRC, the utility will explain whether and how any such factors affected the utility's Mitigation *and Control Program* selections *and Risk Reporting Unit prioritization*. GRC Post-Test Year Reporting: All Controls and Mitigation programs must include ~~*CBRs*~~*Benefit-Cost Ratios* in each of the GRC post-test years as well as an aggregate ~~CBRs~~*Benefit-Cost Ratio* for the entire post-test year period and the entire GRC period, by Tranche.

7.2. Joint IOU Scoped Work Proposal

The Joint IOUs filed a proposal (Joint IOU Scoped Work Proposal) in response to the Staff Scoped Work Proposal. The Joint IOUs generally support

the inclusion of an RRU in the RDF.[70] However, the Joint IOU Scoped Work Proposal argues that while the IOUs can theoretically present RRUs in RAMP applications, those projects will necessarily be largely hypothetical and simply based on risk model outputs. The implemented RRUs are going to be different than the provided forecasts. The Joint IOUs argue they require the appropriate flexibility to adapt their plans based on real-time data and evolving circumstances. The Joint IOU Scoped Work Proposal presents an approach allowing RRUs to be refined as information becomes available.

Additionally, the Joint IOU Scoped Work Proposal emphasizes that certain controls and mitigations do not lend themselves readily to an RRU and are more appropriately forecast at a programmatic level.[71] The Joint IOUs argue that having an RRU for this type of forecast hypothetical work would not provide meaningful benefits to stakeholders. Finally, the Joint IOUs argues that it is premature to include a backcast requirement in the RDF.[72] Assuming that a risk does not change, the Joint IOUs recognize that forecasting and backcasting may be possible at a programmatic level, but argue it may not be feasible with any level of accuracy at the RRU level for all risks and/or mitigation programs.[73]

[70] Joint IOU Scoped Work Proposal at 7.

[71] *Id*. at 10.

[72] *Id*. at 11.

[73] *Id*.

The Joint IOUs do not present a definition of RRU for the RDF, but they do recommend adding the following row to the RDF, between Rows 15 and 16, as a substitute for what was presented in the Staff Proposal:[74]

15.1	Define the Mitigation Risk Reporting Unit	Define Risk Reporting Unit(s) (RRU) for each control and mitigation for physical asset-based risks. The RRU should be: (a) traceable through any stages of execution relevant to the risk and/or mitigation itself, which could include but is not limited to, scoping, designing, permitting, construction/implementation, post-construction. (b) auditable in terms of timing, location, work units, cost, and risk reduction. (c) reasonably forecastable in terms of timing, cost, and risk reduction (d) able to aggregate up to the Mitigation Program or Control Program. The RRU(s) should be defined at the relevant level of detail that is available to the utility at the time of its RAMP or GRC filing. Hence, to the extent that detailed information beyond the mitigation or control level is unavailable, the RRU may be defined at the Control and/or Mitigation level instead. The IOU will provide its rationale for defining the RRU accordingly and parties will be afforded the opportunity to challenge this explanation prior to the IOU filing its subsequent GRC. The RRU(s) for each risk are to be established by each utility in its RAMP filing, beginning with SCE's 2026 RAMP filing. Each utility shall also provide updates to its RRU(s) on a timely basis, to reflect newly available information and details relevant to Controls and/or Mitigations. If a utility updates its RRU(s) it must clearly explain the rationale for the update and how the new RRU(s) differs, or are derived from prior RRU(s).

The Joint IOU Proposal does not recommend adding any definitions to the RDF.[75]

[74] *Id*. at 6.

[75] *Id*. at 12.

7.3. Party Comments

Parties were split in their support of the two proposals, with the IOUs supporting the Joint IOU Scoped Work Proposal and Cal Advocates, EPUC/IS, and TURN (collectively, Joint Intervenors) and PCF supporting the Staff Scoped Work Proposal. The Joint Intervenors and PCF provide limited comment on the Joint IOU Scoped Work Proposal, other than that it should not be accepted by the Commission. Comments from PG&E, SCE, and the Sempra Companies focus on describing the need for exceptions in various aspects of the Staff Scoped Work Proposal. For instance, SCE argues that it is not necessary for the RDF to include a prescriptive list of lifecycle stages.[76] In contrast, the Joint Intervenors request that the Commission add the "retirement/decommissioning phase" to the list of lifecycle stages.[77] Regarding examples of mitigations that would not conform to the lifecycle stages in the Staff Scoped Work Proposal, PG&E and the Sempra Companies provided limited examples but only SCE presented a list of mitigations.[78] The Joint Intervenors argue that the utilities should present their case that a mitigation should be exempt from being presented at the RRU level in a RAMP application and should not be preliminarily excluded in the definition of the RRU itself.[79] The three IOUs oppose requiring RRUs be applied to all Mitigation and Control programs and PG&E emphasizes that Row 28 of the RDF

[76] SCE Opening Comments on Workshop #1 at 12.

[77] Joint Intervenor Opening Comments on Workshop #1 at 5.

[78] PG&E Opening Comments on Workshop #1 at 3, Sempra Opening Comments on Workshop #1 at 3 – 4, and SCE Opening Comments on Workshop #1 at 13 and Appendix B.

[79] Joint Intervenors Reply Comments on Workshop #1 at 7.

provides guidance on when risk analysis is required for non-RAMP programs.[80] The Joint Intervenors argue that the RRU level should be applied to all Mitigation and Control programs, similar to the way the IOUs must present information in the Risk Spend Accountability Report (RSAR).[81]

The Joint Intervenors emphasize that the RRU should extend to more than just asset-based risks including Public Safety Power Shutoffs (PSPS).[82] PG&E argues that it is difficult to conceive of PSPS as an RRU since it only temporarily removes the risk of wildfire.[83] SCE notes that both the Commission and the Office of Energy Infrastructure Safety (OEIS) do not require Risk Spend Efficiencies to be calculated for PSPS and that the Commission considers PSPS a measure of last resort. As such, SCE argues it cannot be considered an acceptable alternative to other wildfire mitigation programs.[84]

The IOUs provide recommended cost thresholds below which a mitigation or control program would be exempt from establishing RRUs. PG&E recommends that the IOUs be required to develop RRUs for control and mitigation programs that contribute to the top 90% of the total estimated mitigation costs over the GRC period.[85] The Sempra Companies recommend, at a

[80] PG&E Opening Comments on Workshop #1 at 9, SCE Opening Comments on Workshop #1 at 18, Sempra Opening Comments on Workshop #1 at 7.

[81] Joint Intervenors Opening Comments on Workshop #1 at 15-16.

[82] Joint Intervenors Opening Comments on Workshop #1 at 11.

[83] PG&E Reply Comments on Workshop #1 at 11.

[84] SCE Reply Comments on Workshop #1 at 8-9.

[85] PG&E Opening Comments on Workshop #1 at 7-8.

minimum, adopting the utility-specific Variance Selection criteria thresholds adopted in D.19-04-020.[86] SCE recommends the cost thresholds for incorporating foundational costs found in D.21-11-009.[87] The Joint Intervenors did not comment on this issue, but the Sempra Companies agree in their reply comments with SCE's approach.[88]

SCE and the Sempra Companies argue that for many mitigation programs it is not possible to forecast out to the third post-test year at the RRU level of granularity.[89] In contrast, the Joint Intervenors argue that the IOUs should be required to forecast an RRU at least 5 years into the future, if not longer.[90] The Joint Intervenors also suggest that if the forecasted data is inaccurate, the utility should present an annual update of the data associated with an RRU prior to the Test Year. [91] SCE notes that such a requirement may not be allowed by the Rate Case Plan, which requires the GRC forecast to be set at a point in time.[92]

PG&E agrees that RRUs should be auditable in how they are planned, managed, and performed.[93] SCE argues that it is not clear what benefit would be

[86] Sempra Opening Comments on Workshop #1 at 7.

[87] SCE Opening Comments on Workshop #1 at 16.

[88] Sempra Reply Comments on Workshop #1 at 3.

[89] SCE Opening Comments on Workshop #1 at 5, Sempra Opening Comments on Workshop #1 at 4.

[90] Joint Intervenors Opening Comments on Workshop #1 at 5.

[91] Joint Intervenors Opening Comments on Workshop #1 at 6.

[92] SCE Reply Comments on Workshop #1 at 12.

[93] PG&E Opening Comments on Workshop #1 at 5.

gained from auditing a "hypothetical project".[94] The Joint Intervenors note that auditing an RRU can inform cost-of service planning and the minimization of abandoned or stranded plant costs.[95] The Joint Intervenors provide a list of additional auditable elements that they argue should be added to the RDF as Row 15.2. In particular, Row 15.2 includes depreciation and rate of return costs charged to the ratepayer over the lifetime of an RRU.[96] All three IOUs oppose the additional elements recommended by the Joint Intervenors on the grounds that forecasting the additional data points five or more years out would be highly speculative.[97] SCE emphasizes that asking for the lifetime costs of depreciation and rate of return for each RRU would represent an expansion of the Results of Operation (RO) model in a GRC application, which may not be feasible to complete.[98] The Joint Intervenors support the backcasting requirement as presented in the Staff Scoped Work Proposal. They argue that without a backcasting requirement, utilities may rename or change programs from one GRC to another which will impede the Commission's ability to hold utilities

[94] SCE Opening Comments on Workshop #1 at 15.

[95] Joint Intervenors Opening Comments on Workshop #1 at 6.

[96] Joint Intervenors Opening Comments on Workshop #1 at 6-10.

[97] PG&E Reply Comments on Workshop #1 at 5-6, Sempra Reply Comments on Workshop #1 at 3-4, SCE Reply Comments on Workshop #1 at 3.

[98] SCE Reply Comments on Workshop #1 at 13.

accountable.[99] PG&E recommends that discussion of the backcast be considered further in the context of the RMAR.[100]

Both the Sempra Companies and the Joint Intervenors are against a One-to-Many mapping of RRUs and argue that such a mapping can potentially lead to double counting of costs. [101] PG&E presents alternative language for dealing with the costs associated with the One-to-Many approach that could be added to Row 15.1 in the Joint IOU Proposal:

> Each IOU shall incorporate the costs of an RRU that impacts multiple Risks by allocating the costs of the RRU across the impacted Risks, and shall clearly and transparently explain and justify their chosen allocations in their RAMP or GRC filings. Furthermore, each IOU shall also provide updates to its allocations on a timely basis, as necessary. If a utility updates the allocations of an RRU, it must clearly explain the rationale for it.[102]

SCE states that it would be necessary to pilot an approach before it could determine the best way to address One-to-Many mapping of RRUs.[103]

In terms of establishing the granularity of an RRU, all three utilities argue that they should be allowed the flexibility to determine if an RRU should be associated with a single asset or whether a group of assets are continuous.[104] The

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[99] Joint Intervenors Opening Comments on Workshop #1 at 20.

[100] PG&E Reply Comments on Workshop #1 at 7.

[101] Sempra Opening Comments on Workshop #1 at 7, Joint Intervenor Opening Comments on Workshop #1 at 15

[102] PG&E Opening Comments at 8-9.

[103] SCE Opening Comments at 17.

[104] PG&E Opening Comments at 6-7, SCE Opening Comments at 15-16, Sempra Opening Comments at 6.

Joint Intervenors argue that RRUs should only remove or mitigate contiguous assets, systems, or locations to ensure that the risk reduction of work completed at a given location is auditable.[105] The Joint Intervenors also argue that in some instances different components of a single asset, such as dams, may have different risk profiles and contains different levels of risk and should be treated as separate RRUs.[106]

The Joint Intervenors provide redlines on the Staff Scoped Work Proposal. For instance, they recommend adding "retirement" to Row 15.1 as part of the lifecycle and requiring the Sempra Companies to include RRU-level data in their 2028 GRC filing.[107] The Joint Intervenors also present an alternative definition for RRU to allow for comparison with work units and ensure applicability to non-asset based mitigations and controls (language additions in *italics* and deletions in ~~strikethrough~~):

- Risk Reporting Unit (RRU): A CPUC jurisdictional effort within Electric Operations or Gas Operations that simultaneously removes or mitigates *the risks associated with* a *contiguous* group of assets, ~~or~~ systems, *or locations* that exhibit high levels of *enterprise* risk. The RRU must include common elements that should include, but are not limited to Consequence Attributes, Risk level, line item costs, work units, *Benefit-Cost Ratios (BCRs), geographical information system (GIS) data,* and time. The RRU can be aggregated *along several dimensions* based on unique identifiers that ~~should~~ include, but are not limited to, *IOU* hierarchy, *risk*

[105] Joint Intervenors Opening Comments at 12.

[106] Joint Intervenors Opening Comments at 12.

[107] Joint Intervenors Opening Comments at 25.

model version, *scenario,* risk event, tranche and mitigation type. [108]

Additionally, the Joint Intervenors recommend adding the following definition for Work Units to the RDF:

- Work Units: Metrics used to quantify the scope of a larger program or project (such as miles of pipe replaced)[109] RRU work units will be a subset of the program-level work units reported in RSARs.[110]

7.4. Discussion

In general, the Commission is persuaded of the approach to scoped work presented in the Staff Scoped Work Proposal. We agree that the term Risk Reporting Unit (RRU) is a better choice than scoped work and we adopt staff's definition with adjustments informed by the Joint Intervenors (additions in *italics*):

- *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, Work Units and time. The RRU can be aggregated along several dimensions based on unique identifiers that include, but are not limited to,*

[108] Joint Intervenors Opening Comments at 24.

[109] D.22-12-002 at 17

[110] Joint Intervenors Opening Comments at 24.

Hierarchy,[111] Scenario,[112] Version,[113] Risk Event, Tranche, and mitigation type.

The Commission is also persuaded that the supplementary definitions proposed by SPD staff and provided in Section 7.1.3 above will add clarity to the RDF and are included in Appendix A. We also agree with the Joint Intervenors that the term Work Unit should also be added to the RDF in Appendix A. This is discussed further in the context of RMAR in Section 8.3.

The Commission rejects the requirements requested by the Joint Intervenors in Row 15.2. In particular, we agree with SCE that requiring the lifetime costs of depreciation and rate of return for each RRU would represent an expansion of the RO model in GRC applications. However, we do note that Pub. Util. Code 739.15 requires IOUs to calculate annual revenue requirement for each year that capital expenditures described in a cost-recovery application to the Commission are expected to remain in the application's rate base. Thus, if discussions regarding refinements to the RO model occur in future proceedings, an important topic could be whether it would be in the interest of ratepayers to require the RO models to generate revenue requests and, if so, at what level of granularity (e.g., program, RRU, etc.).

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[111] 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.).

[112] Scenario refers to forecasts, results, and projections. For details see Section 8.3.

[113] Version refers to a risk model version.

The Commission agrees with the Staff Scoped Work Proposal and the Joint Intervenors that the RRU should be auditable once the activity has taken place or the mitigation becomes used and useful. The Commission is concerned about the difficulty of auditing mitigation spending when an RRU is mapped to more than one mitigation or risk event. For this reason, mapping RRUs to more than one risk event should only be done if an RRU has benefits for more than one risk and in such cases the utility must only present BCR calculations for the primary risk event (i.e., the risk event where the risk is reduced by the most). All the costs of that mitigation must only be associated with that primary risk event. In the event a mitigation has benefits for more than one risk, the utility must demonstrate in the RAMP and in its workpapers that risk reduction is achieved in the non-primary risk events. This approach of mapping RRUs to more than one risk event shall not be applicable in any other case, including tranches.

The Commission, through the RDF, requires IOUs to model PSPS events as risk events.[114] However, the Commission recognizes PG&E's argument that because PSPS events only mitigate the risk of wildfire temporarily, therefore it may be inappropriate to treat PSPS as a distinct RRU. This argument could also hold for Protective Equipment and Device Settings (PEDS). As such, the Commission exempts PSPS and PEDS from the RRU requirements adopted here, but may re-assess the application of RRU requirements to PSPS and PEDS in the future.

[114] D.21-11-009, Ordering Paragraph 1h.

We agree with SCE's approach to establishing a cost threshold for mitigation and control programs based on the same thresholds found in the Phase 1 Decision[115] for foundational costs and do not see the need to develop a new approach as proposed by PG&E. These thresholds are integrated into Row 15.1 of the RDF as described below.

The Commission adopts the edits recommended by the Staff Scoped Work Proposal in Rows 14, 16, and 26 and these changes are codified in the Risk-Based Decision-Making Framework contained in Appendix A of this decision. Although the Joint IOU Proposal recommends removing a backcast requirement from Row 15.1, we agree with the Joint Intervenors that without a backcast requirement, the Commission will have difficulty holding the utilities accountable for changes they make to the granularity of RRUs. Additionally, while we recognize that the farther out an RRU is forecasted, the more uncertainty there could be, as argued by SCE and the Sempra Companies, we are not persuaded that this forecasting is not possible. Ensuring that an RRU is forecastable to at least the third post-test year of a GRC cycle will provide useful information to the Commission and interested parties. At the same time, we recognize that utilities may improve their depth of analysis once they begin implementing the RRU requirements. We expect the development of RRUs to improve from cycle to cycle as the utilities gain more experience using granular information to help develop program forecasts. Utilities' RRUs for wildfire mitigation will be the most developed and accurate, particularly for SCE and

[115] See D.21-11-009 at 141.

SDG&E who are filing in 2026, due to the focus in recent years on wildfire mitigation. We add Row 15.1 to the RDF (additions in *italics*):

5.1	*Define the Mitigation Risk Reporting Unit*	*A Risk Reporting Unit (RRU) will be defined for each mitigation. The RRU must be:* *(a) traceable through most, if not all, stages of a lifecycle, including but not limited to, scoping, designing, permitting, construction/implementation, post-construction, retirement/decommissioning.* *(b) forecastable to at least the third post-test year of a GRC cycle.* *(c) auditable in terms of timing, location, work units, cost, and risk reduction.* *(d) able to aggregate up to the Mitigation Program or Control Program.* *Once the level of granularity of an RRU for each risk is established, beginning with SCE's 2026 RAMP and Sempra Companies' 2028 GRC filings, that level of granularity for the RRU should be maintained for all future filings which include that risk. If a utility wishes to update an RRU's level of granularity it must clearly explain the method it chose to update the granularity and how the granularity of the new RRU differs from the granularity of the prior RRU. Additionally, the utility must provide a Backcast of post-mitigated risk, risk reduction and Benefit-Cost Ratios submitted to the previous cycles of RAMPs and GRCs that are impacted by an update to the RRU's level of granularity.* *The disaggregation of a Mitigation and Control Program to the RRU scale is not required for the following:* *1) Public Safety Power Shutoffs* *2) Protective Equipment Device Settings* *3) Mitigation and Control Programs that do not meet the following thresholds:* *a. For PG&E and SCE, $10 million;* *b. For SDG&E, for its electric and other operations, $5 million;* *c. For SDG&E, for its gas operations, $2.5 million; and,* *d. For SoCalGas, $5 million.*

8. Risk Mitigation Accountability Reporting

The Commission has discussed risk mitigation accountability reporting since at least 2014, as the Risk Mitigation Accountability Report (RMAR) was first mentioned in D.14-12-025 as a utility report that would compare projected benefits and costs of risk mitigation programs adopted in GRCs to the actual benefits and costs realized from these risk mitigations. D.14-12-025 also introduced the Risk Spending Accountability Report (RSAR) which compares GRC-projected spending for approved risk mitigation projects with the actual spending. The RMAR was further conceptualized in subsequent Commission decisions, with D.16-08-018 discussing the development of a common set of performance metrics and D.19-04-020 noting timing issues resulting from the staggered RAMP schedule. In the interim, IOUs were directed to include some of the information originally envisioned as belonging in the RMARs in their annual Safety Performance Metrics (SPM) Reports.[116] The PG&E 2023 Test Year GRC Decision piloted many of the concepts we adopt here for the RMAR, and required an annual filing of a System Hardening Accountability Report (SHAR) to closely examine PG&E's progress in implementing undergrounding of overhead electric lines to reduce wildfire risk. This tool created transparency and allowed parties and the Commission to track PG&E's progress in construction of undergrounding work and see the actual risk reduction achieved. The objective of the SHAR is to inform the review of future requests made by PG&E for ratepayer funding for undergrounding and that future forecasts of unit costs and

[116] D.19-04-020 at 32.

pace of work will be informed by historic actual data.[117] The Staff RMAR Proposal, discussed below, argues that while the SPM, RSAR, and SHAR have many of the key concepts of an RMAR, a stand-alone RMAR will further advance the policy goal of transparency by presenting information that is consistent across utilities.[118] Full implementation of the RMAR has been deferred to the present proceeding. The Staff RMAR Proposal, discussed below, provides a thorough framework for conceptualizing risk reporting in general, and the RMAR in particular, as a consolidated statement of risk that consists of tables that examine different aspects of risk and risk reduction that can be consolidated into a high-level view of risk and risk reduction.

8.1. Staff RMAR Proposal

8.1.1. Consolidated Statement of Risk and Multi-Dimensionality

The Staff RMAR Proposal presents the RMAR as a consolidated statement of risk in which every table in the RMAR is comparative in nature with every presentation of data designed to answer the questions "compared to what" and "why". The Staff RMAR Proposal highlights that the RDF examines risk in at least 11 dimensions: hierarchy, scenario, version, risk event, tranche, mitigation, attribute, risk measure, accounts, work unit, and time. Consequently, SPD staff argues that the RMAR requires multiple tables to capture this dimensionality.

[117] D.23-11-069 at 280.

[118] SPD RMAR Staff Proposal at 14.

8.1.2. The Phases of RMAR and Structure of Tables

SPD staff proposes three components of the RMAR that function as fundamental building blocks of the RMAR.[119] The first component, discussed extensively in Section 7 above, is the RRU. The other two components of the RMAR that function as fundamental building blocks of the RMAR are the Plan Phase and the Results Phase.

The Plan Phase of the RMAR is the forward-looking business case for risk-reducing actions that includes a set of projections based on data, models, and subject matter expertise. In the context of the RDF, the RAMP would ideally function as the Plan Phase, though this would require modifications to the RAMP to include all dimensions reported in the RMAR. Relatedly, SPD staff propose that a high-level backcast be included with initial RMAR submissions showing overall residual risk reduction since RAMPs were first filed in 2016. The backcast would not need to be at the same level of detail as the RMAR and would capture a more holistic view of risk and risk reduction since the beginning of the RDF process. [120]

The Results Phase of the RMAR is comprised of four scenarios, the Plan Scenario, Outcomes Scenario, Results Scenario, and Forecasts Scenario. The Plan scenario is the original plan from the base year. The Outcomes Scenario includes the impacts of risk events that have occurred during the report period and prior report periods. The Results Scenario includes the calculations of mitigation

[119] Staff RMAR Proposal at 22.

[120] *Id*. at 22 – 23.

benefits and costs for the report period and prior report periods. The Forecast Scenario includes updates projections based on new information based on outcomes, modeled results, and advancements in risk modeling. The Plan Phase includes only the Plan Scenario, while the Results Phase includes all the Scenarios, allowing for comparison between scenarios.

SPD staff conceptually organize data within each scenario as either Stock data or Flow data. Stock data is non-additive and focuses on a point in time, such as end-of-period results or the average between two periods. Examples of Stock data provided by SPD staff include pre-mitigated risk, risk reduction, and overall residual risk. Flow data is additive and includes data that represent sums for a value over a given period. Examples of Flow data provided by SPD staff include the inputs into BCRs and mitigation benefits for a given reporting period.[121] For each of the scenarios, SPD staff provide example tables with hypothetical data to show how data for each table should be presented.

8.1.2.1. Plan Phase Tables

The Staff Proposal presents the schema in Table 1 below to describe the structure of Plan Phase reports. Y1 denotes the first year of the plan, and YZ the final year.

[121] Id. at 26.

Table 1: Plan Phase Table Structure

I. Mitigation Cost and Benefit (Flow)	II. Risk Reduction (Stock)
Average Risk	**Average Risk**
Modeled benefit Y1-YZ	Pre-mitigated risk
Modeled cost Y1-YZ	Risk Reduction (YZ)
BCR	Overall residual risk (YZ)
	Risk Tolerance
	% of risk tolerance gap closed
Tail Average Risk	**Tail Average Risk**
Modeled benefit Y1-YZ	Pre-mitigated risk
	Risk Reduction (YZ)
	Overall residual risk (YZ)
	Risk Tolerance
	% of risk tolerance gap closed

Staff state that Plan Phase tables can add further dimensions such as time (years 1 through year 4), risk event, attributes, mitigation detail, and tranches. The Staff RMAR Proposal recommends that Plan Phase tables with mitigation level of detail be required in RMAR tables (See Section 8.5).

8.1.2.2. Results Phase Tables

The Results Phase, by virtue of including the Plan Scenario, is both forward- and backward-looking. As such, Results Phase tables may have multiple views of the time dimension (e.g., report period, prior report periods, prior and future periods, etc.). The Staff RMAR Proposal uses the following notation to describe the time dimension for the results phase:

- *Y1*. Base plan year.

- *YN*. Reporting year. For example, Y3 means the RMAR is discussing year 3 outcomes and results.
- *YZ*. Final year of the plan.
- *Y1YN*. The history of outcomes and results. Y1Y3 would include year 1 through year 3.

o *Forecast.* Includes results for Y1YN and projections after Y1YN through YZ.

8.1.2.2.1. Outcomes Table

The Staff RMAR Proposal describes outcomes as the monetized impact of risk events that have occurred in a given year. The Staff RMAR Proposal uses the schema below to depict how SPD staff proposes outcomes be reported in the RMAR:

Risk Outcomes Flow:

- Outcomes vs. Plan average modeled risk, Y1YN
- Outcomes vs. Plan tail averaged modeled risk, by year

Stock:

- Average Outcomes vs. Average Risk Tolerance Y1YN
- Outcomes vs. Tail Risk Tolerance YN

Staff note that risk outcomes can be presented as a flow and compared to the plan for modeled risk. Risk outcomes can also be presented as a stock and compared to risk tolerance.

8.1.2.2.2. Mitigation Benefits and Costs

The Staff RMAR Proposal defines mitigation benefits and costs as the modeled impacts of mitigations as flow tables. Similar to Outcome Tables, the Mitigation Benefit and Cost Flow Tables cover YN and Y1YN and the Mitigation Benefit and Cost Flow Tables may also include a forecast, if future projections have changed from the plan due to outcomes and other changes since the base

year. The Staff Proposal uses the schema below to describe flow tables for mitigation benefits and costs:

Mitigation Benefit and Cost (Flow)

- Average Risk
- Modeled benefit vs. Plan, YN
- Modeled benefit vs. Plan, Y1YN
- Forecast benefit vs. Plan, Y1YN
- BCR based on Forecast
- Tail Average Risk
- Modeled benefit vs. Plan, YN
- Modeled benefit vs. Plan, Y1YN
- Forecast benefit vs. Plan, Y1YN

8.1.3. Version and Change Control within an RMAR

The Staff RMAR Proposal notes that because the RMAR compares results to an original plan over a period of four years or longer, the Result Phase could differ from the Plan Phase. SPD staff propose two possible reasons for differences between the Results Phase and the Plan Phase:

1. *Real changes to the risk environment*. These include changes to pre-mitigated risk, possibly due to new data regarding climate change; changes in mitigation timing or changes in mitigation effectiveness, perhaps due to improved technology; variances in capital and operating expenditures, etc.
2. *Changes due to organization, models and data, or subjective factors such as assumptions or opinions related to risk modeling*. These changes have nothing to do with real changes in risk or real mitigation impact. They are inevitable over the long periods covered by RMAR and may be necessary – we should

integrate improvements to risk models and data collection, even if it complicates reporting.

SPD staff argues that the purpose of the RMAR is to enable evaluation based on the real changes to the risk environment. However, SPD staff recommends that changes due to organization changes or models/data be captured and adjusted so that commensurability is maintained between the Plan Phase and Results Phase. The overarching idea proposed by SPD staff to maintain commensurability across the phases is to preserve the structures in place at the time of the Plan Phase (e.g., RRU, hierarchy, tranche, data used as inputs in models, modeling assumptions, etc.).

Relatedly, the Staff RMAR Proposal recognizes it will likely be infeasible to report every possible change from RMAR version to RMAR version and back to the original as this would require a replica RMAR for each combination of version changes. Instead, Staff suggest that the RMAR should include "bridging" tables and narratives that capture the key impacts of the changes, and establish that RMAR trends, variances, and comparisons are faithfully representing the risk environment, not organizational and methodological changes. The processes to enable theses "bridging" tables and narratives include:

- Recasting: Modeling the current scenario as if the original state of the organization was still in place to ensure commensurability. Any variances and other changes can be attributed to real changes in the risk environment.
- Backcasting: Achieves commensurability with the original plan by restating the history in terms of current models, data, and knowledge. Staff argue that models and data

must be backward-compatible with risk modeling history and the original plan for backcasting to be possible.[122]

- Replanning: Restatement of the original plan based on current reality due to model changes and unforeseen events that require a restatement of the plan. Staff recommend that there must be strict regulatory approval processes for a Replan as they should be rarely needed.

The Staff RMAR Proposal recommends that preserving the ability to recast and backcast be mandatory, and that utilities be required to have the processes and controls in place to perform recasts and backcasts. Staff recommends that the Commission develop specific guidelines and approval processes for replanning (See Section 8.1.5). [123]

8.1.4. Validating and Evaluating Mitigation Impact

The Staff RMAR Proposal presents four concepts to facilitate an evaluation of mitigation impact: standards, criteria, methodologies, and benchmarks. Standards are the means through which mitigation portfolios are assessed in meeting some RDF goal, such as minimum BCR thresholds or risk tolerance levels for average risk and tail risk. Criteria are the means through which mitigation portfolios are selected, such as safety versus reliability trade-offs. Methodologies are the methods used to calculate mitigation benefits and costs. Benchmarks are the means through which assessment of mitigations are pegged to related empirical phenomena through methods such as reference class

[122] The description of backcast presented in the Staff RMAR Proposal explains how it relates to the RMAR.

[123] *Id*. at 39 – 42.

forecasting. SPD staff recommend that the RMAR present the utility's case for the chosen mitigation and justify why it is optimal compared to the next best alternatives in a way this is rigorous and free of bias.

8.1.4.1. Evaluating Real Mitigation Impact

The Staff RMAR Proposal recommends that utilities should discuss their confidence in model results in the Plan Phase. For example, the utility could state how confident they are that the mitigation impact assumptions are accurate, based on internal data or industry norms. SPD staff argue that the utility could present confidence intervals for key results such as total risk reduction and BCR.

The Staff RMAR Proposal recommends that the utilities should discuss in the Results Phase the extent to which observed results are due to mitigation effectiveness as opposed to other factors such as chance, or changes in models, data, assumptions, or impacts from other risk drivers.[124]

8.1.4.2. Sensitivity Analysis

The Staff RMAR Proposal argues that because the RMAR depends heavily on modeled results as well as modeled plans and forecasts, sensitivity analysis should be performed on each model. SPD staff suggest that sensitivity analysis helps evaluators (and the modelers) understand whether mitigation decisions would change if model inputs and assumptions are changed. One additional area where sensitivity analysis should applied in the RMAR is the impact of new model versions on risk model outputs.

[124] Staff RMAR Proposal at 44-46.

8.1.5. SPD Staff Recommendations on RMAR

On the topic of RMAR, SPD staff recommends the following. First, the Commission should require the RMAR to be integrated into the RDF and require the utilities to regularly file updates to the RMAR in its most recent GRC proceeding along with notifications to the service list of its most recent RAMP proceeding. Definitions and terminology used in the RDF should all apply and be used consistently by the utilities when they produce the RMAR. Staff recommends that the Commission authorize SPD to file a Staff Resolution that accomplishes the following

- Determines the timing of the first RMAR submission and cadence of regular updates.
- Provides guidance for how the utility should demonstrate its confidence that observed results were due to mitigation effectiveness as opposed to other factors.
- Establishes detailed change control procedures for maintaining consistency and comparability between prior and future periods, and between plan, outcomes, results, and forecasts. The Resolution will include details about how and when recasts, backcasts, and replans should occur in the context of RMAR.
- Expands upon the list of required elements for an RMAR submission.[125]
- Allows for future limited changes to required elements to be made by SPD without the need for opening a proceeding or issuing a new Resolution.

[125] These elements were listed in Section 10.1 of the SPD Staff Proposal Workshop #3 RMAR at 54-55.

Second, SPD staff provides a Potential Approach for Utility Accountability[126] but recommends that the Commission not address this approach at this time. SPD recommends that the Commission direct SPD to hold a workshop in preparation for developing a Staff Resolution to further refine the Potential Approach for Utility Accountability or some other approach to holding the utilities accountable.

Third, in a future Staff Resolution, SPD staff recommends that the Commission authorize SPD to consider identifying and reducing duplication in other reporting processes, including the RSAR and SPM Reports.

Fourth, in a future Staff Resolution, SPD staff recommends that the Commission authorize SPD to establish procedures and objectives for conducting an audit of an RMAR, as well as an audit of the internal process and controls for producing the RMAR and its updates.

Fifth, SPD staff recommends that the Commission require each utility to conduct a backcast of the risk reduction achieved since its first RAMP filing using the RMAR structure. Staff recommend that the original RAMP backcast must at minimum provide an Average Risk Mitigation Benefit by Attribute Table for every mitigation and control included in a RAMP and GRC application.[127]

Sixth, SPD staff recommends that the Commission require each utility to include a summary of the RMAR Results Phase in RAMP and GRC filings. This

[126] Staff RMAR Proposal, Section 8.

[127] *See* Table 4.7 of the Staff RMAR Proposal at 33 – 34 for an example table.

requires making the following change to Row 9 of the RDF (language additions in *italics*):

9.	Risk Assessment	Using the Cost-Benefit Approach developed in accordance with Step 1A, for each Risk included in the Enterprise Risk Register, the utility will compute a monetized Safety Risk Value using only the Safety Attribute. The utility will sort its ERR Risks in descending order by the monetized Safety Risk Value. For the top 40% of ERR risks with a Safety Risk Value greater than zero dollars, the utility will compute a monetized Risk Value using at least the Safety, Reliability and Financial Attributes to determine the output for Step 2A. The output of Step 2A, along with the input from stakeholders described in Row 12 below, will be used to decide which risks will be addressed in the RAMP. *The output of Step 2A must include a summary of the Risk Mitigation Accountability Reporting Phase for each risk the utility intends to address in its RAMP application. This summary must include a copy of the utility's RMAR Outcomes Flow Table and Outcomes Stock Table. A narrative description must accompany these tables explaining any discrepancies between the modeled risk and the actual outcomes recorded during the previous GRC Cycle.* The Risk Assessment in preparation for RAMP will follow the steps in Rows 10 and 11.

8.2. Party Comments

Parties are split on the Staff RMAR Proposal, with TURN, EPUC/IS, and Cal Advocates generally in support and PG&E, the Sempra Companies, and SCE generally opposed. The intervenor parties suggest refinements to the Staff RMAR

Proposal while the utilities, while being aligned with the goals of the Staff RMAR Proposal, argue that the Staff RMAR Proposal is too complex, cannot achieve its objectives, or has not given adequate consideration to the consequences of implementing the RMAR as proposed by SPD staff.

TURN notes that RAMP estimates of Plan Phase values are not particularly relevant for RMAR purposes.[128] SCE agrees with TURN and suggests that the values adopted in the GRC decision should serve as the Plan Phase.[129] SCE suggests that the GRC forecasts be compared to actual deployed scope in the RMAR, which can be accomplished using the utilities' risk models at the control/mitigation level for initial reporting.[130] EPUC/IS argues that the only way to continuously improve efficiency and effectiveness between each successive GRC cycle is to compare actual versus forecasted progress.[131] However, the Sempra Companies emphasize that "actual" risk reduction cannot ever be known with certainty and that comparing forecast and actual risk reduction is an exercise in comparing estimates.[132]

The Sempra Companies agree with the Staff RMAR Proposal that the comparison between forecasts and outcomes could be insightful, but notes two challenges. First, many RAMP risks occur infrequently, which is difficult for flow tables which should report on annual risk reduction. Second, the time required to

[128] TURN Opening Comments on Workshop #3 at 2.

[129] SCE Reply Comments on Workshop #3 at 6.

[130] SCE Opening Comments on Workshop #3 at 9.

[131] EPUC/IS Opening Comments on Workshop #3 at 6.

[132] Sempra Opening Comments on Workshop #3 at 7.

effectively administer these analyses may be longer than the allotted timeframe of the RMAR.[133] SCE argues that for some risks, like Hydro Dam Failure, the risk event is so infrequent that the Outcome Tables would be filled with zeros or N/As. SCE also notes that the "outcomes" of a Cybersecurity risk event would be confidential. SCE notes that some outcome metrics are currently provided in the SPM Reports, albeit in a different format.[134]

TURN argues that Outcomes can be compared with the estimated post-mitigation risk values in the GRC adopted plan and that the Commission should require the utility to provide the reasons why the Outcomes differ from the GRC forecasts.[135] TURN also states that exploring the Outcomes in the RMAR could encourage a utility to conclude that it needs to change its assessment of the effectiveness of a mitigation or of the modelled likelihood of the risk event.[136] TURN's approach recognizes the Sempra Companies' comment that an Outcome is not the same as knowing actual risk reduction, but TURN expects the utilities to take the opportunity to explain what was learned from the Outcomes and why Outcomes may or may not be consistent with the Plan Phase forecasts.[137]

Cal Advocates supports including each of the tables listed in Section 10.1 as it will help the Commission to explain any discrepancies between the projected risk mitigation and the actual risk mitigation as described in D.14-12-

[133] Sempra Opening Comments on Workshop #3 at 7-8.

[134] SCE Opening Comments on Workshop #3 at 11.

[135] TURN Opening Comments on Workshop #3 at 10.

[136] TURN Opening Comments on Workshop #3 at 4.

[137] TURN Reply Comments on Workshop #3 at 3.

025.[138] TURN notes that none of the parties objected to the tables proposed in the Staff RMAR Proposal.[139] TURN recommends that in the Plan Phase Table the line item for "Net Mitigation Benefit" in the Plan Phase table be deleted, as this is a value that utilities are not currently required by the RDF to report.[140] TURN recommends adding Outcome Tables that compare Outcomes with the utility's Plan values for post-mitigation risk reduction, as well as compare the utility's Plan values for the key Accounts (line items) with the utility's revisions to those values based on actual results.[141]

Both Cal Advocates and EPUC/IS agree with the multidimensionality of RMAR tables and Cal Advocates in particular supports the dimensions listed in the Staff RMAR Proposal.[142] TURN also agrees with those dimensions, but recommend that tail average risk and risk tolerance not be included in the RMAR.[143] EPUC/IS suggests removing tail average and risk tolerance from RMAR tables.[144] TURN states that the RMAR should not have to wait for the resolution of the risk tolerance topic before being implemented.[145] EPUC/IS

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[138] Cal Advocates Opening Comments on Workshop #3 at 7.

[139] TURN Reply Comments on Workshop #3 at 5.

[140] TURN Opening Comments on Workshop #3 at 12.

[141] TURN Opening Comments on Workshop #3 at 5 – 6.

[142] Cal Advocates Opening Comments on Workshop #3 at 5, EPUC/IS Opening Comments on Workshop #3 at 6 – 7.

[143] TURN Opening Comments on Workshop #3 at 9.

[144] EPUC/IS Opening Comments on Workshop #3 at 8.

[145] TURN Opening Comments on Workshop #3 at 7.

recommends the Commission require the utilities demonstrate the impact of risk mitigations down to the tranche and RRU levels.[146]

SCE notes that the table names in Section 10.1 of the Staff RMAR Proposal may appear to work conceptually, but the actual format, terminology and content for the tables are confusing.[147] TURN states that terms that are used in the proposed Results Phase tables, such as "outcomes", "risk outcomes", "forecasts" and "actuals" would benefit from clear definitions and that, in the context of RMAR, the term "outcome" should be understood as the monetized impact of risk events that have occurred in a year.[148] PG&E agrees with TURN and SCE that greater clarity is needed in many of the terms and recommended that revisions be made to a Lexicon.[149]

TURN recommends changing the sentence in SPD's proposed modifications of Row 9 that reads "This summary must include a copy of the utility's RMAR Outcomes Flow Table and Outcomes Stock Table" to: "This summary must include tables showing *for each risk: (1) the RMAR table showing the Outcomes compared to the Plan Phase post-mitigation risk; and (2) the RMAR table comparing Plan Phase values for risk reduction and residual risk to the utility's revisions to those values based on actual results.*"[150]

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[146] EPUC/IS Reply Comments on Workshop #3 at 3.

[147] SCE Opening Comments on Workshop #3 at 10.

[148] TURN Opening Comments on Workshop #3 at 4

[149] PG&E Reply Comments on Workshop #3 at 4.

[150] TURN Opening Comments on Workshop #3 at 6.

Parties generally agree that progress on work units should be included in an RMAR submission. SCE notes that this information is already submitted by the utilities in the RMAR and if the Commission adopts such a requirement for RMAR, it should only be applicable if the utility's forecast is in work units.[151] TURN argues that the inclusion of work units in the RSAR is not a reason to exclude it from the RMAR, as stakeholders should not have to cross-reference the RSAR to understand the results provided in the RMAR.[152]

TURN and Cal Advocates support the requirement for utilities to explain how changes to utility risk models will impact their RMAR submissions.[153] SCE states that this content should be included but suggests there should be a relevancy threshold and triggers for determining when a utility should undertake recasting, backcasting, or replanning.[154] Cal Advocates presents the following table for establishing triggers:[155]

Commission-required Action	Scenario
Recast	Change in risk model that results in a change in the reported risk reduction of a given mitigation.
Backcast	Change in risk model that results in a change in the reported risk reduction of a given mitigation.

[151] SCE Opening Comments on Workshop #3 at 12.

[152] TURN Opening Comments on Workshop #3 at 11.

[153] TURN Opening Comments on Workshop #3 at 13, Cal Advocates Opening Comments on Workshop #3 at 8.

[154] SCE Opening Comments on Workshop #3 at 14.

[155] Cal Advocates Opening Comments on Workshop #3 at 9.

Replan	Repeated consequential risk model changes or unforeseen event such as a new mitigation coming to light.

SCE argues that Cal Advocates' triggers are too generic and high-level and may require the utility to complete these analyses on a near daily basis. [156] The Sempra Companies also describe Cal Advocates scenarios as under specified and recommends additional discussion on this topic.[157]

PG&E is opposed to any backcasting requirement for the RMAR, RRUs, RAMP, GRC and/or other risk-related filings and reports. Instead, PG&E presents an approach where they plot two curves of risk, one from the old model and one from the updated model, using the same inputs. PG&E claims that the difference between the curves reflect variability from model uncertainty.[158] TURN argues that PG&E's approach makes the case for backcasting because it is disjointed from past estimates and provides no context for why the current year estimate has changed from the original estimate.[159] Cal Advocates similarly notes that PG&E's approach only captures forward-looking changes to the risk buydown curve and does not capture how up-to-date risk data and analysis changes PG&E's risk profile and risk buydown curve.[160]

TURN, EPUC/IS, and Cal Advocates all support the use of causal narratives in the RMAR to demonstrate the relationship between mitigation

[156] SCE Reply Comments on Workshop #3 at 10.

[157] Sempra Reply Comments on Workshop #3 at 9.

[158] PG&E Opening Comments on Workshop #3 at 12.

[159] TURN Reply Comments on Workshop #3 at 6.

[160] Cal Advocates Reply Comments on Workshop #3 at 4-5.

implementation and the stated risk reduction and a demonstration of how a utility can attribute risk reduction to the mitigation implementation.[161] TURN states that utilities can provide their best explanation of the causes of variances between Plan Phase forecasts and Results Phase outcomes in the narrative sections of the RMAR.[162] Similarly, TURN states that the utilities can provide narrative explanations regarding whether achieved risk reduction should be attributable to mitigations or causes other than mitigations.[163] All three utilities are cautious about providing causal narratives.[164] TURN does not expect causation and attribution estimates to be precisely accurate, but argues the utilities should have good reason for deploying each mitigation.[165] EPUC/IS contends that it is the utilities responsibility to demonstrate the causal relationship of their risk mitigation efforts, which should also take into account the interrelationships between various risk mitigations.[166] EPUC/IS argues that even if a utility's confidence in the accuracy of its inference is low, it should be required to declare that lack of confidence, and put forth steps to improve the utility's ability to infer the attribution of risk reduction to a mitigation.[167]

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[161] TURN Opening Comments on Workshop #3 at 13-14, Cal Advocates Opening Comments on Workshop #3 at 9-10, EPUC/IS Opening Comments at 9-10.

[162] TURN Opening Comments on Workshop #3 at 13-14.

[163] TURN Opening Comments on Workshop #3 at 14.

[164] SCE Opening Comments on Workshop #3 at 16-18, Sempra Companies Opening Comments on Workshop #3 at 11-12, PG&E Opening Comments at 13.

[165] TURN Reply Comments on Workshop #3 at 6-7.

[166] EPUC/IS Reply Comments on Workshop #3 at 5.

[167] EPUC/IS Reply Comments on Workshop #3 at 7.

Most parties agree that the RMAR should not be filed as an advice letter but rather filed directly to the docket. TURN suggests that SPD staff can issue deficiency letters as necessary as they conduct their review of the submitted RMAR.[168] SCE, the Sempra Companies, TURN and Cal Advocates all agree that the RMAR should follow the same submission guidelines as required by the RSAR.[169] TURN suggests that the RMAR should also be posted on a CPUC webpage for RMAR reports, similar to the current RSAR page.[170] PG&E suggests that the RMAR be submitted in the utility's currently open GRC proceeding in the year following the last year of the applicable historic period covered by the report. PG&E recommends that issues arising from SPD staff and intervenor evaluation can be addressed in the utility's subsequent RAMP and GRC applications.[171]

The utilities recommend allowing them to pilot an RMAR before allowing any kind of enforcement to take place. SCE argues that through a test-run of the RMAR utilities could better understand the new resources needed.[172] PG&E recommends a simple pilot that should include the following features:

- Pilots should be for a selected subset of risks.

[168] TURN Opening Comments on Workshop #3 at 19.

[169] TURN Opening Comments on Workshop #3 at 18, Cal Advocates Opening Comments on Workshop #3 at 13, Sempra Companies Opening Comments on Workshop #3 at 15, SCE Opening Comments on Workshop #3 at 21.

[170] TURN Opening Comments on Workshop #3 at 18.

[171] PG&E Opening Comments on Workshop #3 at 16.

[172] SCE Opening Comments on Workshop #3 at 23.

- The reports would calculate risk reduction from actual mitigations performed in the selected historic period.
- Mitigations would be at the program level (i.e., not RRUs or tranches) to match the funding/programs adopted in the GRC.
- The actual risk reductions would be compared to forecast risk reduction from mitigations adopted/funded in the GRC.
- For the pilot a utility would use the same risk modelling used to forecast the risk reduction when the mitigations were proposed.
- The RMAR can be refined and expanded if desired after feedback on the pilot reports by the utilities.[173]

The Sempra Companies provide their own pilot approach with a focus on reporting period-to-period change in risk estimates and excluding costs, with a requirement to also normalize for non-mitigation effects on the risk estimation. The pilot would explore a set of measures that describe risk as a probability distribution including expected value, scaled expected value, standard deviation, percentiles, and tail risk. The Sempra Companies would expect the pilot to require the reporting of updates to risk models or external changes that can affect the change in risk estimation in order to "normalize" the period-to-period change in the risk distribution. [174] TURN argues that the Sempra Companies' approach is limited to a few general concepts and concerns that it would like to see addressed in an RMAR but does not provide recommendations for tables or

[173] PG&E Opening Comments on Workshop #3 at 17-18.

[174] Sempra Companies Opening Comments, Appendix.

specific information that should be reported in the pilot.[175] Cal Advocates disagrees with all of the utilities requests to pilot the RMAR because this may provide the Commission with an incomplete experience from which to learn about costs, data, reporting, and resources necessary to comply with RMAR requirements.[176] Cal Advocates does not see an advantage to piloting the RMAR because of the required transition period between the pilot and the actual RMAR and the reduced imperative of a pilot relative to the actual RMAR to provide accurate data.[177]

Parties generally agree that SPD staff should hold another workshop to discuss the enforcement framework, the timing of when RMAR reports should begin, approaches to determining attribution, and any other RMAR related topics the Commission deems necessary to refine within a Staff Resolution. EPUC/IS recommends that to streamline the process the staff Resolution should be based on the Staff RMAR Proposal, comments received during Workshop #3, and Opening and Reply Comments filed on the Staff Proposal and Workshop #3 questions.[178] TURN recommends the following schedule for a follow-on Resolution:

Event	Timing (days from Initial Event)[179]
Issuance of Ph. 4 Decision re RMAR	0 days

[175] TURN Reply Comments on Workshop #3 at 7.

[176] Cal Advocates Reply Comments on Workshop #3 at 2-3.

[177] Cal Advocates Opening Comments on Workshop #3 at 16.

[178] EPUC/IS Opening Comments at 12.

[179] TURN Opening Comments at 19. TURN noted that in terms of the timing of the events, these are their recommended minimum intervals.

SPD-Led Workshop	+ 30 days
Post-Workshop Opening Comments	+ 55 days
Post-Workshop Reply Comments	+ 65 days
Draft Resolution Issued	+ 95 days
Final Resolution Issued	+ 125 days

Cal Advocates suggests that the Staff Resolution should be issued within 90 days of the Phase 4 Decision's adoption and recommends the following schedule for a Staff Resolution:

Step	**Timeframe**[180]
Commission-held workshop on timing, approaches to attribution, and other RMAR aspects	Within 30 days of the Final Decision vote
Opening Comments	14 days after workshop
Reply Comments	14 days after opening comments due
Draft Resolution Issued for public comment	30 days after reply comments
Final Resolution voted out	30 days after Draft Resolution issued.

SCE disagrees with TURN and Cal Advocates' assumption that a single workshop will suffice to resolve all of the RMAR-related issues.[181]

8.3. Discussion

The Commission adopts SPD staff's recommendations with the refinements provided in this discussion section. We agree with SCE, TURN, PG&E, and Cal Advocates that in the context of the RMAR, the Commission adopted GRC decision ideally would serve as the Plan Phase to avoid having two versions of mitigation forecasts. The RMAR tables will be reported at the mitigation program level and we note that intervenors and SPD staff can seek RRU-level data underlying an RMAR through a data request during their

[180] Cal Advocates Opening Comments at 15.

[181] SCE Reply Comments at 6.

evaluation of an RMAR. In accordance with General Order 66-D, utilities may seek confidential treatment of some RMAR Outcomes data.

The Commission adopts the RMAR Guidelines attached to this decision as Appendix C. Appendix C provides definitions for the key terms in the Staff RMAR Proposal, explanations of RMAR line-items, the required tables and table elements, and the required narrative sections.

Based on party comments, Appendix C refines some of the terminology found in the Staff RMAR Proposal. For instance, the high-level term Results Phase is confusing because it also includes the presentation of Results, which are a data point. For that reason, we change the Results Phase to the Reporting Phase. The Staff RMAR Proposal often refers to Projections in the Plan Phase, but it is more common for Commission decisions to adopt "forecasts" in a GRC decision, not "projections". Since an adopted GRC decision would serve as the basis for the Plan Phase, in Appendix C we refer to Forecasts in the Plan Phase in lieu of Projections. Additionally, the term Outcome has a distinct usage within the RDF, which as TURN correctly identified, is not exactly equivalent to the way "outcome" is used in the Staff RMAR Proposal. Therefore, in Appendix C, we use the term Monetized Outcomes. To restate, utilities shall present Forecasts in the Plan Phase Tables and present Outcomes, Results, and Projections in the Reporting Phase Tables. The Reporting Phase Tables are the section of RMAR that compares Monetized Outcomes, Results and Projections to the Forecasts from the Plan Phase. Finally, in Appendix C we also clearly make a distinction between the source of values for line-items in the Plan Phase and the Reporting Phase. All values listed in a Plan Phase Table are a modelled forecast. Values

listed in a Reporting Phase Table may be a modeled result, a modeled projection, an actual result, or an actual outcome.[182]

Some RMAR definitions need to be clarified in the context of the RDF. In addition to the definitions listed in Appendix C, we add the following definitions to the RDF in Appendix A (additions in *italics*):

- *Hierarchy: 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 (e.g., High-Fire Threat Districts, circuits, regions, etc.)*
- *Version: The risk model or methodology used to generate calculations for a given mitigation at a specific point in time.*
- *Work Unit: A metric used to quantify the scope of a program and to understand utility risk spending (e.g., circuit miles).*

As TURN notes, parties generally accepted the tables listed in Section 10.1 of the Staff RMAR Proposal. We agree with TURN that the term Net Mitigation Benefit should be removed from Plan Phase Tables and the Net Mitigation Benefits line-item is no longer present in Appendix C. We agree with TURN and EPUC/IS that reference to risk tolerance should not be included in the RMAR Tables until the Commission provides greater guidance with regard to how the utilities will apply risk tolerance thresholds to their RAMP and GRC applications. We are not persuaded that tail risk should be removed from the RMAR Tables. The RDF still grants the utilities the flexibility to present tail risk in RAMP and GRC applications. Since modelled forecasts of tail risk may be part of the decision-making in a GRC decision, this information should also be

[182] *See* Appendix C at C-3 of the expectation of each line-item in the Reporting Phase Table.

presented in an RMAR, both in Plan Phase and Reporting Phase Tables, and should receive scrutiny from SPD staff and intervenors.

We clarify that the Reporting Phase requires utilities to present mitigation benefits based on modeled results (i.e., based on units of work actually performed) and mitigation costs based on actual results (i.e., based on dollars spent). We agree with TURN that the Reporting Phase BCRs should be based on the utility's revised estimates of mitigation benefits, divided by the revised mitigation costs.

We find TURN's recommendation for Monetized Outcome Tables vague; without an example table it is difficult to discern what kind of table TURN envisions. Similarly, we find TURN's recommended language change to Row 9 difficult to follow, as it is not clear what two tables TURN is referring to. As such, we do not adopt TURN's proposed language change in this decision and instead adopt the changes to Row 9 recommended by SPD staff (additions in *italics* and deletions in ~~strikethrough~~; includes the additions made in Section 5.2):

9.	Risk Assessment	Using the Cost-Benefit Approach developed in accordance with Step 1A, for each Risk included in the Enterprise Risk Register (ERR), the utility will compute a monetized Safety Risk Value using only the Safety Attribute. The utility will sort its ERR Risks in descending order by the monetized Safety Risk Value. For the top 40% of ERR risks with a Safety Risk Value greater than zero dollars, the utility will compute a monetized Risk Value using at least the Safety, Reliability and Financial Attributes to determine the output for Step 2A. The output of Step 2A, along with the input from stakeholders described in Row 12 below, will be used to decide which risks will be addressed in the RAMP. *The output of Step 2A must include a calculation of Overall Residual Risk for a given risk presented in the RAMP filing, along with a diagram and supporting workpapers demonstrating the change of Overall Residual Risk since the utility's first RAMP filing. Diagrams and supporting workpapers must also include a disaggregation of the Overall Residual Risk values based on the Consequence Attributes, both in natural units and dollar values, as well as display the Likelihood of those Consequence Attributes.* *The output of Step 2A must include a summary of the Risk Mitigation Accountability Report Reporting Phase for each risk the utility intends to address in its RAMP application. This summary must include a copy of the utility's Monetized Outcomes Flow Table by Attribute for each Risk Event and Monetized Outcomes Stock Table by Attribute for each Risk Event. A narrative description must accompany these tables explaining any discrepancies between the modeled risk and the monetized outcomes recorded during the previous GRC Cycle.*

		The Risk Assessment in preparation for RAMP will follow the steps in Rows 10 and 11.

SCE and the Sempra Companies argue that the fact that some risks occur infrequently will provide challenges in completing the Monetized Outcome Tables. We agree with TURN that the RMAR provides the utilities an opportunity to explain what was learned from the Monetized Outcomes and why Monetized Outcomes may or may not be consistent with the modeled forecasts of post-mitigated risk in the Plan Phase.

We agree with the parties that submission of the RMAR should follow the RSAR guidelines. That is, the utility shall file and serve the RMAR in: (1) the applicable GRC proceeding(s) in which funding for the risk mitigation activities and spending was authorized; and (2) the current or most recent RAMP and GRC proceedings. Additionally, we agree with TURN that the Commission should post the RMAR and any staff evaluation on a Commission webpage.

We agree with the Staff RMAR Proposal recommendation to defer discussion of the Potential Enforcement Framework and support the development of a workshop and Staff Resolution to address the topic of accountability in full. We also agree with the Staff RMAR Proposal that a future Staff Resolution should also address the timing of the first RMAR filing. Thus, at this time, we agree with TURN and Cal Advocates that it is not necessary to have the utilities pilot the RMAR.

We agree with the Staff RMAR Proposal that there is a need to provide greater guidance regarding recasting, backcasting and replanning through a Staff Resolution. SCE is correct that part of this guidance should include triggers for determining when the utility should undertake a recast, backcast or replan. The Commission agrees that there is a need for the utilities to conduct an original RAMP backcast using the RMAR structure and filed with its first RMAR submission. Precisely which RMAR tables in Appendix C the utility should fill out when completing the original RAMP backcast can be discussed in a workshop to develop a Staff Resolution.

The Commission is persuaded of the need for the utilities to present causal narratives of risk reduction and demonstrate how they can attribute risk reduction to a given mitigation. We agree with TURN that inferring attribution can be presented in narrative sections of the RMAR and we have included such a requirement in Appendix C.

Several issues related to the RMAR are in need of resolution, including:

- Determining the timing of the first RMAR submission and cadence of regular updates.

- Determining a final Approach for Utility Accountability that explores the Potential Enforcement Framework, the applicability of PUC 451.8 or some other approach.
- Determining how the utility should demonstrate its confidence that observed results were due to mitigation effectiveness as opposed to other factors.
- Establishing detailed change control procedures for maintaining consistency and comparability between prior and future periods, and between plan, outcomes, results, and forecasts. The Resolution will include details about how and when recasts, backcasts and replans should occur in the context of RMAR.
- Determining which RMAR Tables in Appendix C should be filled out when the utility completes its original RAMP backcast.
- Expanding upon the list of required elements for an RMAR submission found in Appendix C of this Decision.
- Allowing for future limited changes to the required elements in Appendix C to be made by SPD without the need for opening a proceeding or issuing a new Resolution.

As such, SPD staff should hold a workshop (or workshops) on these issues before issuing a Staff Resolution for comment. We agree with EPUC/IS that the remaining topics to be addressed in a Staff Resolution should be based on the Staff RMAR Proposal, comments received during Workshop #3, and Opening and Reply Comments filed on the Staff RMAR Proposal and Workshop #3 questions. We recommend that Staff host the workshop within 120 days after the issuance of the Phase 4 Decision.

9. Key Term Refinements

To ameliorate possible confusion, we provide three key term refinements in the RDF that do not change the substance of the terms. First, what has previously been called the Cost-Benefit Ratio (CBR) is calculated by dividing the benefit by the cost. As such, it is more appropriately called the Benefit-Cost Ratio (BCR), as used throughout this decision. All mentions to CBR in the RDF have been replaced with BCR. Cost Benefit Approach and Benefit Cost Approach can be used interchangeably, as they do not describe a specific relationship between two values like a BCR, but instead a form of analysis. As such, we make no changes to references to Cost Benefit Approach.

Second, the CPUC-jurisdictional forecast program cost thresholds that determine whether a Step 3 Supplemental Analysis in the GRC is required for a program included in the GRC application, as described in Row 28 of the RDF, should be based on a four-year GRC cycle instead of a three-year GRC cycle. For PG&E, SCE, and SoCalGas, the threshold for capital programs changes from a cumulative $75 million over three years to a cumulative $100 million over four years while the threshold for expense programs changes from a cumulative $15 million in the test year to a cumulative $20 million in the test year. For SDG&E, the threshold for capital programs changes from a cumulative $37.5 million over three years to a cumulative $50 million over four years while the threshold for expense programs changes from a cumulative $7.5 million in the test year to a cumulative $10 million in the test year. These changes are reflected in Row 28 of the RDF, Appendix A.

Finally, the definition of Risk in the RDF lexicon includes the word "often" that may be mistakenly interpreted to mean that Risk as described in the RDF is but one of many possible definitions. We remove "often" from the definition of Risk to clarify that Risk is defined as the product of the LoRE and the CoRE. This is reflected in the Definitions section of the RDF, Appendix A.

10. RAMP Data Templates

RAMP and GRC filings are complex and cover hundreds of program areas and related risk mitigations, risk scores, and other information. Within the present proceeding, Cal Advocates has recommended that the Commission prioritize consideration of data templates to support RAMP and GRC applications to ensure transparent utility reporting of:

- Appropriate units used for a specific mitigation, such as circuit miles, pipeline miles, asset units, staffing levels, inspection levels;
- The cost-efficiency for the specific levels of risk mitigation programs;
- Past and proposed effectiveness of risk mitigation programs, considering safety performance metrics, safety and operational metrics, or other specific mitigation effectiveness measures; and
- Past, current, and projected progress on all risk mitigation programs.[183]

[183] R.20-07-013, Cal Advocates Comments on Phase 3 Roadmap at 3.

During Phase 3 Workshop #5 of the RDF Proceeding, Cal Advocates submitted a data template for party comment.[184] The Commission determined in D.24-05-064 that the process, timing, and lexicon for the Risk Mitigation templates need further development. [185] In that decision, the Commission also authorized continuation of the TWG, established in D.21-11-009, to prepare and propose recommendations for refining the RAMP and GRC templates.[186] In the Phase 4 Scoping Memo, the Commission established that the TWG would support Track 2 to answer the following questions:

- Should the Commission adopt required templates for data presentation for use in the RAMPs as proposed by Cal Advocates? If so, what should be the information requirements and format of the templates?
- What structured method, if any, for collecting and consolidating the more granular project-level data necessary to support the utilities' proposed risk mitigation projects and show how the utilities determine specific targets and forecasts should be integrated into the RDF and adopted for use by the utilities?[187]

The Phase 4 TWG addressing RAMP and GRC Data Templates was convened by SPD Staff on January 24, January 27, January 28, January 29, January 30, 2025. During the TWG, SPD, Cal Advocates, PG&E, SCE, SoCalGas,

[184] R.20-07-013, Phase 3 Workshop #5, Cal Advocates, Recommendation to Develop Risk Mitigation Project Templates, October 31, 2023.

[185] D.24-05-064 at 110.

[186] *Id*. at 123.

[187] R.20-07-013, Phase 4 Scoping Memo, September 13, 2024, at 11.

and the Sempra Companies each presented a Data Template Guideline and Data Template. Pursuant to Administrative Law Judge's Ruling on TWG Material, Cal Advocates, PG&E, SCE, and the Sempra Companies each filed its Data Template Guideline and Data Template on February 18, 2025, and PG&E, SCE, and the Sempra Companies jointly filed a summary report of the TWG on February 18, 2025.[188] Parties' Data Template Guideline and Data Template and the TWG are summarized below.

10.1. Review of Party Data Templates

10.1.1. SPD Data Template

SPD's Data Template consists of seven tables:

- Table 1: Data Set (General)
- Table 2: Cost Breakdown (General)
- Table 3: Risk Model Change Tracker (Electric Grid Infrastructure Specific)
- Table 4: High Fire Threat District and Associated Asset (Electric Grid Infrastructure Specific)
- Table 5: High Consequence Area/Moderate Consequence Area and Associated Assets (Gas Infrastructure Specific)
- Table 6: Financial Inputs (General)
- Table 7: Interruption Cost Estimate (ICE) Calculator Inputs

Table 1 collects key elements and characteristics of a RRU, including, but not limited to, unique identifiers, mitigation plans, and associated risks.[189] Table

[188] R.20-07-013, 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, at 2.

[189] For more information on the RRU, *vide supra*, Section 7: Definition of Scoped Work.

2 breaks down the costs associated with the mitigation of the RRU. Tables 3 and 4 are specific to the electric grid infrastructure. Table 3 tracks changes and updates to the risk modeling and how that affects the risk associated with the assets and systems mitigated by the RRUs. Table 4 documents low-risk associated assets mitigated alongside primary electric grid infrastructure due to operational constraints or interconnected systems,[190] and collects information on how mitigating the low-risk electric grid infrastructure associated assets affects the risk reduction, costs, and BCR of the proposed RRU. Similarly, Table 5, though specific to the gas infrastructure, documents low-risk gas infrastructure associated assets mitigated alongside primary gas infrastructure due to operational constraints or interconnected systems,[191] and collects information on how mitigating the low-risk gas infrastructure associated assets affects the risk reduction, costs, and BCR of the proposed RRU. Table 6 collects financial parameters and metrics required to calculate and evaluate risk mitigations, including discount rates, customer-minute interruptions (CMI), the value of

[190] In Table 4, "low-risk" is defined as electric grid infrastructure assets whose risk level is below the threshold of two standard deviations (where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average risk of electric grid infrastructure assets mitigated by the RRU. R.20-07-013, Phase 4, Track 2, Safety Policy Division Proposed Data Template Guideline for RAMP and GRC Application, February 7, 2025, Footnote 9, at 5.

[191] In Table 5, "low-risk" is defined as gas infrastructure assets whose risk level is below the threshold of two standard deviations (where the standard deviation is a measure of the amount of variation of the values of a variable about its mean) compared to the median and average risk of gas infrastructure assets mitigated by the RRU. R.20-07-013, Phase 4, Track 2, Safety Policy Division Proposed Data Template Guideline for RAMP and GRC Application, February 7, 2025, Footnote 10, at 5.

statistical life (VSL), and the optional present value revenue requirements (PVRR). Lastly, Table 7 collects inputs that can be integrated into the ICE Calculator to estimate the cost per customer-minute interruption, by categorizing outages by time of day, season, and customer type.

Additionally, in SPD Staff's Data Template Guideline, Staff recommends that the Commission:

1. Allow SPD to be able to make updates and changes to the data template without the need for a Commission Decision or Staff Resolution. Utilities could also file Advice Letters to request updates and changes to the data template that staff could dispose of without a Staff Resolution.
2. Allow SPD to establish and organize a Data Template Working Group. This Working Group would allow parties to discuss any refinements that Staff need to make to the Data Templates.
3. These data templates are meant to be submitted with the utility's RAMP Application. As stated in the Phase 4 Workshop #1 Staff Proposal, when the utility files its GRC, it should file an update of the data template if any changes are made between filings.
4. In the middle of a RAMP or GRC Proceeding, if a utility intends to update the data template before the Proceeding closes, they must provide a justification for any changes made to the values found in the original data template submitted with the utility's Application.
5. Require SCE to submit these data templates with its 2026 RAMP Application.

6. Require the Sempra Companies to submit these data templates with its 2028 GRC Application.[192]

10.1.2. Cal Advocates Data Template

Cal Advocates' Data Template consists of four separate templates:

- Risk Mitigation Program template
- Risk Mitigation Project/RRU template
- Geospatial Data Schema – RRU Planned template
- Geospatial Data Schema – RRU Actual template

The Risk Mitigation Program template collects program level data such as mitigation program effectiveness, actual and forecast program costs, among others. The Risk Mitigation Project/RRU template collects project or RRU level data which typically includes elements such as the status of projects and measures (e.g., unit cost, budget, and assessment). The Geospatial Data Schema templates collect and consolidate geospatial data so that risks and mitigation projects/RRUs can then be graphically mapped to produce graphical displays of the circuit segments in the utilities' service territories that experience the greatest risk and where proposed mitigation projects/RRUs will be implemented. While the RRU Planned template collects geospatial data on projects/RRUs that the utilities intend to work on, the RRU Actual template collects geospatial data on projects/RRUs that the utilities actually worked on.[193]

[192] R.20-07-013, Phase 4, Track 2, Safety Policy Division Proposed Data Template Guideline for RAMP and GRC Application, February 7, 2025, at 20.

[193] R.20-07-013, Phase 4, Track 2, Public Advocates Office Proposal to Develop Data Templates, February 18, 2025.

10.1.3. PG&E Data Template

PG&E's Data Template consists of two tables: Risk Results and RRU Supplemental. The Risk Results table emerged from the Transparency Proposal piloted by PG&E in its 2024 RAMP.[194] The RRU Supplemental table is derived from the Risk Results table. PG&E proposes to include RRU information in the Transparency Proposal by adding risk-related result types (e.g., "Risk Before," "Risk After").

10.1.4. SCE Data Template

SCE's Data Template consists of five tables:

- Mitigation Effectiveness (ME) Values
- Costs
- Work Units
- Baseline Input
- Summary

The ME Values table provides mitigation effectiveness values at driver/sub-driver level; rationale/data sources used to develop the mitigation effectiveness values; and useful life and its rationale. The Costs and Work Units tables provide unit costs, foundational costs, and work units by year and tranche. The Baseline Input table provides baseline risk driver frequency, consequence information, and the data sources used by year and tranche. The Summary table provides risk-related data (e.g., pre- and post-mitigated risk), BCR values, and other information by control/mitigation and tranche.

[194] D.21-11-009, Transparency Proposal, Appendix C; R.20-07-013, Pacific Gas and Electric Company's Test of the Transparency Pilot Guidelines, August 5, 2024.

10.1.5. Sempra Companies Data Template

The Sempra Companies' Data Template proposes to include the following tables, but the companies did not provide a table for all of the proposed tables. Tables missing from the template are indicated by an asterisk (*):

- 1. Master Inputs/Model Parameters
- 2. Risk Summary
- 2a. Pre-Mitigated Risk (Risk Level)*
- 2a.1. Expected Value
- 2a.2. Tail Risk
- 2b. Pre-Mitigated Risk (Tranche Level)
- 3. Mitigation Summary
- 3a. Cost (Mitigation Level)
- 3b. Cost (Tranche Level)*
- 3c. Benefits (Mitigation Level)*
- 3c.1. Expected Value
- 3c.2. Tail Risk
- 3d. Benefits (Tranche Level)*
- 4a. Mitigation Level BCR (Lifetime)*
- 4b. Mitigation Level BCR (TY and PTY)*
- 4b.1. TY 2028
- 4b.2. TY 2029
- 4b.3. TY 2030
- 4b.4. TY 2031
- 4c. Tranche Level BCR (Lifetime)*

Table 1 collects input values (e.g., discount rates, VSL, CMI) for calculations across the template. Table 2 enumerates risk characteristics, pre-

mitigated risk scores, mitigations, and tranches. Tables 2a.1 and 2a.2 provide expected value and tail risk calculations for safety, reliability, and financial attributes by risk level. Table 2b provides pre-mitigated risk at the tranche level. Table 3 quantifies BCR calculations by expected value, tail risk, and discount rates. Table 3a summarizes mitigation capital and operating costs for each year by mitigation level. Tables 3c.1 and 3c.2 summarize mitigation benefits at expected value and tail risk for safety, reliability, and financial attributes by mitigation level. Tables 4b.1, 4b.2, 4b.3, and 4b.4 provide mitigation costs and benefits for Test Year (TY) 2028 and attrition years 2029-2031 utilizing various discount rates.

10.2. Party Comments

PG&E, SCE, and the Sempra Companies oppose SPD staff's recommendation to allow SPD staff to make updates and changes to the data template without the need for a Commission decision or staff resolution. PG&E and SCE are concerned that such an approach could allow new RDF requirements to be instituted via the Data Template without proper deliberation and consideration by the Commission.[195] The Sempra Companies note that allowing SPD staff to revise the Data Template on its own accord is "inconsistent with due process."[196] Cal Advocates and TURN support SPD staff's

[195] PG&E Opening Comments on Technical Working Group at 15; SCE Reply Comments on Workshop #2 at 7.

[196] Sempra Companies Opening Comments on Technical Working Group at 2.

recommendation, with caveats. Cal Advocates argues that participation by parties should be required before the Data Template is revised.[197]

TURN supports a process that allows both utility and non-utility parties to have an equal opportunity to propose non-ministerial, material changes to the data templates. TURN asserts that the process should encourage participation by intervenors by allowing substantial contributions to be eligible for intervenor compensation. TURN asserts that the advice letter process should not be the only avenue for proposing changes, as advice letters may only be submitted by utilities. TURN asserts that all parties should be able to recommend changes in a process prescribed by SPD, in which parties present a recommended change and its rationale in a document served on all parties to this proceeding (or any successor proceeding), and then parties have a period of at least 14 days to respond. TURN suggests that any non-ministerial, material changes proposed by a party that SPD supports should be presented for comment in a Draft Resolution prepared by SPD, subject to comment before Commission adoption. TURN suggests any non-ministerial, material changes that SPD seeks on its own should be allowed to skip the prior comment process and go directly to a Draft Resolution for public comment. TURN asserts that SPD should retain discretion to supplement these processes with workshops or informal meetings as it deems appropriate, provided they are open to any interested persons and noticed through a communication to the service list for this (or any successor) proceeding. TURN argues that a Resolution process protects due process

[197] Public Advocates Office Opening Comments on Technical Working Group at 4.

principles by allowing a meaningful opportunity to comment on any proposed changes and ensures compliance with the delegation doctrine by requiring Commission approval of non-ministerial modifications.[198] PG&E notes that TURN's position is similar to its own, and recommends that a ministerial, non-material change be defined as a change solely focus on improving the presentation, accessibility, and comprehension of forecast-based information required by an utility in support of its RAMP and/or GRC application. PG&E recommends that updates to address past performance and accountability reporting be out of scope of the Data Template Working Group and should not be considered ministerial or non-material. Additionally, PG&E argues that a ministerial, non-material change does not institute or result in any new RDF requirements.[199]

No parties oppose SPD staff's recommendation that SPD staff be allowed to establish and organize a Data Templates Working Group where parties can propose and discuss refinements to the adopted data template. PG&E recommends that SPD staff summarize the working group deliberations, SPD staff recommend changes to the template, parties be provided the opportunity to submit comments and reply comments on SPD's recommendation, and the record be submitted for Commission resolution.[200]

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[198] TURN Opening Comments on Technical Working Group at 5 – 6.

[199] PG&E Reply Comments on Technical Working Group at 4.

[200] PG&E Opening Comments on Technical Working Group at 15.

PG&E, SCE, and the Sempra Companies generally oppose adoption of Cal Advocates' RAMP Data Template and Cal Advocates' recommendation that utilities submit annual updates of the RAMP Data Template. PG&E and SCE argue that the accountability data required in Cal Advocates' RAMP Data Template overlaps with data requirements in the annual RSAR and the proposed annual RMAR, thereby unfairly injecting accountability reporting into the data templates.[201] PG&E and SCE are concerned that RMAR requirements have yet to be finalized and adopted by the Commission and, as such, adopting Cal Advocates' RAMP Data Template would pre-ordain an RMAR approach when there are still major elements that need to be explored.[202] PG&E, SCE, and the Sempra Companies argue that because RAMP and GRC filings occur every four years, requiring annual updates to the Data Template would alter the requirements for RAMP and GRC applications without due consideration.[203] TURN supports Cal Advocates' recommendation for utilities to submit annual updates of the Data Template. TURN argues that the templates will supplement and complement the information currently required in annual RSAR and the expected annual RMAR by providing more granular information.[204]

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[201] PG&E Opening Comments on Technical Working Group at 13, 17-18; SCE Reply Comments on Technical Working Group at 5.

[202] PG&E Opening Comments on Technical Working Group at 2-3; SCE Reply Comments on Technical Working Group at 5.

[203] PG&E Opening Comments on Technical Working Group at 18; SCE Opening Comments on Technical Working Group at 12; Sempra Opening Comments on Technical Working Group at 4-5.

[204] TURN Opening Comments on Technical Working Group at 7.

Cal Advocates recommends that RRU geospatial location data and progress data be included in the Data Template. Cal Advocates argues that this data enables mapping of risks and progress to visually identify how mitigation projects prioritize and address the utility's highest risks.[205] PG&E and SCE question how mapping helps rank and prioritize mitigations and whether requiring geospatial information for all risks is useful or appropriate, though PG&E is not opposed to providing relevant geospatial information.[206] Cal Advocates clarifies that mapping enables the Commission and parties to obtain a better understanding of where the work is being done relative to the remaining risk, and emphasizes that its proposal does not require geospatial data for all risks, only risk mitigation projects where geospatial data is applicable.[207]

PG&E, SCE, and the Sempra Companies take issue with the Proposed and Alternative Mitigation field in SPD Staff's Data Template. SDP staff's proposal explains that this field enables comparing risk analyses of several mitigation options for the same RRU. PG&E states that even though this requirement exists for proposed undergrounding projects in a utility's Expedited Undergrounding Plan (EUP), the RDF currently requires alternative analysis only for mitigation programs, not RRUs. PG&E argues that by including this field in the Data Template, SPD staff has introduced a new requirement and that this and other

[205] Cal Advocates Opening Comments on Technical Working Group at 3.

[206] SCE Opening Comments on Technical Working Group at 8; PG&E Reply Comments on Technical Working Group at 3.

[207] Public Advocates Office Reply Comments on Technical Working Group at 13-15.

related fields be removed.[208] SCE and the Sempra Companies contend that D.14-12-025 directs utilities to include two alternative mitigation plans in their RAMP application, not two alternatives for each proposed RRU.[209] SCE urges the Commission not to adopt this sweeping new requirement without due consideration.[210] TURN supports requiring commensurable data for alternatives to the utilities' preferred mitigations and that this requirement be made explicit in the Commission's decision.[211] PG&E notes that it created a spreadsheet tool for TURN to compare commensurable data for system hardening initiatives to reduce wildfire risk.[212]

PG&E recommends that SPD Staff's Data Template allow the utilities to report the risk values they use in their forecasts (i.e., risk-adjusted or risk neutral) in the Pre-Mitigated Risk and Post-Mitigated Risk fields instead of requiring unscaled values. PG&E argues that this requirement imposes a risk-neutral attitude on utilities and is misleading because it assumes the adoption of the Staff Risk Tolerance Proposal.[213]

TURN recommends that the data template adopted in this proceeding include a field for the PVRR of the projects and programs covered by the

[208] PG&E Opening Comments on Technical Working Group at 5.

[209] SCE Opening Comments on Technical Working Group at 3; Sempra Opening Comments on Technical Working Group at 1-2.

[210] SCE Opening Comments on Technical Working Group at 4.

[211] TURN Opening Comments on Technical Working Group at 4.

[212] PG&E Reply Comments on Technical Working Group at 4-5.

[213] PG&E Opening Comments on Technical Working Group at 4-5.

template, and that the Commission modify the RDF to explicitly specify that costs of capital projects and programs used in BCR calculations must be based on the estimated PVRR. TURN agrees with SPD staff that the cost of programs and projects in RAMP and GRC submissions, particularly submissions related to the calculation of BCR, should be based on the present value of the full cost to ratepayers of those activities. TURN asserts that utilities do not include rate of return, taxes, and other loaders in the costs used to calculate the BCR of capital projects, which undervalues the total costs over the life of a capital asset, and leads to overstated BCRs. TURN further argues that including the full revenue requirement impact of capital investments is consistent with the intent of Pub. Util. Code Section 739.15, recently added by Assembly Bill 2847 (Addis, 2024), which authorizes the Commission, in utility application proceedings, to recover capital costs, and to require utilities to estimate the revenue requirement impacts for each year that the capital costs will remain in rate base.[214] The Sempra Companies and SCE disagree with TURN's recommendations on PVRR and encourage the Commission not to adopt them. As the Sempra Companies explain, determination of the final revenue requirement happens at the very end of the RAMP-to-GRC process, whereas RAMP forecasts are developed 3-4 years in advance of a GRC test year. As such, the Sempra Companies argue that the

[214] TURN Opening Comments on Technical Working Group at 2-3.

development of a revenue requirement estimate of RAMP costs at the beginning of the GRC process would provide no value.[215]

SCE recommends removing the Hybrid Discount Rate Field from SPD Staff's Data Template because this rate can be calculated using the Societal Discount Rate and Weighted Average Cost of Capital, which are both included in SPD staff's Data Template. SCE also recommends that the utilities be allowed to develop a reliability input table based on the actual data going into the RAMP models because the ICE 2.0 tool will not be available until the second or third quarter of 2025.[216]

In response to the utilities' request for flexibility in presenting data in pivoted or tabular form, Cal Advocates argues that the tabular format would be more useful and flexible for data analysis recommends that the Commission adopt the tabular template. Cal Advocates also recommends that utilities be permitted to supplement their data templates with pivoted data.[217]

Regarding new requirements resulting from Phase 4 of this Proceeding, the Sempra Companies agree with PG&E that new requirements should not apply to the Sempra Companies' TY 2028 GRC Application, on the principle that changes to the RDF should not be applied mid GRC cycle.[218] SCE recommends

[215] Sempra Companies Reply Comments on Technical Working Group at 5; SCE Reply Comments on Technical Working Group at 3.

[216] SCE Opening Comments on Technical Working Group at 4 – 5.

[217] Cal Advocates Opening Comments on Technical Working Group at 5 – 6.

[218] PG&E Opening Comments on Technical Working Group at 6; Sempra Reply Comments on Technical Working Group at 4.

that a suitable best practice would be to avoid imposing substantive new requirements on a particular utility if the utility's deadline to file its next RAMP falls within one year or less of the effective date of the new requirement.[219]

10.3. Discussion

The Commission is persuaded that the SPD Data Template, with the modifications described here, provides the data necessary to support evaluation of RAMP and GRC applications. It is reasonable to adopt the data template and its guidelines attached to this decision as Appendix D, which we now call the RAMP Data Template and Guidelines. We agree with SPD staff's recommendation that the RAMP Data Template first be submitted with the Sempra Companies' 2028 Test Year GRC Application and SCE's 2026 RAMP Application. We require the utilities to file the RAMP Data Template with every RAMP application filed after January 1, 2026. We adopt SPD staff's recommendations on the RRU to include the following language change to Row 26 of the RDF, as set forth in Appendix A (additions in *italics* and deletions in ~~strikethrough~~): "In the GRC, the utility will provide a ranking of Mitigations~~~~ *and Control Programs* by ~~Cost~~ Benefit-*Cost* Ratios, as follows: *(1) For any dataset of Risk Reporting Units submitted with the RAMP, the utility will provide an update of the dataset, if any is required, and provide an explanation of any differences from its RAMP filing and a justification for why the dataset from the RAMP filing required to be updated*." The Commission therefore requires that the utility file an updated version of the RAMP Data Template with its GRC application along with a

[219] R.20-07-013, Phase 4, Track 2, SCE Reply Comments at 7-8.

narrative explanation of any differences in the dataset compared with the version submitted in the RAMP.

Building on recommendations from TURN, we adopt the following process for making changes to the RAMP Data Template:

1. SPD or any utility or non-utility party may propose one or more changes to the RAMP Data Template by serving a document detailing the proposed change(s) and a rationale for each proposed change to the RAMP Data Template Notification List. In the case of change(s) proposed by a party, the document shall be served upon SPD on the same day it is served upon the RAMP Data Template Notification List.
2. SPD should compile the RAMP Data Template Notification List from the service list of R.20-07-013. Any person, including but not limited to parties of R.20-07-013, wishing to be added or removed from the RAMP Data Template Notification List should submit their request to the SPD. The RAMP Data Template Notification List should be published on the Commission's RAMP website.[220]
3. Parties shall have 15 calendar days to comment on a proposed change and 15 calendar days to reply to comments. Comments may support, oppose, and/or suggest modifications to the proposed change(s), and should include the rationale for any recommendations or positions taken.
4. After conclusion of the comment periods on proposed change(s), SPD may issue a disposition letter to the RAMP Data Template Notification List approving one or more proposed change(s). The disposition letter should explain any approved changes, address comments received, and explain proposed changes not approved.

[220] The Commission's RAMP website is currently located at https://www.cpuc.ca.gov/about-cpuc/divisions/safety-policy-division/risk-assessment-and-safety-analytics/risk-assessment-mitigation-phase.

5. SPD may approve in the same disposition letter changes proposed by more than one party and/or more than one document, and may also convene workshops or working group meetings to discuss any proposed changes.
6. Within 15 calendar days of a disposition letter from the SPD, any party may file and serve upon SPD and the RAMP Data Template Notification List a protest to SPD's disposition on approved changes. The protest shall explain the reason for the party's objection to the approved changes. Any party may within 15 calendar days serve a response to such a protest to SPD and the RAMP Data Template Notification List.
7. After receiving a protest to its disposition letter, SPD may prepare a draft Resolution for Commission consideration of the disputed changes. Alternatively, SPD may prepare and serve to the RAMP Data Template Notification List a modified disposition letter consistent with Paragraph 4 above, and subject to protest by parties as specified in Paragraph 6 above.
8. SPD may propose modifications to this process for making changes or modifications to the RAMP Data Template by preparing a Resolution for consideration by the Commission. Prior to mailing a draft Resolution proposing such modifications, SPD shall provide an explanation of its proposed modifications to the RAMP Data Template Notification List, and Parties shall have 30 calendar days to comment.
9. SPD shall maintain on the Commission website an updated version of the RAMP Data Template and RAMP Data Template Guidelines. SPD is authorized to update the RAMP Data Template Guidelines as necessary to address any changes made to the RAMP Data Template.

We agree with the utilities that the RAMP Data Template should be submitted with both RAMP and GRC filings and should not be updated annually. We are not persuaded that there would be significant benefit to ask the

utility for an annual update of the entire RAMP Data Template at the RRU level of granularity in each of the four years of a utility's GRC Cycle.

The Commission does recognize the benefit of linking geospatial data to the tabular data that informs the cost-benefit approach for determining which mitigations will be implemented to reduce a given risk. However, refinement of how best to integrate geospatial data into the RAMP Data Template is necessary. As such, we do not add geospatial data as a requirement in the RAMP Data Template at this time.

We find SPD staff's addition of the Proposed and Alternative Mitigation field to be an important addition to the data template. We also find that there is precedent for providing this kind of data and that this field has primarily been used to conduct analysis of wildfire mitigations in the past. We also agree with PG&E that the Proposed and Alternative Mitigation Field has relevance for the cost-recovery review of EUP required by Pub. Util. Code 8838.5. The Office of Energy Infrastructure Safety requires that large utilities include a comparison of the project to at least two Alternative Mitigations in their Undergrounding Plans.[221] We further note that PG&E has previously provided TURN spreadsheets for TURN to compare "apples-to-apples data" for comparison between PG&E's proposed and alternative mitigations. Thus, we are not convinced by SCE's assertion that this field would constitute a "new and sweeping requirement" within the context of a RAMP or GRC filing. The

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

Commission requires that when the Sempra Companies file the RAMP Data Template with their 2028 Test Year GRC Application, the Sempra Companies present, at minimum, two alternative mitigations for each proposed RRU that reduces Wildfire and/or PSPS risk. For the data template submitted with SCE's 2026 RAMP and its subsequent GRC application, the Commission requires that SCE present, at minimum, two alternative mitigations for each proposed RRU that reduces Wildfire and/or PSPS risk. The Commission authorizes consideration of the requirement to provide alternative mitigations at the RRU scale in the Data Template Technical Working Group. We authorize SPD staff to develop a Staff Resolution that identifies which mitigations, in addition to mitigations that reduce Wildfire and/or PSPS risk, should be presented with RRU-scale alternative mitigations.

We recognize that the final version of the SPD Data Template was submitted with the PVRR field as optional. We have continued to list the PVRR as optional in the RAMP Data Template. However, this does not remove the need for the utility to comply with the requirements of PUC 739.15. A successor proceeding may discuss whether PVRR should be required to make BCR calculations more accurate and representative of the lifetime costs of an RRU. We agree with SCE that calculation of the Hybrid Discount Rate in its own field is not necessary. We authorize SPD staff to update Table 7 of the RAMP Data Template when the ICE Calculator 2.0 becomes available. Finally, because this decision has deferred final resolution of the risk tolerance issue to a successor proceeding, we recognize that Row 5 of the RDF continues to allow utilities to present scaled consequence and risk values in RAMP and GRC applications. We

agree with SPD staff that it is important to have unscaled risk values at the RRU level presented in the RAMP Data Template so that SPD staff and parties can properly understand the implications of selecting and prioritizing a proposed mitigation without the influence of scaled BCRs. As such, we retain this requirement in the RAMP Data Template. We require utilities to submit a dataset with unscaled risk values, but utilities may submit another dataset with scaled risk values, if they desire.

11. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding. There were no public comments in this proceeding.

12. Conclusion

This decision adopts the changes to the Risk-Based Decision-Making Framework made in Appendix A. This decision also adopts the Risk Mitigation Accountability Report Guidelines in Appendix C and RAMP Data Template and Guidelines in Appendix D.

13. Procedural Matters

This decision affirms all rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All motions not ruled on are deemed denied.

14. Comments on Proposed Decision

The proposed decision of Commissioner John Reynolds in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 14, 2025, by EPUC/IS, PG&E, SCE, the Sempra Companies, TURN, and Cal Advocates, and reply comments were filed on August 19, 2025, by PG&E, EPUC/IS, SCE, MGRA, TURN, and the Sempra Companies. Changes have been made throughout the decision in response to these comments.

15. Assignment of Proceeding

John Reynolds is the assigned Commissioner and Jonathan Lakey is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. California ratepayers face growing challenges in affordability of utility rates.
2. Quantitative analytical tools and concepts in the RDF support the evaluation of proposals for safety investments.
3. Standardized tracking of mitigated risk improves transparency in the use of ratepayer funds and increases the accountability of the utilities in their use of these funds.
4. Requiring utilities to use a minimal set of budget-based scenarios in mitigation portfolio optimization can provide valuable factual information to better understand what impact different budget choices might have on achievable risk reduction.

5. RRU requirements may be inappropriate for Public Power Safety Shutoffs because Public Safety Power Shutoffs temporarily remove wildfire risk.

6. RRU requirements may be inappropriate for Protective Equipment and Device Settings because Protect Equipment and Device Settings temporarily remove wildfire risk.

Conclusions of Law

1. It is reasonable to close this proceeding.

2. It is reasonable to require that CoRE be represented as a probability distribution.

3. It is reasonable to modify Row 10 of the RDF to facilitate representation of CoRE as a probability distribution and to modify the Risk-Based Decision-Making Framework accordingly as set forth in Appendix A.

4. It is reasonable to add the definition of Probability Distribution to the RDF as set forth in Appendix A.

5. It is reasonable to modify the definitions of Consequence and Risk recommended by SPD staff and as set forth in Appendix A.

6. It is reasonable to modify Row 13 of the RDF to facilitate representation of CoRE as a probability distribution as set forth in Appendix A.

7. The definition for Overall Residual Risk should be added to the RDF as set forth in Appendix A.

8. The definition of Residual Risk in the RDF should be modified to reflect that Residual Risk applies to a given GRC cycle as set forth in Appendix A.

9. Row 9 of the RDF should be modified to incorporate the calculation and presentation of Overall Residual Risk as set forth in Appendix A.

10. It is reasonable to adopt a mitigation portfolio optimization framework in the RDF.

11. The optimization model used in mitigation portfolio optimization should include risk reduction as the objective function, the given budget level in dollars as the constraint, and whether a given mitigation is included in a portfolio or not as the decision variable.

12. It is reasonable to require, at minimum, the presentation in the RAMP of the optimal mitigation portfolios for four budget scenarios that are 85%, 90%, 95%, and 100% of the forecasted costs of Mitigations and Controls the filing utility proposed in its RAMP or current GRC.

13. Definitions for Baseline Cost Forecast, Budget Scenario, Enterprise Portfolio, Optimized (Enterprise or Risk Mitigation) Portfolio and Risk Mitigation Portfolio should be added to the RDF as set forth in Appendix A.

14. Row 25.1, which provides direction to utilities on the construction of Optimized Enterprise Portfolios, should be added to the RDF as set forth in Appendix A.

15. Row 25.2, which provides direction to utilities on the construction of Optimized Risk Mitigation Portfolios, should be added to the RDF as set forth in Appendix A.

16. Row 26 of the RDF should be modified to incorporate Optimized Enterprise Portfolios and Optimized Risk Mitigation Portfolios into the RDF as set forth in Appendix A.

17. Definitions for Asset, Backcast, Mitigation/Control Program, and Risk Reporting Unit should be added to the RDF as set forth in Appendix A.

18. The RRU should be auditable once the activity has taken place or the mitigation becomes used and useful.

19. It is reasonable to exempt PSPS and PEDS from the RRU requirements.

20. Row 14 of the RDF should be modified to integrate RRUs into the Definition of Risk Events and Tranches as set forth in Appendix A.

21. Row 16 of the RDF should be modified to integrate RRUs in Expressing Effects of a Mitigation as set forth in Appendix A.

22. Row 26 of the RDF should be modified to integrate RRUs into Mitigation Strategy Presentation in the RAMP and GRC as set forth in Appendix A.

23. Row 15.1 should be added to the RDF to define the Mitigation Risk Reporting Unit as set forth in Appendix A.

24. It is reasonable for the RMAR tables to be reported at the mitigation program level.

25. It is reasonable to adopt the RMAR Guidelines, attached to this decision as Appendix C.

26. Definitions for Hierarchy, Version, and Work Unit should be added to the RDF as set forth in Appendix A.

27. Row 9 of the RDF should be modified to incorporate a summary of the RMAR into the RDF as set forth in Appendix A.

28. It is reasonable for the submission of the RMAR to follow RSAR guidelines.

29. It is reasonable for the Commission to provide guidance to the utilities on recasting, backcasting, and replanning through a Staff Resolution.

30. It is reasonable to require the utilities to provide causal narratives of risk reduction in their RAMP filings and demonstrate how they can attribute risk reduction to a given mitigation.

31. It is reasonable for the Commission to determine the timing of the first RMAR submission and cadence of regular updates through a Staff Resolution.

32. It is reasonable for the Commission to determine an approach for utility accountability through a Staff Resolution.

33. It is reasonable for the Commission to determine how utilities should demonstrate their confidence that observed results were due to mitigation effectiveness as opposed to other factors through a Staff Resolution.

34. It is reasonable for the Commission to establish detailed RMAR change control procedures through a Staff Resolution.

35. It is reasonable for the Commission to determine which RMAR Tables from Appendix C should be filled out when the utilities complete their original RAMP backcast through a Staff Resolution.

36. It is reasonable for the Commission to modify or expand the list of required elements for a RMAR submission in Appendix C through a Staff Resolution.

37. It is reasonable for the Commission to determine through a Resolution whether to allow SPD staff to make limited changes to the required elements in Appendix C without the need for opening a proceeding or issuing a Staff Resolution.

38. It is reasonable for the Commission to allow SPD staff to hold a workshop or workshops prior to developing Staff Resolutions on topics related to the RMAR.

39. The Cost-Benefit Ratio should be referred to as the Benefit-Cost Ratio.

40. It is reasonable to modify Row 28 of the RDF to accurately reflect the four-year GRC cycle as set forth in Appendix A.

41. It is reasonable to remove the word "often" from the definition of Risk in the RDF as set forth in Appendix A.

42. It is reasonable to adopt the RAMP Data Template and Guidelines attached as Appendix D.

43. It is reasonable to require the utilities to file the RAMP Data Template with every RAMP application and GRC application filed after January 1, 2026, starting with the Sempra Companies' 2028 Test Year GRC Application and SCE's 2026 RAMP Application.

44. It is reasonable to require the utilities to file an updated version of the RAMP Data Template with their GRC applications with a narrative explanation of any differences in the dataset compared with the version submitted in their RAMP application.

45. It is reasonable to adopt the process described in Section 10.3 of this decision for making changes to the RAMP Data Template.

46. It is reasonable to include the Proposed and Alternative Mitigation Field in the RAMP Data Templates.

47. It is reasonable to require utilities to present in their RAMP Data Templates, at minimum, two alternative mitigations for each proposed RRU that

reduces Wildfire and/or PSPS risk, for GRC and RAMP applications filed after January 1, 2026, starting with the Sempra Companies' 2028 Test Year GRC Application and SCE's 2026 RAMP Application.

48. It is reasonable for the Commission, through a Staff Resolution, to identify which mitigations, in addition to mitigations that reduce Wildfire and/or PSPS risk, should be presented with RRU-scale alternative mitigations.

49. It is reasonable to authorize SPD staff to update Table 7 of the RAMP Data Template when the ICE Calculator 2.0 becomes available.

O R D E R

IT IS ORDERED that:

The Risk-Based Decision-Making Framework adopted in Decision 24-05-064 is modified as in accordance with Appendix A of this decision and applies to Risk Assessment Mitigation Phase applications and General Rate Case applications filed after January 1, 2026.

San Diego Gas & Electric Company and Southern California Gas Company shall present a minimum of two alternative mitigations for each proposed Risk Reporting Unit that reduces wildfire or Public Safety Power Shutoff risk in the Risk Assessment Mitigation Phase Data Template filed with their 2028 Test Year General Rate Case application.

Southern California Edison Company shall present a minimum of two alternative mitigations for each proposed Risk Reporting Unit that reduces wildfire or Public Safety Power Shutoff risk in the Risk Assessment Mitigation Phase Data Template filed with their 2026 Risk Assessment Mitigation Phase application.

Within 80 days of the issuance date of this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall jointly draft a survey report on approaches to risk tolerance in related industries and serve it on the service list of this proceeding. The survey report shall include the following information: whether a regulator sets the baseline risk tolerance, or, if not or if only partially, how industries or private companies set, implement, and modify risk tolerance thresholds. The survey report shall include, but is not limited to, the following industries: aviation, chemical, mining, oil and gas, nuclear, autonomous vehicles, spaceflight, investor-owned utilities in other jurisdictions, and large California investor-owned electric and/or gas utilities. For the section on large California investor-owned electric and/or gas utilities, the utilities shall include a description of the status quo, explaining the internal process of how each company currently sets the amount of risk they accept in safety, operations, and decision-making.

Rulemaking 20-07-013 is closed.

This order is effective today.

Date August 28, 2025, at San Francisco, California

ALICE REYNOLDS
President
JOHN REYNOLDS
KAREN DOUGLAS
DARCIE L. HOUCK
Commissioners

Commissioner Matthew Baker recused

himself from this agenda item and was not part of the quorum in its consideration.

Appendix A

(RDF Attachment)

(END OF APPENDIX A)

Appendix B

(RDF Redline – attachment)

(END OF APPENDIX B)

Appendix C

(RMAR Guidelines)

(END OF APPENDIX C)

Appendix D

(RAMP Data Template and Guidelines – Attachment)

(END OF APPENDIX D)