

Application: 25-05-
(U 39 M)
Exhibit No.: (PG&E-2)
Date: May 15, 2025
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY
2027 GENERAL RATE CASE
PREPARED TESTIMONY
EXHIBIT (PG&E-2)
POLICY



PACIFIC GAS AND ELECTRIC COMPANY
EXHIBIT (PG&E-2)
POLICY

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CHAPTER 1
SAFETY, RISK, AND CLIMATE RESILIENCE

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A. Introduction

This chapter provides an overview of the following three policy areas in the 2027 General Rate Case (2027 GRC): (1) Safety; (2) Risk; and (3) Climate Resilience.

PG&E is committed to protecting the health and safety of our workforce and the hometowns that we are privileged to serve. This includes managing our processes to prevent workplace injuries and illness; safely operating utility assets; mitigating safety risks across our utility systems; and addressing climate-change impacts. PG&E always keeps safety top of mind to promote a proactive and engaging safety culture that positions us to maintain and operate our utility without incident as we deliver safe, reliable, affordable and clean energy to our customers. Our efforts include implementing nearly 300 specific safety programs companywide to mitigate various risks across our electric and gas operations, power generation, and other functional areas. In addition, our investments are risk-informed to ensure that we appropriately prioritize and scope our work. Finally, we have initiated efforts to identify and quantify climate-change-related risks in order to make our systems more climate resilient.

We address these issues further below.

B. PG&E's Safety Excellence Policy

PG&E's commitment to protect the health and safety of our workforce and the public is documented in our Safety Excellence Policy. We expect that every task be completed without injury or incident as we deliver safe, reliable, resilient, clean, and affordable energy to our customers. Our safety stand, "everyone and everything is always safe," demonstrates our commitment to protecting and preserving life above all else. To make this stand a reality, we must put safety at the heart of all our decisions and actions and have the courage to stop work if it creates an unsafe situation, and only start work when it is safe. Our safety culture encourages us to show empathy to each other and our customers. It is

modeled by our leaders and embraced by each of us as we work in the communities we serve.¹

At PG&E, we are committed to fostering a proactive and engaging organizational culture and safety mindset.² This includes:

- Taking actions to eliminate public and workforce (includes coworkers and contractors) safety incidents and achieve an injury-free workplace with the full participation and engagement of the workforce.
- Creating healthy and safe conditions for our workforce, customers, and our hometowns.
- Managing our assets, including mitigating associated risks, and improving system performance throughout lifecycles to protect our customers, workforce, and environment.
- Generating and delivering safe, reliable, affordable, and clean energy to our customers and our hometowns.
- Complying with legal, regulatory, internal, and other health and safety requirements.
- Challenging ourselves to continuously improve and implement best practices.

Our safety stand and commitment to public safety is reflected in our GRC requests to: (1) implement our wildfire mitigation plan; (2) complete inspection and maintenance activities for electric, gas, and power generation assets; (3) perform emergency response activities; (4) install advanced metering infrastructure; and (5) comply with all applicable safety and health regulatory programs to protect our workforce and the public.

¹ PG&E's Safety Excellence Management System (PSEMS) Manual (April 2023), Message from Leadership, p. 2. The PSEMS Manual is included in workpapers supporting Exhibit (PG&E-7), Ch. 1, beginning on WP 1-25.

² An organizational culture and safety mindset is defined as the core values and behaviors resulting from a collective commitment from leaders and individuals to emphasize safety over competing goals to ensure the protection of people and the environment. Utility Standard SAFE-5005S (Feb. 22, 2024), Organizational Culture Safety Mindset, p. 8.

Through the disciplined application of the PG&E Safety Excellence Management System (PSEMS)^{3,4} PG&E will continue to achieve industry leading safety performance.

1. PG&E Safety Excellence Management System

The PG&E Safety Excellence Management System (PSEMS) provides the framework to systematically manage our processes, assets, and occupational health and safety to prevent injury and illness. This system enables our functional areas to continually improve safety and reflects our commitment to coworker, contractor, and public safety as discussed above.

The system drives continuous improvement in four areas: Asset Management, Occupational Health and Safety, Process Safety, and Organizational Culture and Safety Mindset. It consists of 13 elements that establish governance and operational requirements for how we operate our business to generate and deliver safe, reliable, resilient, clean, and affordable energy to our customers. Our coworkers follow these 13 elements to keep us safe. The elements include:



Leadership Commitment and Engagement. PG&E's safety stand requires that leaders establish expectations and objectives and visibly demonstrate a commitment to protecting the health and safety of our coworkers, contract partners, and the public. In alignment with our Safety Excellence Policy, leaders must engage the workforce to build a strong safety culture through activities such as all-hands meetings, townhalls, and site visits.



Communications and Stakeholder Engagement. PG&E must establish and maintain relationships with all stakeholders including the public through continuous and deliberate formal and informal communications and activities such as community public safety educational meetings including wildfire safety, and other public meetings.

³ Formerly, Health & Safety Management System (HSMS).

⁴ Exhibit (PG&E-7), WP 1-25, PSEMS Manual.



Risk Management. In support of PG&E's safety stand, risks must be identified and evaluated using defined processes that include workplace hazards and consequences and the safeguards to prevent or mitigate them to protect employees, contract partners, and the public. Our RAMP risk analyses are in alignment with this and informs the GRC.



Strategy, Objectives and Planning. PG&E's strategy for providing safe, reliable, affordable, and clean energy to our customers includes planning for the financial, human, and technology resources needed to achieve our safety stands, policies, and objectives. PG&E's Business Plan Deployment (BPD) process supports the achievement of this strategy.



Operational Control. PG&E's planning, execution, and control of work in a safe manner is the outcome of understanding workplace hazards, providing proper equipment and tools, following approved work procedures, recognizing hazard controls, and exercising the authority to Stop Work when needed.



Training and Competence. Safe and reliable PG&E operations rely on competent and qualified personnel and contract partners that safely perform their work responsibilities. Training provides the knowledge, skills, and abilities to proficiently perform work and keep our coworkers, contract partners and the public safe. Our training of workers is ongoing through PG&E Academy computer-based training, in-person hands on instruction, meetings, walkthroughs, and other related instructional methods.



Emergency Preparedness and Response. PG&E's emergency management plans and response activities protect customers and the public. We timely respond to incidents and manage emergency events impacting our workforce, the environment, customers, and communities to maintain safe and reliable operations.



Incident Reporting, Investigation and Corrective Action. PG&E incidents and near-hits are identified, reported, recorded, effectively investigated, and communicated. Learning from incidents, including near-hits, drives corrective actions, risk mitigation and improves the safety of our employees, contractors, customers, and the public.



Contracted Services and Purchased Goods. PG&E contractors must follow contract requirements and work performed must align with Company safety policies and procedures, and business objectives. High and medium risk work contractors are managed as part of the Enterprise Contractor Safety programs.



Management of Change (MOC). Changes to PG&E systems, processes, or people can introduce risk and have unintended consequences for our coworkers, contractors, customers, and the public. The MOC process systematically identifies, evaluates, and manages changes to facilities, equipment, operations, procedures, and the organization to prevent unacceptable risks from being introduced.



Information, Documentation and Records Management. PG&E organizations must ensure consistency and traceability in documents, procedures, records, and technical and other relevant non-financial data required to meet legal, regulatory, internal and stakeholder requirements and Company objectives to protect the public and the communities that we serve.

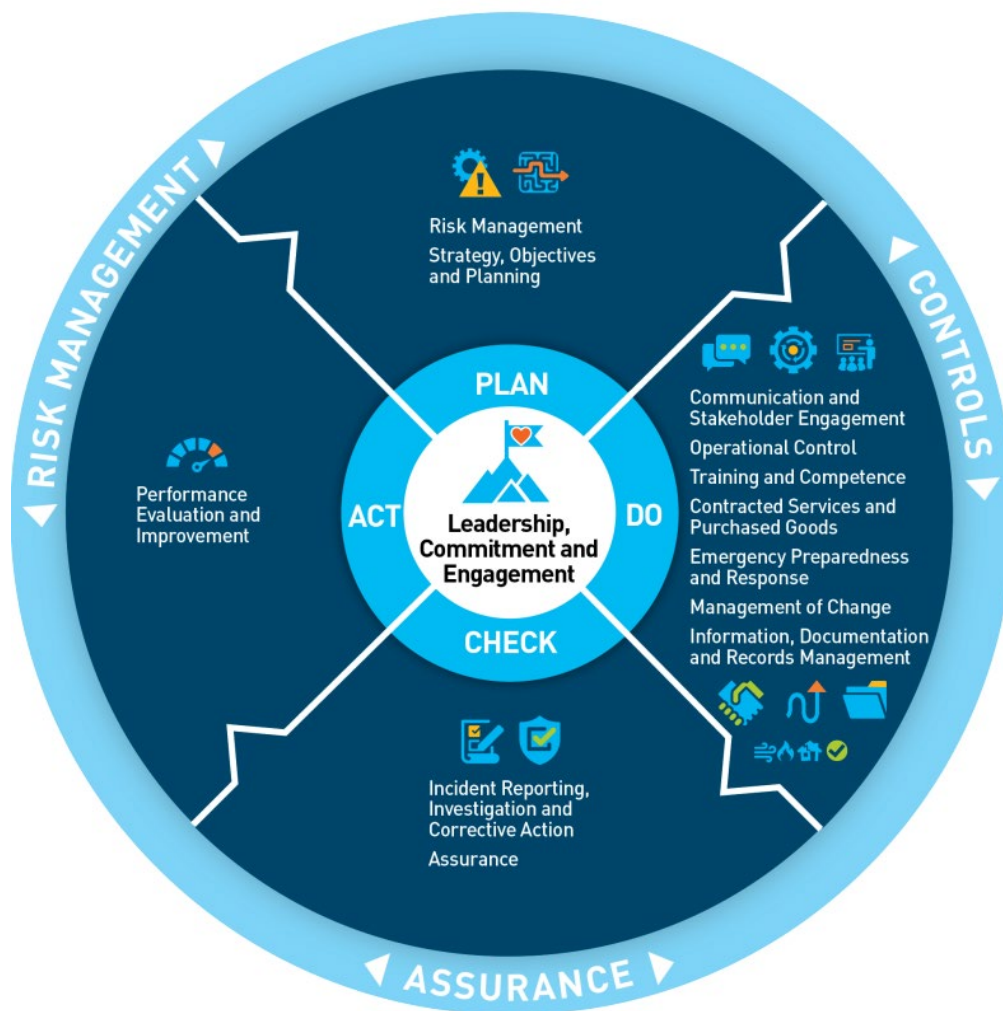


Performance Evaluation and Improvement. PG&E systematically evaluates its safety performance under PG&E's Safety Excellence Management System to drive continuous progress toward top safety performance. Our performance evaluation includes the use of the Plan-Do-Check-Act (PDCA) cycle to review results, establish objectives, assess gaps, prioritize gap closure plans, and execute and monitor the plans and drive improvement across PG&E. (See Figure 1-1 below.)



Assurance. Assurance establishes the necessary controls to achieve and improve safety excellence performance under PG&E's Safety Excellence Management System. Assurance includes compliance with legal, regulatory and PG&E's internal requirements to minimize risk.

**FIGURE 1-1
PSEMS MANAGEMENT SYSTEM CYCLE**



As shown in Figure 1-1, our PSEMS Management System Cycle drives continuous improvement through risk management and planning that informs the scope of various control changes (e.g., communication and stakeholder engagement, operational control, training and competence, etc.). Changes to controls assure safety performance improvements in alignment with our Safety Excellence Policy. Control changes are monitored

through incident reporting, field safety reviews, and investigations. Assurance identifies areas for improvement and informs risk management and planning processes. More information about PG&E's Safety Excellence Management System can be found in the PSEMS Manual.⁵

2. Safety Culture

PG&E's Organizational Culture and Safety Mindset applies to every PG&E employee and contractor, from our board of directors and senior leadership to individual contributors. While executive and senior managers are the leading advocates of safety, safety is a collective responsibility, and no one is exempt from the obligation to put safety first.⁶

The attributes of a Safety Conscious Work Environment (SCWE) and ten traits of a Healthy Safety Culture serve as the framework for our safety culture at PG&E. We describe these attributes and traits below.

a. Safety Conscious Work Environment (SCWE)

At its simplest, a Safety Conscious Work Environment is where: (1) employees feel free to raise safety concerns to their management and to the California Public Utilities Commission (CPUC), without fear of retaliation and (2) employee concerns are promptly reviewed, given the proper priority based on their potential safety significance, and (3) concerns are appropriately resolved with timely feedback to employees. SCWE is a critical element of achieving and maintaining a safety culture.

The attributes of PG&E's SCWE include:

- A management attitude that promotes employee involvement and confidence in raising and resolving concerns;
- A clearly communicated Safety Excellence Policy (see Section B, above) stating that safety has the utmost importance, overriding, if necessary, the demands of production and project schedules;
- A strong, independent assurance program;
- A training program that encourages a positive attitude toward safety;
- A safety ethic at all levels that is characterized by:

⁵ Exhibit (PG&E-7), WP 1-25, PSEMS Manual.

⁶ Utility Standard SAFE-5005S (Feb. 22, 2024), Organizational Culture and Safety Mindset, p. 1.

- An inherently questioning attitude;
- Attention to detail;
- Prevention of complacency;
- A commitment to excellence; and
- Personal accountability in safety matters.

b. The Ten Traits Of A Healthy Safety Culture

PG&E strives to embrace and embed the following ten traits included in Table 1-1 throughout all aspects of the Company and work execution:

**TABLE 1-1
TEN TRAITS OF A HEALTHY SAFETY CULTURE**

Trait	Description
1. Personal Accountability	All individuals take personal responsibility for safety. Responsibility and authority for safety are well defined and clearly understood. Reporting relationships, positional authority, and team responsibilities emphasize the overriding importance of safety.
2. Questioning Attitude	Individuals avoid complacency and continuously challenge existing conditions and activities to identify discrepancies that might result in error or inappropriate action. All coworkers are watchful for assumptions, values, conditions, or activities that can have an undesirable effect on safety.
3. Effective Safety Communication	Communications maintain a focus on safety. Safety Communication includes all aspects of the business. Leaders use formal and informal communication to convey the importance of safety. The flow of information up the organization is seen as important as the flow of information down the organization.

TABLE 1-1
10 TRAITS OF A HEALTHY SAFETY CULTURE
(CONTINUED)

Trait	Description
4. Leadership Safety Values and Actions	Leaders demonstrate a commitment to safety in their decisions and behaviors. Executive and senior managers are the leading advocates of safety and demonstrate their commitment both in work and action. The safety message is communicated frequently and consistently, occasionally as a stand-alone theme. Leaders throughout the enterprise set an example for safety. Corporate policies, standards and procedures emphasize the overriding importance of safety.
5. Decision-Making	Decisions that support or affect the enterprise are systematic, rigorous, and thorough. Coworkers are vested with the authority and understand the expectation, when faced with unexpected or uncertain conditions, to restore the assets, equipment, and systems to a safe condition. Senior leaders support and reinforce conservative decisions.
6. Respectful Work Environment	Trust and respect permeate the organization. A high level of trust is established in the organization, fostered, in part, through timely and accurate communication. Differing professional opinions are encouraged, discussed, and resolved in a timely manner. Coworkers are informed of steps taken in response to their concerns.
7. Continuous Learning	Opportunities to learn about ways to ensure safety are sought out and implemented. Experience is highly valued, and the capacity to learn from experience is well developed. Training, self-assessments, and benchmarking are used to stimulate learning and improve performance. Safety is kept under constant scrutiny through a variety of monitoring techniques, some of which provide an independent “fresh look.”
8. Problem Identification and Resolution	Issues potentially impacting safety are promptly identified, fully evaluated, promptly addressed, and corrected, commensurate with their significance. Identification and resolution of a broad spectrum of problems, including organizational issues, are used to strengthen safety and improve performance.

**TABLE 1-1
10 TRAITS OF A HEALTHY SAFETY CULTURE
(CONTINUED)**

Trait	Description
9. Environment for Raising Concerns	Employees feel free to raise safety concerns without fear of retaliation, intimidation, harassment, or discrimination. The enterprise creates, maintains, and evaluates policies, standards, and procedures that allow coworkers to freely raise concerns.
10. Work Processes	The process of planning and controlling work activities is implemented so that safety is maintained. Work management is a deliberate process in which work is identified, selected, planned, scheduled, executed, closed, and critiqued. The entire enterprise is involved in and fully supports the process

3. PG&E's Safety Leadership

PG&E's Safety Leadership consists of:

- The Chief Executive Officer (CEO), whose safety responsibilities include creating an environment where people are encouraged to raise concerns and where leaders are expected to respond to them, ensuring the adoption, and owning the leadership commitment and engagement element of PG&E's Safety Excellence Management System.
- The Chief Safety Officer (CSO). The VP of EHS and CSO is accountable for: (1) overseeing workforce safety strategy, including, but not limited to the Enterprise Corrective Action Program, Serious Incident and Fatality Prevention, and our Company's safety standards, (2) implementing PG&E's Safety Excellence Management System, and (3) developing programs for Contractor Safety, Transportation Safety and Occupational Safety & Health, which are discussed in detail the Enterprise Health and Safety Chapter.⁷ The CSO reports to the Operations EVP and Chief Operating Officer who reports directly to the CEO.
- Five Regional Safety Directors who are accountable for partnering with regional leadership on identifying region-specific hazards and assessing risk, verifying critical field controls, coaching on positive safety

⁷ Exhibit (PG&E-7), Ch. 1.

interactions, and coordinating the implementation of enterprise-wide workforce safety strategy programs within their regions.

4. Governance Framework: Board of Directors

PG&E's Board of Directors has designated the Safety and Nuclear Oversight Committee to be responsible for safety oversight at PG&E. This committee is responsible for overseeing and reviewing policies, practices, standards, goals, issues, risk, and compliance relating to safety. Among other things, the committee reviews and discusses:

- Enterprise risks and cross-cutting factors,⁸ the actions management is taking to understand these risks and cross-cutting factors, and how management assesses the effectiveness of the various processes and controls to reduce exposure to these risks;
- The Company's goals, programs, policies, and practices with respect to improving safety practices and operational performance, as well as promoting a strong safety culture; and
- Periodically visiting Diablo Canyon and other operating facilities.

The Board holds regularly scheduled meetings. The Safety and Nuclear Oversight Committee must meet at least four times per year. Members of PG&E management regularly attend Board and Committee meetings. The Safety and Nuclear Oversight Committee's charter specifically requires regular review with the CSO of the Company's long-term safety goals and objectives, as well as current staffing and budgeting needs. In addition, the Board annually reviews and approves the list of enterprise risks. Workforce Safety is included on the register as a top ten risk for PG&E.

C. Risk

1. Overview

a. Obligation to Make Safety the Top Priority

We have exercised our best judgment and professional expertise as a prudent operator to select and present in this GRC a portfolio of risk mitigation programs that meets our legislative and moral duty to place

⁸ Cross-cutting factors impact either the likelihood or consequence of other risk events on PG&E's Corporate Risk Register.

safety as the top priority.⁹ Of course, we are also mindful that we must meet this mandate in a manner that balances safety and reliability with customer affordability, which is why this GRC represents a substantially lower percentage revenue requirement increase than in recent GRCs and keeps customer bill impacts at or below inflation.¹⁰ Our professional judgment, expertise, and experience “on the ground” involves assessing and understanding the risks we face, especially catastrophic risk events, and selecting programs that most effectively mitigate those risks at the lowest societal cost. This is how we meet our commitment to being a prudent operator. In doing so we have performed risk analysis following the Commission’s adopted Risk-based Decision-making Framework (RDF).¹¹ We presented that analysis in our 2024 RAMP report and have updated the analysis in this GRC. The Commission staff found that PG&E’s 2024 RAMP analysis “complies with the requirements of the ... RDF.”¹²

As part of the RDF, the Commission approved the use of Risk Scaling in evaluating risks.¹³ We have utilized Risk Scaling as a necessary tool to properly value the low-frequency, high-consequence risks (also known as “tail risk” events) associated with PG&E’s utility system, including events like the San Bruno explosion. Without Risk

⁹ Under the California Public Utilities Code, PG&E is obligated to: “furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities [] as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public” (Section 451); “operate its electric distribution grid in [] a safe, reliable, efficient, and cost-effective manner” (Section 399.2(a)); “place safety of the public and gas corporation employees as the top priority” (Section 963(b)(3)); “demonstrate to the satisfaction of the commission, in its general rate case proceeding, that the requested revenue requirements will be sufficient to enable the gas corporation to fund those projects and activities necessary to maintain safe and reliable service and to meet federal and state safety requirements applicable to its gas plant, in a cost-effective manner”(Section 959).

¹⁰ Exhibit (PG&E-1), Chapter 1.

¹¹ D.22-12-027, Appendix A.

¹² A.24-05-008, Safety Policy Division Evaluation Report on PG&E 2024 RAMP Application (A.) 24-05-008 (Nov. 8, 2024) (SPD Report), p. 2.

¹³ D.22-12-027, Appendix A, p. A-8, No. 7.

Scaling, these risks would be significantly undervalued, and safety would be compromised.

The RDF also expressly allowed mitigation programs selected by the utilities to consider factors such as “Risk Tolerance thresholds” and required utilities to explain whether and how such factors affected the utility’s mitigation selections.¹⁴ To prioritize safety as required by state law, we cannot solely rely on cost-benefit analysis for mitigation selections. That analysis provides helpful directional guidance and remains one important input, as the Commission has acknowledged. But overreliance on models that are by definition imperfect while restricting prudent operator judgment will lead to outcomes that are likely less safe and more costly for our customers in the long term. As mentioned above, we are required to operate our system in a way that promotes the “safety, health, comfort, and convenience” of our customers, coworkers, and the public. To ensure we meet this requirement, the Commission applies a prudent operator standard, which requires PG&E to exercise reasonable judgment in light of what we know or should know, and in the interest of achieving safety, reliability and reasonable cost.¹⁵ Accordingly as part of this assessment, we must evaluate potential serious safety events involving serious injuries or fatalities in our service territory and across the industry when recommending mitigation programs, particularly those with low modeled cost-benefit ratios (CBR).

On April 22, 2025 – three weeks before the filing deadline for our GRC – the Administrative Law Judge (ALJ) assigned to PG&E’s RAMP proceeding issued a ruling that appears to sharply undermine PG&E’s ability to present risk analysis and mitigations supported by Risk Scaling and Risk Tolerance considerations.¹⁶ And by limiting PG&E’s ability to justify mitigation programs with lower CBRs, the ruling also appears to

¹⁴ D.22-12-027, Appendix A, p. A-16, No. 26.

¹⁵ Re Southern California Edison Company, D.87-06-021, 1987 Cal. PUC LEXIS 588, *29; 24 CPUC 2d 476.

¹⁶ A.24-05-008, Administrative Law Judge’s Ruling to PG&E Directing the Service of Additional Information and Other Requirements (Apr. 22, 2025) (ALJ Ruling).

1 be, at least in part, focused on customer affordability – a crucial goal
 2 with which PG&E wholeheartedly agrees and fully supports. However,
 3 we believe that restricting utility operators’ use of Risk Scaling and
 4 precluding us from referencing risk tolerance to assess and mitigate
 5 catastrophic events is shortsighted and more likely to exacerbate costs
 6 to customers, not reduce them.

7 In PG&E’s view, the mere fact that a program has a low CBR does
 8 not mean the program should not be undertaken. If in the exercise of our
 9 prudent operator judgement we determined that a certain risk needs to
 10 be mitigated in order to run a safe system, we will choose the most
 11 cost-effective program to achieve our goal, even if it has a CBR below
 12 1.0. Cost-effectiveness should not be viewed solely in terms of
 13 cost-benefit ratios; it also means fulfilling our obligation to make safety
 14 the top priority based on our “on the ground” judgment, in the least
 15 costly manner.

16 The ALJ ruling requires PG&E to present a “risk-neutral” analysis of
 17 its risks that PG&E does not support because it undervalues tail risk
 18 events such as the San Bruno pipeline explosion (or other catastrophic
 19 incidents across the industry).¹⁷ As discussed in Section C.3.b below, a
 20 “risk-neutral” approach is inappropriate and unhelpful when the risk
 21 consequences involve fatalities or life-altering injuries. Even if the
 22 risk-neutral analysis is merely informational for comparison purposes, it
 23 distracts from prioritizing public safety and thus weakens our ability to
 24 adequately manage catastrophic risks.

¹⁷ Examples of such events discussed in our testimony include: the 2023 explosion in Reading Pennsylvania, attributable to a vintage gas distribution plastic pipe tee, that resulted in 7 fatalities, 10 injuries, and a destroyed building (Exhibit (PG&E-3) Ch. 4, Section B.4.a); the 2011 36-inch diameter vintage transmission pipeline failure caused by land movement in which three homes were destroyed, two of which were occupied at the time (Exhibit (PG&E-3) Ch. 5, Section B.4.a); and the 2018 overpressure event in Merrimack Valley, Massachusetts when a series of structure fires and explosions occurred after high-pressure natural gas was released into a low-pressure natural gas distribution system. One person was killed and 22 individuals, including three firefighters, were transported to local hospitals due to injuries. The fires and explosions damaged 131 structures, including at least 5 homes. (Exhibit (PG&E-3) Ch. 6, Section C.6.a.)

1 The ALJ ruling also forbids us from discussing Risk Tolerance as a
 2 justification for our risk programs even though it is an essential
 3 consideration for risk management, and the utility is required by the RDF
 4 to explain factors that affected the mitigation selections in the GRC.
 5 Indeed, a risk tolerance approach that focuses on addressing
 6 catastrophic public safety tail risks is consistent with more mature risk
 7 policies adopted by the U.S. Nuclear Regulatory Commission (NRC) ¹⁸
 8 and Federal Energy Regulatory Commission (FERC).¹⁹

9 PG&E will comply with the ALJ Ruling (see Section C.3.b), although
 10 we believe it conflicts with our obligations under state law and signals a
 11 troubling departure from tested and recognized catastrophic risk
 12 management approaches in our industry that prioritize safety. Rather
 13 than restricting PG&E's prudent operator judgement, the Commission
 14 should be encouraging utilities to support their GRC programs with the
 15 best justifications demonstrating that safety is the top priority. The
 16 Commission may ultimately disagree with some of our
 17 recommendations but constraining our showing *a priori* will not lead to
 18 the best record, lower customer bills, or safer outcomes.

19 As the operator of the utility system, PG&E is obligated to exercise
 20 its best judgment in selecting programs that prioritize safety. That
 21 judgment requires us to assess our system risks using multiple
 22 approaches and consider prudent operator judgement and expertise in

¹⁸ The NRC has adopted risk tolerance thresholds that focus on preventing catastrophic tail risk events. The NRC's quantitative safety objective states that the risk to an average individual in the vicinity of a nuclear power plant of prompt (early) fatalities that might result from reactor accidents should not exceed one-tenth of one percent (0.1%) of the sum of prompt fatality risks resulting from other accidents to which members of the U.S. population are generally exposed. Based on further guidelines from NRC, this results in an acceptable large early release frequency of no more than 1 in 100,000 years. [NRC 10 CFR Part 50 available at <https://www.nrc.gov/reading-rm/doc-collections/commission/policy/51fr30028.pdf>; Appendix C NRC Quantitative Guidelines from the Framework for Risk-Informing 10 CFR Part 50 available at <https://www.nrc.gov/docs/ML0221/ML022120663.pdf>].

¹⁹ FERC's Division of Dam Safety and Inspections set in its Risk-Informed Decision-Making (RIDM) Guidelines the safety risk criteria to be considered as Tolerable Risk. These criteria result in a suggested "catastrophic" tolerable risk level of no more than 1 in 100,000 years per dam, which translates to 1 in 1,667 years (60-in-100,000) across PG&E's 60 high or significant hazard dams. [[RIDM Guidelines Chapter 3 Risk Assessment Ver 4.1](#), Ch 3.3].

addition to cost-benefit analysis to mitigate risk in a cost-effective manner. We have attempted to do so within the confines of the ALJ ruling.

b. Summary of Risk Reduction Portfolio

In this GRC, PG&E seeks funding for a portfolio of risk mitigation and control programs that comprehensively address and reduce the operational risks faced by the Company.²⁰ Risk reduction achieved by the programs proposed in this GRC is approximately \$320 billion, with more than \$250 billion of the risk reduction coming from control programs PG&E proposes to continue. This risk reduction is achieved through approximately \$31.5 billion in proposed spend over 2027-2030.²¹

As described in PG&E's 2024 RAMP Report, a mitigation is commonly defined as a measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of a risk event for a specific period of time.^{22,23} Examples of mitigation programs include undergrounding overhead assets in high fire risk areas or installing new slam-shut devices to prevent overpressure events in the gas system. In contrast, a control is a currently established measure that modifies risk, such as standard operation/routine work that is undertaken as part of normal business operations and is not a new program.²⁴ Examples of control programs include cathodic protection of gas pipes or preventing vegetation encroachment around aboveground gas or electric assets.

²⁰ As mentioned in Section B.1. above, PSEMS Element 3 requires risks to be identified and evaluated using defined processes that include associated hazards and consequences and the safeguards to prevent or mitigate them to protect employees, contract partners, and the public. The RAMP risk analyses align with this and inform the GRC.

²¹ The total risk reduction is as computed by the application of PG&E's Cost-Benefit Approach, and the total reflects the net present value of the lifetime of benefits from risk reducing work. The proposed spend is not discounted and reflects proposed spend for programs with computed risk reduction. These data are included in Exhibit (PG&E-2), WP 1-14.

²² A.24-05-008, PG&E's 2024 RAMP, Exhibit (PG&E-2), p. 2-38, lines 2-4.

²³ D.22-12-027, Appendix A, p. A-4.

²⁴ D.22-12-027, Appendix A, p. A-3.

1 While not a requirement, PG&E distinguishes controls and mitigations
2 for good reason. Risk reduction (as presented above) is a calculated value
3 based on the difference in risk event frequency and/or consequence before
4 and after a program is implemented. It is generally more straightforward to
5 estimate this difference by comparing the current state to the proposed
6 (mitigated) state than it is to estimate the difference between the
7 uncontrolled state (inherent) and the current state. Controls can generally be
8 expected to offer greater risk reduction than mitigations. This context is
9 important when considering the meaning of risk reduction and the quality of
10 CBRs across control and mitigation programs. It also explains why PG&E's
11 portfolio of controls offers greater risk reduction than PG&E's portfolio of
12 mitigations; we have driven significant risk off the system via controls,
13 though there is still further risk reduction to achieve.

14 The overall portfolio-wide cost-benefit ratio (CBR) of our proposed
15 mitigation and control spending for programs with CBRs presented in this
16 GRC is 9.8. The portfolio CBR is 5.8 and 12.0 for mitigation and control
17 programs, respectively.²⁵ CBR is a metric for representing the benefit to
18 cost ratio of a mitigation, where benefit is described in terms of risk
19 reduction. The RDF Proceeding Phase II Decision states that "The
20 Cost-Benefit Ratio calculation should be calculated by dividing the dollar
21 value of Mitigation Benefit by the Mitigation cost estimate."²⁶ In simple
22 terms, the portfolio-wide CBR of 9.8 indicates that on average, each dollar
23 spent on mitigating risk yields nearly 10 dollars in risk reduction benefits
24 calculated on a present value basis over the benefit life. We believe this high
25 portfolio-wide CBR further demonstrates that PG&E is committed to
26 selecting the right mitigation programs to reduce the most risk across our
27 system for the lowest societal cost. Likewise, in the cases where we
28 propose programs that have lower CBRs, we are doing so deliberately
29 based on prudent operator judgment of what is required to operate our
30 system safely. We are proposing those programs because we believe they

²⁵ Calculations can be found in Exhibit (PG&E-2), WP 1-14.

²⁶ D.22-12-027, Appendix A, p. A-15, No. 25.

1 protect the safety of our customers and the public, despite having lower
2 formulaic cost-benefit ratios.

3 PG&E considered various factors to ensure the risk mitigation spending
4 requested in this GRC further reduces safety, reliability and financial risks
5 and aligns with regulatory requirements, operational needs, and industry
6 best practice. To support its funding requests, PG&E's prepared testimony
7 explains the factors that justify its GRC forecasts at both the enterprise level
8 (Section C.3.c below) and at the Functional Area level (Exhibits (PG&E-3, 4,
9 5, and 7)) where risk mitigation program forecasts are presented.

10 In Section C.2 of this chapter, PG&E describes its approach to
11 enterprise and operational risk management.

12 In Section C.3, PG&E describes how it implemented the Commission's
13 RDF and performed the required quantitative risk analysis. We also identify
14 and discuss factors considered in the mitigation selection process to
15 balance the uncertainty associated with the quantitative modeling results
16 with the requirement that PG&E provides safe, reliable, and affordable
17 service.

18 In Section C.4 we respond to Safety Policy Division's (SPD's) and other
19 parties' feedback on PG&E's RAMP and discuss risk modeling updates
20 made in this GRC.

21 **2. PG&E's Approach to Enterprise and Operational Risk Management**

22 PG&E's Enterprise and Operational Risk Management (EORM)
23 Department has centrally governed the Company's processes for identifying,
24 assessing, mitigating, and monitoring risk (namely, Enterprise Risk
25 Management (ERM) Program) since its inception in 2012. PG&E's ERM
26 Program has evolved since that time because of lessons learned, feedback
27 from external stakeholders, benchmarking, and risk management best
28 practices.

29 This section provides an overview of the current state of PG&E's ERM
30 Program. For additional details on PG&E's Risk Management Organization,
31 including the structure and specific responsibilities of the EORM
32 Department, please see Exhibit (PG&E-7), Chapter 10.

a. Objective of PG&E's ERM Program

The objective of PG&E's ERM Program is to facilitate data-driven risk-informed decision-making that results in measurable risk reduction. PG&E's ERM processes are based on the principles of the widely-used International Organization for Standardization (ISO) 31000 Risk Management standard ²⁷ and help the Company to systematically identify, evaluate, prioritize, mitigate, and monitor risks inherent in its operations.

The EORM Department provides central coordination of risk management, analysis, and execution. Through application of the ERM framework and continual improvements, PG&E comprehensively identifies risks that could lead to significant consequences at an enterprise level and then provides risk metrics for comparing and prioritizing actions that have the best potential to reduce risk.

b. Implementation of ERM

The ERM Program is an integral part of how PG&E provides safe and reliable utility service. To accomplish this, the EORM Department provides governance for PG&E's ERM Program and provides Functional Areas across the Company the tools, methods, support, and oversight to:

- Identify risks through horizon scanning;
- Evaluate risks using a blend of qualitative and quantitative techniques;
- Determine risk response strategy and develop and implement response plans; and
- Monitor and report risk and mitigation status.

For additional background information, please see PG&E's 2024 RAMP, Exhibit (PG&E-2), Chapter 1 where PG&E provides a detailed overview of its ERM Program, risk organization structure and details on risk governance and oversight throughout the Company.

²⁷ ISO 31000 is a family of standards relating to risk management codified by the ISO. The purpose of ISO 31000 is to provide principles and generic guidelines on risk management. ISO 31000 seeks to provide a universally recognized paradigm for practitioners and companies employing risk management processes.

c. Corporate Risk Register

The ERM Program provides governance and support to Functional Areas (FA) for managing risks on the PG&E's Corporate Risk Register (CRR). The CRR currently includes 33 event-based risks and seven cross-cutting factors. A cross-cutting factor is a risk that impacts multiple risk events on PG&E's CRR.²⁸ In its 2024 RAMP Report, PG&E provides a detailed overview of each of the seven cross-cutting factors. For additional information, please see PG&E 2024 RAMP, Exhibit (PG&E-2), Chapter 3.

Attachment A to this chapter lists all risks currently on PG&E's CRR. The Attachment includes: the definition of the risk event or cross-cutting factor, the 2027 Test Year (TY) baseline risk scores, the 2027 TY baseline safety risk scores, citations to the discussion of the risk in the 2024 RAMP Report where applicable, and citations to additional information about the risk event or cross-cutting factor in PG&E's prepared testimony.

Attachment B to this chapter includes a cross-cutting factor mapping table that lists each of the cross-cutting factors and identifies which risk events they impact.

3. PG&E's Implementation of the Risk-Based Decision-Making Framework

The Commission superseded the S-MAP Settlement Agreement approved in D.18-12-014 (SA Decision) in the Risk OIR Phase 2 decision. In that decision, the Commission adopted a Risk-Based Decision-Making Framework (RDF).²⁹ A key aspect of the RDF was the replacement of the "Multi-Attribute Value Function" (MAVF) adopted in the SA Decision with a Cost-Benefit Approach (CBA) that includes standardized dollar valuations of Safety, Electric Reliability and Gas Reliability Consequences from Risk Events. As the Commission noted in the Decision: "Requiring the IOUs to

²⁸ A.24-05-008, PG&E's 2024 RAMP, Exhibit (PG&E-2), p. 2-37, lines 5-6. For example, Emergency Preparedness and Response (EP&R) examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. EP&R is a crosscutting factor that impacts several risk events such as Wildfire, Failure of Electric Distribution Overhead Assets, Loss of Containment (LOC) risks and Large Uncontrolled Water Release.

²⁹ D.22-12-027, Appendix A, Risk-Based Decision-Making Framework.

1 use the Cost-Benefit Approach, which monetizes Attributes, provides a more
 2 transparent way for the IOUs to calculate Risk and risk reduction Benefits in
 3 the RDF as compared to the MAVF approach adopted in the SA
 4 Decision.”³⁰

5 PG&E evaluated its top safety risks using the new CBA and presented
 6 the risk and mitigation analysis in its 2024 RAMP Report. PG&E was the
 7 first utility to use the CBA in a RAMP Report. In subsection (a) below PG&E
 8 provides a summary of the RDF implementation steps; in subsection (b) we
 9 discuss compliance with the April 22, 2025, Administrative Law Judge ruling
 10 in PG&E’s RAMP; and in subsection (c) PG&E discusses the RDF in the
 11 broader context of PG&E’s risk mitigation strategy.

12 **a. RDF Summary**

13 As noted in D.22-12-027, Appendix A, the RDF “constitute[s] the
 14 minimum required elements applicable to risk and risk mitigation
 15 analysis in RAMP and GRC proceedings.”³¹ Specifically, the RDF
 16 requires utilities to implement the following steps to analyze risk and
 17 mitigation choices:

- 18 • Building a CBA – Step 1A;
- 19 • Identifying Risks for the Enterprise Risk Register – Step 1B;
- 20 • Risk Assessment and Risk Ranking in Preparation for RAMP –
 21 Step 2A;
- 22 • Selecting Enterprise Risks for RAMP – Step 2B; and
- 23 • Mitigation Analysis for Risks in RAMP – Step 3.

24 Each of the Steps, and the associated Rows are described in detail
 25 in Appendix A to the Risk OIR Phase II Decision.³²

26 PG&E’s implementation of Steps 1A and 3 are described in detail in
 27 PG&E’s 2024 RAMP Report, Exhibit (PG&E-2), Chapter 2. PG&E’s
 28 implementation of Steps 1B, 2A, and 2B are described in PG&E’s 2024
 29 RAMP Report, Exhibit (PG&E 2), Chapter 4.

³⁰ D.22-12-027, p.55, Findings of Fact 4.

³¹ D.22-12-027, Appendix A, p. A-6.

³² D.22-12-027, Appendix A.

b. April 22, 2025 ALJ Ruling

As discussed in Section C.1.a above, on April 22, 2025, approximately three weeks before the filing date for PG&E's 2027 GRC application, the ALJ assigned to PG&E's RAMP docket issued a ruling directing PG&E "to serve additional information and comply with other requirements."³³ The ruling states "By June 20, 2025, PG&E shall comply with the requirements of this ruling."³⁴

We discuss each requirement of the ruling below.

1) Risk evaluation using a risk-neutral, linear scaling function, including cost benefit ratios (CBRs). (ALJ ruling Section 2.1)

PG&E is directed to conduct a parallel risk evaluation using a risk-neutral, linear scaling function to establish a neutral baseline for GRC stakeholders to compare the impacts of its risk-averse scaling function on the selection decisions regarding risk mitigation.

In accordance with the RDF, PG&E's RAMP utilized a Risk Scaling approach. PG&E believes that this approach is essential to properly value tail risk mitigations in a cost-benefit analysis.

PG&E has commented extensively on the need for Risk Scaling in the Risk OIR³⁵ and reiterates its position here. Risk-neutral scaling – essentially managing to averages – is ill-suited to capture catastrophic outcomes. Firstly, it is a fallacy to assume that stable average losses, a crucial assumption for risk-neutral scaling, can be determined reliably for all risks. Furthermore, for catastrophic risks, averages drawn from historical data will tend to underrepresent risk simply because extreme, tail events are the most significant contributors to the average, but by definition they are exceedingly rare.³⁶ This is illustrated by observing the average safety loss from

³³ A.24-05-008, ALJ Ruling, p. 1.

³⁴ ALJ Ruling, p. 11.

³⁵ R.20-07-013, Opening Comments of Pacific Gas and Electric Company on Workshop #4 (Nov. 6, 2023).

³⁶ Taleb, Statistical Consequences of Fat Tails: Real World Preasymptotics, Epistemology, and Applications (The Technical Incerto Collection), STEM Academic Press (2020), p. 31.

wildfires in PG&E's service territory over time. In the 2015 to 2016 period, based on CalFire data there were 79 fires larger than 300 acres, with an average of 0.11 fatalities per event³⁷. If one were to assume that averages are stable, then this value would be representative of averages calculated from any dataset of 79 events. Statistically speaking, it would predict with 99.999 percent confidence that the average calculated from any set of 79 events would not exceed 0.38 fatalities/event.³⁸ Yet if the 79 fires from September 12th, 2017, through November 8, 2018, were selected,³⁹ the average would be 1.72 fatalities/event,⁴⁰ surpassing by more than four-fold the previously calculated 99.999% confidence interval value of 0.38. Without long run stable averages, risk-neutral scaling results in shortsighted behavior and dismisses the existence of "black swan" events.

A risk-neutral attitude also does not consider the possibility of ruin – in other words, the cumulative odds and consequences that an individual (or community) faces are very different from the odds faced by the overall population. Risk-neutral proponents often use gambling situations to justify their reasoning. However, these analogies are inapposite. We are not adopting the perspective of the "house," which can make up its losses from a steady stream of gamblers playing games with well understood averages. Instead, we are required by law and moral obligation to ensure the safety of individuals and communities that are exposed daily to hazardous commodities and potential events that can cause irrecoverable

³⁷ Data is in Exhibit (PG&E-2), WP EO-WLDFR-7.

³⁸ The sample standard deviation of the data was 0.554. Using the corresponding z-score of 4.26 for the 99.999th percentile, the one-sided confidence interval is bounded at $0.14 + 4.26 \times 0.554 / \sqrt{79} \approx 0.38$ fatalities/event.

³⁹ One of the two reported fires on September 12, 2017, the Berry fire, was not included in order to keep the sample size at 79 fires.

⁴⁰ Data is in Exhibit (PG&E-2), WP EO-WLDFR-7.

1 harm. When ruin is considered, risk-neutral scaling is
 2 inappropriate,⁴¹ and potentially irresponsible.

3 Finally, there is no evidence to suggest that our customers are
 4 risk-neutral. On the contrary, the existence of insurance markets
 5 show that customers are generally risk-averse. PG&E has
 6 demonstrated in its 2024 RAMP⁴² that a wide range of entities,
 7 including public utilities, are risk-averse and hence that adopting a
 8 risk-averse attitude (i.e., non-linear scaling) is reasonable. It is also
 9 consistent with the risk management approach across the utility
 10 industry and other high-hazard industries such as nuclear,
 11 construction, chemical process, aerospace and aviation, oil and gas,
 12 and pipeline industry.

13 As discussed in the overview section, we strongly disagree with
 14 the requirement to present a risk-neutral approach. PG&E
 15 fundamentally believes that this approach incorrectly values risk in
 16 our industry.

17 Nevertheless, in compliance with the ruling, we are providing
 18 the requested information on Risk Values without applying PG&E's
 19 risk-averse scaling function in Exhibit (PG&E-2), WP 1-13 and
 20 mitigation and control CBR values without applying PG&E's
 21 risk-averse scaling function in Exhibit (PG&E-2), WP 1-16.

22 **2) Specify All Applicable Regulatory Requirements for Each Risk**
 23 **Mitigation Project or Program Where Regulatory Compliance or**
 24 **Requirements Are Cited as Justification for the Risk Mitigation**
 25 **Program or Project. (ALJ ruling Section 2.2)**

26 Our showing in this rate case describes the applicable
 27 regulatory and compliance requirements for forecasted risk
 28 mitigation projects or programs.

29 **3) Provide Electric Reliability Cost Calculations Using the**
 30 **Disaggregated Approach Recommended in the SPD Evaluation**

⁴¹ O. Peters and M. Gell-Mann, Evaluating gambles using dynamics, Chaos 26(2) (Feb. 2, 2016).

⁴² A.24-05-008, PG&E's 2024 RAMP, Exhibit (PG&E-2), pp. 2-19 to 2-23.

Report. For the Disaggregated Approach, PG&E Must Also Provide Separate Risk Analyses Using a Risk-Neutral Risk-Scaling Function and PG&E’s preferred Risk-Averse Scaling Function (ALJ ruling Section 2.1)

PG&E disagrees with the ALJ Ruling’s conclusion at pages 9-10 that “PG&E’s estimation of the monetary cost of each customer minute of power interruption (CMI) based on a system-wide average likely leads to an inflated value and does not accurately represent the appropriate cost per CMI used to estimate the reliability cost”. PG&E believes that the accuracy and impact of the aggregated approach and the appropriateness of the disaggregated approach ordered by the ruling requires further consideration in the Rulemaking proceeding. The disaggregated approach raises numerous issues, including the potential consequence of treating customers differently based on economic status, location, etc.

In this GRC, PG&E provides Risk Values and CBRs using the Cost-Benefit Approach, with a single monetization factor of \$3.33 per customer-minute interrupted (in 2024 dollars) for electric reliability. Because the ICE 2.0 (Phase 1) Calculator was not released by Lawrence Berkeley National Labs (LBNL) until late April 2025, PG&E derived this value from the reliability value of \$3.16/CMI used in the 2024 RAMP (obtained from the ICE 1.0 calculator, in 2023 dollars) and adjusted it for inflation.

As requested in this ruling, PG&E will provide, by June 20th, 2025, the Risk Values and CBRs using aggregated and disaggregated approaches, and, consistent with D.22-12-027 OP 2(b), utilizing the “most current version” of ICE Calculator – version 2.0.

4) Remove Risk Tolerance as a Justification for Mitigation Selections Unless the Commission Has Established a Risk Tolerance Standard. (ALJ ruling Section 2.1)

PG&E has consistently recognized that the Commission – not the utilities – should establish Risk Tolerance standards. As we stated in our 2024 RAMP Report: “The Commission has recognized

1 the need for discussion and clear guidance on Risk Tolerance and
 2 has expressed its intention to address this topic in future Phases of
 3 the Risk OIR. In the meantime, PG&E's risk mitigation strategies,
 4 as described in this report, are selected to ensure that safety
 5 remains PG&E's top priority."⁴³ Further, as we said in comments in
 6 Phase 4 of the Rulemaking: "PG&E recognizes the critical role of a
 7 Commission-adopted risk tolerance standard to allow for a more
 8 complete evaluation of the mitigation programs, and the
 9 determination of the appropriate level of spending."⁴⁴

10 To date the Commission has not adopted any Risk Tolerance
 11 standard. So, to comply with the ALJ's ruling we do not cite any
 12 determination by PG&E or the Commission regarding a Risk
 13 Tolerance standard as justification for our proposed risk mitigation
 14 programs in this GRC.

15 Rather, in our testimony we employ our professional
 16 experience, expertise, and prudent operator judgment to consider
 17 safety risks beyond formulaic CBR values. We do not assert that
 18 these risks are "intolerable." As the ALJ ruling correctly points out,
 19 and with which PG&E agrees, establishing Risk Tolerance
 20 standards for California is the Commission's responsibility. We
 21 believe, however, that understanding the potential for catastrophic
 22 risk consequences that our programs are designed to mitigate is an
 23 important factor to be considered along with CBRs, compliance
 24 requirements and other factors cited to support the programs. It is
 25 critical for the record to reflect PG&E's prudent operator judgement
 26 as distinct from the CBR perspective, especially in the absence of
 27 any established Risk Tolerance standard.

28 **c. Factors influencing Mitigation Strategy**

29 PG&E has made significant progress in developing and
 30 implementing the RDF in the GRC. This filing represents the first time

⁴³ A.24-05-008, PG&E's 2024 RAMP, Ch. 1, pp. 1-13 to 1-14.

⁴⁴ R.20-07-013, Opening Comments of Pacific Gas and Electric Company on Workshop #2: Overall Residual Risk, Risk Tolerance and Simple Optimization (Jan. 3, 2025), p. 12.

any utility has applied the CBA to compute Cost-Benefit Ratios in support of its GRC. Based on our implementation experience, we acknowledge that this framework is not a singular tool for developing a comprehensive utility risk mitigation strategy, nor should any party expect it to be. While the Commission and stakeholders continue to refine the framework with the aim of improving the usefulness of risk models and CBRs via the Risk OIR, we must account for several existing gaps in important areas of the framework and methodology. CBRs cannot be the sole (or even the primary) factor informing the selection of mitigation strategies. As a prudent operator obligated to provide safe and reliable service, we must consider other factors which the Commission explicitly acknowledges in the RDF:

“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 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.”⁴⁵

CBR is one of the various factors for evaluating the efficiency and effectiveness of risk mitigations. As CBRs mature and better reflect the benefit and cost of risk mitigations, they can serve as useful guidance in validating mitigation selection. For example, In-Line Inspection (ILI) used to assess the integrity of gas transmission pipelines is assigned a CBR of 7.1 by the modeling. Direct Assessment for gas transmission pipe integrity management, an alternative where ILI is not feasible, has a CBR of 2.4. These relative CBR values validate the fact that, where feasible, ILI is preferred because it provides the most effective integrity assessment.

In addition, CBRs are one of the factors considered in helping prioritize programs in the planning process. In an effort to support more transparent risk-informed decision making in PG&E’s planning process, PG&E first established the Risk-Based Portfolio Prioritization Framework (RBPPF) in 2021 and has subsequently incorporated the framework in

⁴⁵ D.22-12-027, Appendix A, p. A-16, No. 26 (emphasis added).

its annual Business Plan Deployment (BPD) Process to use a consistent and comparable approach to categorizing and scoring proposed investments. To help prioritize funding, part of that process assigns each investment a “Funding Tier” as informed by the investment’s risk reduction CBR as one of the factors. Additional information on how the RBPPF is used in PG&E’s business planning and execution is described in Exhibit (PG&E-2), Chapter 2.

While CBRs provide a useful data point based on quantitative models, risk mitigation planning decisions should be informed by both quantitative models and other factors that must be weighed and balanced in planning for the future, including factors that are either not addressed or not captured adequately in PG&E’s current quantitative models. In Decision (D.) 22-12-027, the Commission also recognized that factors other than CBRs may influence selection of risk mitigations, such as modeling limitations and/or uncertainties.

The RDF also specifies “Risk Tolerance thresholds” as a factor that can influence mitigation selection. While we are mindful that the Commission has not yet established a Risk Tolerance standard, we nevertheless believe that it is critical to balance CBRs with other risk considerations, such as the potential for catastrophic safety events, to ensure that safety is not compromised for financial efficiency.

In determining the appropriate portfolio of risk mitigation programs in this GRC, we have considered factors including:

- Safety as the top priority;
- Prudent operator judgment;
- Modeling limitations and uncertainties; and
- Compliance requirements.

1) Safety as the Top Priority

We anchor on the principle of safe and reliable operations, seeking to eliminate incidents involving serious injuries or fatalities related to our assets and operations, consistent with PG&E’s stands that “everyone and everything is always safe” and “catastrophic wildfires shall stop.” These stands are aligned with California law that requires safety to be the top priority.

1 With the transition to a Cost-Benefit Approach following RDF
 2 guidance to monetize safety and reliability attributes in the
 3 calculation of risk, PG&E has observed a significant reduction in the
 4 proportion of safety risk value relative to total risk value for PG&E's
 5 top safety risks.⁴⁶ For example, Figure 1-2 below shows that the
 6 safety attribute risk represents 8.6 percent of total risk across
 7 PG&E's top safety risks, and 9.5 percent of the total wildfire risk
 8 value. In contrast, in PG&E's 2023 GRC, the safety attribute
 9 represented 35.6 percent of total risk for top safety risks, and 33.7
 10 percent for wildfire risk. While there are myriad changes to models
 11 and data between rate cases, including progress in mitigating risk,
 12 this observed difference in the importance of safety risk is largely
 13 driven by how safety, reliability and financial impacts are normalized
 14 to the same unit (now dollars under the CBA).

⁴⁶ SPD also observed this from PG&E's 2024 RAMP report and stated: "PG&E's monetization of Safety and Reliability attributes result[ing] in placing less emphasis on safety and more emphasis on reliability, especially [on] electric reliability." SPD further noted two effects of this change: risk events with significant potential property damage impacts and significant reliability impacts would have higher relative risk rankings than in the 2020 RAMP; and for the same risk event, mitigations that are relatively more effective at lessening the severity of electric service disruptions as opposed to having more safety reduction impact would be more highly favored in the 2024 RAMP than they would have been in the 2020 RAMP. A.24-05-008, SPD Evaluation Report on PG&E's 2024 RAMP Nov. 8, 2024, p. 3.

FIGURE 1-2
COMPARING RELATIVE CONTRIBUTION OF RISK BY ATTRIBUTE FOR SELECTED RISKS
BETWEEN PG&E'S TEST YEAR 2023 AND 2027 GRCS

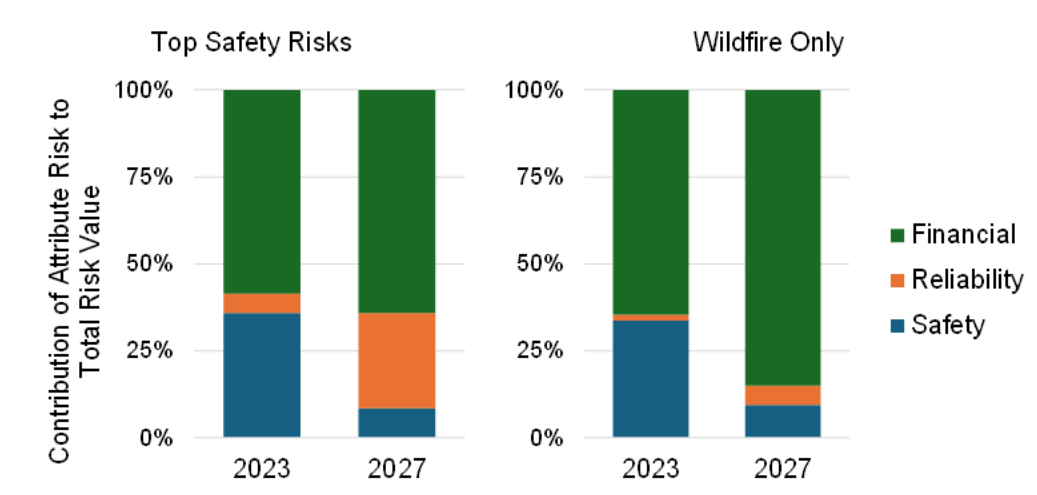


Figure 1-2 demonstrates that while monetized risk scores and CBRs are useful measures, they might not be the most suitable approach to evaluate and manage PG&E's safety risks. Among the concerns, the methodologies used in determining the value of Attributes, e.g., VSL, were not intended to address the range of potential consequences encountered by PG&E and its customers (for further discussion, see C.3.c.3 below). Monetization, or any single-valued approach to risk, also presages that all manner of trade-offs can be made among Safety, Reliability and Financial attributes. Put simply, the monetization approach was not designed to ensure that Safety is the top priority, and so we should be under no pretense that it does. Risk scores and CBRs should be only one component of a multi-faceted approach that never loses sight of PG&E's obligation to operate its system in a prudent manner.

Consider the San Bruno pipeline explosion, which led to 8 fatalities and 51 serious injuries (as well as financial damage). After the explosion, the Commission resolved to ensure that such an

1 event “never happens again.”⁴⁷ Following this catastrophic event,
 2 PG&E undertook a series of actions to drive down the likelihood of
 3 such an event happening again.

4 An illustrative analysis of the San Bruno explosion using the
 5 CBA framework shows why utilities must not exclusively rely on
 6 CBRs to make risk mitigation decisions. Applying hindsight, we can
 7 estimate the costs and benefits of a course of actions for avoiding a
 8 San Bruno risk event using monetization factors from the RDF’s
 9 CBA framework. Focusing the analysis exclusively on transmission
 10 pipelines in high consequence areas (e.g., greatest potential for
 11 catastrophic safety consequences), the estimated cost of
 12 hydrotesting, the only inspection method available at the time that
 13 could have detected the anomaly that led to rupture, is
 14 approximately \$4.2 billion. Applying the monetization factors to the
 15 realized consequences of the San Bruno pipeline explosion
 16 (\$0.34 billion in safety consequences, \$0.72 billion in financial
 17 consequences),⁴⁸ the \$1.1 billion in benefits of avoiding another
 18 San Bruno do not exceed the hydrotesting costs. In short, the
 19 calculated ratio of benefits to cost is only 0.25. Further, since
 20 70 percent of the \$1.1 billion consequence are financial losses,
 21 preventing San Bruno could be categorized as primarily avoiding
 22 financial damages with additional safety risk avoidance. We present
 23 this hypothetical to highlight that, if a CBR was the sole (or even
 24 primary) factor informing the decision to mitigate San Bruno, it would
 25 lead to a decision to accept rather than mitigate the risk. Layering in
 26 the Commission’s resolution that such an event should never occur
 27 again, as an example of additional factors relevant to decision

⁴⁷ Order Instituting Rulemaking (Feb. 24, 2011), R.11-02-019, p. 1: “The human suffering caused by these events is overwhelming. Families lost loved ones, and an entire community endured widespread destruction. The depth of this tragedy is the source of our resolve to take all actions necessary to ensure that it never happens again.”

⁴⁸ Estimating monetized safety consequences is a two-step process: Computing Equivalent Fatalities (8 fatalities and 51 serious injuries = $8 + 51 \times 0.25 = 20.75$ EF), and monetizing the natural units of EF ($20.75 \times \$16.22\text{M} = \337M). Financial costs are taken from a PHMSA dataset.

1 making, we arrive at an alternative, and preferred, decision to
2 execute the work to ensure public safety.

3 PG&E is poignantly aware of the profound and wide-ranging
4 impacts from unlikely but highly consequential safety risk events and
5 prioritizes work to mitigate against them. Accordingly, programs
6 forecast in this GRC include mitigations that are aimed at preventing
7 serious safety events even when the CBRs of those mitigations
8 indicate the mitigation costs exceed the modeled value of risk
9 reduction. As required by RDF Row 26, PG&E explains in this GRC
10 how each mitigation was chosen in order to make sure safety
11 remains the top priority, even though electric reliability has become
12 a significantly larger contributor to the risk values than in the past
13 and the CBR for safety mitigations may be lower than 1.

14 **2) Prudent Operator Judgment**

15 To underscore the example above: a hypothetical, purely
16 formulaic cost-benefit analysis of preventing the San Bruno pipeline
17 rupture today would yield a ratio of benefits to costs that is well
18 under 1.0. Of course, we do not believe any stakeholder in this
19 proceeding would suggest that PG&E not implement programs to
20 prevent another San Bruno-like catastrophe; we are highlighting the
21 importance of going beyond CBRs to achieve our shared goal of
22 safeguarding our customers and the public from known risks that
23 have catastrophic outcomes. We must maintain our commitment to
24 exercising our professional expertise, experience, and judgment to
25 operate our system in a safe and prudent manner. To do so it is
26 critical to assess risk in a multi-faceted manner, i.e., to consider
27 other measures besides monetized risk values and cost-benefit
28 ratios. And as mentioned, the Commission requires PG&E to
29 exercise that judgment in a reasonable way in light of what we
30 know, or should know, at the time we are making critical operating

1 decisions. For safety-related activities, we must employ industry
2 best practices.⁴⁹

3 Those industry best-practices and exercising operator judgment
4 include ensuring that we are: appropriately considering and
5 mitigating catastrophic tail risks, not just “average” risks; learning
6 from incidents in our system and across the industry; deploying risk
7 mitigation strategies to prevent recurring or similar events; and,
8 where cheaper alternatives are not available or inferior, deploying
9 mitigation programs that address public safety.

10 For proposed programs with CBRs below 1.0, PG&E provides
11 explanations and justifications for our proposals in the functional
12 area testimony. Below are a few examples of low CBR programs
13 that we have forecast in this GRC that mitigate potentially
14 catastrophic safety events.

15 Gas Transmission Vintage Pipe Replacement Program.⁵⁰ This
16 program targets vintage construction and fabrication threats
17 interacting with land movement as a high risk for transmission pipe
18 assets. The program is assigned a CBR of 0.01 by the modeling.
19 We are nevertheless proposing to replace the three highest risk
20 vintage pipe segments on the transmission system threatened by
21 potential site-specific land movement. One of the justifications for
22 this proposed work is to reduce the risk of catastrophic safety events
23 that have occurred in the industry. In November 2011, a landslide
24 interacting with a weld defect on a 36-inch diameter transmission
25 pipeline with older construction methods failed in Morgan County,
26 Ohio.⁵¹ Three homes were destroyed, two of which were occupied
27 at the time. To further illustrate the very real risk of vintage pipe

⁴⁹ D.14-06-007, pp. 31, 36. State law encourages operators to meet or exceed minimum requirements and apply best practices. California Public Utilities Code Sections 961(b), (c) and (d).

⁵⁰ Exhibit (PG&E-3), Ch. 5, Section B.4.

⁵¹ The pipeline was constructed in 1963, and the welding practices at that time did not meet current standards. There were limited inspection procedures during the construction phase, which meant that defects in the welds were not adequately detected or addressed.

1 interacting with land movement, the photographs below show the
2 land slide that impacted a PG&E pipeline which was badly damaged
3 but not ruptured in Marin County on March 21, 2023. Due to
4 modern construction techniques, this pipeline did not rupture.
5 However, if vintage features existed in the slip zone, the pipe would
6 have ruptured due to the displacement experienced. 90,000
7 customers in Novato could have lost gas service and Highway 101
8 could have been impacted, including any potential safety impacts
9 from an ignition.

FIGURE 1-3
FIGURE L021G – NOVATO LANDSLIDE OVERVIEW



FIGURE 1-4
FIGURE L021G – UNCOVERED PIPE

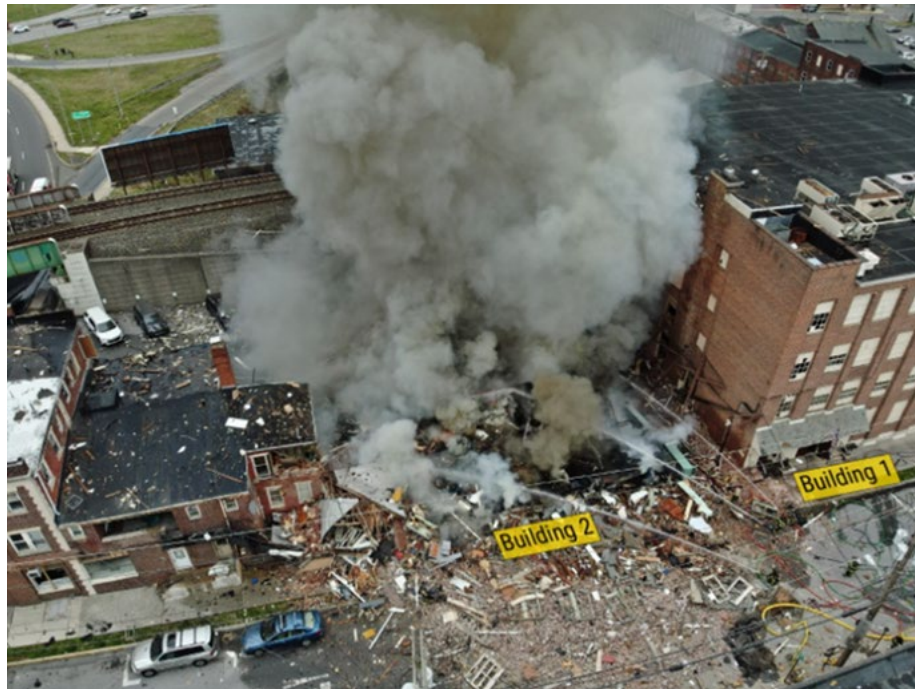


Plastic Distribution Main Replacement Program.⁵² PG&E established the Plastic Pipe Replacement Program in 2012 to mitigate risks associated with leaks on gas distribution pipe installed before 1985 with Aldyl-A plastic and similar plastic materials. Plastic materials of pre-1985 vintage have a susceptibility to slow crack growth when exposed to stress, such as tree roots, differential settlement, or rock impingement. The program is assigned a CBR of 0.03 by the modeling. Nevertheless, PG&E proposes replacing 139 miles per year of its highest risk plastic pipe. One of the justifications for this proposed work is to reduce the potential for failures that have occurred in the industry, some with catastrophic consequences. This risk is very real: PG&E has incurred seven incidents resulting in an ignition or explosion associated with pre-1985 Aldyl-A pipe leakage since 1982. Recently, in 2023 a gas-fueled explosion and fire occurred in West Reading, Pennsylvania resulting in 7 fatalities, 10 injuries, and a destroyed building. The NTSB Pipeline Investigation Report determined “that

⁵² Exhibit (PG&E-3), Ch. 4, Section B.4.

the probable cause of the explosion was degradation of a retired 1982 Aldyl-A polyethylene service tee with a Delrin polyacetal insert that allowed natural gas to leak and migrate underground into the R.M. Palmer Company candy factory buildings, where it was ignited by an unknown source.”⁵³ The photograph below shows the catastrophic consequence.

FIGURE 1-5
2023 ALDYL-A NATURAL GAS-FUELED EXPLOSION AND FIRE



Venting Manhole Cover Program: ⁵⁴ This program targets existing solid and grated manhole covers in high-pedestrian zones in San Francisco and Oakland. Electric vaults can explode if flammable gases accumulate and are ignited (perhaps by an electric spark). The risk to public safety from this high energy release is two-fold: people near to the vault can be seriously injured or killed

⁵³ NTSB, Pipeline Investigation Report PIR-25-01, UGI Corporation Natural Gas-Fueled Explosion and Fire (Mar. 24, 2023), p. 84, available at: <https://www.nts.gov/investigations/AccidentReports/Reports/PIR2501.pdf> (accessed Apr. 14, 2025).

⁵⁴ Exhibit (PG&E-4), Ch. 16.

1 in the blast, and an unattached manhole cover can become a
 2 massive projectile threatening pedestrians or those in vehicles. A
 3 recent manhole explosion in New York State made national news,
 4 as a woman and two children were mere feet from an exploding
 5 vault.⁵⁵ Though the venting manhole cover program is assigned a
 6 CBR of 0.5 by the modeling, PG&E proposes to continue work to
 7 improve and maintain public safety in the face of this known hazard.
 8 The replacement hinged venting manhole covers stay in place
 9 during a vault explosion to reduce the potential for exposure to hot
 10 gases from the vault and eliminate the risk of a projectile manhole
 11 cover and force of the explosion.

12 Lower Bucks Dam Resurface Downstream (DS) Face:⁵⁶ This
 13 project is one of a suite encompassed by the Internal Erosion
 14 mitigation program addressing the Large Uncontrolled Water
 15 Release (Dam Failure) risk event. These are often multi-year capital
 16 projects (this project started in 2019 and is expected to be
 17 completed in 2029). This specific resurfacing project is in response
 18 to severe observed spalling and surface delamination. The project
 19 is assigned a CBR of 0.002 by the modeling. Dam operators across
 20 the nation have overseen numerous, recent failure events, including
 21 the 2017 Oroville spillway incident, the 2020 Edenville and Sandford
 22 dam failures in Michigan, and the Rapidan event in Minnesota.
 23 Thankfully, no lives were lost in these incidents, but they serve as a
 24 reminder of the catastrophic potential of asset failure and the
 25 necessity of managing the often unique needs of these aging
 26 installations to maintain public safety.

27 **3) Modeling Limitations and Uncertainties**

28 Quantitative models are important but should be placed in
 29 context of prudent utility management. Modeling limitations and
 30 uncertainties caution against relying too heavily on the current

⁵⁵ CNN, Woman and Children Narrowly Escape Manhole Explosion, available at:
<https://www.cnn.com/2025/04/22/us/video/manhole-explosion-woman-children-narrowly-escape-cprog-digvid> (accessed May 2, 2025).

⁵⁶ Exhibit (PG&E-5), Ch. 3.

1 estimation of Risk Values and CBRs to prescribe future investment
2 plans when a more flexible approach should be considered. Key
3 modeling limitations and uncertainties are discussed below.

4 First, emerging and poorly understood risks and factors are not
5 well addressed by current risk models, due to their inherently high
6 uncertainty, rapidly evolving nature and/or little to no historic data to
7 confidently guide the analysis. Three examples of these are climate
8 change, cybersecurity, and changes in the utility industry. With
9 respect to climate change, while it is certain that assets will face
10 increasing threat from natural hazards—both in the form of acute
11 events such as flash flooding that can destroy utility facilities, or
12 chronic exposure to high temperatures that shortens the operational
13 life of assets—the timing and the magnitude of the impacts on the
14 likelihood and consequence of asset failures is highly uncertain.
15 Also, since the model discounts future benefits of mitigations to the
16 present value, potential climate mitigation options will likely not be
17 deemed cost-effective when an investment is also mitigating
18 potential impact decades in the future. In contrast to the uncertainty
19 in climate change risk decades from now, the cybersecurity threat
20 landscape is changing so rapidly that predicting the
21 capabilities/methods of threat actors just months into the future is
22 difficult. The GRC cycle, however, requires forecasts about work
23 needed to address emergent cybersecurity threats to be prepared
24 three to seven years ahead. Lastly, there is a looming nationwide
25 need for a greater electric grid capacity to accommodate
26 decarbonization, electric vehicles, and significant load growth to
27 support an expanding digital economy. These factors are not fully
28 captured given limited data and inability to accurately predict the
29 trajectory of these trends and their impacts on PG&E's risks.

30 Second, the estimates of risk reduction benefits from mitigation
31 and control programs are uncertain. As discussed earlier, to
32 estimate risk reduction benefits of proposed risk mitigations and
33 controls, the current state of risk (i.e., baseline risk levels) must be
34 compared to either a future hypothetical state where a mitigation is

implemented (e.g., pipeline in an area at risk of subsidence is rerouted through a stable area) or some counterfactual state where a control was not implemented (e.g., rights-of-way for overhead conductors were never maintained). It can be exceedingly difficult to estimate the risk reduction from this work or the level of risk in the absence of this work. Comprehensive empirical support would require data spanning historical episodes of both program activity and inactivity, structured in a way that allows the specific effects of the program to be disentangled from other confounding factors. This challenge is especially acute for risk events characterized by unlikely but potentially catastrophic consequences as well as for longstanding control programs, for which there is a paucity of relevant historical experience (e.g., risk level in the absence of the leak management, routine vegetation management, and locate and mark programs). For this reason, PG&E draws on the informed judgement of subject matter experts to specify program effectiveness, and caution should be exercised in relying on modeled CBRs to inform the selection of mitigation and control programs, in particular addressing low frequency/high consequence events.

Third, the current modeling approach, which uses the Department of Transportation (DOT)'s Value of Statistical Life (VSL) to monetize safety attributes for cost-benefit analysis, may result in undervaluing benefits of utilities' safety risk mitigation programs. While DOT's VSL is widely used in cost-benefit analysis, PG&E notes the importance of recognizing that VSL is deduced from an *individual's willingness to pay* for small risk reductions (using data from wage-vs-risk studies);⁵⁷ it does not, by design, capture the

⁵⁷ See, e.g., Department of Transportation (2021), Departmental Guidance: Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, p. 3, which notes that wage-vs-risk studies deduce VSL from "the wage differential that employers must pay workers to accept riskier jobs, taking other factors into account." DOT emphasizes these studies as foundational to its VSL guidance: "[t]he Panel unanimously concluded that we should base our guidance only on hedonic wage studies completed within the past 10 years that made use of the CFOI database and used appropriate econometric techniques." *Id.*, p. 5.

1 social value of safety or all potential downsides of a safety risk event
 2 to customers and society-at-large.⁵⁸ More specifically, the studies
 3 underlying the DOT's VSL guidance examine the relationship
 4 between wages and job risk to inform a risk-compensation tradeoff;
 5 they are not engineered to explicitly measure lost productivity,
 6 clean-up costs, medical costs, effects on family and community, and
 7 more.⁵⁹ Hence, although VSL can help inform a "lower bound on
 8 the social benefits of reductions in mortality risks ...,"⁶⁰ its scope is
 9 limited and leaves significant room for uncertainty.

10 Fourth, the current modeling of the risk reduction benefits of the
 11 programs for the CBR calculation may not capture the full benefit of
 12 the programs, because it is fundamentally limited to how the risk is
 13 defined and modeled in the first place. If the risk in the CRR is
 14 defined narrowly, the risk reduction benefit computed for mitigations
 15 for that risk is limited to the benefit of reducing that risk as defined.

58 See, e.g., Colmer, What is the meaning of (statistical) life? Benefit-cost analysis in the time of COVID-19, Oxford Review of Economic Policy (Aug. 29, 2020), available at: https://academic.oup.com/oxrep/article/36/Supplement_1/S56/5899010 (accessed Apr. 9, 2025), where it is noted that:

"[t]he VSL reflects private willingness to pay for a very small reduction in mortality risk. It does not capture the value of a person's life to the rest of society. As such the total benefits of interventions to reduce mortality risk will be understated as the social benefits are not accounted for."

59 See, e.g., Andersson and Treich, Handbook in Transportation Economics, Chapter, The Value of a Statistical Life, Advances in Transport Policy and Planning (2011), available at: https://www.tse-fr.eu/sites/default/files/medias/doc/by/andersson/andersson_treich_hanbook_vsl_chapter_2011.pdf (accessed Apr. 9, 2025), which states:

"The individual WTP may not reflect a reduction in costs to society such as medical, police surveillance, damage, and lost productivity. Jones-Lee et al. (1985) found evidence that respondents did not account of such other effects of the safety improvements,"

or Colmer, What is the meaning of (statistical) life? Benefit-cost analysis in the time of COVID-19, Oxford Review of Economic Policy (Aug. 29, 2020), *supra*, which states:

"[s]ociety also bears the cost of grief and loss of companionship that is experienced by the family and friends of the deceased (Posner and Sustain, 2015; Beckerman, 2019). As in the case of identifiable lives, it is not possible to credibly assign a monetary value to such considerations."

60 See Colmer, What is the meaning of (statistical) life? Benefit-cost analysis in the time of COVID-19, Oxford Review of Economic Policy, *supra*.

For example, PG&E's Loss of Containment (LOC) risks from gas assets are currently scoped narrowly as loss of containment events which focus on potential safety impacts. Thus, gas programs that primarily or significantly provide operational and reliability benefits do not have their full benefits included in the CBR calculation, because the risk models used do not capture full reliability risk but only Loss of Containment risk. Programs mitigating such risks that primarily provide non-safety reliability benefits include, for example, the Gas Routine Compression and Processing (C&P) program.⁶¹ This program addresses issues identified during routine maintenance or normal operation of C&P facilities that must be remedied to maintain current levels of service and reliability.⁶² The program is primarily intended to maintain reliability of the gas system to help ensure that PG&E can consistently and dependably deliver gas to its customers as expected over time. Yet the program is evaluated in the modeling solely for its benefits with respect to the Loss of Containment at Gas Measurement and Control or Compression and Processing Facility (MCCPF) risk. Thus, the calculated CBR may not fully capture the overall value of the forecasted work. Instead, the CBR evaluates the benefit of the program in terms of reducing the defined risk, compared against the cost of the program. While this information is valuable, it should not be the sole factor in determining the appropriate level of funding for these programs.

Lastly, many CBRs have Low Estimate Quality (EQ) maturity as evaluated using the criteria PG&E used in the Transparency Pilot.⁶³ This indicates that PG&E is still in the early stages of developing the risk and mitigation modeling, which will take time and experience to

⁶¹ Routine C&P Program (MATs JTY and 76N), Exhibit (PG&E-3), Ch. 6, Section B.2.

⁶² Other programs primarily providing reliability benefits are listed in Exhibit (PG&E-3) Ch. 3, Section B.4.a.

⁶³ As directed by D.24-05-064, Ordering Paragraph (OP) 2, PG&E filed its "test" of the Transparency Pilot Guidelines (D.24-05-064, Appendix B) on August 5, 2024, as a purely informational purpose.

1 mature. PG&E includes the Estimate Quality Assessment of CBRs
 2 presented in this GRC in three classifications: Low, Medium, and
 3 High, as shown in Exhibit (PG&E-2), WP 1-14. The EQ maturity for
 4 programs with computed and presented CBRs in this case is
 5 roughly 60% Medium and 40% Low, with no CBRs considered High
 6 EQ.

7 **4) Compliance Requirements**

8 PG&E is required to continue certain programs with low CBRs
 9 to comply with long-standing federal and state requirements.
 10 Examples of these clearly valuable programs that are assigned low
 11 CBRs by the modeling are discussed below:

- 12 • Programs to address atmospheric corrosion on gas mains and
 13 services (CBR: 0.01);⁶⁴
- 14 • Preventative maintenance on gas mains and services (CBR:
 15 0.02 and 0.009, respectively);⁶⁵
- 16 • Gas Encroachment Program (identifies and corrects locations
 17 where customers or third parties have built over PG&E gas
 18 distribution facilities) (CBR: 0.004) ⁶⁶
- 19 • Gas Distribution Regulator Station Maintenance (CBR: 0.2).⁶⁷

20 The low CBR scores for such compliance-mandated work may
 21 be due to specific modeling and data issues discussed above. For
 22 example, these are in many cases longstanding control programs,
 23 for which it can be exceedingly difficult to estimate the level of risk
 24 in the absence of that work in order to reliably estimate the risk
 25 reduction benefits from the control, because there is often little to no
 26 historical data to inform risk assessment. The fact that this work is
 27 mandated can also be understood as an implicit determination by

⁶⁴ MATs FHK, FHL, FHM and FIQ mandated by 49 CFR §192.481(c), Exhibit (PG&E-3), Ch. 8, Sections B.1 and G.4.

⁶⁵ Gas Mains (MAT FHA) and Gas Services (MAT FHE) mandated by 49 CFR §192.481(c), Exhibit (PG&E-3), Ch. 8, Section C.3.-

⁶⁶ MATs FIO and 50J mandated by the CPUC GO 112-F, Exhibit (PG&E-3), Ch. 4, Sections B.2 and B.7.

⁶⁷ MATs FHB and FIB mandated by 49 CFR 192.739, Exhibit (PG&E-3), Ch. 8, Section H.1.

the regulator or the industry that the safety consequences of not doing such work outweigh the costs of the work. Regardless of the reasons for the low scores, however, these results for *mandated* programs reinforce the Commission's guidance that risk scores are merely one of a number of factors that should be evaluated when deciding whether to fund safety programs that are *not* specifically mandated.⁶⁸

d. Risk Mitigation Strategy in the GRC

In this GRC, PG&E seeks funding for a portfolio of risk mitigation programs that comprehensively address and reduce the operational risks faced by the Company. As discussed above, our strategy rests on the need to balance the quantitative analysis with other relevant factors, and the need to preserve flexibility going forward in the face of a dynamic risk environment.

Balancing all relevant factors: In this GRC we considered multiple factors in the mitigation selection process to balance the limitations and uncertainty associated with the quantitative modeling and to ensure that PG&E provides safe and reliable service. In determining the appropriate portfolio of risk mitigation programs, we considered the CBR values from the risk modeling, while focusing on safety as the top priority; assessing the level of safety risks, not only using the risk values obtained applying the cost-benefit approach but also prudent operator judgement to consider the potential for catastrophic events; understanding modeling limitations and uncertainties; and aligning with regulatory requirements, operational needs, and industry practice.

The need for flexibility: In a dynamic risk environment, flexibility in program implementation is important to achieve safety, reliability, and affordability for Californians. Risk and mitigation analysis will continue to evolve as we proceed with planning, implementation, monitoring our risk landscape and maturing our risk models and our mitigation plans,

⁶⁸ Similar reasoning applies to programs with low CBRs that follow industry best practices that are widely recognized as prudent and cost-effective to maintain safe and reliable operations.

financial forecasts and work plans could change in both scope and scale accordingly.

4. RAMP to GRC Integration

a. Overview

PG&E filed its 2024 RAMP Report on May 15, 2024 (Application (A.) 24-05-008).⁶⁹ The Safety Policy Division (SPD) filed a report evaluating PG&E's RAMP Report on November 8, 2024 (SPD Report).⁷⁰ PG&E also received comments from other interested parties on October 9, 2024 including the Public Advocates Office at the California Public Utilities Commission, The Utility Reform Network (TURN), Mussey Grade Road Alliance (MGRA), Energy Producers and Users Coalition (EPUC) and the Indicated Shippers, and the Small Business Utility Advocates.⁷¹ PG&E filed opening and reply comments on December 6⁷² and 17, 2024, respectively.⁷³

In its report, SPD acknowledged that PG&E's RAMP is the first application of the new CBA to assess risk mitigation proposals that was adopted in the Risk OIR Phase 2 Decision. SPD further confirmed that PG&E's RAMP generally complies with the requirements of that Decision.⁷⁴

PG&E appreciates SPD and parties' review and feedback and believes that this collaborative method for analyzing PG&E's safety risk events will ultimately result in a fundamentally sounder approach to managing those risks.

⁶⁹ PG&E's 2024 RAMP is included herein as Exhibit (PG&E-2), WP 1-10.

⁷⁰ A.24-05-008, SPD Report (Nov. 8, 2024).

⁷¹ Parties commenting on PG&E's 2024 RAMP are: Public Advocates Office at the California Public Utilities Commission; TURN; MGRA; EPUC and the Indicated Shippers; and SBUA. MGRA and Cal Advocates, resubmitted their informal comments with minor corrections, respectively, on October 11, 2024, and October 15, 2024.

⁷² A.24-05-008, PG&E's Comments on SPD's Report (Dec. 6, 2024).

⁷³ A.24-05-008, PG&E's Reply Comments in Response to Parties' Opening Comments on SPD's Report (Dec. 17, 2024).

⁷⁴ D.22-12-027.

b. Responding to SPD and Parties' Feedback on PG&E's 2024 RAMP Report

In all, PG&E identified 306 items in the SPD Report and party comments that EORM and the Functional Areas are responding to in this GRC. Attachment D includes all SPD and Party comments and PG&E's responses. Below, PG&E provides responses to some of the key feedback provided by SPD and intervenors.

1) Electric Reliability Attribute Value

SPD and other Parties commented on PG&E's use of a single territory-wide value for electric reliability. PG&E calculated the electric reliability value of \$3.17 per customer-minute interrupted based on a territory-wide average assuming equal distribution of residential, commercial, and industrial customers in all areas. However, SPD finds that this method overestimates the value of reliability in rural areas, comprising the bulk of PG&E's high fire threat district (HFTD) areas, where few commercial or industrial customers are located. This high reliability value then inflates the apparent benefit of wildfire mitigation proposals in these areas. SPD recommends that PG&E use a disaggregated approach to estimate reliability values.

Similarly, TURN believes that a geo-tiered evaluation of \$/CMI, using tier-specific average SAIDI values provides more accurate results by considering the varying risk profiles and SAIDI data across different geographic tiers.

In its updated calculation of the monetized attribute values for the 2027 GRC described in Section d. below, PG&E complied with the Risk OIR Phase II Decision requirements. PG&E has been exploring methods to address the reliability value concern but determined that it will continue to use the ICE 1.0 system-wide aggregate value for the time being, given the recently released (at this time of preparing the testimony) new version of ICE calculator that will again indicate different values for electric reliability. This will help prevent unnecessary swings in the calculated CBRs between

1 to the 2024 RAMP (ICE 1.0 system-wide) and new results when
2 applying ICE 2.0 at the geographically granular level.

3 On April 22nd, 2025, the ALJ assigned to PG&E's 2024 RAMP
4 docket issued a ruling that required PG&E to provide cost-benefit
5 analysis based on the disaggregated (and optionally, aggregated)
6 approach to Electric reliability values. Concomitantly, in late April
7 2025 LBNL released version 2.0 of the ICE Calculator for Phase 1
8 utilities. Accordingly, and consistent with D.22-12-027 OP 2(b),
9 PG&E will provide the analysis required in the ALJ Ruling utilizing
10 the "most current version" of ICE Calculator (i.e., version 2.0,
11 Phase 1) by June 20th, 2025, as directed.

12 **2) Risk-Averse Risk Scaling Function**

13 SPD evaluated PG&E's approach of constructing a new
14 risk-averse risk scaling function based on risk premium ratios
15 calculated from insurance products or catastrophic bonds it
16 purchases to transfer risks to reinsurers and the capital markets and
17 concluded that it is valid. Though SPD found PG&E's methodology
18 to derive risk-averse risk-scaling factors was justified, it
19 recommended PG&E submit a set of risk analysis (risk scores and
20 cost-benefit ratios) in the 2027 GRC using a risk-neutral scaling
21 function to allow Commission and stakeholders to gain insight into
22 what effects the risk-averse scaling function had on risk evaluations
23 and risk mitigations, and expenditure levels. Following SPD's
24 recommendation, and pursuant to the ALJ ruling, PG&E is providing
25 risk scores and CBRs using a risk-neutral scaling function in Exhibit
26 (PG&E-2), WP 1-13 and Exhibit (PG&E-2), WP 1-16.

27 **3) No Identification of Compliance Requirements**

28 SPD provided feedback on PG&E's 2024 RAMP that PG&E
29 frequently did not identify mitigations or controls that are needed to
30 comply with regulatory requirements or adequately cite or explain
31 those requirements. In this GRC, PG&E identifies mitigations and
32 controls that are needed for regulatory requirements and cites or
33 explains those requirements in the applicable forecast chapter.

4) Continued Funding of Controls with Low CBR

SPD recommended PG&E treat risk reduction programs approved in the prior GRCs as newly-proposed programs requiring adequate justification for continued funding in the 2027 GRC. In this GRC, PG&E provides some context on why the CBRs are low or uncertain in Section C.3.c above and then provides specific justification for requesting the funding for such programs in each chapter.

5) CA Adjustment of VSL

TURN argued in its Informal Comments on PG&E's 2024 RAMP Report that "PG&E's method [for adjusting DOT VSL by California's higher inflation and real income than U.S. average] is wrong,"⁷⁵ reasoning that:

"[t]ypically, VSL estimates...inherently factor in variables such as age, income, and wealth, making them representative of a nationwide valuation. Thus, aside from adjusting for inflation, there is no need for further escalation of the VSL as it encompasses a comprehensive national perspective,"⁷⁶

"[s]implistic adjustments based on the use of state-level economic data like CPI and median wages leads to biased or inaccurate VSL estimations,"⁷⁷ and

"[t]o correctly apply a California-correction, [PG&E] would need a meta-analysis of California-specific VSL estimates, and then update them for the base year as provided in the DOT guidance."⁷⁸

PG&E appreciates TURN's comments on the VSL and understands that TURN does not oppose adjusting the DOT VSL for California but suggests using a different approach than what PG&E used for adjustment. PG&E does not agree with TURN on what constitutes a correct analysis. Ultimately, PG&E's California adjustment aligns with the DOT's own VSL update guidance that

⁷⁵ A.24-05-008, TURN's Informal Comments on PG&E's RAMP Report (Oct. 9, 2024), p. 5.

⁷⁶ *Id.*, p. 6.

⁷⁷ *Id.*

⁷⁸ *Id.*

provides adjustments to price and income, and nothing else, as the principal contributors to VSL.

c. Risk Modeling Updates

1) Updated Monetized Attributes

Since filing the 2024 RAMP Report, PG&E has updated the monetized attributes for Safety, Electric Reliability, and Gas Reliability to reflect the availability of more recent data used to calculate the monetize attribute values and update the attribute base year from 2023 to 2024. Table 1-2 compares the monetized attributes from the 2024 RAMP Report with the monetized attributes used to calculate risk scores and risk reduction values in the 2027 GRC. For a detailed explanation of how PG&E calculates each of the monetized attributes, see PG&E's 2024 RAMP Report, Exhibit (PG&E-2), Chapter 2, Section C.5.

TABLE 1-2
2024 RAMP AND 2027 GRC MONETIZED RISK ATTRIBUTES

Line No.		Safety Attribute (VSL) \$M per Equivalent Fatality	Electric Reliability Attribute \$/Customer Minute Interrupted	Gas Reliability Attribute \$/Customer
1	2024 RAMP (\$2023)	\$15.2 million	\$3.17	\$1,569.75
2	2027 GRC (\$2024)	\$16.2 million	\$3.33	\$1,616.05

2) Inflation Adjustment for Future Years

Some risk mitigation programs provide risk reduction benefits over multiple years; therefore, PG&E must calculate monetized risk attribute values for each year over the expected life of the risk reduction from a risk mitigation program. Since public data used in the monetized attribute value calculations is only available through 2024, PG&E is applying an annual escalation multiplier to the 2024 monetized risk attribute values for future years. For the escalation multiplier, PG&E is using the average annual Consumer Price Index for All Urban Consumers (CPI-U) growth forecast of 2.3 percent

from the 2024 Long Term Budget Outlook published by the Congressional Budget Office.⁷⁹

Note that PG&E shows risk values for future years in 2024 real dollars (i.e., stripping out the inflation impact), rather than in nominal dollars, for easier comparison of annual risk values over different years.

Attachment C includes a table that lists each of the RAMP risks and RAMP cross-cutting factors and identifies applicable risk policy and forecast chapters in this GRC. The table also identifies where in testimony in this GRC PG&E addresses Safety Policy Division (SPD) and party feedback. Finally, the table identifies the GRC workpaper that compares chapter references, cost forecasts, and CBRs between the RAMP and GRC for risk control and mitigation programs presented in this GRC.

D. Climate Resilience

PG&E recognizes climate change as a cross-cutting factor that increases the frequency and severity of many of the event-based risks in the Corporate Risk Register.

We have made significant progress since the 2023 GRC in integrating the assessment of climate-driven physical risk into how we do business. Our actions to respond to this risk form the basis of our ongoing work to achieve the stand of Clean and Resilient Energy for All.

This testimony describes the relationship between this GRC and our long-term strategy to preserve safety, affordability, and reliability in the face of more frequent and severe climate-driven natural hazards. The following sections detail what climate resilience means at PG&E and where we are in our journey to build climate resilience:

- Subsection 1 provides an overview of projected climate conditions and associated hazards, as well as detailed projections for several climate variables relevant to energy system planning.

⁷⁹ Congressional Budget Office, The 2024 Long-Term Budget Outlook (March 2024), Long-Term Economic Projections that support Table 3-1, available at: <https://www.cbo.gov/system/files/2024-03/57054-2024-03-LTBO-econ.xlsx> (accessed Mar. 20, 2025).

- Subsection 2 describes the arc of PG&E's approach to climate resilience and how we plan to build climate resilience going forward.
- Subsection 3 provides key findings from PG&E's 2024 Climate Adaptation and Vulnerability Assessment.
- Subsection 4 discusses adaptation strategies that can help build climate resilience.
- Subsection 5 concludes this testimony by addressing the importance of resilience investment and the ways in which building climate resilience is a shared goal across communities, regions, essential service providers, and other stakeholders.

1. Expected Climate Conditions

A coherent climate adaptation strategy starts with using the best available climate projections to understand the characteristics of our future operating environment. PG&E has begun using the latest projections from the United Nation's Intergovernmental Panel on Climate Change (IPCC) Coupled Model Intercomparison Project (CMIP) 6 effort. The state of California takes these global climate model results and creates downscaled climate projections as part of the state's current work on the Fifth Climate Change Assessment.⁸⁰

The new CMIP 6 climate projections are based on a Shared Socioeconomic Pathways (SSP) framework. The SSP framework considers both emissions trajectories *and* socioeconomic factors to provide a more comprehensive view of potential emissions futures. These emissions futures, in turn, provide the basis for expected climate conditions, as the relationship between GHG emissions and changes in global temperature are well understood. PG&E's climate resilience work is informed by scenario

⁸⁰ California Governor's Office of Land Use and Climate Innovation, Climate Assessment, Science and Research, California's Fifth Climate Change Assessment, research priorities, and tools, available at: <https://lci.ca.gov/climate/icarp/climate-assessment/> (accessed Apr. 9, 2025).

1 SSP 3-7.0,⁸¹ which is the planning scenario the CPUC recommends in
 2 D.24-08-005. SSP 3-7.0 represents a high-emissions future that diverges
 3 sharply from the targets of the Paris Climate Agreement.⁸² This future
 4 presents adaptation challenges to PG&E and our customers.

5 Specifically, these evolving climate conditions threaten infrastructure
 6 reliability, public safety, and the availability of water and other resources
 7 crucial to PG&E's operations. To proactively address these risks, PG&E's
 8 Climate Resilience team continues to refine models and integrate climate
 9 projections to prioritize investments in wildfire prevention, grid hardening,
 10 and infrastructure improvements that enhance resilience to both gradual and
 11 extreme climate impacts.

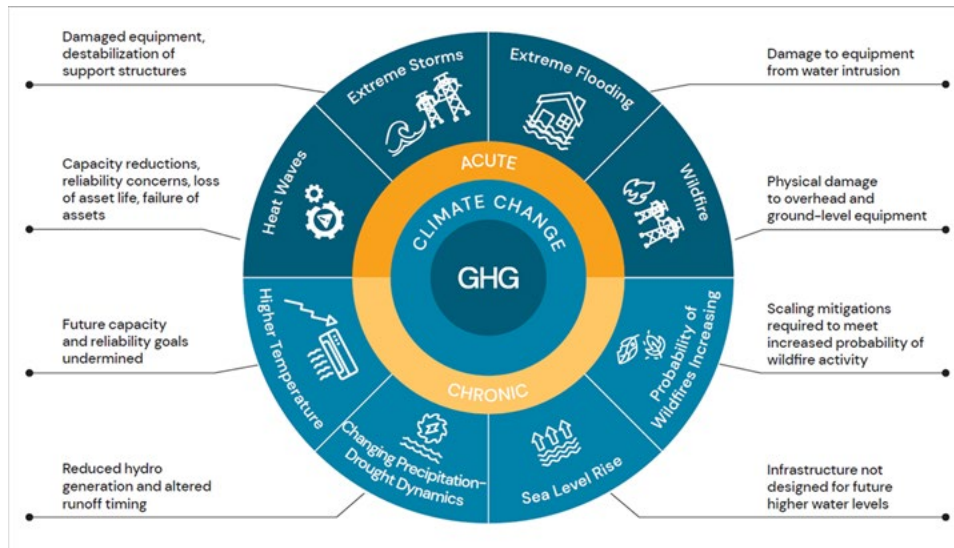
12 **a. Climate Hazard Summary**

13 Climate change impacts the energy system in both direct and
 14 indirect ways. Figure 1-6 depicts the relationship between greenhouse
 15 gas emissions and natural hazards impacted by climate change, and
 16 identifies a range of acute and chronic hazards driven by climate
 17 change. Figure 1-6 lists potential operational impacts caused by acute
 18 and chronic climate-driven events. To plan properly for the growing
 19 impacts of climate change, PG&E is working to assess and address
 20 changes in both acute and chronic climate hazards to ensure a reliable
 21 and resilient energy system into the climate-altered future.

⁸¹ SSP3-7.0 envisions a world in which cooperation on climate and environmental issues is limited. This "Regional Rivalry" scenario results in continued reliance on fossil fuels, high emissions, and a global temperature increase nearing 3–4°C by 2100—far exceeding the Paris Agreement's goals. This would have drastic impacts, as crossing the 2°C threshold is associated with severe risks, including ecosystem collapse, intensified extreme weather events, and substantial social and economic disruptions, especially for vulnerable regions and communities.

⁸² The Paris Agreement, adopted in 2015 by nearly 200 countries, aims to limit global warming to well below 2°C, with a more ambitious goal of keeping it within 1.5°C above pre-industrial levels. Achieving these targets requires a substantial reduction in greenhouse gas emissions—specifically, net-zero emissions by around 2050 to 2070.

FIGURE 1-6
ENERGY SYSTEM IMPACT PATHWAYS FOR ACUTE AND CHRONIC CLIMATE CHANGE HAZARDS



b. Projected Climate Impacts in California

Due to climate change, California is likely to experience more frequent and intense heat waves, extended wildfire seasons, severe droughts, and changes in precipitation patterns.

Extreme Heat: The frequency and severity of extreme heat events are rising across California. Projections based on the SSP scenarios show significant increases in the number of extreme heat days. These extreme heat events have implications for energy demand (e.g., as air conditioning use spikes during high temperatures) and place additional strain on grid infrastructure.

Wildfires: California has seen record-breaking wildfire seasons in recent years, exacerbated by drought and extreme high temperatures. In 2020 alone, over 4 million acres burned—more than double the previous record—highlighting how climate conditions are contributing to fire spread and severity. California's Fourth Climate Change

Assessment⁸³ notes that wildfire risks will continue to increase, especially under high-emission scenarios, further impacting air quality, displacing communities, and threatening energy infrastructure. For PG&E, projected increases in wildfire risk further underscore the critical importance of our undergrounding, vegetation management, and other wildfire risk reduction measures, as documented in our Wildfire Mitigation Plans.⁸⁴

Hydrological Conditions: The state is likely to experience severe drought conditions due to expected reduced snowpack from higher temperatures and changes in seasonal precipitation patterns. According to the California Department of Water Resources, climate change will result in a decline between 48 percent to 65 percent of the state's snowpack by 2100, which would significantly impact water availability, especially during the summer months. The overall decrease in water availability is projected to be accompanied by more concentrated and intense precipitation during winter months and less rainfall during the rest of the year.

Sea-Level Rise and Coastal Flooding: Rising sea levels present a growing risk to California's coastal communities. In 2024, the state released new sea level rise projections to be used in future planning efforts. These results indicate that sea levels along the California coast could rise between 6 to 14 inches by 2050, from global mean sea levels in 2000, and by up to 6 feet by 2100 in the most extreme scenario.⁸⁵

⁸³ California's Fourth Climate Change Assessment, available at: <https://climateassessment.ca.gov/state/overview/> (accessed Apr. 9, 2025) - Synthesis results from California's Fifth Climate Change Assessment () have not been released, available at: <https://lci.ca.gov/climate/icarp/climate-assessment/> (accessed Apr. 9, 2025). The underlying climate projections future reports from the Fifth Climate Change Assessment are available and have been approved for use in Utility planning per D.24-08-005.

⁸⁴ PG&E's 2023-2025 Wildfire Mitigation Plan, available at: <https://www.pge.com/assets/pge/docs/outages-and-safety/outage-preparedness-and-support/pge-wmp-r5-040224.pdf> (accessed Apr. 9, 2025).

⁸⁵ State of California, Sea Level Rise Guidance, 2024 Science & Policy Update, available at: <https://opc.ca.gov/wp-content/uploads/2024/05/California-Sea-Level-Rise-Guidance-2024-508.pdf> (accessed Apr. 9, 2025).

1 Sea level rise impacts coastal infrastructure and increases the risk of
2 flooding, particularly in high-density urban areas.

3 **c. Climate Conditions Expected over the Next Decade**

4 Table 1-4 shows the results of the median scenario using SSP 3-7.0
5 of key climate variables. Three periods of analysis are included in this
6 table. The Baseline Period considers the 20-year average between
7 1995 and 2014. The 2020 decadal average is based on the median
8 global climate model results from 2015 to 2035, and the 2030 decadal
9 average is based on results from 2025 to 2045.

10 While the focus of this table is on the 2020-2040 period, the
11 investments made in the 2027-2030 GRC period will, in many cases, be
12 in operation for many decades.

TABLE 1-3
CLIMATE PROJECTIONS FOR PG&E SERVICE TERRITORY USING A MEDIAN SCENARIO
FROM SSP 3-7.0

Line No		Climate Variables	Baseline 1995-2014	2020 Decadal Average	Change from Baseline to 2020s (percent)	2030 Decadal Average	Change from Baseline to 2030s (percent)
1	Temperature	1-in-2-year daily maximum temperature (Fahrenheit)	101.70	103.30	1.57 percent	104.20	2.46 percent
2		1-in-10-year daily maximum temperature (Fahrenheit)	105.60	107.50	1.80 percent	108.60	2.84 percent
3		Number of 3-Day Heat Waves above 99°F (Events per year)	2.10	2.60	23.81 percent	2.80	33.33 percent
4		Summer Season (June-September) Average (Fahrenheit)	69.40	71.00	2.31 percent	71.70	3.31 percent
5		Annual Average Temperature (Fahrenheit)	56.60	57.80	2.12 percent	58.50	3.36 percent
6	Precipitation	Annual Precipitation (inches)	32.10	31.90	-0.62 percent	32.10	0.00 percent
7		Number of Events with 1-day Precipitation Above 1 Inch (Events)	9.50	9.40	-1.05 percent	9.60	1.05 percent
8		Number of Events with 5-day Precipitation Above 3 Inches (Events)	11.50	11.40	-0.87 percent	11.20	-2.61 percent
9		1-in-20-year maximum 30-day precipitation (Inches)	22.45	23.26	3.64 percent	23.36	4.07 percent
10		Annual average 1-day precipitation totals (Inches)	0.47	0.49	3.96 percent	0.50	5.23 percent
11		Annual average 5-day precipitation totals (Inches)	1.04	1.07	2.75 percent	1.09	4.15 percent
12	Regional Annual Maximum Snowpack	Bay Area Region (Snow water equivalent in inches)	0	0	-	0	-
13		South Coast Region (Snow water equivalent in inches)	0.1	0.1	0.00 percent	0.1	0.00 percent
14		Inland South Region (Snow water equivalent in inches)	5.2	4.9	-5.77 percent	4.7	-9.62 percent
15		North Coast Region (Snow water equivalent in inches)	3	2.3	-23.33 percent	2.2	-26.67 percent
16		Inland North Region (Snow water equivalent in inches)	6.8	5.5	-19.12 percent	4.7	-30.88 percent

TABLE 1-3
CLIMATE PROJECTIONS FOR PG&E SERVICE TERRITORY USING A MEDIAN SCENARIO
FROM SSP 3-7.0
(CONTINUED)

Line No		Climate Variables	Baseline 1995-2014	2020 Decadal Average	Change from Baseline to 2020s (percent)	2030 Decadal Average	Change from Baseline to 2030s (percent)
17	Wildfire	Days with Fire Weather Index (FWI) Above the historical 95th percentile	19.48	22.31	14.50 percent	24.78	27.21 percent
18	Drought	Longest annual average consecutive dry days (Average of all Grid Cells)	104.78	110.08	5.05 percent	109.61	4.61 percent
Note: Source: Cal-Adapt, 5th California Climate Assessment, SSP 3-7.0, Median scenario							

1 Table 1-4 shows the change in mean sea levels at three tidal
 2 stations in PG&E's service territory. As a critical infrastructure operator,
 3 PG&E has decided to use the Intermediate-High sea level rise scenario
 4 from the Ocean Protection Council's planning recommendations from
 5 the 2024 State of California Sea Level Rise Guidance report.⁸⁶ In
 6 addition to chronic changes in mean sea levels, this table also includes
 7 an estimate on the area of land impacted by a 1-in-100-year storm event
 8 using projections the United States Geological Service Coastal Storm
 9 Modeling System.

⁸⁶ State of California, Sea Level Rise Guidance, 2024 Science & Policy Update, available at: <https://opc.ca.gov/wp-content/uploads/2024/05/California-Sea-Level-Rise-Guidance-2024-508.pdf> (accessed Apr. 9, 2025).

TABLE 1-4
CHANGE IN MEAN SEA LEVELS FROM A 2000 ANNUAL AVERAGE FOR PG&E SERVICE
TERRITORY USING THE INTERMEDIATE-HIGH SCENARIO

Line No		Climate Variable	Region	Tide Gauge	1995	2020	2030
1	Sea Level Rise	Mean Sea Level Rise (millimeters above 2000 sea level) ¹	Bay Area	San Francisco	-10	75	126
2			South Coast	Monterey	-9	67	114
3			North Coast	Arena Cove	-2	59	102
4		Land Area Inundated from a 1-in-100-year storm event (km ²) ²	Bay Area	San Francisco	n/a		220.7
5			South Coast	Monterey			59.8
6			North Coast	Arena Cove			339.5
Note: Sources:(1) 2024 State of California Sea Level Rise Guidance from Ocean Protection Council & the (2) United States Geological Service Coastal Storm Modeling System (CoSMoS) Data							

1 PG&E aims to ensure that its investment strategies consider the
 2 range of potential future conditions associated with SSP 3-7.0.
 3 California's climate is increasingly characterized by intensifying
 4 heatwaves, prolonged droughts, severe wildfires, and shifting
 5 precipitation patterns. We are committed to using climate projections to
 6 better understand changes in both extreme weather events and
 7 changes in average conditions. The following sections detail how we
 8 will continue our efforts to use the best available climate science to
 9 design a more resilient energy system in the future.

10 2. Climate Resilience Strategy

11 a. Our Climate Resilience Stand and Defining Climate Resilience

12 PG&E is committed to delivering for our customers a clean and
 13 resilient energy system. This includes resilience to more frequent and
 14 extreme natural hazard events (acute hazards) as well as changing
 15 average conditions (chronic hazards) caused by climate change. In
 16 practice, at PG&E, becoming climate resilient means that we
 17 systematically account for the physical risks of climate change in how
 18 we plan, invest in, and operate the energy system on behalf of the

communities we serve.⁸⁷ PG&E has a robust system in place to plan for current and future wildfire conditions. The climate resilience strategy described in this section details our efforts to plan for all natural hazards impacted by climate change.

Incorporating changing environmental conditions into our planning and investment strategy will ensure that we can deliver for customers today and into the climate-altered future. PG&E has over a century of experience maintaining and restoring energy service to communities of northern and central California in the face of natural hazards endemic to our state. Yet, climate change has already increased – and will continue to increase – the risk of ahistorical environmental conditions that, if not managed, will negatively impact PG&E’s ability to provide excellent service to our customers and maintain affordability. This is why PG&E is building the resilience needed to continue to serve our hometowns today and tomorrow.

Climate resilience means continuing to deliver on our commitments to customers in the face of projected climate hazards. This requires that PG&E’s core processes – particularly risk assessment and investment planning and also supporting functions like procurement – are informed by the best available climate projections.

b. Recent Changes

PG&E’s current climate resilience function was established in 2017 with the goal of representing climate-driven risk in PG&E’s 2017 RAMP Report.⁸⁸ The climate resilience function has continued to expand and adjust to meet PG&E’s needs since that time, aligned with the Foundational Mitigation activities submitted in the Company’s RAMP Report.

⁸⁷ PG&E 20222 Climate Strategy Report (June 2022), available at: <https://www.pge.com/content/dam/pge/docs/about/pge-systems/PGE-Climate-Strategy-Report.pdf> (accessed Apr. 9, 2025).

⁸⁸ I.17-11-003, PG&E 2017 Risk Assessment and Mitigation Phase Report (Nov. 30, 2017), Ch. 22, Climate Resilience, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M201/K962/201962691.PDF> (accessed Apr. 9, 2025).

1 In 2020, PG&E designated “Climate Resilience” as an enterprise
 2 cross-cutting risk factor to acknowledge that climate-driven natural
 3 hazards are contributing drivers to many different enterprise risk events.
 4 PG&E has currently identified six primary climate-driven contributors to
 5 risk: (1) increased severity and frequency of storm events; (2) sea level
 6 rise; (3) land subsidence; (4) change in temperature extremes;
 7 (5) changes in precipitation patterns and drought; and (6) wildfire.⁸⁹

8 In the 2024 RAMP Report,⁹⁰ PG&E made climate risk-related
 9 improvements from the 2020 RAMP on three fronts: (1) recency of
 10 climate projection data used; (2) granularity at which climate data are
 11 incorporated into the modeling; and (3) integration of the relationship
 12 between climate change and a degradation in asset health.

13 In 2024, PG&E also submitted our first ever Climate Adaptation and
 14 Vulnerability Assessment, and its findings are being applied to the
 15 Company’s risk modeling efforts to further develop impacts of climate
 16 change on risk events.

17 **c. Areas of Future Focus**

18 PG&E has learned a great deal about climate resilience since 2017,
 19 regarding both the nature of projected climate hazards as well as how to
 20 successfully integrate climate projections into company processes to
 21 impact decision-making and build resilience.

22 PG&E is currently working on the 2027 Climate Adaptation
 23 Vulnerability Assessment that will be used to inform both our 2028
 24 RAMP and 2031 GRC. The Company is also advancing climate
 25 integration of enterprise risk models, and is working to characterize the
 26 value of climate-driven hazards and associated mitigations. Detailed
 27 below are several priorities we are working on:

⁸⁹ A.20-06-012, PG&E Application to Submit Its 2020 RAMP (June 30, 2020), Ch. 20 and Attachment A, Cross Cutting Factors, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M341/K517/341517004.PDF> (accessed Apr. 9, 2025).

⁹⁰ See A.24-05-008, PG&E’s 2024 RAMP, Exhibit (PG&E-2), Ch. 6, Climate Resilience and Ch. 3 Cross-Cutting Factors.

Alignment of Long-Term Risk Assessment with Near-Term

Investments: There is a need to align operational risk assessment as performed in RAMP and long-term climate risk assessment as performed in Climate Adaptation Vulnerability Assessment. Currently, Climate Adaptation Vulnerability Assessment outputs may or may not align with the event-based nature of RAMP risk bowties, and discounting of out-year risk in RAMP may dampen climate risk signals, inadvertently delaying mitigation activities until after risks have materialized. PG&E is working on these and other technical challenges within the context of both Climate Adaptation Order Instituting Rulemaking (R.18-04-019) and Risk Based Decision-Making Framework (R.20-07-013) proceedings.

Complexity of Using Climate Scenarios in Utility Planning: In August 2024, the CPUC created new guidance for the use of climate projections in utility planning functions.⁹¹ There will be challenges in adopting the use of climate change projections across different aspects of utility planning.

Typical practices for using climate projections are to analyze multiple global climate model results to understand multi-decadal trends and changing environmental conditions, rather than precise year-by-year forecasts that are often needed for utility planning.

Value of Resilience in Investment Planning: At present, there are few accepted methods for assessing the value of climate-resilience investments, making it difficult for companies to focus resources where they will be most effective. Long timescales, multiple drivers of uncertainty, a lack of “off-the-shelf” resilience metrics, and the inherent challenges in valuing the benefits of long-term investments make comparing and justifying investments difficult, especially with regard to more immediate and well-defined risk events.

Equity and Climate Resilient Investment Planning: An important element of climate adaptation – as articulated by the CPUC, intervening parties, and our customers – is the opportunity to address

⁹¹ D.24-08-005, pp. 83-84, OPs 2 and 3 specify the use of the SSP 3-7.0 global climate model results.

1 past injustices imposed upon historically marginalized communities
2 while building climate resilience. PG&E is committed to a clean and
3 resilient energy system for all, and maintains, through our Environmental
4 and Social Justice Policy, that we will make better business decisions by
5 understanding the impacts of our activities and investments on
6 environmental and social justice communities while providing more
7 sustainable, inclusive, and equitable customer solutions.

8 This policy is consistent with our approach to the 2024 Climate
9 Adaptation Vulnerability Assessment, which included significant
10 engagement of customers living in a designated disadvantaged,
11 vulnerable community (DVC)⁹² to better understand their lived
12 experience of climate-driven hazards and their energy-related needs.
13 However, while PG&E's community partners involved in the effort rated
14 the engagement a success, it remains difficult to translate community
15 preferences, which are largely and understandably focused on
16 immediate needs, into actionable inputs for infrastructure investment
17 planning.

18 PG&E is required to file its next Community Engagement Plan with
19 the CPUC in May 2026, consistent with D.24-08-005, in which the
20 CPUC advanced the filing date of the Company's next Climate
21 Adaptation Vulnerability Assessment to May 2027. Phase II, Track II of
22 the Climate Adaptation Order Instituting Rulemaking is currently still
23 open and is considering refinements to the requirements of the
24 Community Engagement efforts as well as the intent for how
25 Investor-Owned Utilities may consider community feedback on climate
26 resilience issues. PG&E remains committed to working with
27 disadvantaged, vulnerable communities and other stakeholders to solicit
28 perspectives and recommendations on how climate change is impacting
29 these communities and how the Company may support community
30 climate resilience.

⁹² D.20-08-046, p. 119, OP 1 defines what is designated disadvantaged, vulnerable community. *Id.*, pp. 120-124, OPs 4, 5, 6, and 7 detail the requirements associated with each Investor-Owned Utility to conduct engagement with these communities.

3. 2024 Climate Adaptation Vulnerability Assessment

PG&E filed its 2024 Climate Adaptation Vulnerability Assessment on May 15, 2024.⁹³ The 2024 Climate Adaptation Vulnerability Assessment was PG&E's latest effort to holistically evaluate how climate change will impact the Company's assets, operations, and services. This evaluation did not include a direct assessment of how changes in climate hazards will impact the Company's *planned* investments, instead focusing on how long-term climate hazards may impact the Company's *existing* assets, operations, and services.

Consistent with Ordering Paragraph 12 of D.20-08-046,⁹⁴ PG&E is presenting a list of vulnerabilities identified in the 2024 Climate Adaptation Vulnerability Assessment as the climate risk rankings for each asset family.

Table 1-5 summarizes the climate risk rankings for each climate hazard assessed in the 2024 Climate Adaptation Vulnerability Assessment and the Company's corresponding impacted assets, operations, and services. The 2024 Climate Adaptation Vulnerability Assessment assessed multiple climate hazards, including high-heat, high precipitation and flooding, sea level rise, and wildfire impacts.

⁹³ PG&E Climate Adaptation and Vulnerability Assessment (2024), available at: <https://www.pge.com/assets/pge/docs/about/corporate-responsibility-and-sustainability/-report.pdf> (accessed Apr. 10, 2025).

⁹⁴ D.20-08-046, pp. 128-129, OP 12.

TABLE 1-5
2024 CLIMATE ADAPTATION VULNERABILITY ASSESSMENT CLIMATE RISK RANKING

Line No.	Functional Area	Asset Families	High Heat	Heavy Rain /Flooding	Sea Level Rise	Wildfire
1	Electric	Transmission	Moderate	Moderate	Moderate	High
2	Electric	Substation	Moderate	Moderate	Moderate	Moderate
3	Electric	Distribution	High	Moderate	Moderate	High
4	Gas	Compression & Processing, Storage	Low	High	High	Moderate
5	Gas	Measurement and Control	Low	Moderate	Low	Low
6	Gas	Transmission Pipeline	Low	Moderate	Low	Low
7	Gas	Distribution Pipeline	Low	Moderate	Low	Moderate
8	Gas	LNG/CNG	Low	Low	Low	Low
9	Generation	Hydroelectric – non-Dam assets	Low	High	Not Applicable	High
10	Generation	Hydroelectric – FERC high and significant hazards dam	Low	Moderate	Not Applicable	High
11	Generation	Natural Gas	Low	Low	Low	Low
12	Generation	Solar	Low	Low	Low	Low
13	Generation	Nuclear	Low	Low	Low	Low
14	Facilities	Offices, yards, aviation, etc.	Low	Low	Low	Low
15	IT Assets	Data centers, fiber optic cable, etc.	Low	Low	Low	Low
16	Multiple	Operations and Services	Low	Low	Low	Low

4. Climate Adaptation Options and Climate Resilience Strategies

PG&E's 2024 Climate Adaptation Vulnerability Assessment included a list of potential climate adaptation options for each asset family with a high or moderate climate risk ranking.⁹⁵

a. Defining the Climate-Informed Investment Attribute

Climate change continues to impact our assets and operations, from increasing wildfire risks, to causing more extreme storm conditions, more frequent and intense heat waves, and coastal and inland flooding.

⁹⁵ See PG&E's Climate Adaptation Vulnerability Assessment (2024), Section 4, Adaptation and Resilience: Potential Measures and Next Steps for a more detailed accounting of potential CAVA adaptation options, available at: <https://www.pge.com/assets/pge/docs/about/corporate-responsibility-and-sustainability/CAVA-report.pdf> (accessed Apr. 10, 2025). The list of the potential Climate Adaptation Options is also available in PG&E's 2024 RAMP Report, A.24-05-008, Exhibit (PG&E-2), pp. 6-9 to 6-10, Table 6-4.

1 Given these substantial climate-driven impacts, we have begun to use a
2 long-term investment perspective for climate-informed investments.

3 This investment perspective is designed to identify those
4 investments included in our 2027 GRC that intentionally enhance energy
5 system reliability or recoverability relative to projected climate-driven
6 natural hazards.

7 At present, a climate-informed investment considers whether an
8 investment is primarily motivated as a response to natural hazard
9 conditions impacted by climate change. Furthermore, a
10 climate-informed investment must be: (1) a wildfire investment; (2) an
11 investment that directly addresses a vulnerability identified in the 2024
12 Climate Adaptation and Vulnerability Assessment; or (3) a project
13 supported by a design standard that has been updated to align with
14 projected climate conditions or other climate-informed analysis.

15 Investments that only enhance baseline operational capabilities in
16 response to current natural hazard conditions and do not explicitly
17 include the consideration of future environmental conditions do not
18 qualify as climate-informed investments.

19 **b. Climate-Informed Investments in the 2027 GRC**

20 Since the 2023 GRC, PG&E has made progress assessing climate
21 vulnerability, in the form of the 2024 Climate Adaptation and
22 Vulnerability Assessment, and integrating climate data into key
23 processes, like the RAMP-driven risk assessment process as well as the
24 Company's asset design standards.

25 The climate-informed investments identified in the 2027 GRC are
26 based on the climate-informed investment criteria as described above.
27 All programs, projects, or work activity included in the Company's
28 investment plan were evaluated to determine if they met this criteria.
29 Table 1-6 identifies the capital and expense costs associated with
30 climate-informed investments for each chapter. See Exhibit (PG&E-2),
31 WP 1-18 through WP 1-21 for the list of programs, projects, or work
32 activity that qualify as climate-informed investments in this GRC. The
33 majority of climate-informed investments are for wildfire mitigation and

control programs.⁹⁶ This table provides the cost of the investment that has been identified and its exhibit and Chapter number. Capital forecasts are for years 2027-2030 and expense forecasts are for year 2027.

TABLE 1-6
LIST OF CLIMATE-INFORMED INVESTMENTS INCLUDED IN THE 2027 GRC

Line No	Chapter Number	Chapter Title	Dollar Amount (\$000's)
1	Exhibit (PG&E-4), Electric Distribution		
2	Chapter 4	Wildfire Mitigation Summary and Strategy Support	\$26,179 (Capital) \$27,802 (Expense)
3	Chapter 5	Wildfire Situational Awareness and Forecasting	\$48,957 (Capital) \$34,408 (Expense)
4	Chapter 6	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	\$307,615 (Capital) \$187,377 (Expense)
5	Chapter 7	Wildfire System Hardening	\$1,723,006 (Capital) \$3,325 (Expense)
6	Chapter 8	Vegetation Management	\$971,856 (Expense)
7	Chapter 9	Capacity, Engineering and Planning	\$51,291 (Capital)
8	Chapter 11	Electric Emergency Recovery	\$1,543,327 (Capital)
9	Chapter 14	Distribution Inspections	\$85,629 (Expense)
10	Chapter 15	Overhead Maintenance and Poles	\$7,646,430 (Capital) \$263,320 (Expense)
11	Chapter 17	Overhead Infrastructure Replacement and Reliability	\$15,000 (Capital)
12	Chapter 18	Substation Asset Management	\$11,311 (Capital) \$4,575 (Expense)
13	Chapter 21	Electric Distribution and Wildfire Mitigation Information Technology	\$243,281 (Capital) \$28,959 (Expense)
14	Chapter 22	Grid Modernization and Grid Technology	\$800 (Expense)
15	Chapter 23	Electric Distribution Support Activities	\$1,877 (Expense)
16	Exhibit (PG&E-5), Energy Supply		
17	Chapter 3	Hydro Operations Costs	\$24,980 (Capital)
18	Exhibit (PG&E-6), Customer & Enterprise Solutions		
19	Chapter 2	Local Customer Engagement	\$23,920 (Expense)
20	Chapter 9	Electric AMI Program	\$90,537 (Capital) \$1,220 (Expense)
21	Exhibit (PG&E-7), Shared Services and IT		
22	Chapter 9	Emergency Preparedness & Response	\$25,234 (Capital) \$95,190 (Expense)

The investments identified above are not necessarily investments that specifically qualify as Climate Adaptation and Vulnerability

⁹⁶ Wildfire mitigation and control programs can be identified through risk program IDs that contain the following codes followed by three additional digits: WLDFR-M, WLDFR-C, WSPSPS-M, WSPSPS-C, WEPSS-M, WEPSS-C.

Assessment Investment Proposals, as outlined in Attachment A to D.24-08-005.⁹⁷ Those investments, as defined by the Commission in D.24-08-005, “must be **demonstrably incremental** to those investments approved for reliability, safety and resiliency purposes in the most recent GRC.”⁹⁸

c. Climate Resilience Team Foundational Activities

PG&E’s Climate Resilience Team is responsible for critical foundational mitigation activities to support and enable the Company’s climate resilience strategy, with a focus on the integration of climate data into critical decision-making processes. The Climate Resilience Team is responsible for administering the Company’s Climate Resilience True North Strategy and the management of the Enterprise Climate Change Cross Cutting Factor. The Climate Resilience Team’s costs are recorded in Exhibit (PG&E-4), Chapter 23 under the major work category AB# and LJA.

The Climate Resilience Team works closely with engineering and planning departments across the Company to ensure that climate change is properly considered in investment planning and risk management activities consistent with Ordering Paragraph 3 of D.24-08-005. The Climate Resilience Team’s work can be considered in four areas, each of which is discussed below.

1) Climate-Informed Design Guidance

A key finding from PG&E’s 2024 Climate Adaptation Vulnerability Assessment was that updating design standards for assets was a key first step to building climate resilience. Climate-informed design standards ensure PG&E invests in equipment that is sufficiently robust to achieve its expected useful life even as climate-driven hazards intensify, thereby preserving value and performance of the energy system for customers. In 2024, the Company updated its Summer Temperature District Map,

⁹⁷ D.24-08-005, Attachment A, issued guidelines on incremental climate adaptation and resilience investments.

⁹⁸ D.24-08-005, Attachment A, p. 1 (emphasis in original).

1 a critical document in appropriately sizing transformers across
2 different parts of the service area. In 2025, PG&E has expanded its
3 efforts to 26 additional design standards that currently rely on
4 historical weather data.

5 PG&E will be working to integrate climate resilience into its
6 Integrated Grid Planning process to be able to value climate
7 resilience investments relative to other pressing grid needs to
8 ensure that all grid needs are being met while maintaining
9 affordability.

10 **2) Climate Data Initiative**

11 PG&E is developing an internal data management project called
12 the Climate Data Initiative (CDI) (CLIMT-M08). This project will
13 support additional climate change data analysis, including the
14 Climate Resilience Team's Internal Consulting (CLIMT-M13) and the
15 next iteration of the Climate Adaptation Vulnerability Assessment
16 (CLIMT-M14). To achieve this, PG&E is creating a repository of
17 climate projection datasets to use within the Company's internal
18 data infrastructure to allow for the pairing of asset data with climate
19 projections.

20 The aim for this foundational effort will be to create:

21 (1) Data tools that other groups within PG&E can use
22 independently to better plan for the impacts of climate change.

23 (2) Methods to easily share climate data sets to different
24 business units that have a need for climate data and to create
25 tools to visualize the impacts of different climate conditions on
26 PG&E infrastructure and assets.

27 To support this effort, an ongoing review of climate change
28 science and available data will be required to ensure that the
29 Company's risk mitigation efforts are reflective of these changes as
30 new climate models are developed and additional research on
31 climate risk is published. PG&E will also be conducting additional
32 internal studies to better understand new climate data that is
33 released as part of California's Fifth Climate Change Assessment
34 and how it might impact the Company's risk to different types of
35 future climate hazards.

The Climate Resilience team receives requests from different functional areas and business groups across the company to undertake ad hoc projects related to integrating forward looking climate data into project planning and asset replacement forecasts. This includes developing new statistical tools using climate projection data and the Company's asset data as well as developing detailed engineering studies to better understand how expected asset lifetimes will be impacted by various climate hazards.

3) Climate-Informed Risk Management

Through the incorporation of targeted climate change projection data in PG&E's risk modeling efforts, the company is enhancing the climate resilience of its assets and building a more resilient and safe energy system for our customers.

PG&E has found that integrating climate data into enterprise and operational risk models is a time- and resource-intensive effort. Consistent with Phase III of the OIR to Further Develop a Risk Based Decision Making Framework proceeding (R.20-07-013), PG&E will continue to develop more quantitatively informed enterprise risk models. This effort will expand on the existing climate-informed risk modeling efforts to include scenario analysis and an expansion of risk models that have difficult-to-quantify relationships between climate hazard conditions and risk events.

PG&E's risk management of the enterprise climate-change, cross-cutting factor work was described in the Company's 2024 RAMP Report. A list of these mitigations is provided below.

- CLIMT-M08 – Research Climate Science and Impacts;
- CLIMT-M10 – Governance, Integration, and Continuous Improvement;
- CLIMT-M12 – Climate Adaptation Plans;
- CLIMT-M13 – Internal Consulting;
- CLIMT-M14 – Climate Adaptation Vulnerability Assessment 2.0;
- CLIMT-M15 – Climate Informed Risk Assessment; and
- CLIMT-M16 – Climate Informed Design Guidance.

The Climate Change Cross Cutting Factor enterprise risk reports annually to the Sustainability and Governance Committee of the PG&E Board, consistent with Ordering Paragraph 13 from D.20-08-046.⁹⁹ The Climate Resilience Team will also consider additional studies in partnership with other groups at the Company to better understand the impacts of climate change.

4) Climate Adaptation Vulnerability Assessment and Community Engagement

The Climate Resilience Team is also responsible for submitting the Company's Climate Adaptation Vulnerability Assessments and the associated Community Engagement Plans as part of the requirements from the Climate Adaptation OIR, R.18-04-019.¹⁰⁰ Direct costs from these two efforts are recorded in the Climate Adaptation Vulnerability Assessment Memorandum Account, as detailed in Ordering Paragraph 10 of D.20-08-046¹⁰¹ and are not included in the Climate Resilience Team's budget forecast.

As of now, we project two full-time equivalent employees overseeing the project management of the Climate Adaptation Vulnerability Assessment in 2027.

5. Climate Resilience Conclusion

PG&E will continue to build the capability to better quantify the impacts of climate change and the benefits of a more climate resilient energy system to our customers. PG&E will mature this function so we can plan for the environmental conditions new investments will operate under over their expected lifetime. The Climate-Informed Design Standard program is one such example of a no regrets effort to build resilience over time as we advance our understanding of climate change impacts.

⁹⁹ D.20-08-046, p. 129, OP 13.

¹⁰⁰ CPUC, Climate Adaptation, available at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/climate-change> (accessed Apr. 10, 2025).

¹⁰¹ D.20-08-046, p. 128, OP 10.

1 Academic research and common sense indicate that proactive
2 adaptation to climate-driven natural hazards may impose higher costs in the
3 short-run, but provide significant benefits in reliability and affordability in the
4 long-run. However, as detailed in the preceding sections, representing the
5 costs and benefits of climate resilience investments and then integrating
6 those investments into the larger universe of utility investment priorities is a
7 complex and evolving process.

8 PG&E is committed to continuous improvement regarding climate risk
9 integration, using both internal learnings and the increasing number of
10 industry-focused external resources. This testimony demonstrates the
11 significant strides PG&E has made to plan and invest for changing climate
12 conditions through its risk management efforts, making climate change
13 projections available across the company, reviewing electric design
14 standards as part of the Climate-Informed Design Guidance effort, and
15 developing processes to better integrate climate change as a part of the
16 investment planning process.

17 This climate resilience section establishes a marker for what PG&E
18 considers to be climate-informed investments and sets a baseline of the
19 amount of customer revenue dedicated to investments that are necessary to
20 consider the future impacts of climate change. PG&E is committed to
21 working toward an even better climate-informed Test Year 2031 GRC. To
22 this end, PG&E will continue to advance the integration of climate
23 projections across core decision-making processes over the coming years.

24 **E. Conclusion**

25 This concludes Exhibit (PG&E-2), Chapter 1.

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT A
PG&E'S CORPORATE RISK REGISTER

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT A
PG&E'S CORPORATE RISK REGISTER

Attachment A, Table 1A-1 is Pacific Gas and Electric Company's (PG&E) Corporate Risk Register (CRR). The CRR lists PG&E's enterprise risk events and cross-cutting factors. A cross-cutting factor is an item that is not a risk event itself, but impacts either the likelihood or consequence of other items on the CRR. Along with the name and definition of each risk event and cross-cutting factor, Table 1A-1 also includes:

- The 2027 test year baseline risk value and 2027 test year safety value for each General Rate Case (GRC) risk;
 - Whether the risk event or cross-cutting factor was included in PG&E's 2024 Risk Assessment and Mitigation Phase (RAMP) Report and, if so, the applicable 2024 RAMP Report chapter number; and
- An exhibit and chapter reference to where the risk event or cross-cutting factor is discussed..

TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
1	Access Asset Incident Risk	2027 TY Baseline Risk Value: 7.71 2027 TY Baseline Safety Risk Value: 7.71	Any incident occurring on an access asset (e.g., roads, bridges) which results in property damage and/or safety event; or an inability to utilize the access asset resulting in safety, financial, and/or reliability consequences due to inability to complete scheduled asset maintenance or respond to an emergency event.	No	Exhibit (PG&E-7), Ch. 5
2	Aviation Occurrence	2027 TY Baseline Risk Value: 5.64 2027 TY Baseline Safety Risk Value: 4.31	Accident associated with the operation of fixed wing aircraft or helicopter during the time any person boards the aircraft with the intention of flight and until all persons have disembarked.	No	Exhibit (PG&E-7), Ch. 2
3	Climate Change (Cross-Cutting Factor)	N/A	Impact of climate change on PG&E's risk drivers and consequences.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-4), Ch. 23
4	Contract Management (Cross-Cutting Factor)	N/A	Impact of contract management controls that affect PG&E's risk drivers and consequences.	No	Exhibit (PG&E-7), Ch. 3
5	Contractor Safety Incident	2027 TY Baseline Risk Value: 31.39 2027 TY Baseline Safety Risk Value: 31.39	Any event resulting in a contractor recordable injury or fatality, excluding events resulting from asset failure.	Yes: Exhibit (PG&E-7), Ch. 1	Exhibit (PG&E-7), Ch. 1
6	Cybersecurity Risk Event (Risk Event and Cross-Cutting Factor)	2027 TY Baseline Risk Value: 1,068.61 2027 TY Baseline Safety Risk Value: 26.79	A coordinated malicious attack targeting PG&E's core business functions, resulting in a disruption or damage of systems used for gas, electric, or business operations.	Yes: Exhibit (PG&E-2), Ch. 3 and Exhibit (PG&E-7), Ch. 2	Exhibit (PG&E-7), Ch. 8
7	Data Loss Event	2027 TY Baseline Risk Value: 108.03 2027 TY Baseline Safety Risk Value: 0.00	A confirmed incident in which sensitive, confidential or otherwise protected data has been accessed and/or disclosed in an unauthorized fashion.	No	Exhibit (PG&E-7), Ch. 8

**TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)**

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
8	Electric Transmission System-Wide Blackout	2027 TY Baseline Risk Value: 1,999.47 2027 TY Baseline Safety Risk Value: 55.14	A system-wide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system with the inability to restore the grid in a timely fashion.	Yes: Exhibit (PG&E-4), Ch. 2	N/A – Outside CPUC Jurisdiction
9	Emergency Preparedness and Response (Cross-Cutting Factor)	N/A	Impact of emergency preparedness and response controls that affect PG&E's risk drivers and consequences.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-7), Ch. 9
10	Employee Safety Incident	2027 TY Baseline Risk Value: 35.26 2027 TY Baseline Safety Risk Value: 27.04	Any event resulting in an employee recordable injury or fatality, excluding events resulting from asset failure.	Yes: Exhibit (PG&E-7), Ch. 3	Exhibit (PG&E-7), Ch. 1
11	Extended Unplanned Shutdown of a Critical Power Generation Asset	2027 TY Baseline Risk Value: 96.91 2027 TY Baseline Safety Risk Value: 0.00	Extended Unplanned Shutdown of a Critical Power Generation Asset.	No	Exhibit (PG&E-5), Ch. 2
12	Failure of Electric Distribution Overhead Assets	2027 TY Baseline Risk Value: 4,891.60 2027 TY Baseline Safety Risk Value: 83.45	Failure of distribution overhead assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.	Yes: Exhibit (PG&E-4), Ch. 4	Exhibit (PG&E-4), Ch. 3
13	Failure of Electric Distribution Substation Assets	2027 TY Baseline Risk Value: 474.46 2027 TY Baseline Safety Risk Value: 4.54	Failure of distribution substation assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources or inability to deliver energy.	No	Exhibit (PG&E-4), Ch. 3
14	Failure of Electric Distribution Underground Assets	2027 TY Baseline Risk Value: 823.19 2027 TY Baseline Safety Risk Value: 19.54	Failure of distribution underground assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.	Yes: Exhibit (PG&E-4), Ch. 5	Exhibit (PG&E-4), Ch. 3

(PG&E-2)

TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
15	Failure of Electric Transmission Overhead Assets	2027 TY Baseline Risk Value: 1,313.07 2027 TY Baseline Safety Risk Value: 18.43	Failure of transmission overhead assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources and inability to deliver energy.	No	N/A – Outside CPUC Jurisdiction
16	Failure of Electric Transmission Substation Assets	2027 TY Baseline Risk Value: 349.38 2027 TY Baseline Safety Risk Value: 1.79	Failure of transmission substation assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources or inability to deliver energy.	No	N/A – Outside CPUC Jurisdiction
17	Failure of Electric Transmission Underground Assets	2027 TY Baseline Risk Value: 127.49 2027 TY Baseline Safety Risk Value: 1.43	Failure of transmission underground assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, reduced operational redundancy in critical urban centers, or large-scale prolonged outages.	No	N/A – Outside CPUC Jurisdiction
18	Hazardous Material Release	2027 TY Baseline Risk Value: 53.32 2027 TY Baseline Safety Risk Value: 0.00	Release of hazardous materials; current and historical; sudden and accidental, or continual; by PG&E or by an agent acting on behalf of PG&E or under PG&E's authority. Natural gas, solid waste, non-hazardous waste, and 3rd party facilities are out of scope.	No	Exhibit (PG&E-7), Ch. 5
19	Insufficient Capacity to Meet Customer Demand	2027 TY Baseline Risk Value: 2.72 2027 TY Baseline Safety Risk Value: 0.14	Failure to maintain capacity on the system on high demand days.	No	Exhibit (PG&E-3), Ch. 3
20	IT Asset Failure (Risk Event and Cross-Cutting Factor)	2027 TY Baseline Risk Value: 412.84 2027 TY Baseline Safety Risk Value: 0.00	Failure of IT hardware/infrastructure and/or software asset(s) resulting in IT service interruption(s) or system outage(s) that inhibit or disrupt Mission and Business Critical Processes.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-7), Ch. 7

**TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)**

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
21	Large Overpressure Event Downstream of Gas Measurement and Control Facility	2027 TY Baseline Risk Value: 69.28 2027 TY Baseline Safety Risk Value: 59.02	Failure of a Gas Measurement and Control station to perform its pressure control function resulting in a large overpressure event that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	Yes: Exhibit (PG&E-3), Ch. 3	Exhibit (PG&E-3), Ch. 3
22	Large Uncontrolled Water Release (Dam Failure)	2027 TY Baseline Risk Value: 254.68 2027 TY Baseline Safety Risk Value: 22.77	Failure of High or Significant hazard dams, where failure or mis-operation could cause loss of human life and/or could cause economic loss, environmental damage, disruption of lifeline facilities, and other concerns.	Yes: Exhibit (PG&E-5), Ch. 1	Exhibit (PG&E-5), Ch. 2
23	Liquidity Shortage	N/A	The lack of sufficient liquidity to meet PG&E's financial obligations (liquidity is defined as the availability of cash)	No	Exhibit (PG&E-9), Ch. 2
24	Loss of Containment at Gas Measurement and Control or Compression and Processing Facility	2027 TY Baseline Risk Value: 1.79 2027 TY Baseline Safety Risk Value: 0.23	Failure at a Gas Measurement and Control or Compression and Processing station resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	No	Exhibit (PG&E-3), Ch. 3
25	Loss of Containment at Natural Gas Storage Well or Reservoir	2027 TY Baseline Risk Value: 3.75 2027 TY Baseline Safety Risk Value: 0.89	Failure at a gas storage well or reservoir resulting in loss of containment, with or without an unplanned ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	No	Exhibit (PG&E-3), Ch. 3
26	Loss of Containment on CNG Station Equipment	2027 TY Baseline Risk Value: 0.59 2027 TY Baseline Safety Risk Value: 0.55	Failure of CNG station equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	No	Exhibit (PG&E-3), Ch. 3

(PG&E-2)

**TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)**

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
27	Loss of Containment on Gas Customer Connected Equipment	2027 TY Baseline Risk Value: 11.87 2027 TY Baseline Safety Risk Value: 2.70	Failure of gas customer connected equipment resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers.	No	Exhibit (PG&E-3), Ch. 3
28	Loss of Containment on Gas Distribution Main or Service	2027 TY Baseline Risk Value: 102.32 2027 TY Baseline Safety Risk Value: 16.22	Failure of a gas distribution main or service resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	Yes: Exhibit (PG&E-3), Ch. 2	Exhibit (PG&E-3), Ch. 3
29	Loss of Containment on Gas Transmission Pipeline	2027 TY Baseline Risk Value: 134.97 2027 TY Baseline Safety Risk Value: 108.44	Failure of a gas transmission pipeline resulting in a loss of containment, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	Yes: Exhibit (PG&E-3), Ch. 1	Exhibit (PG&E-3), Ch. 3
30	Loss of Containment on LNG/CNG Portable Equipment	2027 TY Baseline Risk Value: 0.23 2027 TY Baseline Safety Risk Value: 0.04	Failure of LNG/CNG portable equipment during operations resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial losses, and the inability to deliver natural gas to customers.	No	Exhibit (PG&E-3), Ch. 3
31	Motor Vehicle Safety Incident	2027 TY Baseline Risk Value: 7.23 2027 TY Baseline Safety Risk Value: 5.28	Any motor vehicle accident involving a PG&E vehicle (or one operated on behalf of PG&E) resulting in recordable injuries or fatalities for employees or the public, property damage, and other consequences.	No	Exhibit (PG&E-7), Ch. 1
32	Nuclear Core Damaging Event	2027 TY Baseline Risk Value: 3.96 2027 TY Baseline Safety Risk Value: 0.21	Nuclear reactor core-damaging event with the potential for radiological release at the Diablo Canyon Power Plant (Diablo Canyon) due to equipment failure, natural disaster, or some other significant event.	No	N/A – no longer presented in the GRC

**TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)**

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
33	Nuclear Extended Shutdown	2027 TY Baseline Risk Value: 93.43 2027 TY Baseline Safety Risk Value: 0.00	An extended shutdown of the Diablo Canyon Power Plant (for longer than three months or with a financial impact greater than \$100 million) due to equipment failure, natural disaster, regulatory action, or some other significant event.	No	N/A – no longer presented in the GRC
34	Physical Attack (Cross-Cutting Factor)	N/A	Impact of physical-attack events that affect PG&E's risk drivers and consequences.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-7), Ch. 8
35	Public Contact with (Intact) Energized Electrical Equipment	2027 TY Baseline Risk Value: 58.84 2027 TY Baseline Safety Risk Value: 58.84	Public Contact with Intact Energized Electrical Equipment is focused on public exposure to energized electrical equipment under normal operating conditions and is not a result of an asset failure.	Yes: Exhibit (PG&E-4), Ch. 3	Exhibit (PG&E-4), Ch. 3
36	Real Estate and Facilities Failure	2027 TY Baseline Risk Value: 51.10 2027 TY Baseline Safety Risk Value: 18.72	Due to a seismic, flood, landslide, building fire, or physical security event, a building, facility, or property is deemed unsafe, or inaccessible for operation or occupancy such that we are unable to perform work and support operational needs.	No	Exhibit (PG&E-7), Ch. 4
37	Data, Information, and Records Management (Cross-Cutting Factor)	N/A	Failure to implement an effective records and information management program can result in unsafe and inefficient operations. Inadequate processes and controls related to the collection, maintenance, and disposition of data, records, and information that can result in non-compliance, security gaps, and poor-quality data for critical decision making and business operations.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-7), Ch. 6
38	Seismic (Cross-Cutting Factor)	N/A	Seismic events can be a significant driver to failure in all Functional Area assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.	Yes: Exhibit (PG&E-2), Ch. 3	Exhibit (PG&E-7), Ch. 9
39	Third-Party Risk (Cross-Cutting Factor)	N/A	Impact of vendor actions involving Safety, Cyber, Privacy, Insurance, Credit, that affect PG&E's risk drivers and consequences.	No	Exhibit (PG&E-9), Ch. 3

(PG&E-2)

**TABLE 1A-1
PG&E'S CORPORATE RISK REGISTER
(CONTINUED)**

Line No.	Name of Risk Event or Cross-Cutting Factor	2027 Test Year (TY) Baseline Risk Values	Definition	Included in PG&E's 2024 RAMP Report	2027 GRC
40	Wildfire with PSPS and EPSS	2027 TY Baseline Risk Value: 6,495.91 2027 TY Baseline Safety Risk Value: 241.17	A wildfire that may endanger the public, private property, sensitive lands, or environment originating from PG&E assets or activities. In the near term due to the use of PSPS and EPSS we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS.	Yes: Exhibit (PG&E-4), Ch. 1	Exhibit (PG&E-4), Ch. 3

(PG&E-2)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT B
CROSS-CUTTING FACTOR TO RISK EVENT MAPPING TABLE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT B
CROSS-CUTTING FACTOR TO RISK EVENT MAPPING TABLE

Attachment B, Table 1-B1 lists each of the enterprise risk events represented in PG&E's 2027 GRC Application and the seven cross-cutting factors (CCFs) and identifies which risk events are impacted by which CCFs. The visibility of CCFs in the Bow Tie figures included in some risk testimony chapters, e.g., Exhibit (PG&E-3), Chapter 3, reflects the nature of the quantification of each CCF. Where the CCF can be included as a standalone driver or sub driver with specific event frequency (e.g., Physical Attack) or as a standalone outcome (e.g., Seismic – Rupture), the CCF will be visible at this summary level. Certain CCFs that quantitatively impact the likelihood or consequences of the risk event will not appear on the Bow Tie, as the impact is embedded within the model underlying the frequency or consequence values (e.g., escalating Natural Hazard frequency over time due to Climate Change). For each of these four CCF examples, there would be a “Yes” relationship between CCF and Risk Event because there is some quantified connection between the CCF and the Risk Event. For others, where the connection is perhaps not sufficiently clear as to be quantified or difficult to distinguish within the available risk event data, CCFs have a “Yes*” mapping to indicate that there is a relationship between the CCF and Risk Event, but not one that is quantitatively modeled. For example, for the Emergency Preparedness and Response (EP&R) CCF, if a risk event occurs such as Loss of Containment on Gas Transmission Pipeline and PG&E implements EP&R activities (PG&E activates the Emergency Operations Center (EOC)), EOC activities (e.g., coordination with first responders), which are essential to manage/contain the consequence of the risk event, the degree to which this broad set of response activities reduces risk is not readily quantifiable.

TABLE 1B-1
MAPPING CROSS-CUTTING FACTORS TO RISK EVENTS

Line No.	Exhibit	Risk ID	Risk Name	Cross-Cutting Factor						Seismic
				Climate Change	Cyber Attack	EP&R (1)	IT Asset Failure	Physical Attack	DIRM (2)	
1	3	LOCTM	Loss of Containment on Gas Transmission Pipeline	Yes*	No	Yes*	No	Yes	Yes	Yes
2	3	LOCDM	Loss of Containment on Gas Distribution Main or Service	Yes*	No	Yes*	No	Yes	Yes	Yes
3	3	LRGOP	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Yes*	Yes*	Yes*	Yes*	Yes*	Yes	No
4	3	CCEQP	Loss of Containment on Gas Customer Connected Equipment	No	No	Yes*	No	Yes	Yes	Yes
5	3	NGSWR	Loss of Containment at Natural Gas Storage Well or Reservoir	Yes	Yes	Yes*	No	Yes	Yes	Yes
6	3	MCCPF	Loss of Containment at Gas Measurement and Control or Compression and Processing Facility	Yes	Yes	Yes*	No	Yes	Yes	Yes
7	3	CNGEQ	Loss of Containment on CNG Station Equipment	No	No	Yes*	No	Yes	Yes	No
8	3	LNCNG	Loss of Containment on LNG/CNG Portable Equipment	No	No	No	No	Yes	Yes	No
9	3	CPCTY	Insufficient Capacity to Meet Customer Demand	No	No	Yes*	No	No	Yes	No
10	4	WLDFR	Wildfire with PSPS and EPSS	Yes	Yes*	Yes*	Yes*	Yes	Yes	Yes
11	4	DOVHD	Failure of Electric Distribution Overhead Assets	Yes	Yes*	Yes*	Yes*	Yes	Yes	Yes
12	4	DUNGD	Failure of Electric Distribution Underground Assets	Yes	Yes*	Yes*	Yes*	Yes	Yes	Yes
13	4	DSBSN	Failure of Electric Distribution Substation Assets	Yes*	Yes*	Yes*	No	Yes	Yes	Yes
14	4	PCEEE	Public Contact with Intact Energized Electrical Equipment	No	No	No	No	Yes	Yes*	No

(PG&E-2)

**TABLE 1B-1
MAPPING CROSS-CUTTING FACTORS TO RISK EVENTS
(CONTINUED)**

Line No.	Exhibit	Risk ID	Risk Name	Cross-Cutting Factor						Seismic
				Climate Change	Cyber Attack	EP&R (1)	IT Asset Failure	Physical Attack	DIRM (2)	
15	5	GSHUT	Extended Unplanned Shutdown of Critical Power Generation Asset	No	No	No	Yes*	No	Yes	Yes
16	5	LGUWR	Large Uncontrolled Water Release (Dam Failure)	Yes*	Yes*	Yes	Yes	Yes	Yes	Yes
17	7	CNTSI	Contractor Safety Incident	Yes*	No	Yes*	No	Yes	Yes*	No
18	7	EMPSI	Employee Safety Incident	Yes*	No	Yes*	No	Yes	Yes	No
19	7	MTRSI	Motor Vehicle Safety Incident	Yes*	No	No	No	No	Yes	No
20	7	AVATN	Aviation Occurrence	No	No	Yes*	No	No	Yes	No
21	7	REFFL	Real Estate and Facilities Failure	Yes*	No	Yes*	No	Yes	Yes	Yes
22	7	ACASI	Access Asset Incident	Yes*	Yes*	No	Yes*	Yes	Yes*	Yes*
26	7	HZMAT	Hazardous Material Release	No	No	No	No	No	Yes	No
23	7	ITAFLL	IT Asset Failure	Yes*	Yes*	Yes*	No	Yes*	Yes	Yes*
24	7	CYBER	Cybersecurity Risk Event	No	No	Yes*	Yes*	Yes*	Yes	No
25	7	DTALS	Data Loss Event	No	Yes	Yes*	No	Yes	Yes	No

Note:

Yes – The cross-cutting factor has been quantified in the model.

Yes* – The cross-cutting factor does influence the baseline risk, but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No – The cross-cutting factor does not meaningfully influence the baseline risk.

(1) EP&R – Emergency Preparedness and Response.

(2) DIRM – Data, Information, and Records Management (previously Records and Information Management, or RECIM).

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT C
RAMP RISK AND CROSS-CUTTING FACTORS TO GRC
INTEGRATION ROADMAP

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT C
RAMP RISK AND CROSS-CUTTING FACTORS TO GRC
INTEGRATION ROADMAP

Attachment C Table 1C-1 lists each of the RAMP risks and RAMP cross-cutting factors and identifies applicable risk policy and forecast chapters in this GRC. The table also identifies where in testimony in this GRC PG&E addresses Safety Policy Division (SPD) and party feedback. Finally, the table identifies the GRC workpaper that compares chapter references, cost forecasts, and CBRs between the RAMP and GRC for risk control and mitigation programs presented in this GRC.

**TABLE 1C-1
MAPPING PG&E'S 2024 RAMP INFORMATION TO THE 2027 GRC**

Line No.	Name of Risk Event or Cross-Cutting Factor	Risk Policy Chapter	Functional Area Forecast Chapter	Testimony Response to SPD and Party RAMP Comments	WP Comparing RAMP to GRC Forecasts ^(b)
1	EORM ^(a)	Exhibit (PG&E-2), Ch. 1	Exhibit (PG&E-7), Ch. 10	Exhibit (PG&E-2), Ch. 1, Section C.4.b, Exhibit (PG&E-2), Ch. 1, Attachment D	N/A
2	Climate Change (Cross-Cutting Factor)	N/A	Exhibit (PG&E-4), Ch. 23	N/A	Exhibit (PG&E-2), WP 1-15
3	Contractor Safety Incident	Exhibit (PG&E-7), Ch. 1	Exhibit (PG&E-7), Ch. 1	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-7), Ch. 1, Section F.2.a	Exhibit (PG&E-2), WP 1-15
4	Cyber Attack (Cross-Cutting Factor)	N/A		N/A	N/A
5	Cybersecurity Risk Event	Exhibit (PG&E-7), Ch. 8	Exhibit (PG&E-7), Ch. 8	N/A	Exhibit (PG&E-2), WP 1-15
6	Electric Transmission Systemwide Blackout	N/A	N/A	Exhibit (PG&E-2), Ch. 1, Attachment D	N/A
7	Employee Safety Incident	Exhibit (PG&E-7), Ch. 1	Exhibit (PG&E-7), Ch. 1	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-7), Ch. 1, Section F.1.a	Exhibit (PG&E-2), WP 1-15
8	EP&R (Cross-Cutting Factor)	N/A	Exhibit (PG&E-7), Ch. 9	Exhibit (PG&E-2), Ch. 1, Attachment D	N/A
9	Failure of Electric Distribution Overhead Assets	Exhibit (PG&E-4), Ch. 3	Exhibit (PG&E-4), Ch. 6, 7, 8, 9, 11, 14, 15, 17, 23	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-4), Ch. 3, Section C.2.b	Exhibit (PG&E-2), WP 1-15
10	Failure of Electric Distribution Underground Assets	Exhibit (PG&E-4), Ch. 3	Exhibit (PG&E-4), Ch. 8, 16, 23	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-4), Ch. 3, Section C.3.b	Exhibit (PG&E-2), WP 1-15
11	IT Asset Failure (Cross-Cutting Factor)	N/A	Exhibit (PG&E-7), Ch. 7	Exhibit (PG&E-2), Ch. 1, Attachment D	Exhibit (PG&E-2), WP 1-15
12	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Exhibit (PG&E-3), Ch. 3	Exhibit (PG&E-3), Ch. 6, 8, 9	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-3), Ch. 3, Section C.3.b	Exhibit (PG&E-2), WP 1-15

(PG&E-2)

TABLE 1C-1
MAPPING PG&E'S 2024 RAMP INFORMATION TO THE 2027 GRC
(CONTINUED)

Line No.	Name of Risk Event or Cross-Cutting Factor	Risk Policy Chapter	Functional Area Forecast Chapter	Testimony Response to SPD and Party RAMP Comments	WP Comparing RAMP to GRC Forecasts ^(b)
13	Large Uncontrolled Water Release (Dam Failure)	Exhibit (PG&E-5), Ch. 2	Exhibit (PG&E-5), Ch. 3	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-5), Ch. 2, Section C.1.b	Exhibit (PG&E-2), WP 1-15
14	LOC on Gas Distribution Main or Service	Exhibit (PG&E-3), Ch. 3	Exhibit (PG&E-3), Ch. 4, 8, 9, 11	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-3), Ch. 3, Section C.2.b	Exhibit (PG&E-2), WP 1-15
15	LOC on Gas Transmission Pipeline	Exhibit (PG&E-3), Ch. 3	Exhibit (PG&E-3), Ch. 5, 8, 9, 11	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-3), Ch. 3, Section C.1.b	Exhibit (PG&E-2), WP 1-15
16	Physical Attack (Cross-Cutting Factor)	N/A	Exhibit (PG&E-7), Ch. 8	Exhibit (PG&E-2), Ch. 1, Attachment D	Exhibit (PG&E-2), WP 1-15
17	Public Contact with Intact Energized Electrical Equipment	Exhibit (PG&E-4), Ch. 3	Exhibit (PG&E-4), Ch. 7, 8, 15, 18, 23	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-4), Ch. 3, Section C.4.b	Exhibit (PG&E-2), WP 1-15
18	Records and Information Management (Cross-Cutting Factor) ^(c)	N/A	Exhibit (PG&E-7), Ch. 6	Exhibit (PG&E-2), Ch. 1, Attachment D	Exhibit (PG&E-2), WP 1-15
19	Seismic (Cross-Cutting Factor)	N/A	Exhibit (PG&E-7), Ch. 9	Exhibit (PG&E-2), Ch. 1, Attachment D	N/A
20	Wildfire with PSPS and EPSS	Exhibit (PG&E-4), Ch. 3	Exhibit (PG&E-4), Ch. 4, 6, 7, 8, 9, 11, 14, 15, 17, 18	Exhibit (PG&E-2), Ch. 1, Attachment D Exhibit (PG&E-4), Ch. 3, Section C.1.b	Exhibit (PG&E-2), WP 1-15
(a) EORM responds to SPD and Party comments related to RAMP Report, Exhibit (PG&E-2), Chapter 2, Risk Modeling and CBR. (b) While the workbook comparing the estimated costs for risk controls and mitigations in the 2024 RAMP Report to the forecast costs for risk controls and mitigations in the 2027 GRC is included as an attachment to this chapter, the Functional Area that sponsors each risk event (e.g., Wildfire is sponsored by Electric Operations) is sponsoring those costs. (c) Records and Information Management was recently renamed to Data, Information, and Records Management (DIRM).					

(PG&E-2)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT D
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND
MITIGATION PHASE REPORT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ATTACHMENT D
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND
MITIGATION PHASE REPORT

As required in D.22-10-002,¹ Table 1D-1 below addresses PG&E's responses to SPD's Evaluation Report and party comments on PG&E's 2024 RAMP Report.

¹ D.22-10-002, Appendix A, Requirement 22.

TABLE 1D-1
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

Party Abbreviations:	
Safety Policy Division (SPD)	The Utility Reform Network (TURN)
California Public Advocates (PubAdv)	Mussey Grade Road Alliance (MGRA)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
1	SPD	3	Effects of Monetizing Safety and Reliability Attributes - The most significant difference between the 2024 RAMP and previous RAMPs is the monetization of the safety and reliability attributes of risk. As previously noted in the section comparing the 2020 and PG&E 2024 RAMPs, one significant effect of monetizing the Safety attribute was to effectively place less emphasis on the Safety attribute relative to the Reliability and Financial attributes. This occurred because the attribute weights and ranges PG&E selected in the 2020 RAMP implied a very high VSL of \$100 million, whereas, in the 2024 RAMP, in compliance with the monetization requirement, PG&E explicitly selected a California adjusted VSL of \$15.2 million.	PG&E complied with the Phase II Decision of the RDF OIR in its update of calculating monetized attribute values.	2	EORM
2	SPD	3	Electric Reliability Cost – PG&E calculated the electric reliability value of \$3.17 based on a territory wide average assuming equal distribution of residential, commercial, and industrial customers in all areas. However, SPD finds that this method overestimates the value of reliability in rural areas, comprising the bulk of PG&E's high fire threat district (HFTD) areas, where few commercial or industrial customers are located. This high reliability value then inflates the apparent benefit of wildfire mitigation proposals in these areas. SPD recommends that PG&E use a disaggregated approach to estimate reliability values.	PG&E complied with the Phase II Decision of the RDF OIR in its update of calculating monetized attribute values. PG&E has been exploring methods to address the reliability value concern and determined that it will use the ICE 1.0 system-wide aggregate value in the GRC. This will help ensure continuity of calculated CBRs. PG&E plans to update this value when updated ICE values become available and has had the time and opportunity to do the necessary analysis.	2	EORM
3	SPD	4	SPD recommends that PG&E submit a parallel set of risk analyses in the 2027 GRC filing using a risk-neutral scaling function. At a minimum, the parallel analyses should contain risk scores and cost-benefit ratios of the proposed and alternative mitigations (including mitigations classified as controls) using this risk-neutral scaling function.	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC in Exhibit (PG&E-2), WP 1-13 and Exhibit (PG&E-2), WP 1-16.	2	EORM
4	SPD	4	4. No identification of Compliance Requirements – PG&E frequently did not identify mitigations (or controls) that are needed to comply with regulatory requirements or adequately cite or explain those requirements.	PG&E will attempt to identify all mitigations and controls that fulfill a compliance requirement in the GRC.	2	EORM
5	SPD	4	PG&E should treat each such controls as a newly proposed mitigation requiring adequate justification for its continued funding in the TY 2027 GRC since all non-compliance-related controls and newly proposed mitigations are in competition with one another for funding from the same limited pool of ratepayer funds.	PG&E regularly reviews its work prioritization as part of normal business operations and in preparing the RAMP and the GRC and does not presume ratepayer funds are being directed to all projects.	2	EORM
6	SPD	4	6. Alternatives are often Unrealistic Alternatives – The Alternative mitigations are often not realistic alternatives to the proposed mitigation plan. The primary proposed plan is often the pre-ordained mitigation plan, with the alternatives having unacceptably low cost-benefit ratios to be realistic alternatives to the proposed plan. Within each risk chapter, little uniformity was found regarding whether the Alternatives are alternatives to a mitigation or the entire proposed plan.	PG&E complies with the S-MAP in its alternative analysis and notes there is often little flexibility in the way it implements mitigations and compliance requirements to achieve necessary goals. PG&E will strive to improve its alternatives analysis with this feedback in mind.	2	EORM
7	SPD	12	The PG&E RAMP Report does not describe how the 32 risk events were derived.	From PG&E's 2024 RAMP Prefiling on February 7 2024, Slide 10: Steps PG&E Applied to Select Preliminary RAMP Risks Regulatory requirement PG&E identified 11 risks as the top 40% of ERR risks with a Safety Risk Value greater than zero dollars. Risks below the 40% threshold The top 40% of ERR risks includes Electric Transmission System-wide Blackout, which is not funded under the jurisdiction of the GRC proceeding. To ensure GRC-funded safety risks are adequately represented, PG&E also included Failure of Electric Distribution Underground Assets to its preliminary RAMP risk selection.	2	EORM
8	SPD	29	SPD's evaluation of PG&E's workpaper, GO-LOCTM-19_DVC analysis, discovered a coding error in PG&E's estimate of natural units according to DVCs and non-DVCs. However, this error was found not to impact the estimate of risk reduction or NPV Spend for the mitigations proposed to be implemented in the DVCs and non-DVCs.	As it does not impact the evaluation, PG&E will rectify the coding error but not resubmit the ESJ Pilot.	2	EORM
9	SPD	30	SPD recommends that PG&E should present both the natural units and the monetized value of risk in its 2027 GRC filing and workpapers related to an ESJ analysis of the LGUWR risk event.	PG&E is not required to and does not plan to resubmit the ESJ Pilot for the 2027 GRC.	2	EORM
10	SPD	30	The risk analysis presented in Table 1-15 lacks key information necessary for understanding the implications of PG&E's mitigations and the impacts on DVCs. PG&E did not include subtotals for the HFRA and Non-HFRA percentage of DVC Customers, Baseline Wildfire Risk, DVC Risk, Non-DVC Risk and percentage DVC Risk. Moreover, PG&E's study should emphasize that the HFRA shows significant differences between the population density of DVC Customers and the percentage of risk faced by the DVCs.	PG&E supports SPD's analysis and believes it is worthwhile supplemental information that can be gleaned from PG&E's ESJ Pilot. However, this additional information is not required in the ESJ Pilot. PG&E recommends that the information SPD finds useful to the ESJ analysis be considered in future RDF Rulemaking.	2	EORM

TABLE 1D-2
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
11	SPD	33	SPD recommends that PG&E explain in its 2027 GRC filing how allocating these consequences proportionally to DVC customers within each tranche is appropriately data supported, and how this approach is related to PG&E's estimation of the reliability attribute via the Interruption Cost Estimator (ICE) calculation.	PG&E disagrees with the recommendation as the ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC. Further, this analysis would require population density studies which is not directed in the ESJ Pilot. PG&E recommends this be further explored in the RDF OIR.	2	EORM
12	SPD	34	SPD recommends that PG&E explain in the Test Year 2027 GRC how these two microgrid programs translate into improvements in safety and reliability for DVCs facing risk events presented in the 2024 RAMP	PG&E explains in Exhibit 4 Chapter 22 of the 2027 GRC the expected impacts of its grid modernization efforts including for microgrid programs.	2	EORM
13	SPD	34	SPD recommends that PG&E explain in the Test Year 2027 GRC why mitigation for GHG emissions and local air pollutants programs have yet to be implemented.	PG&E provides in its GRC Introductory Testimony actions that are being taken to reduce GHG Emissions.	2	Corporate Sustainability
14	SPD	35	SPD recommends that PG&E provide a clear quantitative analysis in its 2027 GRC filing on how mitigations will impact climate resilience in DVCs. Additionally, SPD recommends PG&E quantitatively clarify the relationship between mitigations presented in the 2027 GRC and climate resilience in DVCs in its upcoming Climate Pilot White Paper (due September 15, 2025, as ordered in D.24-05-064)	Using the RDF and CAVA methodologies, there is insufficient capability to reliably perform a quantitative analysis at this time. PG&E has identified climate-informed investments in the GRC in order to assist to determining programs that include a climate resilience component.	2	Climate
15	SPD	36	While this approach is not all-encompassing, SPD agrees with MGRA and recommends that PG&E adopt SDG&E's "acres burned" as an interim proxy for estimating the impact of wildfire smoke on DVCs in PG&E's 2027 GRC filing.	PG&E is not required to and does not plan to submit the ESJ Pilot for the 2027 GRC, so the analysis for wildfire smoke impacts to DVCs will not be updated for the GRC.	2	EORM
16	SPD	36	SPD recommends that PG&E include CBR calculations for all LOCTM, LGUWR, and Wildfire mitigation programs in DVCs and Non-DVCs	CBRs were not required by the ESJ Pilot nor is it required to be revisited in the 2027 GRC.	2	EORM
17	SPD	39	Further engagement and effort is needed on CAVA, energy sectors, community preferences, local and tribal governments, and equity considerations for climate adaptation.	Per D.24-08-005, PG&E will provide its Community Engagement Plan, which is in development and details PG&E's engagement plans, in May 2026.	2	Climate
18	SPD	39	SPD observed that PG&E did not integrate CBR calculations for climate change, as PG&E claims that it still considers this a foundational activity, not a risk-reducing program	Using the RDF and CAVA methodologies, there is insufficient capability to reliably perform a quantitative analysis at this time. PG&E has identified climate-informed investments in the GRC in order to assist to determining programs that include a climate resilience component. As PG&E has agreed to in the RDF Rulemaking, this year, PG&E will propose a method for inclusion of Climate impacts and mitigations for consideration.	2	Climate
19	SPD	39	Finally, SPD recommends that PG&E explain its short- and long-term climate investment strategy and capital investment plan in its 2027 GRC filing.	PG&E has identified climate-informed investments in the GRC in order to assist to determining programs that include a climate resilience component.	2	Climate
20	SPD	101	SPD recommends PG&E continue to evaluate the proposed scope and scale of LOCTM-M002, LOCTM-M003, and LOCTM-M004 as presented in the 2024 RAMP application. These mitigations are tied to compliance requirements that do not have a specified time frame for compliance. Funding for these mitigations should be carefully evaluated in the 2027 GRC filing.	The support and justification for these mitigation programs can be found in Exhibit (PG&E-3), Chapter 5. This includes the benefits and need for these mitigations as well as a linkage to code required work and intent to comply with PUC 958.	3	Gas Operations
21	SPD	101	SPD recommends PG&E continue to evaluate the appropriateness of including LOCTM-M002, LOCTM-M003, and LOCTM-M004 as mitigations within its 2027 GRC filing for the reasons outlined in the Summary of Findings in this report regarding the use of operational and execution considerations and risk tolerance as justifications. SPD recommends PG&E provide further justification for factors affecting mitigation selection in its 2027 GRC filing	The support and justification for these mitigation programs can be found in Exhibit (PG&E-3), Chapter 5. This includes the benefits and need for these mitigations as well as a linkage to code required work and intent to comply with PUC 958.	3	Gas Operations
22	SPD	101	SPD recommends that PG&E improve risk reduction estimation for C008 for the years 2028 through 2030 as PG&E estimated the cost for those years in the 2024 RAMP filing.	LOCTM-C008 will incorporate a new unit based MAT which will improve the risk value calculation.	3	Gas Operations
23	SPD	101	SPD recommends PG&E propose most of its mitigation work in the highest-risk tranches in its 2027 GRC filing.	Through it's Risk-Based Portfolio Prioritization Framework and other inputs to the work planning process, PG&E considers risks associated with individual projects, along with tranche risk within which individual projects such as where they are located and categorized. PG&E includes the best available and relevant information when proposing mitigation work in the 2027 GRC filing.	3	Gas Operations
24	SPD	102	SPD recommends PG&E continue to closely analyze whether the remaining 1.1 miles of bare steel pipeline should be replaced.	As stated in data response RAMP-2024-DR_SPD_022-Q005, bare steel is a data input into our risk algorithm pertaining to Subpart O threat identification. For that reason, bare steel might be replaced depending on the outcome of the risk algorithm pertaining to Subpart O threat identification. Bare steel, as the only factor being lack of external coating, does not justify replacement as bare steel pipelines were an acceptable design when constructed and are under protection by cathodic protection systems designed for their environment in accordance with subpart I.	3	Gas Operations
25	SPD	102	SPD recommends PG&E continue to evaluate whether proposing mitigations with low CBRs, when compared against the proposed control's CBRs, is prudent in a safe, reliable, and affordable system.	Through it's Risk-Based Portfolio Prioritization Framework and other inputs to the work planning process, PG&E evaluates compliance requirements, affordability, and many other factors when proposing mitigations which are not reflected in CBRs.	3	Gas Operations
26	SPD	102	SPD recommends PG&E continue to improve modeling of environmental consequences from a LOCTM event.	As stated in data response RAMP-2024-DR_SPD_004-Q004, environmental damage is implicitly included in the financial consequence. PG&E models financial consequences based on PHMSA incident data, which includes the costs due to environmental cleanup and damage.	3	Climate

TABLE 1D-3
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
27	SPD	102	SPD recommends that, at least for High Consequence Areas, and possibly also for Moderate Consequence Areas, PG&E distinguish whether ruptures or leaks resulted in an ignition for both COF categories and consequence classifications.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events, the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
28	SPD	102	SPD recommends PG&E provide further justification for the factors affecting mitigation selection in its 2027 GRC filing. If these mitigations with low CBRs are needed to comply with regulatory requirements, they should be identified as such. The relevant regulatory requirements must also be cited.	Through it's Risk-Based Portfolio Prioritization Framework and other inputs to the work planning process, PG&E evaluates compliance requirements, affordability, and many other factors when proposing mitigations which are not reflected in CBRs. PG&E clearly cites the relevant regulatory requirements for mitigation programs with low CBRs in its 2027 GRC, Exhibit (PG&E-3) testimony.	3	Gas Operations
29	SPD	250	Clarify the definition of an LOCDM event, specifically how PG&E determines which non-ignition events are considered for inclusion. Alternatively, SPD recommends PG&E examine whether the scope of the risk should be altered to remove loss of containment events without ignition.	PG&E clarifies that the LOCDM risk includes loss of containment events on mains, services, and risers. SPD stated confusion around inclusion of meter set leaks, which are not in scope for LOCDM but are included in the CCEQP risk instead. A minor LOC event is defined as one that does not meet the PHMSA reportable criteria (injury requiring in-patient hospitalization or fatality, \$50K+ in total costs measured in 1984 dollars), whereas the definition of a major LOC event is aligned to these criteria. All LOC events are included regardless of ignition because there are financial consequences for non-ignition events that need to be accounted for in the risk. Additionally, each LOC event has a non-zero potential to result in a major incident and focusing on ignition-only events would inaccurately represent this.	3	Gas Operations
30	SPD	250	Provide detailed justification and explanation for both the inclusion and scale of any LOCDM control or mitigation with a CBR less than 1.0 in the upcoming GRC filing, as listed in Table 11-8.	Details of the benefits and need for LOCDM control and mitigation programs can be found in Exhibit (PG&E-3), Chapter 4.	3	Gas Operations
31	SPD	264	SPD recommends PG&E continue to evaluate the appropriateness of including LRGOP-M001, LRGOP-M003, LRGOP-M005, LRGOP-M006, and LRGOP-M007 as mitigations within the 2024 RAMP/2027 GRC application for the reasons outlined in this report regarding use of modeling limitations, risk tolerance, and operational and execution considerations as justifications. SPD recommends PG&E provide further justification for the factors affecting mitigation selection in its 2027 GRC filing. If these mitigations with low CBRs are needed to comply with regulatory requirements, they should be identified as such. The relevant regulatory requirements must also be cited.	PG&E included these LRGOP mitigations in the 2024 RAMP because PG&E believed it was appropriate to do so. PG&E will continue to propose programs it considers prudent to maintain a safe and reliable affordable system. PG&E clearly cites the relevant regulatory requirements for mitigation programs with low CBRs in its 2027 GRC, Exhibit (PG&E-3) testimony.	3	Gas Operations
32	SPD	264	SPD recommends the scope and scale of LRGOP-M005 be closely scrutinized in PG&E's 2027 GRC filing.	PG&E will review the scope and scale of this mitigation in the 2027 GRC. PG&E stated in its 2024 RAMP that this program is not intended solely to mitigate LRGOP risk. As a result, the CBR presented in the RAMP does not account for all the benefits provided by the program.	3	Gas Operations
33	SPD	264	SPD recommends PG&E propose work relating to LRGOP-M003 – GD OPP Program in the 2027 GRC filing conditioned on clear compliance requirements by an official PHMSA rulemaking (PHMSA Notice of Proposed Rulemaking (NPRM) – PHMSA-2021-0046).	Because the timing of the adoption of the NPRM into law is unknown, PG&E is not presenting forecasts for required activities in its 2027 GRC forecast.	3	Gas Operations
34	SPD	264	SPD recommends PG&E propose most of the mitigation work for the highest risk tranches in the 2027 GRC filing.	The term "most" appears to refer to work units. This may not be appropriate in the facilities context since (1) there are many more smaller stations than larger stations, so a larger volume of smaller station units may be required and (2) this may not be appropriate because work units may be executed for reasons other than reducing LRGOP risk. No further action required on the part of PG&E	3	Gas Operations
35	SPD	264	SPD recommends PG&E continue to evaluate whether proposing mitigations with low CBRs, when compared against the proposed controls, is prudent.	PG&E included these mitigations in the 2024 RAMP because PG&E believed it was appropriate to do so. PG&E will continue to propose programs it considers prudent to maintain a safe and reliable affordable system.	3	Gas Operations
36	SPD	264	SPD recommends PG&E include the following cross-cutting factors as risk drivers: Physical Attack and Cyber Attack. OP events and the functioning of regulators are strongly vulnerable to sabotage involving these two cross-cutting factors.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
37	SPD	265	SPD recommends PG&E consider the consequence of Physical Attacks in this risk.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
38	SPD	265	SPD recommends PG&E to quantify the Physical Attack and Cyber Attack cross-cutting factors and incorporate them into the risk models.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
39	SPD	265	SPD recommends PG&E distinguish whether ruptures or leaks resulted in an ignition for consequence classifications.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
40	SPD	303	Require PG&E to provide detailed explanations of the processes utilized to incorporate SME judgement into the risk modeling.	SME judgement, applied through TIMP threat steering committees, is primarily focused on review of risk results/model outputs (which are compared to industry standards) and risk benefit for different assessment methods.	3	Gas Operations

TABLE 1D-4
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
41	SPD	89	SPD recommends PG&E add distinctions for ignition and no ignition events at least for HCAs to further contextualize its analysis of LOCTM risk.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
42	SPD	92	Additional research is needed to determine the impact [of climate change] to a LOCTM event.	Given that SPD later states "PG&E has adequately analyzed CCFs", PG&E plans to evaluate the impact of climate change on LOCTM events in future GRCs, building on the current CAVA analysis which indicates that climate change is expected to have a limited impact on gas transmission assets.	3	Gas Operations
43	SPD	99	PG&E should continue to evaluate whether proposing mitigations with comparatively low CBRs is prudent.	PG&E included these control and mitigation programs in the 2024 RAMP because PG&E believed it was appropriate to do so. PG&E will continue to propose programs it considers prudent to maintain a safe and reliable affordable system. Further justification and compliance requirements for these control and mitigation programs can be found in Exhibit (PG&E-3), Chapter 5.	3	Gas Operations
38	SPD	265	SPD recommends PG&E to quantify the Physical Attack and Cyber Attack cross-cutting factors and incorporate them into the risk models.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
39	SPD	265	SPD recommends PG&E distinguish whether ruptures or leaks resulted in an ignition for consequence classifications.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
40	SPD	303	Require PG&E to provide detailed explanations of the processes utilized to incorporate SME judgement into the risk modeling.	SME judgement, applied through TIMP threat steering committees, is primarily focused on review of risk results/model outputs (which are compared to industry standards) and risk benefit for different assessment methods.	3	Gas Operations
41	SPD	89	SPD recommends PG&E add distinctions for ignition and no ignition events at least for HCAs to further contextualize its analysis of LOCTM risk.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
42	SPD	92	Additional research is needed to determine the impact [of climate change] to a LOCTM event.	Given that SPD later states "PG&E has adequately analyzed CCFs", PG&E plans to evaluate the impact of climate change on LOCTM events in future GRCs, building on the current CAVA analysis which indicates that climate change is expected to have a limited impact on gas transmission assets.	3	Gas Operations
43	SPD	99	PG&E should continue to evaluate whether proposing mitigations with comparatively low CBRs is prudent.	PG&E included these control and mitigation programs in the 2024 RAMP because PG&E believed it was appropriate to do so. PG&E will continue to propose programs it considers prudent to maintain a safe and reliable affordable system. Further justification and compliance requirements for these control and mitigation programs can be found in Exhibit (PG&E-3), Chapter 5.	3	Gas Operations
44	SPD	232	SPD is concerned with the lack of clarity in the definition of risk, specifically in determining which distribution-level LOC events are included in the risk analysis. SPD observes that in its 2023 annual report of system-wide leaks associated with the "Natural Gas Leak Abatement Program" (NGLA) established through Rulemaking (R.)15-01-008, PG&E identified approximately 280,000 leaks in its meter set assemblies and over 20,000 leaks in distribution pipelines.413 This is a significantly higher total of distribution-level leaks (LOC) than the 28,726 LOCDM events stated by PG&E in its 2024 RAMP filing (PG&E 3, Chapter 2). In its risk definition, PG&E states risk analysis includes failures of gas distribution mains and services "that can lead to significant impact." While SPD agrees that not every leak should be included in the risk analysis, it is unclear what criteria PG&E applied when determining which non-ignition LOC events are categorized as having "significant impact" given the high frequency and low consequence of most non-ignition LOC events. SPD recommends PG&E provide more clarity in its 2027 GRC Application of how it determines which non-ignition LOC distribution events qualify, and not qualify, for consideration.	PG&E clarifies that the LOCDM risk includes loss of containment events on mains, services, and risers. SPD stated confusion around inclusion of meter set leaks, which are not in scope for LOCDM but are included in the CCEQP risk instead. A minor LOC event is defined as one that does not meet the PHMSA reportable criteria (injury requiring in-patient hospitalization or fatality, \$50K+ in total costs measured in 1984 dollars), whereas the definition of a major LOC event is aligned to these criteria. All LOC events are included regardless of ignition because there are financial consequences for non-ignition events that need to be accounted for in the risk. Additionally, each LOC event has a non-zero potential to result in a major incident and focusing on ignition-only events would inaccurately represent this.	3	Gas Operations
45	SPD	234	While SPD acknowledges the improvement in granularity by tranching, additional granularity may be necessary to perform more targeted work, given the poor Cost Benefit Ratio (CBR) values for the large costs and scale of work currently proposed in mitigations LOCDM-M001 "Pipeline Replacement Program (Steel)" and LOCDM-M002 "Pipeline Replacement Program (Plastic)."	PG&E uses a federal code compliant DIMP operational risk model that prioritizes steel and plastic pipe at a segment level. This operational model is utilized to identify program pipe projects for replacement. Additional granularity by tranching for the Enterprise Risk Model (LOCDM Risk) will not change the individual projects identified for replacement. Additional tranching of the LOCDM risk likely will not materially change the CBR values.	3	Gas Operations
46	SPD	243	While SPD acknowledges that some activities may be related to regulatory compliance, it is unclear in the 2024 RAMP which control programs fall under that category. SPD recommends PG&E be required to provide justification in the General Rate Case (GRC) filing for spending on any of the 16 controls with a CBR less than 1.0.	Specific time frame for compliance to support justification for control programs can be found in Exhibit (PG&E-3), Chapter 4.	3	Gas Operations

TABLE 1D-5
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
47	SPD	245	SPD also observes the relatively low CBR values for the proposed mitigations. As can be seen in Table 11-6, of the four mitigation programs listed in the LOCDM chapter, all fall below a breakeven CBR of 1.0, with PG&E identifies regulatory compliance as factors for selecting M002-Pipeline Replacement Program (Plastic) and M004-New Valve Installations, it is unclear whether all projects within these two programs are necessary to satisfy regulatory requirements. M001, M002, and M006 all having exceptionally low CBRs of 0.1 or less. While SPD acknowledges that SPD recommends PG&E provide justification in its 2027 General Rate Case (GRC) filing for spending on any projects associated with the mitigations in this chapter.	Specific time frame for compliance to support justification for mitigation programs can be found in Exhibit (PG&E-3), Chapter 4.	3	Gas Operations
48	SPD	20	SPD recommends that PG&E not use a territory wide average of the monetized value of electric reliability in its 2027 GRC. When preparing its 2027 GRC Application, SPD recommends that PG&E either use the disaggregated approach found in the SPD data requests or an equally logical approach to disaggregation that may be proposed by parties.	PG&E will evaluate the electric reliability monetization post 2027 GRC Filing. This is explained in Exhibit (PG&E-2), Chapter 1, Section C.4.b.	4	Electric Operations
49	SPD	34	SPD recommends that PG&E explain in the Test Year 2027 GRC how these two microgrid programs translate into improvements in safety and reliability for DVCs facing risk events presented in the 2024 RAMP.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
50	SPD	35	SPD recommends that PG&E provide a clear quantitative analysis in its 2027 GRC filing on how mitigations will impact climate resilience in DVCs.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
51	SPD	35	Additionally, SPD recommends PG&E quantitatively clarify the relationship between mitigations presented in the 2027 GRC and climate resilience in DVCs in its upcoming Climate Pilot White Paper (due September 15, 2025, as ordered in D.24-05-064).	PG&E disagrees with this recommendation and does not intend to implement it. The Climate Pilot White Paper required by D.24-05-064 does not require PG&E or any utility to "quantitatively clarify the relationship between mitigations presented in the 2027 GRC and climate resilience in DVCs."	4	Electric Operations
52	SPD	36	SPD recommends that PG&E include CBR calculations for all LOCTM, LGUWR, and Wildfire mitigation programs in DVCs and Non-DVCs.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
53	SPD	39	Furthermore, PG&E should reduce gaps among DVC customers to meet the needs of existing program goals	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
54	SPD	246	SPD recommends that PG&E justify any projects associated with any alternative mitigations listed in the LOCDM chapter, if included in the 2027 GRC.	PG&E does not identify specific projects associated with mitigations at time of GRC filing as the mitigation programs are forecast at a programmatic level.	3	Gas Operations
55	SPD	52	SPD recommends that PG&E research the nature of risk drivers that lead to catastrophic outcomes, and then develop a mitigation workplan that focuses on mitigating those drivers, where possible.	PG&E responds to this comment in the testimony, Exhibit (PG&E-4), Chapter 3, Section C. 1. b.	4	Electric Operations
56	SPD	76	SPD finds no discernable correlation between the risk/mile values and PG&E's assigned tranches.	PG&E disagrees with this statement. There is a discernable correlation between risk per mile to assigned tranches. This can be seen in Table 1-6 in the 2023 Baseline, which for risk per mile for tranches 1 through 10 is in descending order. In the 2027 TY Baseline, for tranches 4 through 10, the risk per mile is also in descending order. In tranches 1 through 3, you will see a varied risk/mile due to mitigations expected from 2023-2026. Work is already being performed in the highest risk tranches and would appear as a lowered contribution to the overall risk and reduction in the risk per mile in these tranches.	4	Electric Operations
57	SPD	76	In its 2024 RAMP filing, PG&E changed its designation of exposure miles for the various wildfire risk bow ties and other scenarios to include Secondary and Service (S&S) OH miles.	PG&E agrees with this statement.	4	Electric Operations
58	SPD	76	PG&E reduces the number of tranches from 25 (5x5) for HFRA Distribution Primary miles in its TY 2023 GRC to 10 tranches in 2024 RAMP. Moving from the more granular 25 tranches to a coarser 10 tranche approach for HFRA Distribution Primary raises two primary concerns: a. Loss of granularity and over-aggregation could lead to less precise risk management and prioritization of mitigation efforts. b. Increased complexity in comparing risk data in the 2024 RAMP with historical data could hinder the ability to track progress, evaluate the effectiveness of past risk mitigation measures, and assess changes in wildfire risk over time.	PG&E appreciates the feedback. As outlined in the RAMP Report (Exhibit (PG&E-4), Chapter 1, Section 4. d), since 2021, PG&E has used WDRM risk scores to inform prioritization of wildfire mitigation workplans, focusing on risk reduction through LoRE times CoRE. This approach organizes risk into deciles based on circuit segment risk scores, and as such, the new tranches are more in line with the workplans.	4	Electric Operations
59	SPD	76	Most wildfire workpapers, especially those allocated to system hardening, lack consistency and cohesion. Specific examples include: a. PG&E doesn't clearly outline the process for assigning risk-based tranches to specific circuit segments. There is no correlation between risk/mile and PG&E's assigned tranches. b. No explanation of the criteria or methodology PG&E used to select miles planned for undergrounding is provided. c. PG&E doesn't explain how the circuit segments were chosen for undergrounding.	a. PG&E's distribution tranches are based on WDRM v4. The distribution tranching can be broken down into three steps. Step 1) Sort circuit segments based on the mean risk and segmenting into 10 tranches that are each 1/10th of the total WDRM distribution risk. Step 2) Leverage WDRM circuit segment level frequency of ignitions and calibrate to historical actual ignitions + avoided PSPS and EPSS ignitions. These steps provide a frequency of ignitions at the circuit segment level based on mean consequence as modeled by the WDRM_v4. Additional allocation of the frequency is transformed based on HFRA/non-HFRA, fire types by tranche, and RFW/Non-RFW outcomes. Step 3) The frequencies are multiplied by the consequence which are defined based on fire-type (i.e. catastrophic, destructive, large, small) to calculate the final risk scores by tranche. b. PG&E's system hardening approach generally aligns with the procedures for selecting mitigation alternatives outlined in the EUP Guidelines that were adopted February 20, 2025 (EUP Guidelines). PG&E identifies high risk circuit segments to be included in its system hardening program. PG&E selects a primary mitigation for each circuit segment (overhead hardening or undergrounding) based on the results of economic analyses. See Exhibit. (PG&E-4), Ch. 7, Section B(2) for additional detail in the 2027 GRC. c. See response to part (b) above.	4	Electric Operations

TABLE 1D-6
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
60	SPD	76	SPD finds apparent discrepancies in PG&E's responses, explaining how it assigns circuit segments to tranches.	PG&E acknowledges that the wording is different in the various data responses, however, the methodology remains the same. The steps are outlined in line 108. It should also be noted that Table 1-3, 1-4, and 1-5 include activities expected from 2023-2026. Work is already being performed in the highest risk tranches and would appear as a lowered contribution to the overall risk and reduction in the risk per mile in these tranches.	4	Electric Operations
61	SPD	76	Equipment failure and vegetation contact are the two most frequent risk drivers, comprising 72 percent of all risk events and 76 percent of the total risks.	PG&E agrees with this statement for Transmission and Distribution HFTD and HFRA only.	4	Electric Operations
62	SPD	76	SPD finds that the risk score for climate change impact increases from \$22,000 M in 2023 to \$26,000 M in 2030, while it decreases slightly until 2050 when it starts rising sharply again. SPD finds that PG&E did not provide sufficient explanation for these differing expected climate change impacts, such as the model(s) used to estimate them.	PG&E appreciates this feedback. PG&E has reviewed these climate projections and the results are consistent with the ICF projected outputs. Climate impact is modeled as a percent increase of ignitions occurring when a Red Flag Warning (RFW) is in place while keeping the total ignition frequency the same. The rate of increase is based on forecast of days above historical 95th percentile Fire Weather Index (FWI) provided by ICF Climate Center for 2030, 2050 and 2080 at the circuit segment level for distribution in workpaper CC-CLIMT-14, and at Electric Transmission Line (ETL) level for transmission in workpaper CC-CLIMT-15. Projections for the number of days above historical 95th Percentile FWI use California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. Projections are developed for each distribution circuit segment to create 20-year averages of the number of days per year above historical 95th Percentile FWI centered on 2030, 2050, and 2080. Future time horizons consider average conditions over a 20-year time window to characterize long-term regional trends, rather than year-to-year noise in the meteorological projections. A 20-year historical model baseline centered on 2004 is also included. Source: https://analytics.cal-adapt.org/data/	4	Electric Operations
63	SPD	76	TURN commented that the PG&E climate change model involving red flag warning ignitions is complex and counterintuitive. The climate risk increases exactly through the rate case period and then decreases afterwards.	PG&E finds this statement true. The climate risk increases exactly through the risk case period and then decreases afterwards is driven by ICF provided forecast of days above historical 95th percentile Fire Weather Index (FWI), which uses California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. According to ICF, it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables. More technical details regarding how PG&E incorporates ICF's forecast into wildfire risk modeling can be found in PG&E response to TURN data request 005 Q1a in addition to Exh. 2 Workpapers CC-CLIMT-14 and CC-CLIMT-15.	4	Electric Operations
64	SPD	76	Based on Exhibit PG&E-4, Table 1-11, the number of ignitions resulting in catastrophic outcomes, is only 1.3 percent of all ignitions. SPD finds that the small number of predicted catastrophic events is based on a small number of historical data points, which can introduce uncertainty as a predictor of future catastrophic events.	PG&E appreciates the feedback. PG&E mitigates the uncertainty due to the small sample size of PG&E caused catastrophic events by estimating the catastrophic event frequency using conditional probability of a fire greater than 300 acres becoming destructive/catastrophic events based on all electric-power caused fires in PG&E's service territory supplemented with non-electric-power caused fires when electric-power caused fires are too few to yield robust estimates. PG&E relies on PG&E caused ignitions and avoided ignitions by PSPS and EPSS programs to estimate the number of ignitions and fires greater than 300 acres, but determining the yearly frequency of catastrophic events based just on PG&E fires can introduce great uncertainty due to the small count of catastrophic events. PG&E also includes more years of recent data in the analysis when feasible to reduce uncertainty in forecasting catastrophic events.	4	Electric Operations

TABLE 1D-7
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
65	SPD	76	SPD finds that PG&E's analysis is based solely on ignition data, while there are other sources of information such as unplanned outages and fault data.	PG&E appreciates the feedback. In addition to historical ignition data and WDRM outage-to-ignition based predictions, PG&E uses PSPS hazards/damages and EPSS outages to estimate avoided ignitions to establish the baseline wildfire risk with no PSPS and EPSS. PG&E is looking to incorporate results from Wildfire Transmission Risk Model (WTRM) in the wildfire risk bowtie once the WTRM is fully vetted and calibrated. The Transmission Composite Model (TCM) component of WTRM estimates annual probability of failure at asset level due to various threats and hazards based on a combination of first principles models and machine learning models. There is a need to further develop a model or a calibration method to convert failure prediction to ignition likelihood.	4	Electric Operations
66	SPD	76	SPD finds that PG&E prioritized the mitigation measures based on risk tranches, Tranches 1 to 5 for undergrounding and Tranches 3 to 5 for covered conductor hardening. However, PG&E has not demonstrated how it addresses the small percentage of catastrophic outcomes with a focused workplan.	PG&E appreciates the feedback. A more comprehensive approach is taken in selecting mitigations. This is addressed in the 2027 GRC Testimony, Exhibit (PG&E-4), Chapter 3, Section C. 1. b through the "layers of protection" strategy.	4	Electric Operations
67	SPD	77	SPD finds a potential overlap between the DOVHD and EPSS risk analysis.	PG&E respectfully disagrees. There is no overlap between DOVHD and EPSS risk. DOVHD risk is from failure of distribution overhead assets whereas EPSS risk is the incremental impact from an outage occurring when EPSS is enabled.	4	Electric Operations
68	SPD	77	SPD finds that PG&E has not demonstrated in its RAMP filing how it is focusing PSPS and EPSS strategies to ensure they are applied effectively in the highest risk areas.	PSPS and EPSS are operational mitigations utilized when conditions are elevated for wildfire risk represented through our Fire Potential Index (FPI). These programs are dependent on the forecasted and current weather conditions that cover the entire PG&E territory. These programs are targeting specific locations where the risk of wildfire is the greatest during elevated weather conditions.	4	Electric Operations
69	SPD	77	SPD finds that PG&E has not presented information regarding how it could leverage technology to reduce EPSS outages that would have traditionally only been momentary.	PG&E does use technology to reduce EPSS outages. Refer to Exhibit (PG&E-4), Chapter 6 for technologies reducing EPSS impacts.	4	Electric Operations
70	SPD	77	PG&E's calculation of the financial consequence attribute assumes that the value of each structure destroyed in a wildfire would be worth \$1 million. TURN commented that PG&E's assumption significantly overstates the actual recorded data from 2015-2022 and exhibits a weighted average of \$723,000 per structure destroyed.	PG&E maintained an update to the structure consequence assumption of \$1M/structure. SPD recommended using the weighted average of \$723,000 (by structures) from 2015-2022 data. Considering inflation PG&E calculated \$972K/structure. Given the January catastrophic events in Los Angeles, PG&E made a decision to maintain the current assumption of \$1M/structure given that this recent event will lead to an increase in consequence assumption.	4	Electric Operations
71	SPD	77	SPD finds significant differences between the population of DVC customers and the percentage of risk faced by the DVCs in the HFRA Distribution tranches. Within PG&E's HFRA, 16 percent live within a DVC, which was noted in TURN's Informal Comments, and these HFRA/DVC customers face a disproportionate amount of wildfire risk: 31 percent. PG&E Tables 1-16 and 1-17 present the risk reduction benefits, and reliability impacts, from allocation of PSPS and EPSS mitigations to DVCs in the HFRA tranche group, since that is where those mitigations are applied. However, there appears to be an error in the tables since the value used for the Overall Total percentage of DVC customers is taken from Table 1-15's Grand Total of both HFRA and non-HFRA Distribution tranches.	PG&E agrees with the statement and re-evaluated the tables. In the 2024 RAMP Exh. 4 Ch. 1, Table 1-16 Overall Total %DVC Cust. should be 16% not 29%. Similarly, Table 1-17 Overall Total %DVC Customers should be 16% not 29%, and Table 1-18 Overall Total % DVC Customers should be 28% not 29%. PG&E verified that the Overall Total row was only used to display a summary of the information in the column and was not used to inform other calculations in the analysis, thus the impact is limited to this value displayed in the tables and does not plan to submit errata for this change at this time.	4	Electric Operations
72	SPD	77	PG&E finds that the allocation of PSPS and EPSS consequences was done proportionally to DVC customers in each tranche but does not provide details of how that was done, nor how the ICE reliability value was applied.	The percentage of DVC customers was used as a consistent multiplier across the tranches and consequences. The ICE reliability value is calculated separately for the electric reliability. It is then multiplied by the DVC customer percentage for the DVC impact.	4	Electric Operations
73	SPD	77	As part of the ESJ Pilot Study, PG&E did not estimate the impacts of wildfire smoke that disproportionately impact DVCs; instead, it stated that wildfire smoke impacts generally require further study.	PG&E will investigate opportunities to incorporate wildfire smoke impacts in future iterations.	4	Electric Operations
74	SPD	77	SPD finds, as noted in MGRA's Informal Comments, that PG&E should follow the example of SDG&E to use the measure of "acres burned" as a proxy for estimating wildfire smoke.	PG&E will investigate opportunities to incorporate wildfire smoke impacts in future iterations.	4	Electric Operations
75	SPD	77	SPD finds the CBRs for EPSS and PSPS are 51.9 and 42.8, respectively, whereas the CBRs for System Hardening, underground and overhead, are substantially lower at 7.9 and 17.8, respectively.	The CBRs values listed for EPSS (51.9), PSPS (42.8), System Hardening, underground (7.9) and overhead (17.8) are correct for the 2024 RAMP Report. The updated CBR values for 2027 GRC are located in Exhibit 4, Chapter 3 Workpaper Table 3-17. The updated CBR values for EPSS is 33.80; PSPS is 23.33; System Hardening Overhead is 13.53; and System Hardening Underground is 7.26. While programs like EPSS and PSPS have higher CBR values than System Hardening, CBRs are not the only consideration for these investments. PG&E is engaging in positive investments to provide permanent risk reduction for public safety, improved customer reliability, and overall customer satisfaction through our System Hardening program.	4	Electric Operations
76	SPD	77	PG&E uses program IDs "DOVHD-M022", "PCEEE-M003", and "WLDFR-M022" to refer to its System Hardening [Underground] proposal in HFTD/HFRA locations. The three program IDs refer to the same program but apply to three different risks in the RAMP report. For the wildfire risk chapter, the "WLDFR" program ID applies.	PG&E finds this statement true.	4	Electric Operations
77	SPD	77	SPD created Table 1-5 to compare the risk reduction benefits for each corresponding risk chapter from this same mitigation program. PG&E breaks down WLDFR-M022 into 30 HFTD Distribution tranches (10 primary, 10 secondary, and 10 service lines).	PG&E finds this statement true.	4	Electric Operations

TABLE 1D-8
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
78	SPD	77	SPD notes that PG&E's WLDFR-M022 undergrounding program consists of Primary distribution lines and Secondary and Service lines (S&S), which SPD separated by costs and CBRs as shown in Table 1-5. The CBR for HFTD/HFRA Primary lines is 10.7, while the CBR for S&S lines is 2.1. Service lines on PG&E distribution system pose 4 percent of the wildfire risk, while secondary lines comprise about 3 percent of the wildfire risk. PG&E has noted that HFTD/HFRA primary distribution lines pose 10X greater risk than PG&E's secondary and service (S&S) drops combined. Table 1-6 indicates that though the risk reduction for S&S lines is one-tenth of that for the Primary lines, the cost of undergrounding the S&S lines is disproportionally half the cost of the Primary lines.	PG&E finds this statement true as primary lines have higher risk than secondary and service lines.	4	Electric Operations
79	SPD	78	The PG&E workpapers provide system hardening mitigation risk reduction, capital expenditures (CapEx), and CBRs for both program and tranche levels. However, PG&E does not clearly explain how these values have been calculated from more granular data like circuit segments, nor the underlying data supporting these calculations.	Tranche level CBRs were provided in Workpaper RM-RMC-15 RAMP Mitigations and Controls and their CBRs for 2024 RAMP Report. A similar workpaper is included in the 2027 GRC filing. PG&E will calculate CBRs at the circuit segment level for both undergrounding and overhead hardening for circuit segments that are considered for system hardening in the EUP using our Wildfire Benefit Cost Analysis (WBCA) tool. The WBCA documentation will describe the assumptions and provides the support data for the mitigation risk reduction values and capital expenditures that are used in the CBR calculations.	4	Electric Operations
80	SPD	78	SPD observed that some circuit segments show more than 100 percent discrepancies between the overhead circuit miles of lines to be replaced and the circuit miles of planned underground installation. For example, in the Alleghany 1102CB project, 35 miles of underground lines are being installed to replace a 17.78-mile overhead circuit segment. SPD notes that: a. While the 1.25 conversion factor is applied uniformly across all projects, this approach may oversimplify the unique challenges of individual projects. Variations in terrain, local conditions, and routing complexities can lead to significantly different conversion ratios, and applying a blanket factor may not always accurately capture these differences. b. The Alleghany 1102CB project exhibits a considerable deviation from the 1.25 conversion factor, with nearly double the underground miles installed compared to the overhead lines being replaced. Such cases warrant closer scrutiny, as outliers like this project may require more customized risk reduction calculations or specific handling. c. Limiting the risk exposure to the original overhead mileage ensures a fair calculation of risk reduction but could overlook the added complexities and costs of projects requiring extensive rerouting. Although the risk reduction is linked to the removal of overhead lines, projects involving significant rerouting may warrant special consideration in cost-benefit analyses or project prioritization frameworks. The additional mileage from rerouting could substantially increase project costs without being fully reflected in the risk reduction and CBR metrics, potentially misrepresenting the cost-benefit analyses and justifications for project selections.	SPD observes discrepancies between the overhead line miles to be replaced that the planned underground installation. PG&E used a 1.25 factor to convert overhead miles removed to underground miles installed (e.g. for every 1 overhead mile removed PG&E undergrounds 1.25 miles). The Commission determined that PG&E's 1.25 conversion factor is reasonable for the purpose of establishing a reasonable cost estimate for undergrounding (Decision 23-11-069, Findings of Fact No. 102).	4	Electric Operations
81	SPD	78	SPD finds that although EPSS and PSPS are highly effective at reducing wildfire risk, the negative impacts of service interruption fall disproportionately on customers in high fire threat areas, and the Commission considers PSPS as a mitigation of last resort, so that non-interruptive mitigations are preferred.	PG&E agrees with this statement.	4	Electric Operations
82	SPD	78	SPD finds that PG&E has observed positive indications for the use of REFCL compared to EPSS, including reduced fault energy and the ability to ride through momentary faults. PG&E estimates a 65 percent mitigation effectiveness for REFCL in anticipation of their SB 884 filing.	PG&E has put REFCL into service and are actively demonstrating the technology and gaining operational experience. PG&E is evaluating which locations REFCL would provide benefits in a cost effective way. PG&E does not view REFCL as replacement to EPSS. PG&E will continue to find, examine, and deploy other technologies to reduce momentary outages.	4	Electric Operations
83	SPD	78	SPD finds that while undergrounding is the most effective in terms of absolute wildfire risk reduction, it is the least cost-efficient option. Covered conductor has 65 percent of the NPV risk reduction as undergrounding for the same primary tranche miles, at 37 percent of the costs for a CBR of 17.44.	PG&E's system hardening plans consist of a balanced system hardening portfolio that considers wildfire risk, reliability risk and cost-effectiveness. While undergrounding is PG&E's preferred solution for mitigating ignition risk in the highest risk areas because it is the most effective way to almost permanently reduce wildfire risk and significantly reduces outage program risk, undergrounding is less cost efficient than overhead hardening. In the highest risk locations, the long-term benefits of undergrounding including greater wildfire risk reduction, reliability improvement and operational cost avoidance (e.g. less vegetation management). In many other locations wildfire risk can be appropriately mitigated and managed through a combination of overhead hardening and operational mitigations such as Public Safety Power Shutoff (PSPS) and Enhanced Power Safety Settings (EPSS). PG&E's recognizes the need to balance affordability and risk reduction. As such, our forecast for 2027 represents a balanced portfolio that includes 192 miles of overhead hardening and 307 miles of undergrounding. (See Exhibit (PG&E-4), Ch. 7, Section C for more details)	4	Electric Operations
84	SPD	79	Only PG&E's Alternative Plan 1, WLDFR-A001/WSPSPS-A001 was presented as a clear alternative to a specific PG&E proposed mitigation (i.e. WLDFR-M022). The other three alternatives were presented more as additional projects that PG&E is piloting or considering in the future. Hence, PG&E did not meet the requirement to provide two Alternatives as required by the RDF decision.	PG&E disagrees with not meeting the requirement to provide two alternatives. On page 32 of D.14-12-025 and on pages 5-6 in the Straw Proposal that was adopted, it states "The RAMP would contain at least the following: For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan." Projects that are being piloted or considered in the future is not stated as an exclusion.	4	Electric Operations

TABLE 1D-9
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
85	SPD	79	PG&E's Alternative Plan 1, WLDFR-A001/WSPSPS-A001 maintained nearly the same level of capital investment costs as PG&E's proposed WLDFR-M022. PG&E's Alternative Plan 1 replaced the undergrounding of Secondaries & Services (S&S) with overhead hardening of S&S and increased the primary undergrounding miles. Specifically, PG&E's Alternative1 proposed undergrounding 2,300 miles of primary distribution lines in HFTD/HFRA while mitigating the associated S&S lines through overhead hardening with covered conductor. This results in a better CBR of 9.7 when compared to PG&E's original plan of Undergrounding 1,710 miles of primary lines and 889 of S&S lines, which has a CBR of 7.9.	PG&E agrees with this statement.	4	Electric Operations
86	SPD	79	In PG&E's Alternative Plan 1, a portion of the budget is also allocated to address the backlog of identified pole tags which PG&E states provides no incremental risk benefit.	PG&E agrees with this statement.	4	Electric Operations
87	SPD	79	Although PG&E's Alternative Plan 1 shows a higher CBR compared to PG&E's proposed WLDFR-M002 (9.7 vs 7.9) and offers some cost savings, additional elements like the backlogged pole tags add cost without risk benefit.	PG&E agrees with this statement.	4	Electric Operations
88	SPD	79	SPD WLDFR Scenario 3 is an SPD-requested alternative similar to PG&E Alternative Plan 1 with lower costs by maintaining the same 1,711 miles of primary line undergrounding as PG&E's proposed plan (WLDFR-M022) and installing covered conductor on 890 miles of S&S lines rather than undergrounding them.	PG&E agrees with this statement.	4	Electric Operations
89	SPD	79	PG&E stated that neither Alternative 1 WLDFR-A001 nor SPD's WLDFR Scenario 3 attribute supplemental risk reduction to hardening secondaries and services.	PG&E agrees with this statement.	4	Electric Operations
90	SPD	79	SPD's Scenario 3 produced a CBR of 10.1 compared to the proposed WLDFR-M002 CBR of 7.9, reducing costs by almost \$2 billion while achieving 93 percent of the WLDFR-M002 risk reduction.	PG&E agrees with this statement.	4	Electric Operations
91	SPD	79	SPD finds that Scenario 3's comparison of risk reduction and CBRs would be improved by including risk reduction provided by the S&S overhead hardening.	PG&E agrees with this statement.	4	Electric Operations
92	SPD	79	SPD WLDFR Scenario 4 is another SPD-requested scenario for alternative analyses where covered conductor is installed instead of PG&E's WLDFR-M022 undergrounding proposal. SPD WLDFR Scenario 4 results demonstrate that overhead hardening (covered conductor) is more cost efficient than undergrounding, even for the tranches with the highest risk.	PG&E agrees with this statement.	4	Electric Operations
93	SPD	79	SPD observed that overhead hardening (covered conductors) is approximately 63 percent more cost efficient (CBR of 17.4 vs. CBR of 10.7) than undergrounding for the top 5 tranches with the highest risk.	PG&E agrees with this statement.	4	Electric Operations
101	SPD	81	PG&E provide the details of why each circuit segment was assigned to a particular tranche and explain why lower risk circuit segments are assigned to higher risk tranches.	Circuit segments are ranked based on mean risk score as modeled by the WDRM, basically normalizing risk by length. For this reason, you may have a circuit segment yielding a higher risk score, but lower mean risk, due to the length and number of assets on the line.	4	Electric Operations
102	SPD	81	PG&E provide a more detailed explanation of how its risk modeling incorporates the highest frequency drivers (i.e., equipment failure and vegetation contact) when selecting mitigation strategies, particularly focusing on drivers associated with ignitions leading to catastrophic wildfires.	Refer to Exhibit (PG&E-4), Chapter 3, Section C.1.d.	4	Electric Operations
103	SPD	81	PG&E provide more explanation and justification about the differing expected climate change impacts presented in the 2024 RAMP, including the climate change model(s), data and assumptions.	The climate risk increases exactly through the risk case period and then decreases afterwards is driven by ICF provided forecast of days above historical 95th percentile Fire Weather Index (FWI), which uses California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. According to ICF, it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables. More technical details regarding how PG&E incorporates ICF's forecast into wildfire risk modeling can be found in PG&E response to TURN data request 005 Q1a in addition to Exh. 2 Workpapers CC-CLIMT-14 and CC-CLIMT-15.	4	Electric Operations

TABLE 1D-10
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
104	SPD	81	PG&E describe how it accounts for the uncertainty due to the small sample size of catastrophic events, and a more detailed explanation of its statistical analyses and risk modeling approach.	PG&E mitigates the uncertainty due to the small sample size of PG&E caused catastrophic events by including non-PG&E caused fires in the following ways: 1) Estimate conditional probability of a fire greater than 300 acres becoming destructive/catastrophic using all electric-power caused fires in PG&E's service territory supplemented with non-electric-power caused fires when electric-power caused fires are too few to yield robust estimates. PG&E relies on PG&E caused ignitions and avoided ignitions by PSPS and EPSS programs to estimate the number of ignitions and fires greater than 300 acres, but determining the yearly frequency of catastrophic events based just on PG&E fires can introduce great uncertainty due to the small count of catastrophic events. Please refer to PG&E's response to TURN data request 005 Q2b for technical details on these conditional probabilities are used in the risk modeling. 2) Calibrate consequence distributions of fires burned over 300 acres, including outcomes of large and destructive fires using all fires in PG&E's service territory. This is appropriate as PG&E considers it is reasonable to assume that once a fire grows over 300 acres, the fire spread is determined on fuel moisture, weather, topography, and other environmental factors regardless of the cause. The benefit of including non-utility fires in this case is to increase the number of data points for calibrating statistical consequence distributions and hence achieve more robust results. PG&E fits the consequence data to Pareto/Power-Law and Log-normal probability distributions. These distributions have been established by extensive studies and considerable vetting in Phase 3 of the CPUC's Risk-based OIR, R.20-07-013 to adequately capture the risk of extreme consequences.	4	Electric Operations
105	SPD	81	PG&E consider incorporating related data such as unplanned outages and fault data into its risk modeling analyses to reduce uncertainty, increase accuracy and sensitivity of its modeling to better predict and manage catastrophic risk events.	PG&E appreciates the feedback. In addition to historical ignition data and WDRM outage-to-ignition based predictions, PG&E uses PSPS hazards/damages and EPSS outages to estimate avoided ignitions to establish the baseline wildfire risk with no PSPS and EPSS. PG&E is looking to incorporate results from Wildfire Transmission Risk Model (WTRM) in the wildfire risk bowtie once the WTRM is fully vetted and calibrated. The Transmission Composite Model (TCM) component of WTRM estimates annual probability of failure at asset level due to various threats and hazards based on a combination of first principles models and machine learning models. PG&E continues to enhance its modeling and is aware that developing a model or a calibration method to convert failure prediction to ignition likelihood is needed.	4	Electric Operations
106	SPD	81	PG&E explain how it accounts for the potential overlap between the DOVHD and EPSS risk analyses and proposed mitigations.	There is no overlap between DOVHD and EPSS risk. DOVHD risk is from failure of distribution overhead assets whereas EPSS risk is the incremental impact from an outage occurring when EPSS is enabled.	4	Electric Operations
107	SPD	81	PG&E refine PSPS and EPSS strategies to ensure they are not widely impacting areas with low likelihood of ignition and low consequence.	PSPS and EPSS are operational mitigations utilized when conditions are elevated for wildfire risk represented through our Fire Potential Index (FPI). These programs are dependent on the forecasted and current weather conditions that cover the entire PG&E territory. These programs are targeting specific locations where the risk of wildfire is the greatest during elevated weather conditions.	4	Electric Operations
108	SPD	81	PG&E comprehensively examine and deploy technologies (including, but not limited to, REFCL) that can significantly reduce momentary outages.	PG&E will continue to examine technologies that reduce momentary outages. Currently a few pilots are running (Early Fault Detection and Distribution Fault Anticipation) for monitoring for incipient conditions which provide a leading indicator of a future outage.	4	Electric Operations

TABLE 1D-11
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
109	SPD	81	PG&E use the 2015-2023 weighted average of recorded dollar damage per structure destroyed when estimating the financial consequences attribute.	PG&E maintained an update to the structure consequence assumption of \$1M/structure. SPD recommended using the weighted average of \$723,000 (by structures) from 2015-2022 data. Considering inflation, PG&E calculated \$972K/structure. Given the January catastrophic events in Los Angeles, PG&E made a decision to maintain the current assumption of \$1M/structure given that this recent event will lead to an increase in consequence assumption.	4	Electric Operations
110	SPD	81	PG&E present the HFRA and Non-HFRA subtotals PG&E 2024 RAMP, Exhibit PG&E-4, Chapter 1, Table 1-15 for its TY 2027 GRC filing with its ESJ analysis.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
111	SPD	81	PG&E ensure the Grand Totals represent the correct DVC proportion.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
112	SPD	81	PG&E provide an explanation how allocating PSPS and EPSS consequences to DVC customers is supported by the data.	The ESJ Pilot was only required to be in PG&E's 2024 RAMP and will not be updated for the 2027 GRC.	4	Electric Operations
113	SPD	82	PG&E adopt SDG&E's "acres burned" as an interim proxy for estimating the impact of wildfire smoke, including its impact on DVCs, unless PG&E incorporates another way to do so.	PG&E is not required to and does not plan to submit the ESJ Pilot for the 2027 GRC, so the analysis for wildfire smoke impacts to DVCs will not be updated for the GRC.	4	Electric Operations
114	SPD	82	PG&E clarify whether and how it uses CBR values to select the most efficient risk mitigation measures at both the circuit segment and tranche.	This is explained in 2027 GRC Testimony, Exhibit (PG&E-4), Chapter 3, Section C. 1. b.	4	Electric Operations
115	SPD	82	PG&E provide information on what steps it is taking to reduce PSPS and EPSS impacts and develop other protective engineering solutions.	PG&E describes the work for EPSS and PSPS in Exhibit (PG&E-4), Chapter 6. For EPSS, this includes the installation of more protective devices with settings optimized for system performance and helicopters and drones are on standby to perform visual examination not discernable with ground patrol only. Additionally, there are animal abatement (Exhibit (PG&E-4), Chapter 15) and vegetation programs (Exhibit (PG&E-4), Chapter 8) aimed at reducing outages on EPSS enabled circuits. For PSPS, the installation of more sectionalization devices to support segmenting circuits near HFRA boundaries and operationally, addressing electric and vegetation tags to reduce the impact and scope of PSPS events. Both temporary generation and customer battery programs aim in mitigating EPSS and PSPS outages. Ancillary benefits of system hardening and undergrounding include the potential to reduce PSPS and EPSS impacts. Other protective engineering solutions include down conductor detection and gridscope devices. More information can be found in Exhibit (PG&E-4), Chapter 6.	4	Electric Operations
116	SPD	82	PG&E provide CBR calculations for undergrounding and covered conductor and other hardening and operational mitigation alternatives for each tranche and each circuit segment for which it proposes investments to mitigate wildfire risks.	PG&E will calculate CBRs for all circuit segments considered for system hardening in its EUP. CBRs will be calculated for undergrounding, overhead hardening, hybrid projects (a combination of undergrounding and overhead hardening on a single circuit segment).	4	Electric Operations
117	SPD	82	PG&E reduce its heavy reliance on undergrounding and propose overhead hardening and other alternative mitigations for a significantly larger portion of its proposed system hardening miles in its 2024 RAMP since undergrounding is the least cost-efficient wildfire mitigation.	PG&E's system hardening plans consist of a balanced system hardening portfolio that considers wildfire risk, reliability risk, and cost-effectiveness. While undergrounding is PG&E's preferred solution for mitigating ignition risk in the highest risk areas because it is the most effective way to near permanently reduce wildfire risk and significantly reduces outage program risk, undergrounding is less cost efficient than overhead hardening. In the highest risk locations, the long-term benefits of undergrounding including greater wildfire risk reduction, reliability improvement and operational cost avoidance (e.g. less vegetation management). In many other locations, wildfire risk can be appropriately mitigated and managed through a combination of overhead hardening and operational mitigations such as Public Safety Power Shutoff (PSPS) and Enhanced Power Safety Settings (EPSS). PG&E recognizes the need to balance affordability and risk reduction. As such, our forecast for 2027 represents a balanced portfolio that includes 190 miles of overhead hardening and 307 miles of undergrounding. (See Exh. 4, Ch. 7, Section C for more details)	4	Electric Operations
118	SPD	82	PG&E provide an update on the progress of the REFCL pilot at Calistoga and if the pilot is not yet completed, the pilot project plan detailing the remaining steps to acquire the necessary data on REFCL to perform mitigation analysis.	The Calistoga REFCL demonstration project is not yet complete. PG&E is continuing to gain operational experience with the technology and look at potential deployment opportunities. The Final EPIC report will be released at the end of the 2025.	4	Electric Operations
119	SPD	82	PG&E provide more granular information regarding the upstream and downstream circuit miles (refer to Summary of Findings, #48), including but not limited to, miles, costs, and justification, in addition to the associated high-risk circuit segments.	The EUP will address operational considerations affecting upstream and downstream circuit segments.	4	Electric Operations
120	SPD	82	PG&E investigate the feasibility and provide related information for various mitigations, undergrounding (UG), covered conductor (CC), CC+REFCL, CC+EPSS, and EPSS-solely mitigations, and any other proposed mitigations, for each circuit segment.	In the EUP, PG&E will provide information about undergrounding, overhead hardening and hybrid projects (circuit segments with both undergrounding and overhead hardening on the same circuit segment) for each circuit segment as required by the EUP Guidelines (Section 2.7.10). PG&E is not required to provide information about other mitigation combinations at the circuit segment level in the EUP. PG&E does estimate the effectiveness of mitigation combinations (e.g. covered conductor + EPSS) in the HFTD.	4	Electric Operations

TABLE 1D-12
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
121	SPD	82	PG&E calculate an estimated CBR, stating the assumptions made, at the circuit segment level for each mitigation.	CBRs are provided at the tranche level for each control and mitigation in workpaper, RM-RMCBR-15 Mitigations and Controls and their CBRs.xlsx. A similar workpaper will be provided for 2027 GRC. A mapping of the circuit segment to tranche is provided in the individual program analysis workpaper.	4	Electric Operations
122	SPD	82	PG&E provide justifications for mitigations at the circuit segment level in its TY 2027 GRC filing for segments that have been scoped and also explain what assumptions they have made for un-scoped segments that led to their proposed mitigation work plan.	The process of selecting mitigations at the circuit segment level is explained through our "layers of protection" wildfire mitigation strategy in Exhibit (PG&E-4), Chapter 3, Section C.1.b.	4	Electric Operations
123	SPD	82	PG&E identify and explain why the risks for any circuit segment changes more than 20 percent from PG&E's WDRM risk model V3 to V4, and how it impacts PG&E's mitigation proposal.	WDRM risk values are relative within a version and do not predict an absolute value. Therefore, risk results cannot be directly compared between versions as WDRM v3 and v4 produce different sums of system risk. PG&E recommends to compare risk rankings between versions rather than raw risk values. Risk rankings for WDRM are typically produced using normalized risk rather than total risk. Total risk skews results to the longest circuits ranking the highest, where as normalized risk, known as mean risk for v3 and risk per primary overhead mile for v4, favors circuit segments with the highest concentration of risk along its length.	4	Electric Operations
124	SPD	82	PG&E explain why a circuit segment in the proposed mitigation plan in its 2024 RAMP (using V3) has more than a 20 percent change in length (mileage) when reported in its TY 2027 GRC (using V4).	The WDRM v3 and v4 risk models were developed on different service territory snapshots to define the circuit segments used for aggregating risk. In between versions, circuit segment definitions routinely change as circuit segments get merged and split to satisfy operational needs. This often results in circuit segments with consistent names experiencing significant length changes. In addition, operational changes can lead to a named circuit segments disappearing entirely and new circuit segment names appearing in new WDRM version.	4	Electric Operations
125	SPD	82	PG&E provide details regarding all changes in circuit segment risk, length, and name, as outlined in the template provided by SPD, to enable a better understanding and review of PG&E's planned mitigations.	There are multiple reasons for a significant difference to exist between in the circuit segment summed risk data reported for WDRM v3 and v4 for any given circuit segment. The first, and most important, reason is that a direct comparison of WDRM v3 and v4 risk sum totals does not result in a meaningful number. As mentioned for line 123, the WDRM does not produce absolute risk values, only relative risk values. More simply put, PG&E does not calibrate the WDRM models to predict a targeted service territory sum of risk. Therefore, each WDRM, in its pursuit of improving differentiation in risk between individual circuit segments, produces a different sum of risk for the distribution service territory. For WDRM v3, the sum of territory risk was approximately 2,100 units of risk. For WDRM v4, the sum of territory risk was approximately 1,100 units of risk. As a result, one would expect the risk sum for any individual circuit segment, all other attributes equal, to decrease by almost 50 percent between WDRM v3 and v4. The second reason, as discussed in line 124 is that any percentage change in length for a circuit segment between versions will likely result in a similar percentage change to the summed risk. If the length increases, we would expect to see a corresponding increase in the risk value. This is one of the primary reasons that PG&E typically ranks circuit segment for wildfire risk on a normalized, rather than summed, risk value. The third reason is the numerous model improvements that were implemented for WDRM v4. As reported in the WDRM v4 documentation, these improvements generally shifted risk higher into the mountain foothills than WDRM v3. The WDRM v4 improvements are discussed throughout the WDRM v4 documentation suite. A summary of major improvements include: 1) A concentrated effort to improve the data quality of training and covariate data sets for both the consequence and event probability models, leading to better differentiation in risk. 2) Event Probability Modeling: o Converting most equipment asset probability models from pixel-based to asset based, improving individual asset predictions as well as improving asset-risk attribution to circuit segments. o Introducing several new equipment asset models for better differentiation of risk. o Adding new covariate data for trees and wind to the vegetation models, enabling better differentiation of vegetation risk. 3) Wildfire Consequence Modeling o Introducing Dry Wind Conditions as a covariate to the consequence model to help identify days with the highest potential consequence at a location. o Implementing consequence adjustments for Fire Suppression and Public Egress to distinguish general areas of concern. The interactions between the multiple improvements implemented in WDRM v4 make it difficult to determine with any certainty which model improvement, or combination of improvements, resulted in an observed change between WDRM v3 and v4 CS summed risk values. PG&E provided details regarding changes in circuit segment risk, length, and name in Data Request SPD 007 Question 1 Attachment 1.	4	Electric Operations

TABLE 1D-13
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
126	SPD	109	Although PCEEE events have decreased in recent years (from six and eight in 2018 and 2019, respectively, to three and one in 2021 and 2022, respectively), SPD observed the sample size for PCEEE events is (fortunately) very small. Due to the small sample size, statistical methods may be ineffective for providing meaningful conclusions.	For PCEEE, the 2024 RAMP Report included 8 events in 2018, 10 events in 2019, 4 in 2021, and 3 in 2022. Please refer to EO-PCEEE-6_SIF_Incidents_2018-2022.xlsx for details on the historical events. PG&E will continue to consider additional information and methodologies for meaningful conclusions.	4	Electric Operations
127	SPD	109	SPD observed that of the seven cross-cutting factors only physical attack impacts likelihood and has been quantified in the model. While RIM might affect the likelihood, it has not been quantified.	PG&E finds this statement accurate.	4	Electric Operations
128	SPD	109	SPD observed that both the Locate and Mark (to provide accurate physical locations of underground infrastructure) and Additional Signage (to add clear and visible signage, pole wraps, or stickers on its poles) programs exhibit low cost-benefit efficiencies, with CBRs of 0.2 and 1, respectively. PG&E should identify which mitigation activities are compliance-related, including those with a low CBR, so such low values can be assessed in the appropriate context.	Locate and Mark is a compliance driven control program. More information can be found about Locate and Mark in Exhibit 2, Gas Operations. Additional Signage is not compliance-related.	4	Electric Operations
129	SPD	110	PCEEE-C002 – Public Safety Awareness demonstrates the highest cost efficiency (CBR=7.6) compared to the other PCEEE mitigations and controls.	PG&E finds this statement accurate.	4	Electric Operations
130	SPD	110	Alternative Plan 1, PCEEE-A001: EPSS non-HFTD, with a CBR of 0.2 is not a cost-efficient measure to reduce PCEEE risk.	PG&E finds this statement accurate.	4	Electric Operations
131	SPD	110	Alternative Plan 2, PCEEE-A002: Proximity Warning Alarms, with a CBR of 2.9 exhibits a reasonable cost efficiency with a CBR of 2.9.	PG&E finds this statement accurate.	4	Electric Operations
132	SPD	110	SPD recommends PG&E consider using longer historical data or employing Bootstrap Resampling to generate a larger number of samples. Alternatively, Bayesian analysis could be used, incorporating prior information (from previous studies or expert knowledge) and updating it with observed data to estimate probabilities.	PG&E is currently investigating augmenting historical data with additional information to address the limited number of events in its current dataset.	4	Electric Operations
133	SPD	110	Additionally, since small sample sizes may limit statistical analyses, SPD suggests PG&E consider augmenting quantitative data with qualitative insights, especially in exploratory research. Patterns and trends from small datasets may be better understood when combined with contextual or qualitative information.	PG&E will investigate opportunities to improve the PCEEE risk model in future iterations.	4	Electric Operations
134	SPD	110	SPD recommends PG&E consider leveraging advanced technology and innovative solutions, such as real-time mapping, high-precision GIS, and real-time communication tools to improve the efficiency of its mitigation and control programs. These tools could include mobile apps, chat boxes, and digital platforms that allow contractors and the public to quickly request, locate, and view marked areas, thereby streamlining processes and reducing risks more effectively.	PG&E continues to explore tools that could improve efficiency of its mitigation and control programs. As they materialize, mitigations that result will be identified.	4	Electric Operations
135	SPD	110	SPD recommends that PG&E should focus on the mitigations and controls with higher cost-benefit ratios, such as PCEEE-C002 – Public Safety Awareness with a CBR of 7.6 and PCEEE-A002: Proximity Warning Alarms with a CBR of 2.9.	PG&E is currently providing Public Safety Awareness messaging and is planning a pilot program revolving around Proximity Warning Alarms in 2025.	4	Electric Operations
136	SPD	110	PG&E should identify all compliance-related controls and mitigations so that low CBR values can be assessed in the proper context.	Each forecast chapter (Exhibit (PG&E-4), Chapters 4 through 23) lists out any specific compliance-related activities for controls and mitigations. For PCEEE, Locate and Mark can be found in Exhibit 3, Chapter 8. Public Safety Awareness can be found in Exhibit (PG&E-4), Chapter 23.	4	Electric Operations
137	SPD	124	PG&E's "Other" category, comprising 26.2 percent, or 7,501 annual risk events, poses concerns of a potential lack of clarity and/or deficiency in PG&E's risk assessment analysis for DOVHD.	Vast majority of other category includes failure events without known causes where patrol found nothing. PG&E continues to strive to identify possible cause with reasonable efforts.	4	Electric Operations
138	SPD	124	SPD observes that PG&E defined some outcome categories differently in the 2020 and 2024 RAMP filings. Specifically, Asset Failure coinciding or not coinciding with IT asset failure was included as a category in the 2020 RAMP but is absent in 2024.	The IT asset failure outcome category has been removed from the DOVHD risk model due to low quality of modelling around coincident event, and it has a very low risk contribution.	4	Electric Operations
139	SPD	125	Additionally, the 2024 RAMP introduced outcome categories for wire-down and EPSS components that were not present in the 2020 RAMP. The consequences associated with these categories vary significantly.	PG&E agrees, wire-down vs non wire-down as well as EPSS and would-be EPSS events show significant difference in the 2024 RAMP vs the 2020 RAMP analysis. In the GRC filing, the DOVHD model was further simplified to remove EPSS and would-be EPSS. Updates to the DOVHD model are explained in Exhibit (PG&E-4), Chapter 3, Section C. 2.	4	Electric Operations
140	SPD	125	SPD reviewed the alternative mitigation plans. Only Alternative 1 offers an alternative to the proposed grid hardening work plan. Alternative 2 offers a potential incremental mitigation beyond the base proposal but does not appear to be ready for deployment without doing a pilot first.	PG&E suggested alternatives that can be considered. It is noted that alternative 2 was not ready to be implemented, however, Chapter 6 discusses our pilot into emergent technology and grid monitoring.	4	Electric Operations
141	SPD	125	In this chapter, PG&E did not provide substantial narrative justification for mitigations and controls with CBRs less than 1.0.	PG&E identifies mitigations and controls with CBRs less than 1.0 and provides factors affecting mitigation selection such as operational execution considerations, compliance requirements, and/or modeling limitations. More details on compliance-related activities or other considerations for DOVHD can be found in Exhibit (PG&E-4), Chapter 6, 9, 15, and 17.	4	Electric Operations
142	SPD	125	Some control and mitigation programs are identified with different IDs depending on the risk they are applied to. When this type of program produces benefits for multiple risks, PGE does not indicate the individual risk benefit contribution to the total benefit in the risk chapters, but only the aggregate total.	For risk programs that benefit multiple risks, PG&E intentionally only included the aggregate risk reduction and aggregate CBRs in RAMP risk chapters to avoid unnecessary confusion. PG&E intends to use the same approach in the 2027 GRC. However, for programs that benefit multiple risks, the individual risk benefit contribution to the total risk reduction and the individual risk contribution to the program CBR was included in RAMP Exhibit (PG&E02) WP RM-RMCBR-15. PG&E is providing a similar WP in the 2027 GRC.	4	Electric Operations

TABLE 1D-14
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
143	SPD	125	SPD recommends that PG&E provide additional granular details on “Other” categories in its 2027 GRC filing.	It is not feasible to make this improvement in 2027 GRC. PG&E will consider this in near future.	4	Electric Operations
144	SPD	125	SPD recommends that PG&E should explain the absence of IT asset failure coincidence as an outcome category in the TY 2027 GRC filing. Additionally, PG&E should explain the changes in category choices between the 2020 and 2024 RAMPs in the TY 2027 GRC filing.	The IT asset failure outcome category has been removed from the DOVHD risk model due to low quality of modelling around coincident event, and it has a very low risk contribution.	4	Electric Operations
146	SPD	125	SPD recommends that PG&E provide detailed narrative justifications for controls and mitigations with CBR less than 1.0 in the 2027 GRC filing.	PG&E identifies mitigations and controls with CBRs less than 1.0 and provides factors affecting mitigation selection such as operational execution considerations, compliance requirements, and/or modeling limitations. More details on compliance-related activities or other considerations for distribution overhead can be found in Exhibit 4, Chapter 6, 9, 15, and 17.	4	Electric Operations
147	SPD	125	When a single program has risk benefit application in more than one chapter, SPD recommends that PG&E should present in the 2027 GRC filing the allocations of risk reduction from each risk in addition to the overall costs and benefits of the program.	For risk programs that benefit multiple risks, PG&E intentionally only included the aggregate risk reduction and aggregate CBRs in RAMP risk chapters to avoid unnecessary confusion. PG&E intends to use the same approach in the 2027 GRC. However, for programs that benefit multiple risks, the individual risk benefit contribution to the total risk reduction and the individual risk contribution to the program CBR was included in RAMP Exhibit (PG&E02) WP RM-RMCBR-15. PG&E is providing a similar WP in the 2027 GRC.	4	Electric Operations
148	SPD	139	SPD finds that, in response to DR No. SPD_008-Q001 and in their 2nd Errata Notice, PG&E corrected their description of data. SPD finds that PG&E DOE-417 event data was utilized for individual Grid Emergency Sub-Drivers in and the data is from 2010 through 2022 or 13 years.	PG&E agrees with this statement.	4	Electric Operations
149	SPD	139	SPD finds that 2010 is an appropriate cutoff point for risk modeling purposes due to significant NERC regulatory improvements made after the 2003 Northeast Blackout	PG&E agrees with this statement.	4	Electric Operations
150	SPD	139	SPD finds that it was appropriate for PG&E to exclude Third Party ‘Foreign Object’ incidents in its risk analysis due to their typical short duration and/or localized scale of impact.	PG&E agrees with this statement.	4	Electric Operations
151	SPD	139	SPD finds that aggregated Frequency (Events/Yr) for Drivers of 0.00655 multiplied times aggregated Outcomes (CoRE) of 286,283 equals \$1,903M shown in Figure 1, PG&E's Electric Transmission Systemwide Blackout Risk Bow Tie.	PG&E agrees with this statement.	4	Electric Operations
152	SPD	139	SPD finds there could be value in dividing the transmission assets into various exposure segments especially since PG&E has a very large territory.	This feedback will be considered for the 2028 RAMP application.	4	Electric Operations
153	SPD	139	SPD finds that PG&E only utilized only 1 tranche for their entire system.	PG&E agrees with this statement.	4	Electric Operations
154	SPD	139	SPD finds that the sub-driver frequencies are infrequent, with DVE estimated to be the most common with a systemwide blackout event every 1-in-400 years. SPD finds that Cyber Attack is projected to be the least common sub-drivers with a systemwide blackout event every 1-in-25,000 years.	PG&E agrees with this statement, however, the cyber attack subdriver is 0.0004 (1 in 25,000) for Test Year Baseline Proposed 2023.	4	Electric Operations
155	SPD	139	In Bow tie, although Cyber Attack is only 1% of Outcome Frequency and 1% of Outcome Risk, SPD finds that it has a larger CoRE than for all non-Cyber Attack outcomes.	PG&E agrees with this statement.	4	Electric Operations
156	SPD	139	For cross-cutting factors, SPD finds that Seismic (SSMIC), Climate (CLIMT), Cyber Attack (CYBER) and Physical Attack (PHYSA) are included in risk modeling. SPD finds that climate escalations for Heat, Wildfire, Rain and Heat-Wildfire are from 2023 through 2122.	PG&E agrees with this statement.	4	Electric Operations
157	SPD	139	SPD finds that PG&E defined the distribution of Consequences for each Risk Event.	PG&E agrees with this statement.	4	Electric Operations
158	SPD	139	SPD finds that PG&E provided the source for Electric Reliability consequence of 12.3468 billion CMI. SPD finds that PG&E calculated Electric Reliability consequence for CyberAttack using 24 hours incremental restoration time.	PG&E agrees with this statement.	4	Electric Operations
159	SPD	139	SPD finds that PG&E calculated Indirect Safety using 6 EF/BillionCMI (BCMI), resulting in PG&E calculating 12.35 EFs for Indirect Safety not associated with Cyber Attack and 20.40 EFs for Indirect Safety associated with Cyber Attack. SPD finds that PG&E's electric reliability modeling does not double count indirect safety impacts.	PG&E agrees with this statement.	4	Electric Operations
160	SPD	139	SPD finds that the \$66.22 per customer (slope) was multiplied times the number of PG&E electricity customers, or 5,594,973 customers, for the value of 370,511,265. SPD finds that this value is escalated to get to the Financial value of \$449M/event.	PG&E agrees with this statement.	4	Electric Operations
161	SPD	139	SPD finds that inflation rates along with multipliers are used to convert to 2023 dollars and finds that the Financial Attribute utilized 1.186557 escalation.	PG&E agrees with this statement.	4	Electric Operations
162	SPD	139	SPD finds that PG&E did not conduct risk mitigation cost benefit analysis for its controls and mitigation	PG&E agrees with this statement.	4	Electric Operations
163	SPD	139	SPD finds that the Commission established the Transmission Project Review (TPR) Process effective January 1, 2024, in Resolution E-5252.	PG&E agrees with this statement.	4	Electric Operations

TABLE 1D-15
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
164	SPD	140	SPD finds that E-5252 stated: "For transmission Stakeholders to have a clear sense of the assumptions used in planning, prioritizing, and approving transmission projects, the TPR Process will include information on whether and how each transmission owner has applied the most current RDF to each project."	PG&E agrees with this statement.	4	Electric Operations
165	SPD	140	SPD finds that E-5252 "Attachment B E-5252 Draft Transmission Project Review Process Data Template in an Accompanying Excel File" includes the data field requirements for CBR data from the RDF/RAMP as Field 66 Cost-Benefit Analysis.	PG&E agrees with this statement.	4	Electric Operations
167	SPD	140	SPD recommends that PG&E divide its territory into multiple sections of its transmission grid to model large transmission outages in future risk modeling even if they are not systemwide blackouts.	This feedback will be considered for the 2028 RAMP application. PG&E is evaluating a regional black out risk that will address this comment.	4	Electric Operations
168	SPD	140	Similar to the Exposure section recommendation, SPD recommends PG&E divide their large service territory into multiple tranches.	This feedback will be considered for the 2028 RAMP application. PG&E is evaluating a regional black out risk that will address this comment.	4	Electric Operations
169	SPD	140	SPD recommends PG&E reevaluate if the assumed frequencies are adequate for risk modeling purposes and specifically whether the Grid Emergency & Cyber Attack frequency is adequate	This feedback will be considered for the 2028 RAMP application.	4	Electric Operations
170	SPD	140	SPD recommends that PG&E further evaluate the risk driver frequencies, specifically reconsidering whether 7.5% annual increase for Cyber Attack is appropriate.	This feedback will be considered for the 2028 RAMP application.	4	Electric Operations
171	SPD	140	SPD recommends that PG&E conduct risk modeling for the identified controls and mitigations irrespective of the funding authorization jurisdiction and specifically for the TPR Process.	PG&E agrees with this recommendation and is currently in the initial phases of providing CBRs for the TPR process for select programs. Transmission Systemwide Blackout mitigations will be considered.	4	Electric Operations
172	SPD	140	SPD recommends that PG&E divide the BLKOT-M001 Site Hardening Mitigation into multiple mitigations for specific substation sites.	This feedback will be considered for the 2028 RAMP application. PG&E is evaluating a regional black out risk that will address this comment.	4	Electric Operations
173	SPD	140	SPD recommends that PG&E conduct risk modeling for the alternative mitigation strategies irrespective of the funding authorization jurisdiction and specifically to be utilized in the TPR Process.	This feedback will be considered, prioritized alongside other requirements for the TPR process, and dependent on resource and time constraints.	4	Electric Operations
174	SPD	140	SPD recommends that PG&E divide the BLKOT-A001 Additional Site Hardening Mitigation into multiple mitigations for specific substation sites.	This feedback will be considered for the 2028 RAMP application. PG&E is evaluating a regional black out risk that will address this comment.	4	Electric Operations
175	SPD	140	SPD recommends PG&E divide BLKOT-A002 into two separate mitigations for Enhanced Operational Tools and Increased Operational Support Personnel.	This feedback will be considered for the 2028 RAMP application.	4	Electric Operations
176	SPD	140	SPD recommends that PG&E conduct risk modeling, including cost benefit ratio calculations, for the identified controls and mitigations and alternative mitigations irrespective of the funding authorization jurisdiction.	This feedback will be considered, prioritized alongside other requirements for the TPR process, and dependent on resource and time constraints.	4	Electric Operations
177	SPD	227	Consolidating all underground electric distribution assets into one risk ensures that all underground distribution assets fall within the purview of a RAMP risk.	PG&E finds this statement acceptable.	4	Electric Operations
178	SPD	227	Data sources for this risk appear to be either wholly or mostly lagging data.	PG&E uses historical data sources which is inherently lagging data, however, there is one leading indicator component, health need, which is incorporated into the tranche. More information is discussed in Exhibit (PG&E-4), Chapter 3 in the Failure of Electric Distribution Underground Assets.	4	Electric Operations
179	SPD	227	The highly discrete nature of some underground assets makes a homogenous risk profile within each tranche not always feasible.	PG&E finds this statement acceptable.	4	Electric Operations
180	SPD	227	The D1 driver is virtually synonymous with the risk event itself and the very name of the risk captured by the risk bow tie. Listing the risk event itself (or a very close analog) as a driver of the risk event is not particularly useful for visualizing the risk.	At the driver level, the distribution underground equipment failure is the cause of the risk event. PG&E does have the granular sub-driver information (such as primary cable failure, transformer failure, primary splice failure, secondary cable failure) and is considering to enhance the bowtie visual based on top sub-drivers for the 2028 RAMP application.	4	Electric Operations
181	SPD	227	Five control programs, DUNGD-C006, DUNGD-C007, DUNGD-C014, DUNGD-C015, and DUNGD-C016, and the two mitigation programs DUNGD-M006 and DUNGD-M008 have a CBR value less than 1. They present an opportunity for ratepayer cost savings by limiting risk mitigation activities to tranches where the CBR values are greater than or equal to 1.	In the 2027 GRC filing, one control program, DUNGD-C007 LBOR Switch Replacement, and one mitigation program, DUNGD-M002 Venting Manhole Cover Replacements, have CBR values that are under 1. These programs are discussed in more details in Exhibit (PG&E-4), Chapter 16.	4	Electric Operations
182	SPD	227	PG&E did not identify which controls are compliance-related, making interpretation of the low CBRs challenging.	In the GRC, compliance-related activities for DUNGD controls are detailed mostly in Exhibit (PG&E-4), Chapter 16.	4	Electric Operations
183	SPD	227	For the DUNGD-M006 program, PG&E did not include any data in the 2024 RAMP workpapers regarding the expected remaining life of the transformers or the likelihood of their failure in the next few years.	Please refer to workpaper EO-DUNGD-7_Network Target Replacement.xlsx tab "transformer" for projected failure rate of the 22 targeted High-Rise Dry-Type transformers to be replaced.	4	Electric Operations
184	SPD	227	Due to the low CBR, DUNGD-M008, should provide additional information to justify its implementation in the 2027 to 2030 GRC funding period.	DUNGD-M006, DUNGD-M007, and DUNGD-M008 have been reclassified since the 2024 RAMP Report. Please refer to Exhibit (PG&E-4), Ch. 3, Table 3-3 for the latest mapping.	4	Electric Operations

TABLE 1D-16
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
185	SPD	227	Existing mitigations (i.e., controls) with low CBRs should not be automatically approved for continued funding.	Each forecast chapter (Exhibit (PG&E-4), Chapters 4 through 23) lists any specific compliance-related activities for controls and mitigations. For DUNGD, all mitigations and controls, with the exception of Locate and Mark and Public Safety Awareness, can be found in Exhibit (PG&E-4), Chapter 14 and 16. Locate and Mark can be found in Exhibit (PG&E-3), Chapter 8. Public Safety Awareness can be found in Exhibit (PG&E-4), Chapter 8 and 23.	4	Electric Operations
186	SPD	227	The graphical tranche-level CBR presentations are a valuable tool for analyzing the cost- effectiveness of risk mitigations. PG&E should continue to include these diagrams in future RAMP and GRC workpapers.	Tranche-level CBRs are provided in the 2027 GRC filing. Refer to Workpaper RM-RMCBR-15 for the tranche-level CBRs.	4	Electric Operations
188	SPD	227	SPD recommends that PG&E incorporate (more) leading indicator data into the data quantification sources.	PG&E uses historical data sources which is inherently lagging data, however, there is one leading indicator component, health need, which is incorporated into the tranche. More information is discussed in Exhibit (PG&E-4), Chapter 3 in the Failure of Electric Distribution Underground Assets.	4	Electric Operations
189	SPD	227	SPD recommends that the oversized D1 risk driver be broken into finer gradations based on equipment types, such as primary cable failure, transformer failure, primary splice failure, secondary cable failure, and other equipment failure. This would allow for a more meaningful graphical presentation of the risk analysis.	At the driver level, the distribution underground equipment failure is the cause of the risk event. PG&E does have the granular sub-driver information (such as primary cable failure, transformer failure, primary splice failure, secondary cable failure) and is considering to enhance the bowtie visual based on top sub-drivers for the 2028 RAMP application.	4	Electric Operations
190	SPD	228	SPD recommends that to the maximum extent practicable, PG&E should apply each risk mitigation program only to those tranches with a CBR of at least 1, while recognizing there may be valid considerations to deviate from this recommendation.	PG&E will continue working with SME to forecast the tranche (or location) where the work will be performed whenever the data is available.	4	Electric Operations
191	SPD	228	SPD recommends that PG&E must identify all compliance-related control programs.	Each forecast chapter (Exhibit (PG&E-4), Chapters 4 through 23) lists any specific compliance-related activities for controls and mitigations. For DUNGD, all mitigations and controls, with the exception of Locate and Mark and Public Safety Awareness, can be found in Exhibit (PG&E-4), Chapter 14 and 16. Locate and Mark can be found in Exhibit (PG&E-3), Chapter 8. Public Safety Awareness can be found in Exhibit (PG&E-4), Chapter 8 and 23.	4	Electric Operations
192	SPD	228	SPD recommends that PG&E to justify the DUNGD-M006 program by providing data or analysis on the age, expected remaining life, and the likelihood of failure before 2031 for each of the 22 transformers if they were not replaced before 2027. This data and/or analysis using the data should be included with the Test Year 2027 GRC workpapers.	Please refer to workpaper EO-DUNGD-7_Network Target Replacement.xlsx tab "transformer" for projected failure rate of the 22 targeted High-Rise Dry-Type transformer to be replaced. Due to a lack of detailed information by each transformer, all 22 transformers are assumed to be installed in 1985, and PG&E forecasted the failure rates over the future years based on an observed industry failure curve. PG&E strives to collect more detailed data by individual transformers as more data can be available.	4	Electric Operations
193	SPD	228	SPD recommends that PG&E must provide more adequate justification for funding the DUNGD-M008 program in the Test Year 2027 GRC.	DUNGD-M006, DUNGD-M007, and DUNGD-M008 have been reclassified since the 2024 RAMP Report. Please refer to Exhibit (PG&E-4), Ch. 3, Table 3-3 for the latest mapping.	4	Electric Operations
194	SPD	228	SPD recommends that controls with low CBRs should not be automatically approved for continued funding. They should be re-justified with each new RAMP and GRC based on their new CBRs and other considerations.	PG&E appreciates the feedback. Each forecast chapter (Exhibit (PG&E-4), Chapters 4 through 23) lists any specific compliance-related activities for controls and mitigations. For DUNGD, all mitigations and controls, with the exception of Locate and Mark and Public Safety Awareness, can be found in Exhibit (PG&E-4), Chapter 14 and 16. Locate and Mark can be found in Exhibit (PG&E-3), Chapter 8. Public Safety Awareness can be found in Exhibit (PG&E-4), Chapter 8 and 23.	4	Electric Operations
195	SPD	253	OP events and the functioning of regulators are distinctly vulnerable to potential sabotage. Accordingly, SPD recommends that PG&E include two additional cross-cutting factors, Physical Attack and Cyber Attack, as risk drivers in the risk model for the LRGOP risk in its 2027 GRC filing.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
196	SPD	50	SPD recommends PG&E break down the exposure mile data based on three voltage categories (High or above 38 kilovolts (kV), Medium or 1 kV to 38 kV, and Low voltage or below 1 kV),63 with the S&S OH miles categorized as low voltage, in PG&E's TY 2027 GRC.	It is not clear how the recommended tranching will provide additional value.	4	Electric Operations
197	SPD	81	PG&E break down the exposure mile data based on three voltage categories (High, Medium, and Low voltage) with the S&S OH miles categorized as Low voltage.	It is not clear how the recommended tranching will provide additional value.	4	Electric Operations
198	SPD	255	As discussed in the Bow Tie observation section, SPD recommends PG&E quantify the cross-cutting factors of Physical Attack and Cyber Attack as risk drivers for LRGOP risk.	PG&E has included these two cross-cutting factors in the LRGOP model in the 2027 GRC.	3	Gas Operations
199	SPD	257	SPD observes that the consequence classifications PG&E uses do not distinguish ruptures or leaks that resulted in an ignition from ruptures or leaks that did not result in an ignition. SPD finds that there is significant variance in consequences for risk events when there is an ignition compared to when there is no ignition. Therefore, SPD recommends PG&E add distinctions for ignition and no ignition to further contextualize its LRGOP risk analysis.	PG&E has implemented an algorithm to calculate the probability of ignition in rupture events for Class locations 1-2 pipe within the TIMP operational risk model and will work on a probability of ignition algorithm in rupture events on HCA pipe. For leak events the TIMP operational risk model has not planned to implement probability of ignition but will make this a priority.	3	Gas Operations
200	SPD	260	SPD notes that the Commission has not issued a decision regarding risk tolerance and PG&E did not provide more information on risk tolerance (e.g. defining a risk tolerance number or framework). Therefore, using risk tolerance as a factor affecting selection is not justified for the following mitigation: LGROP-M003 – GD OPP Program (CBR = 0.016).	PG&E provides further explanation regarding its use of risk tolerance for addressing LRGOP in Exh. 3 Ch. 3 Sec. B. 4. a. of the 2027 GRC Testimony.	3	Gas Operations

TABLE 1D-17
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
201	SPD	260	SPD acknowledges that although modeling limitations may hinder the quantification of benefits for the following proposed mitigations, the CBRs for these mitigations are 1-2.22 orders of magnitude lower than the CBR threshold of 1.0. Therefore, justification for the following proposed mitigations is insufficient: · LRGOP-M001 – GT SCADA Visibility (CBR = 0.092) · LRGOP-M006 – GD SCADA Visibility (ERX) (CBR = 0.006) · LRGOP-M007 – GD SCADA Visibility (RTU) (CBR = 0.009)	PG&E included these mitigations (LRGOP-M001, LRGOP-M006, & LRGOP-M007) in the 2024 RAMP because PG&E believed it was appropriate to do so. PG&E will continue to propose programs it considers prudent to maintain a safe, reliable, and affordable system. Further justification for these mitigation programs can be found in Exhibit (PG&E-3), Chapter 6.	3	Gas Operations
203	SPD	39	Finally, SPD recommends that PG&E explain its short- and long-term climate investment strategy and capital investment plan in its 2027 GRC filing.	Using the RDF and CAVA methodologies, there is insufficient capability to reliably perform a quantitative analysis at this time. PG&E has identified climate-informed investments in the GRC in order to assist to determining programs that include a climate resilience component.	4	Climate
204	SPD	227	The Alternative Plans presented by PG&E are not realistic alternatives to the Proposed Plan because of the low CBRs.	On page 32 of D.14-12-025 and on pages 5-6 in the Straw Proposal that was adopted, it states "The RAMP would contain at least the following: For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan." Low CBRs can reflect the reasoning behind not choosing or pursuing the alternative.	4	Electric Operations
205	SPD	228	PG&E should present alternative, more realistic and competitive mitigation plans than the proposed one.	On page 32 of D.14-12-025 and on pages 5-6 in the Straw Proposal that was adopted, it states "The RAMP would contain at least the following: For comparison purposes, at least two other alternative mitigation plans the utility considered and an explanation of why the utility views these plans as inferior to the proposal plan." Low CBRs can reflect the reasoning behind not choosing or pursuing the alternative.	4	Electric Operations
206	SPD	142	From the Bow Tie, one would expect to find the baseline risk score as the product of frequency times outcome (LoRE times CoRE),229 or 33.3 events per year times \$1.2 million per event = \$39.9 million. However, the risk score presented is different at \$38.6 million. The reason appears to be that the CoRE value in the Bow Tie has been truncated to \$1.2 million; one can find a more precise value in the Consequences Table230 for CoRE of \$1.16 million. When the \$1.16 value is multiplied by the 33.3 frequency, the Bow Tie risk score is obtained. This kind of discrepancy leads to confusion and necessitates cross-referencing with tables to confirm the values presented are consistent.	PG&E will review the bow tie data analysis during the RAMP to GRC model updates and make changes to the tables as needed to clarify presentation of the analysis results in the 2027 GRC testimony	7	Shared Services
207	SPD	143	PG&E presents risk exposure as the number of contract-partner-hours-worked – 40,001,279. However, this value conflicts with a larger number of contractor employee work hours-- 43.67 million hours -- cited earlier in the chapter (p. 1-3, line 4). This discrepancy should be explained or corrected in PG&E's 2027 GRC filing.	Addressed in data response RAMP-2024-DR_SPD_019-Q007. (on RAMP 2024 sharepoint) and will be updated in the 2027 GRC testimony (the bow tie model is correct).	7	Shared Services
208	SPD	144	Vegetation Management (or VM) is one of the four Tranches PG&E employs for its Contractor Safety risk, the remaining three being electric assets work, gas assets work, and driving on paved roads. PG&E doesn't explain its reasoning for carving out a Tranche category specifically for VM, and thereby creating a second Tranche category also pertinent to electric assets. Given that VM work is among the most dangerous work done by utility workers, it could reasonably infer that VM work alone is responsible for a share of risks comparable to or exceeding that of the other three tranches.	Agree - no action needed	7	Shared Services
209	SPD	146	Recommendation: 1) PG&E should do a deeper alternative plan analysis to demonstrate that the proposed plan provides the best balance of cost and risk reduction compared to alternative portfolios of controls and mitigations.	Response to recommendation 1): PG&E agrees with the SPD and will implement a deeper alternative plan analysis as part of the next RAMP report filing.	7	Shared Services
210	SPD	146	Recommendation: 2) PG&E should present the CBR data for each individual control measure.	Response to recommendation 2): PG&E appreciates the recommendation from the SPD. In response, the controls in the Contractor Safety Programs are integrated as a contractor safety management system and many require minimal funding as most of the costs are covered by the contractor. Individual control measure CBRs would not represent the management system.	7	Shared Services
211	SPD	148	For each risk category incident, PG&E's Bow Tie indicates a weighted average outcome of \$0.10 million per incident, with 378 qualifying safety incidents per year and an expected Risk Value of \$37.8 million. However, this result is inconsistent with the \$39.1 million Risk Value figure presented in PG&E's Bow Tie diagram. The Risk Value of \$39.1 million is derived from PG&E's Table 3-4,240 which gives the frequency value as 378.01 and the Consequence of Risk Event (CoRE) aggregated value as \$0.103 million. For better clarity, the outcome values should not be truncated to two digits so that the CoRE value of 0.103 was readily apparent as the reason for the Risk Value of \$39.1 million.	PG&E will review the bow tie data analysis during the RAMP to GRC model updates and make changes to the tables as needed to clarify presentation of the analysis results in the 2027 GRC testimony.	7	Shared Services
212	SPD	152	Of the 378 total days away/frequency incidents, 12.9 are described as "All Other" in Table 3-4, or 3.4 percent of incidents. However, no CoRE consequence value is shown for the All Other category , while DART and SIF incidents do show a CoRE value). Presumably, these 12.9 incidents are included as part of the risk drivers that contribute to the total of 378 incidents in the Bow Tie. The absence of a consequence score is not explained in the RAMP narrative. There is no contribution to the consequence score from this driver category and yet the total risk score includes these incidents when multiplying Likelihood of a Risk Event (LoRE) by the CoRE value to obtain the risk score. SPD recommends explaining this missing information in the RAMP and GRC narratives.	Addressed in data response RAMP-2024-DR_SPD_019-Q001.	7	Shared Services
213	SPD	157	Recommendation 1) SPD recommends that the absence of values, such as the All Other category's missing consequence score, be corrected and/or addressed in a narrative explanation in the GRC application.	Response to recommendation 1): PG&E agrees with the SPD and has updated the employee safety risk bow tie to include the All Other category missing consequence score and has included the definition of All Other as a footnote. That reads: "All Other outcomes" include SIF Potential incidents that did NOT result in a DART injury.	7	Shared Services

TABLE 1D-18
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
214	SPD	157	Recommendation 2) SPD recommends that PG&E consider segmenting the SIF outcome for employee risk as they do for contractor risk.	Response to recommendation 2): PG&E appreciates the SPD's feedback and provides the following response. It is not possible to segment the Employee Safety Incident risk SIF outcomes in the same way as the Contractor Safety Incident risk SIF outcomes. In addition to Actual or Potential SIF outcomes, the employee safety risk outcomes include DART case claim causes. The analogous Potential SIF outcome in Contractor risk is split between the DART and All Other outcomes in Employee risk. This is because for Employee risk, there is a financial consequence in addition to safety. In addition, employee safety risk outcomes also include DART cases as a financial consequence represented by the average workers' compensation claim cost. There is no financial consequence included with the contractor safety risk as workers' compensation claims costs as they are covered by the contractor.	7	Shared Services
215	SPD	157	Recommendation 3) SPD recommends PG&E's forthcoming GRC filing should examine the cost benefits and risk tradeoffs of proposed controls and mitigations for potential savings from reduction of programs and/or measures with lower CBRs.	Response to recommendation 3): PG&E agrees with the SPD and will continue to examine the cost benefits and risk tradeoffs of proposed controls and mitigations for potential savings from reduction of programs and/or measures with lower CBRs and include them in the 2027 GRC testimony only as needed.	7	Shared Services
216	SPD	157	Recommendation 4) SPD recommends that PG&E consider alternative mitigation plans that provide significantly different cost options and indicate tradeoffs in risk reduction in the GRC and future RAMP filings.	Response to recommendation 4): PG&E agrees with the SPD and will consider the evaluation of alternative mitigation plans that provide significantly different cost options and indicate tradeoffs in risk reduction in the GRC and future RAMP filings.	7	Shared Services
219	EPUC	3	the application of a risk-averse RAF should not become an excuse for ignoring or otherwise not managing routine risks with higher frequency of occurrence.	PG&E does not ignore routine risk due to the Risk Attitude Function.	2	EORM
220	EPUC	3	The RAF ultimately used in risk analysis should also address routine risks to identify the most economic means of mitigating public safety risks via utility resource planning.	PG&E supports this proposal and does use multiple factors in prioritizing work in order to ensure "routine risks" are also addressed, e.g., MVI mitigations.	2	EORM
221	EPUC	3	PG&E's analysis would be better informed by using a range of risk multipliers more specifically tied to the type of catastrophic risk event	PG&E will consider this proposal based on future changes to the RDF and its own risk evolution.	2	EORM
222	EPUC	4	PG&E should develop ranges of risk premium multipliers for catastrophic risk events that are more closely tied to the event type.	PG&E will consider this proposal based on future changes to the RDF and its own risk evolution.	2	EORM
223	EPUC	4	It would be more appropriate to replace the singular curve with multiple curves that are more representative of the safety and reliability risk associated with each event type	PG&E will consider this proposal based on future changes to the RDF and its own risk evolution.	2	EORM
224	EPUC	4	The Commission should require PG&E to provide that risk-neutral RAF analysis to SPD, so that SPD can assess the cost-effectiveness and rate affordability impacts of PG&E's proposed risk-averse RAF.	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
225	EPUC	5	Recommendation #1: Request that PG&E develop and apply a suite of RAF curves for the catastrophic loss region showing the spread in risk premium multipliers for each discrete category of covered risks (e.g., cyber, wildfire, etc.), rather than adopting a singular RAF for application to all categories of risk.	PG&E will consider this proposal based on future changes to the RDF and its own risk evolution. PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
226	EPUC	5	Recommendation #2: Request that PG&E develop and apply a suite of RAF curves for the elevated loss region showing the spread in risk premium multipliers for each discrete category of covered risks, rather than adopting a singular RAF for application to all categories of risk.	PG&E will consider this proposal based on future changes to the RDF and its own risk evolution. PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3).	2	EORM
227	EPUC	5	Recommendation #3: Require PG&E to submit its RAMP analysis with a risk-neutral RAF for comparison with its proposed risk-averse RAF analysis	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
228	EPUC	6	Recommendation #4: Require PG&E to provide detailed explanations of the processes utilized to incorporate SME judgement into the risk modeling	PG&E will consider this proposal in its next RAMP to provide further clarification on its risk analysis processes.	2	EORM
229	EPUC	8	Recommendation #6: Require PG&E to utilize PGE customer data rather than statewide averages in the ICE calculator—if not for this 2024 RAMP, then for its 2028 RAMP.	PG&E expects this concern to be remedied with the customer-centric use of the ICE 2.0 tool which is expected to be implemented by PG&E's 2028 RAMP	2	EORM
230	EPUC	8	Recommendation #7: Require PG&E to provide a detailed narrative of the inherent limitations of the ICE calculator, and any adjustments made to inputs or outputs to compensate for those limitations.	PG&E expects this concern to be remedied with the customer-centric use of the ICE 2.0 tool which is expected to be implemented by PG&E's 2028 RAMP	2	EORM
231	MGRA	2	for the GRC PG&E should be required to submit a linear weighting function alternative in its GRC	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM

TABLE 1D-19
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
232	MGRA	22	PG&E's GRC application should not be considered unless it includes calculation of CBR assuming linear risk scaling.	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
233	MGRA	22	PG&E's GRC application should not be considered unless it provides additional information supporting its use of the Phoenix Reinsurance bond and showing that the risk premium of this bond is based on quality risk analysis that is as good as or better than PG&E's risk analysis. This showing must indicate whether the CAT bond is using a Pareto distribution for wildfire loss estimates, and whether PG&E itself continues to use its Pareto based consequence model.	PG&E provided justification for its use of the catastrophic insurance bonds markets for use in its scaling function. PG&E's continued use of the risk-averse scaling function is permitted in the Risk-Based Decision-Making Framework. PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will provide CBRs calculated with a risk neutral function in the 2027 GRC for comparison.	2	EORM
234	MGRA	22	PG&E should incorporate uncertainty into its risk calculation through a mechanism other than the CAT bond. The suggested mechanism is to use the function derived from PG&E's consequence cap analysis to provide the basis for a Monte Carlo varying around the 5X Camp fire value using a lognormal distribution with deviation suggested by SMEs.	PG&E appreciates the suggestion for another mechanism to incorporate uncertainty and will consider it as it develops its next RAMP. PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
235	TURN	4	TURN suggests a more nuanced application of the ICE Calculator by incorporating customer location data, at a minimum by geographic tiering, and potentially at more granular levels such as tranche and circuit segment levels, where feasible. For electric risks where the tranches are not broken at the level of geographical tiers, the use of proxies, such as historical reliability impact by spatial classification, may be appropriate.	PG&E expects this concern to be remedied with the customer-centric use of the ICE 2.0 tool which is expected to be implemented by PG&E's 2028 RAMP	2	EORM
236	TURN	4	TURN believes that a geo-tiered evaluation of \$/CMI, using tier-specific average SAIDI values provides more accurate results by considering the varying risk profiles and SAIDI data across different geographic tiers. Using this approach, TURN recommends using the more representative average of 1.83 \$/CMI (2023) based on data provided in Table 2.	PG&E expects this concern to be remedied with the customer-centric use of the ICE 2.0 tool which is expected to be implemented by PG&E's 2028 RAMP	2	EORM
237	TURN	4	TURN recommends the use of \$13.23 million as the 2023 VSL, based on escalation of the DOT VSL from 2012 (\$9.1 million). Alternatively, analysis conducted by the California Air Resources Board (CARB), suggests a mid-point California-specific VSL of \$9.0 million (2013) which translates to \$12.33 in 2023 dollars, after applying an adjustment factor (1.37) based on California-specific CPI-U.	PG&E appreciates the suggestion and will continue to evaluate reasonable methods of calculating VSL in compliance with the Phase II decision of the RDF OIR. As PG&E complied with the Phase II Decision of the RDF OIR in its update of calculating monetized attribute values, it does not intend to make the change suggested in the 2027 GRC.	2	EORM
238	TURN	9	Consistent with D.24-05-064, PG&E's GRC Showing Should At Least Supplement Its CBR Calculations with CBRs Based on a Linear Scaling Function	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
239	TURN	11	PG&E's GRC Filing Should Allow the Commission and Intervenors to Compare the Cost-Effectiveness of Alternative Mitigations on an "Apples to Apples" Basis	PG&E complies with the S-MAP in its alternative analysis and notes there is often little flexibility in the way it implements mitigations and compliance requirements to achieve necessary goals. PG&E will strive to improve its alternatives analysis with this feedback in mind.	2	EORM
240	TURN	22	The use of climate change models to derive increases in RFW ignitions is not only extremely complex, PG&E's and ICF's modeling assumptions are highly opaque and virtually impossible, at least in the context of a single RAMP proceeding, to replicate, verify, or determine whether the inputs are reasonable	The climate risk increases exactly through the risk case period and then decreases afterwards is driven by ICF provided forecast of days above historical 95th percentile Fire Weather Index (FWI), which uses California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. According to ICF, it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables. More technical details regarding how PG&E incorporates ICF's forecast into wildfire risk modeling can be found in PG&E response to TURN data request 005 Q1a in addition to Exh. 2 Workpapers CC-CLIMT-14 and CC-CLIMT-15.	2	EORM

TABLE 1D-20
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
241	TURN	22	The calculation appears designed to increase the impact of climate change exactly through the rate case cycle (2027-2030), after which climate change impacts would remain constant or decrease. At minimum, this is counterintuitive. This finding further highlights the inappropriateness of incorporating this significant driver of wildfire risk as presented, without further Commission understanding and review	The climate risk increases exactly through the risk case period and then decreases afterwards is driven by ICF provided forecast of days above historical 95th percentile Fire Weather Index (FWI), which uses California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. According to ICF, it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables. More technical details regarding how PG&E incorporates ICF's forecast into wildfire risk modeling can be found in PG&E response to TURN data request 005 Q1a in addition to Exh. 2 Workpapers CC-CLIMT-14 and CC-CLIMT-15.	2	EORM
242	TURN	28	PG&E's analysis is simply not useful for determining the extent to which DVCs benefit, or do not, from wildfire risk reduction programs.	PG&E appreciates the suggestion and will consider how best to incorporate ESJ as necessary based on future requirements of the RDF.	2	EORM
243	TURN	30	PG&E uses geography-agnostic data to calculate an interruption cost estimate of \$3.17/CMI across its territory. This approach does not account for geographical differences in customer distribution and respective reliability impacts. TURN recommends a more nuanced four-tiered evaluation of \$/CMI using tier-specific SAIDI values, resulting in an average electric reliability cost of \$1.83/CMI.	PG&E complied with the Phase II Decision of the RDF OIR in its update of calculating monetized attribute values.	2	EORM
244	TURN	30	PG&E's hybrid approach for the Safety Attribute, applying California-specific adjustments to the DOT's nationwide Value of Statistical Life (VSL) to arrive at a VSL of \$15.2 million, is contrary to DOT guidelines on the use of VSL and contrary to D.22-12-027. TURN recommends adhering to DOT guidelines by using the DOT's 2012 Value of Statistical Life (VSL) of \$9.1 million, adjusted to \$13.2 million for the year 2023.	PG&E complied with the Phase II Decision of the RDF OIR in its update of calculating monetized attribute values.	2	EORM
245	TURN	30	PG&E has not demonstrated that its extremely convex scaling function is reasonable. As required by D.24-05-064, PG&E's GRC submission should include alternative risk score and CBR results based on a risk neutral scaling function.	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	2	EORM
246	TURN	30	PG&E's GRC filing should include workpapers that allow intervenors and the Commission to compare the CBRs of alternative mitigations assuming they are performed in the same risk areas. At minimum, upon request, PG&E should provide workpapers enabling such an apples-to-apples comparison within the customary 10 business-day data request cycle	PG&E complies with the S-MAP in its alternative analysis and notes there is often little flexibility in the way it implements mitigations and compliance requirements to achieve necessary goals. PG&E strives and is highly successful at responding to data requests in the customary 10 business-day data request cycle. PG&E supports TURN in providing a data request if there is difficulty understanding its alternative analyses.	2	EORM
247	TURN	31	In modeling climate change impacts, PG&E should incorporate less drastic annual increases for the rate case period in baseline wildfire risk based on its current modeling results while the Commission allows for more robust analysis of the issue in the S-MAP proceeding.	The climate risk increases exactly through the risk case period and then decreases afterwards is driven by ICF provided forecast of days above historical 95th percentile Fire Weather Index (FWI), which uses California-specific Localized Constructed Analogs version 2 (LOCA2) downscaled projections for daily maximum temperature, daily minimum relative humidity, daily average wind speed, and daily precipitation totals. According to ICF, it is not unusual for FWI projections to decrease between two near-term time horizons, as precipitation, wind, and humidity are not increasing or decreasing linearly through time. FWI is a dynamic variable influenced by many different variables pulling it in different directions through time, but temperature will accelerate by late-century (2080) overwhelming any variability in the remaining variables. More technical details regarding how PG&E incorporates ICF's forecast into wildfire risk modeling can be found in PG&E response to TURN data request 005 Q1a in addition to Exh. 2 Workpapers CC-CLIMT-14 and CC-CLIMT-15.	2	EORM
248	TURN	31	PG&E conclusion that disadvantaged and vulnerable communities (DVCs) disproportionately benefit from wildfire risk reduction is poorly supported based on the current iteration of its DVC analysis. PG&E's conclusions about benefits to DVCs should be based on a more solid analytical foundation.	PG&E appreciates the suggestion and will consider how best to incorporate ESJ as necessary based on future requirements of the RDF.	2	EORM
249	SPD	182 185 207	9. In its 2027 GRC filing, PG&E should provide clear and detailed explanations regarding how the RIM cross-cutting factor operates in the context of LGUWR.	The RIM multiplier in PG&E's 2024 RAMP workpaper (PG&E-2) Ch3 CC-RECIM-2 was calculated based on estimates of incremental financial burden on PG&E Functional Areas attributable to records maturity based on assessments made by an independent third party, IGMM. Since the assessment was made, the progress of records maturity has been accounted for and the estimate adjusted to 2%. The current methodology for estimating financial impacts due to records maturity is being revised internally to align with updated records governance procedures and measures.	5	Generation
250	SPD	383 (7)	PG&E has not demonstrated the reasonableness of its extreme scaling function	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	5	Generation

TABLE 1D-21
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
251	SPD	385 (9)	Consistent with D.24-05-064, PG&E's GRC Showing Should At Least Supplement its CBR Calculations with CBRs Based on a Linear Scaling Function	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	5	Generation
252	SPD	25	PG&E should explicitly state its risk tolerance for a LGUWR event and identify how its risk tolerance might diverge from that of its ratepayers.	PG&E does not currently use risk tolerance for LGUWR mitigation selection. The CPUC has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. PG&E believes CPUC should provide guidance on how explicit risk tolerance should be developed.	5	Generation
253	SPD	207	16. PG&E should include 2024 actual operating expenses for Controls in its 2027 GRC filing and require PG&E to clearly explain any differences between actuals and forecasts within its 2027 GRC filing.	The SPD compared 2023 actuals to 2024 forecast on GEN-LGUWR-08. Inputs to _CBR-Input workpaper for control projects provided in the PG&E RAMP filing. SPD noted that "...in some cases (actuals) are significantly higher than the 2024 forecasted expenses" and that "Except for Helms, it appears that the 2024 forecasts are poorly estimated". The equivalent workpaper with 2024 actuals and forecast can be found Exhibit (PG&E-5), WP 2-1 to 2-11_Risk Program Costs and CBRs. Generally, differences between 2024 actuals and 2025 forecasts for projects can occur for various reason such as, but not limited to: -Costs for expense projects may only be within a one year period and not carry over to the next year. -Costs for multi-year expense projects may complete in one year and not carry over to the next year. -Projects are completed sooner than originally planned which works down the budget sooner than forecasted.	5	Generation
254	SPD	208	20. In its 2027 GRC filing, PG&E should describe explicitly how each of its five mitigation programs can support the operational considerations discussed in the 2024 RAMP narrative	PG&E's LGUWR five mitigation programs help proactively maintain dams and their components. PG&E believes that it is almost always significantly more expensive to respond to a dam safety incident than to proactively maintain the dams and their components. A description of the mitigations are as follows: LGUWR M001 – Internal Erosion Mitigations: PG&E implements internal erosion mitigations (LGUWR M001) to minimize the potential for internal erosion failure modes to initiate and develop for earth fill and rockfill embankment dams. LGUWR M002 – Spillway Remediations: PG&E implements spillway remediation mitigations (LGUWR M002) to ensure its dams can safely pass the design flood events. LGUWR M003 – Seismic Retrofits: PG&E implements seismic retrofit mitigations (LGUWR M003) to ensure dams and components will not fail under the seismic design loads. LGUWR M004 – LLO Refurbishments: PG&E implements LLO refurbishments (LGUWR M004) to ensure the reservoir can be drained during an emergency or for dam maintenance. LGUWR M005 – Physical Security: PG&E implements mitigations against physical attack (LGUWR M005) to reduce the likelihood of malicious threats from third party individuals or groups on dam safety. A summary of each mitigation program can also be found as part of the Energy Supply, Chapter 3: Hydo Operations Costs, 2027 GRC Hydro Project Summaries workpapers.	5	Generation

TABLE 1D-22
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
255	SPD	26	The Commission should require PG&E to be transparent about its use of risk tolerance and its impact on mitigation selection, and provide a risk-neutral LGUWR analysis with its 2027 GRC application.	PG&E does not currently use its own risk tolerance for mitigation selection for the LGUWR risk. The CPUC has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. PG&E believes CPUC should provide guidance on how explicit risk tolerance should be developed. PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	5	Generation
256	SPD	208	22. Any costs submitted to the 2027 PG&E GRC associated with the AMS should be included in a detailed narrative of the program and explain why they have been classified as a foundational activity or mitigation.	The asset management system (AMS) is a governance framework that is integrated into how PG&E programs function. Funding is embedded in all asset management work. The AMS is described in more detail in section B.1. of Chapter 2, Energy Supply Management, of this 2027 GRC filing. The AMS ensures that asset management practices align with organizational goals, focusing on maximizing asset value while minimizing risks and costs.	5	Generation
257	SPD	182	While reviewing the relationship of LGUWR to the Climate Adaptation Vulnerability Assessment (CAVA) results, PG&E notes that the adaptive capacity of PG&E's hydro generation assets to future climate hazards was a key factor in determining its climate risk rankings. While this may be true, it is not explicitly or quantitatively demonstrated in the 2024 RAMP filing. SPD recommends that PG&E clarify this relationship in its upcoming Climate Pilot White Paper, due no later than September 15, 2025, as ordered in D.24-05-064.	PG&E will clarify this relationship in the Climate Pilot White Paper that is due post GRC-filing on September 15, 2025, per D.24-05-064.	5	Generation
258	SPD	185	The CC-RECIM-2_PGE ERIM Consequence Multiplier.xlsx is in fact a workpaper from the 2023 GRC without a ReadMe worksheet to explain how the workpaper operates. The multiplier in this workpaper from April 2023 for Power Generation is 2 percent, but SPD recommends that PG&E should update this workpaper before it is submitted to the 2027 GRC with a justification for this number.	The current methodology for estimating financial impacts due to records maturity is being revised internally to align with updated records governance procedures and measures.	5	Generation
259	SPD	189 PDF (191)	The narrative and workpapers provide no explanation of the way RCEM or LifeSIM work. The only additional information provided is that the data integrated into these models came from the US Army Corps of Engineers (USACE) National Structure Inventory (NSI) database. SPD recommends PG&E should include in its 2027 GRC a proper citation to information about the RCEM and LifeSim models and the NSI database.	PG&E added citations for RCEM and LifeSIM in the "Readme" sheet of the workpaper GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences". This workpaper is submitted as part of the 2027 GRC risk workpapers.	5	Generation
260	SPD	207	12. When filing the 2027 GRC, PG&E present its measure of risk, risk reduction, NPV Benefits and CBRs for LGUWR using both a linear and non-linear scale.	PG&E recognizes that regarding the Risk-Averse Risk Scaling Function, "SPD evaluated this approach and concluded that it is valid" (SPD Evaluation Report on PG&E 2024 RAMP, pg. 3). PG&E will additionally provide risk neutral risk scores and CBRs in the 2027 GRC.	5	Generation
261	SPD	189	In addition to using RCEM or LifeSIM to update the safety attribute for LGUWR, it would also be important to establish more accurate estimations of responses to uncontrolled releases. SPD recommends that PG&E consider the Response Time by Social Vulnerability Index (ReTSVI) or an equivalent approach to model the risk reduction benefits of a proper evacuation. Such a model could help provide a more accurate measure of the benefits of the abovementioned Emergency Preparedness and Response cross-cutting feature.	The fatality rates and modeling parameters using the LifeSIM and RCEM were calibrated based on case histories of dam failures. In general, risk practitioners in the dam industry believe that life safety consequences calculated by these two models have an-order-of-magnitude uncertainties due to the inherent complexity of trying to model randomness in population-at-risk, decision making, and actual capability to warn and evacuate people. PG&E believes the impact of social vulnerability index would likely be captured within the order-of-magnitude uncertainty bounds.	5	Generation
262	SPD	183	According to PG&E, the logic is that there would be "more time to warn and evacuate people who are located farther away than those immediately downstream of the dam." While this may be true, this correlation of additional warning time for people located farther away is only a loose proxy for EP&R. This correlation should be explained more clearly, and if possible, it should be quantified. SPD recommends that PG&E should explicitly quantify EP&R within workpapers and the narrative of the application in the 2027 GRC filing.	PG&E agrees that correlation of additional warning time with people located farther away is only a loose proxy for EP&R. This simplifying assumption was made for the consequences developed for RAMP 2020 using the DeKay and McClelland method, which should be considered as screening-level analyses. PG&E is currently incorporating the time to detect and ability to issue warnings in the life safety consequence analysis (LifeSIM and RCEM).	5	Generation

TABLE 1D-23
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
263	SPD	206	1. PG&E should create nine tranches using the LoRE and CoRE approach in addition to the current method of one tranche per dam (if PG&E wishes to retain that approach). Requiring PG&E to provide the nine LoRE and CoRE tranches will ensure that decision-makers can properly assess the prioritization of mitigations to reduce the risk of LGUWR risk events.	PG&E believes that creating nine tranches (or aggregating risks from one dam-per-tranche) solely based on LoRe and CoRE may not be appropriate for LGUWR because this will likely result in mixing dams with different characteristics within the same tranche. This is because the potential failure modes for concrete gravity, concrete arch, embankment, rockfill, slab and buttress dams are different and would require different types of mitigations.	5	Generation
264	SPD	206	2. PG&E consider modeling the safety and financial consequences as well as the likelihood of citizens being injured or drowning after falling into PG&E's water conveyance system as well as any mitigations to reduce the likelihood or consequence of such a risk event in its 2028 RAMP filing.	PG&E Power Generation is developing risk for water conveyance as part of the wider risk assessment efforts for power generation functional area. However, risk for water conveyance will only be included in RAMP if its risk is high enough to meet PG&E's selection criteria for RAMP. The risk for water conveyance should not be included in LGUWR, which is the risk for dam failures.	5	Generation
265	SPD	281 (11)	G. PG&E should not exclude its water conveyance system as a top RAMP risk.	PG&E Power Generation is developing risk for water conveyance as part of the wider risk assessment efforts for power generation functional area. However, risk for water conveyance will only be included in RAMP if its risk is high enough to meet PG&E's selection criteria for RAMP. The risk for water conveyance should not be included in LGUWR, which is the risk for dam failures.	5	Generation
266	SPD	7	SPD recommends that "PG&E consider modeling the safety and financial consequences as well as the likelihood of citizens being injured or drowning after falling into a PG&E water conveyance system and any mitigations to reduce the likelihood or consequence of such a risk in its 2028 RAMP filing."28 Cal Advocates supports SPD's recommendation. Furthermore, Cal Advocates recommends that the Commission direct PG&E to include an analysis of this risk in all future RAMPs and GRCs.	PG&E Power Generation is developing risk for water conveyance as part of the wider risk assessment efforts for power generation functional area. However, risk for water conveyance will only be included in RAMP if its risk is high enough to meet PG&E's selection criteria for RAMP. The risk for water conveyance should not be included in LGUWR, which is the risk for dam failures.	5	Generation
267	SPD	207	3. PG&E provide an explanation of why Foregone Revenue has been modeled at such a higher degree for Iron Canyon in its 2027 GRC filing.	There is an increased in the financial consequences for Iron Canyon between RAMP 2020 and RAMP 2024 due to inclusion of replacement values for damaged dams and powerhouses downstream of Iron Canyon and an assumption of 10-year for foregone revenue to clean-up, rebuild, and begin power generation again. As shown in sheet "Replacement Summary" of "GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences", replacement costs for Jamees Black powerhouse, Pit 5 powerhouse, Pit 6 powerhouse, Pit 7 powerhouse, Pit 6 dam, Pit 7 dam, and Pit 7 afterbay dam were added for RAMP 2024. The calculation for 10-year of foregone revenue can be found in workpaper "GEN-LGUWR-15_CONFIDENTIAL_Foregone Revenue".	5	Generation
268	SPD	207	4. PG&E provide a more detailed explanation for why the McCloud dam's risk score relative to the other dams dropped considerably in the 2024 RAMP filing	The likelihood of failure and consequences for McCloud did not significantly change from RAMP 2020 to 2024. PG&E believes that the reason McCloud drops in ranking is because risks for other dams were increased, either due to increased in likelihood of failure or financial consequences due to cascading failures (cost of dam replacements due to cascading failures were not included in the 2020 RAMP). There are no cascading failures of dams and powerhouses downstream of McCloud.	5	Generation
269	SPD	207	5. An updated list of PFMs be included as part of PG&E's testimony in its GRC.	The list of updated PFMs can be found in the workpaper "GEN-LGUWR-01_Risk Model Input File".	5	Generation
270	SPD	207	6. PG&E should explain in detail in its 2027 GRC filing what exactly changed between the 2020 RAMP and 2024 RAMP filings with its flood, seismic, and normal drivers that resulted in such a significant shift in the modeling.	As described in SPD's comments, the changes between 2027 GRC and 2024 RAMP included increased in event frequencies for each of the three main drivers (flood, seismic, and failure under normal operations) and percentage contribution in the risk. The increased in event frequencies were primarily driven by inclusion of more potential failure modes (PFM) and PFMs that resulted in partial dam breach. PFMs that results in partial dam breach tend to have higher likelihood of failure but results in smaller consequences. The seismic risk driver increased from 8 percent of total risk in 2027 GRC to 37 percent in 2024 RAMP due to two main reasons: 1) the criteria developed in GRC 2027 underestimated the seismic capacity of the dams and this criteria was revised for 2024 RAMP, and 2) the revised seismic hazard analysis in 2021 resulted in increased ground motions and annual exceedance probabilities for some of the dams. PG&E anticipates that the changes in event frequencies as well as driver percentage contribution in risks will continue to change, sometimes quite significantly, until the LGUWR bowtie risk modeling matures.	5	Generation

TABLE 1D-24
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
271	SPD	207	7. PG&E should properly explain why it made the changes to the “probability of failure” variable associated with the flood driver at 13 dams in its 2027 GRC filing.	PG&E developed a preliminary criteria to estimate the conditional probability of failure values for RAMP 2020 and these criteria can be found in rows 87 through 130 of the sheet "Overall baseline" of spreadsheet "PGEN-LGUWR-07B_RAMP PHII". In 2024 RAMP, PG&E refined the criteria to estimate these conditional probability of failure values, which resulted in changes to some of these values. The criteria can be found in sheet "2024 Flood Risk Criteria" of the spreadsheet "GEN-LGUWR-10_CONFIDENTIAL_Flood Risk". As part of PG&E's continuous improvement efforts, PG&E may continue to refine the criteria and "probability of failure" values.	5	Generation
272	SPD	207	8. PG&E should explain why it does not consider the potential for a physical attack to result in partial dam breaches in its 2027 GRC filing.	PG&E conservatively assumes that a successful physical attack would result in a full dam breach. Even so, the risk of physical attack constituted only 0.1 percent of the total risk in 2024 RAMP. If PG&E assumes the physical attack would result in a partial dam breach, PG&E believes this would not significantly change the risk.	5	Generation
273	SPD	207	10. PG&E should provide sufficient citations of workpapers and external resources so that stakeholders evaluating the PG&E 2027 GRC Application can easily locate the source of the information discussed in the narrative of testimony.	This recommendation is tied to the statement on page 180 of the SPD report that states "PG&E needs to better provide links and citations to the databases it uses to inform its risk assessments, such as the International Commission on Large Dams (ICOLD) database. Unfortunately, throughout the evaluation period and as of this writing, the website for this database is inaccessible. More importantly, it should be noted that ICOLD is proprietary and requires an expensive subscription to access it. SPD recommends that PG&E explore other open-source databases, such as Global Dam Watch or the Global Dam Tracker, which are now the industry standard and have been well-discussed in scientific literature." The ICOLD data sets were provided in the sheet "ICOLD Case History" of the spreadsheet "GEN-LGUWR-12_CONFIDENTIAL_Internal Erosion" submitted in RAMP 2024.	5	Generation
274	SPD	207	11. The Outcome 1 and Outcome 2 distinction be removed when PG&E files its 2027 GRC. Additionally, PG&E should describe the eight “sub-outcomes” in greater detail in the 2027 GRC narrative.	PG&E believes it is important to differentiate consequences that results in loss of human life and without, and proposes to continue using outcomes 1 and 2. The 8 sub-outcomes contain intermediate categories to capture consequences that are smaller than a full dam breach. These sub-outcome categories are: 1) Fair Weather (FW) - safety, economic, and asset replacement consequences for full dam breach during a fair weather condition (no storm). Foregone revenue assumed to be 10 years. 2) Flood (full dam breach) - safety, economic, and asset replacement consequences for full dam breach during flood condition. Foregone revenue assumed to be 10 years. 3) 50% FW (partial dam breach) - safety, economic, and asset replacement consequences that are 50 percent of the consequence for fair weather, full dam breach. Foregone revenue assumed to be 3 years. 4) 25% FW (partial dam breach) - safety, economic, and asset replacement consequences that are 25 percent of the consequence for fair weather, full dam breach. Foregone revenue assumed to be 1 year.5) Lower bound (partial dam breach) - life safety is limited to no more than 3 fatalities. This is useful for very high hazard dams to capture failure mode that results in limited fatalities. Economic, and asset replacement consequences are 5 percent of the consequence for fair weather, full dam breach. Foregone revenue assumed to be 1 year. 6) Damaged State (High) - No loss of life. Asset replacement consequences are 10 percent of the consequence for fair weather, full dam breach. Foregone revenue assumed to be 1 year. 7) Damaged State (Medium) - No loss of life. Asset replacement consequences are 5 percent of the consequence for fair weather, full dam breach. Foregone revenue assumed to be 3 months. 8) Damaged State (Low) - No loss of life. Asset replacement consequences are 2 percent of the consequence for fair weather, full dam breach. No foregone revenue. Because each potential failure mode (PFM) is unique and has different consequences based on the scope of the PFM, PG&E assign the consequences to the one of these 8 categories. If needed, PG&E may revise the percentages for the intermediate categories as the risk modeling matures.	5	Generation
275	SPD	207	13. PG&E conduct a data quality assessment between its inundation maps and the data submitted within its workpapers as well as a data quality assessment on the number of structures considered at risk from a LGUWR risk event. SPD expects these assessments to occur before PG&E files its 2027 GRC application, but at least completed before PG&E files its next RAMP application in 2028.	PG&E is starting to update the inundation maps as part of the 10-year programmatic updates. This effort will include quality assessments on the number of structures that could be inundated by flows from a potential dam breach.	5	Generation
276	SPD	207	14. PG&E should explain in its GRC filing why it determined it is necessary to model floods in a manner that exceeds FEMA's expectations and what implications that decision has for the calculation of CoRE in the LGUWR risk event.	FEMA maps flood maps are limited to storms with annual exceedances up to 1/100. PG&E is required by FERC to design the spillways to pass the deterministic flood criteria (IDF), which can be floods up to the large probable maximum flood (PMF). In general, PG&E's IDF for high and significant hazard dams (FERC's classification) are significantly larger and rarer than storms used to develop the FEMA maps.	5	Generation

TABLE 1D-25
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
277	SPD	207	15. Regarding the Foregone Revenue estimate, PG&E should adjust its assumption that the duration for loss of revenue generation for full dam break should be 10 years instead of 1 year. Additionally, in its 2027 GRC filing, PG&E should clearly explain how the Foregone Revenue is a financial consequence that accrues to ratepayers. If any percentage of Foregone Revenue does not accrue to ratepayers, it should be removed from PG&E's 2027 GRC filing.	As described in the 2024 RAMP chapter (Exhibit 5 Energy Supply, Line 16, page 1-24), the 10 years loss of revenue generation for the full dam breach was already included in the 2024 RAMP. The loss of revenue generation does not accrue to the ratepayers.	5	Generation
278	SPD	207	17. PG&E should provide greater clarity in its 2027 GRC filing into how it expects to spend the money associated with a “budget plug” to reduce risk associated with LGUWR. Moreover, PG&E should not use a budget plug approach again in a future RAMP or GRC filing.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
279	SPD	208	19. PG&E should disaggregate the five bundled groups, bundle groups 1,4, 5, 6, and 7, in its 2027 GRC filing.	PG&E has disaggregated the bundled groups submitted in the 2024 RAMP Filing into individual projects.	5	Generation
280	SPD	195	SPD recommends that PG&E clearly explain in its 2027 GRC filing why it requires this \$112 million, how PG&E will spend this money to address internal erosion, and, most importantly, how much risk PG&E expects to mitigate at each dam where these investments will be made.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
281	SPD	195	SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of \$122 million as well as the specific dams where it intends to implement new Spillway Remediations.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
282	SPD	195-196	More than 85 percent of the M003 costs requested in the 2024 RAMP application are listed as a budget plug, amounting to \$72 million. As with its other controls and mitigations, PG&E states that the budget plugs are intended to be enough money to cover the seismic retrofits for three dams. However, in its 2023 GRC filing, even the most expensive annual budget for seismic retrofits at two dams (Upper Peak Dam and Belden Forebay) is \$6 million each. Therefore (at most) PG&E should only require \$18 million per year to cover the costs for seismic retrofits at three dams. According to GEN-LGUWR-08_Inputs_to_CBR-Input, PG&E's request for \$30 million each in 2029 and 2030 is illogical based on PG&E's own workpaper. SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of \$72 million, describe the specific dams where it intends to implement new seismic retrofits, and clearly explain how much risk PG&E expects to mitigate at each dam where these investments will be made.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
283	SPD	196	SPD recommends that PG&E should clearly explain in its 2027 GRC filing why it requires this budget of \$78 million, describe the specific dams where it intends to implement new LLO refurbishments and clearly explain how much risk PG&E expects to mitigate at each dam where these investments will be made.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
284	SPD	197	SPD recommends that PG&E should clearly explain in its GRC filing why it requires this budget of \$20 million as well as the specific dams where it intends to implement new physical security mitigations.	PG&E removed its use of budget plugs for capital projects in the 2027 GRC. All capital projects are reported as individual projects, along with the cost-benefit ratios (CBR) to perform these projects.	5	Generation
285	SPD	208	18. PG&E should clarify how the deteriorated LLO multiplier impacts risk model variables in its 2027 GRC filing.	In this preliminary model, a low-level outlet (LLO) in deteriorated condition is assumed to increase the likelihood of internal erosion for embankment dams by a factor of ten because the LLO is unavailable when needed to drawdown the reservoir in the event that an internal erosion failure mode is developing. For concrete dams, a LLO in deteriorated condition is assumed to increase the seismic likelihood of failure by a factor of 2. PG&E notes that this is a preliminary model and will continue to refine this model.	5	Generation
286	SPD	208	23. PG&E provide two portfolios with a mixture of alternatives across all 60 of its dams and across all five of its mitigation programs. As an alternative portfolio, PG&E could also present dam removal and its associated costs. PG&E does not need to exhaust every scenario possible, but it needs to provide two professionally designed alternative portfolios with sufficient details for a decisionmaker's consideration in its 2027 GRC filing.	PG&E wants to clarify that the two alternatives provided in RAMP (seepage mitigation program for Relief dam) is an example of alternatives analysis performed specifically for Relief dam, and it is not a portfolio alternative. Because each dam is unique in terms of design, method of construction, and materials used, the scope and type of mitigation will differ between dams. The alternative for Relief was provided as an example on how the evaluation of alternatives were performed when selecting between different mitigation measures. PG&E will consider the option of adding a dam removal alternative in the alternative analysis for a selected project.	5	Generation
287	SPD	208	24. Integrating public engagement programs into the LGUWR risk model when PG&E submits its 2028 RAMP.	PG&E currently provides hydro safety brochure to residents located downstream of high hazard dams on an annual basis. It is, however, difficult to quantify what is the effectiveness of specific public engagement activities in a risk model. In general, risk practitioners in the dam industry believes that life safety consequences calculated by the RCEM and LifeSIM models have an-order-of-magnitude uncertainties due to the inherent complexity of trying to model randomness in population-at-risk, decision making, and actual capability to warn and evacuate people. PG&E believes the impact of the public engagement program would likely be captured within the order-of-magnitude uncertainty bounds.	5	Generation
288	SPD	198	SPD encourages PG&E to spend more time and effort on one of the components of the AMS: Hydro Public Safety Program. Regarding the 2024 RAMP filing, there is limited engagement with the general public in PG&E's use of Controls and Mitigations to reduce risk. Public engagement programs should reduce the consequence of a risk event, and PG&E should estimate that risk reduction will be as high as possible. The scientific literature on the importance of public outreach in a dam breach is extensive. SPD encourages PG&E to take these approaches seriously and SPD expects public engagement programs to be integrated within the LGUWR risk model when PG&E submits its 2028 RAMP.	PG&E currently provides hydro safety brochure to residents located downstream of high hazard dams on an annual basis. It is, however, difficult to quantify what is the effectiveness of specific public engagement activities in a risk model. In general, risk practitioners in the dam industry believes that life safety consequences calculated by the RCEM and LifeSIM models have an-order-of-magnitude uncertainties due to the inherent complexity of trying to model randomness in population-at-risk, decision making, and actual capability to warn and evacuate people. PG&E believes the impact of the public engagement program would likely be captured within the order-of-magnitude uncertainty bounds.	5	Generation

TABLE 1D-26
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
289	SPD	171	In the recent RDF Proceeding D.24-05-064, the Commission required the utilities by December 6, 2024 to submit a report on improvements to data needed for properly analyzing its risks and a timeline for making those improvements. SPD expects PG&E to include a deeper description of its efforts to improve PFMs in collaboration with FERC in that report.	PG&E filed its Data Assessment Report on December 6, 2024. The report includes high level action plans to address data quality to further mature our risk bowtie model and improve on the current limitations of our model.	5	Generation
290	SPD	178	A footnote in the RAMP narrative referencing the 2024 Flood Risk spreadsheet in the GEN-LGUWR-10 workpaper would have been helpful. In the future, PG&E should provide sufficient citations to easily locate the source of the information discussed in the narrative. Likewise, a significant number of new flood-related PFMs were developed for the 2024 RAMP, but PG&E provided minimal details in either the narrative or workpapers.	The individual workpapers, along with its contents, are referenced in the master workpaper titled "GEN-LGUWR_00_Risk Workpaper Index" and "readme" tab of "GEN-LGUWR-07_Inputs_to_Bowtie". PG&E will ensure that the flow of these workpapers are easier to understand, either by better description in the RAMP narrative or the "readme" section of the workpapers.	5	Generation
291	SPD	183	In this RAMP filing, PG&E has not attempted to model the increased likelihood of a LGUWR risk event due to a cyberattack. In future RAMP and GRC filings, it would be important for PG&E to distinguish how distinct the cross-cutting impacts from a cyber attack versus the Information Technology Asset Failure (ITAF) would be. On the surface, it is not clear that the impacts of these two cross-cutting factors would be that different when it comes to the LGUWR. Ultimately, both would increase the likelihood, and possibly the consequence, of a catastrophic LGUWR event, but it is not clear that a cyber attack would result in a higher increase to the likelihood and/or consequence than ITAF, and vice versa. If PG&E does see a distinction, it should describe that distinction in detail for decision-makers in a future Application to the Commission.	As part PG&E's risk assessment efforts, PG&E will review risk models for ITAF and CyberAttack and, if needed, make revisions to these models.	5	Generation
292	SPD	183	PG&E should also clarify why EP&R is not considered a control since it does appear to maintain a reduced level of consequence in the event of a dam breach.	EP&R is currently considered foundational as part of the Dam Safety Program. PG&E acknowledges that EP&R may be viewed as a control. As part of PG&E's risk assessment efforts, PG&E will review if it is appropriate to consider EP&R as a control and, if needed, make revisions to this model.	5	Generation
293	SPD	198	Overall, it is not clear why PG&E no longer describes DSP as a Control as was done in the 2020 RAMP and 2023 GRC. PG&E informed SPD through a data request response that, as presented in the 2024 RAMP, the components of DSP do not reduce risk on their own, therefore it is not possible to quantitatively calculate risk reduction benefits for this program. However, PG&E also clarified that "the risk reduction benefits for EAP can be calculated by taking the difference in consequences between a scenario with an EAP program (current life safety consequence values) and a scenario with no EAP program (assuming limited to no warning for downstream population)."Based on this clarification, staff recommend that PG&E return the EAP to a Control in its 2027 GRC filing and provide a full cost-benefit analysis of this Control	EP&R is currently considered foundational as part of the Dam Safety Program. PG&E acknowledges that EP&R may be viewed as a control. PG&E will evaluate if EP&R should be considered a control and, if needed, make revisions to the model.	5	Generation
294	SPD	185	Due to its unsophisticated approach and lack of transparency on many of the assumptions associated with ITAF, SPD strongly encourages PG&E to keep discussion of ITAF limited to the LGUWR risk in its 2027 GRC filing. If PG&E can develop a more robust approach to analyzing this as a true cross-cutting factor that influences multiple risks, SPD recommends PG&E to address that change in a future RAMP filing.	As part PG&E's risk assessment efforts, PG&E will review risk models for ITAF and, if needed, make revisions to these models.	5	Generation
295	SPD	187	PG&E claimed that for dams with larger spillway control structures, it also developed inundation maps for failure of these control structures during a FW scenario. However, it is not clear from the workpapers to which dams PG&E is referring. SPD recommends that PG&E should clearly explain to which dams it developed inundation maps for failure of spillway control structures when PG&E submits this information in the 2027 GRC.	Inundation maps were developed for 20 spillway control structures and they are Belden Forebay, Bucks Storage, Crane Valley, Cresta, Drum Forebay, Lake Fordyce, Lower Bear, Lower Peak, McCloud, Pit 1 Forebay, Pit 3, Pit 4, Pit 6, Pit 7, Rock Creek (Feather), Salt Springs, Scott, Spaulding No.3, Tabeaud, and Wishon.	5	Generation
296	SPD	188	SPD found that there are discrepancies between the time that the front wave arrives at a cross section in the inundation map compared with the data submitted in the GEN-LGUWR14_CONFIDENTIAL_LifeLoss_Economic_Consequences.xlsx workpaper. For instance, according to the inundation map the front wave will arrive at cross section #15 within 52 minutes, but in the 2024 RAMP workpaper the wave will arrive at the same cross-section within 59 minutes. SPD recommends that PG&E conduct a data quality assessment between its inundation maps and the data submitted within its workpapers.	PG&E will perform data quality assessments to ensure data submitted in the life consequence workpapers align with the inundation maps. The time-to-arrival time for Rock Creek (Drum), which were developed for 2020 RAMP, were corrected for the flood dam breach and the corrections did not result in significantly changes to the estimates for life safety.	5	Generation
297	SPD	188	PG&E did not properly cite the NOAA flood data, which led to the calculation of the injury ratio of 1.87. In a data request, PG&E provided a copy of the data used to calculate this ratio, which is based on 36 flooding events in California that occurred from 1996-2016.359 SPD recommends that PG&E should provide a proper citation link to NOAA when first referencing this data in its 2027 GRC filing and clearly explain how it analyzed the NOAA data in the narrative of the filing.	The NOAA flood data and computation of the injury ratio, which was provided to CPUC in a data request dated reference and data were provided to CPUC on July 22, 2024, are now included in sheet "Injuries" of the workpaper "GEN-LGUWR-14_CONFIDENTIAL_LifeLoss_Economic_Consequences_CPUC.xlsx".	5	Generation
298	SPD	189	PG&E should also provide references to peer-reviewed scientific literature demonstrating the use of these models for measuring LGUWR fatalities.	PG&E is following industry state-of-practice as developed by United States Army Corps of Engineers (USACE) and United States Bureau of Reclamation (USBR), and recommended by the Federal Energy Regulatory Commission (FERC). Recommendation for these two methods can be found in FERC's Engineering Guidelines for the Evaluation of Hydropower Projects guidelines (Section 18-9.2.2 of Chapter 18-level 2 risk analysis). Link to FERC's website is: https://www.ferc.gov/industries-data/hydropower/dam-safety-and-inspections/eng-guidelines	5	Generation
299	SPD	189	Moreover, seeing that PG&E is in the process of updating the remaining 47 dams using RCEM or LifeSIM, SPD recommends that the details of this process and a timeline for completion be included in the data update report.	As described in the December 6, 2024 data quality assessment report, the timeline to complete life safety analysis for the remaining 47 dams is approximately 6 years. This timeline could change depending on availability of funding and resources to perform these updates.	5	Generation

TABLE 1D-27
FEEDBACK TO PG&E'S 2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
(CONTINUED)

Line No.	Party	Page No.	SPD/Party Feedback	PG&E's Response	RAMP Exhibit	Functional Area
300	SPD	189	SPD recommends that PG&E develop a more accurate approach to modeling the financial impact of an LGUWR in terms of damage to infrastructure along with a detailed description of what "infrastructure" includes and how the costs of each type of infrastructure is estimated. Without these details, the financial attribute may be severely underestimated or overestimated depending on where the LGUWR risk event occurs.	PG&E will evaluate the feasibility of incorporating damage to infrastructure in the financial consequence model. PG&E may start with using more empirical or simplified approaches to estimate damage to infrastructure such as bridges, roads, and other critical lifelines.	5	Generation
301	SPD	189	PG&E should provide a process and a timeline for creating a new method and approach for data collection to estimate the financial impact of LGUWR on infrastructure and have it included in the data update report. ³⁶⁴	PG&E will evaluate the feasibility of incorporating damage to infrastructure in the financial consequence model. PG&E may start with using more empirical or simplified approaches to estimate damage to infrastructure such as bridges, roads, and other critical lifelines.	5	Generation
302	SPD	198	SPD recommends that PG&E consider removing the paint recoat projects from its CapEx numbers and instead designate them as OpEx.	These recoating projects can be capitalized and were therefore included in the 2027 GRC as CapEx numbers.	5	Generation
303	SPD	199 (PDF 38)	Regarding the ESJ Pilot results, it is not clear why PG&E did not complete the calculation to include a CBR calculation for all mitigation programs across the DVC and non-DVCs in GEN-LGUWR16_CONFIDENTIAL_Environmental_&_Social_Justice workpaper.	The ESJ Pilot was required only for PG&E's 2024 RAMP. LGUWR will perform additional risk analysis if there are new requirements per the Risk-Based Decision Making Framework and S-MAP SA.	5	Generation
304	SPD	199 PDF32	Additionally, it is not clear why PG&E presented the safety consequences in natural units rather than the monetized attribute value as is required by D.22-12-027.	The ESJ Pilot was required only for PG&E's 2024 RAMP. LGUWR will perform additional risk analysis if there are new requirements per the Risk-Based Decision Making Framework and S-MAP SA.	5	Generation
305	SPD	204	PG&E has mentioned this limitation of its model, SPD recommends that PG&E should file an update to these modeling limitations in PG&E's report of data collection efforts by December 6, 2024 as required by D.24-05-064.	PG&E filed its Data Assessment Report on December 6, 2024. The report includes high level action plans to address data quality to further mature our risk bowtie models and improve on the current limitations of our model.	5	Generation
306	TURN	397 (21)	TURN has identified two issues with PG&E's climate change calculation. 1. The use of climate change models to derive increases in RFW ignitions is not only extremely complex, PG&E's and ICF's modeling assumptions are highly opaque and virtually impossible, at least in the context of a single RAMP proceeding, to replicate, verify, or determine whether the inputs are reasonable. 2. The calculation appears designed to increase the impact of climate change exactly through the rate case cycle (2027-2030), after which climate change impacts would remain constant or decrease. At minimum, this is counterintuitive. This finding further highlights the inappropriateness of incorporating this significant driver of wildfire risk as presented, without further Commission understanding and review.	The Fire Weather Index (FWI), also known as the Fosberg Fire Weather Index, is a widely used metric for an indication of fire potential conditions. The use of the FWI metric as a replacement for Red Flag Warning Days in the Enterprise Risk model was proposed by ICF, the primary consultant of the Climate Resilience Team for both the company's Climate Adaptation Vulnerability Assessment and the Climate Change Cross-Cutting Factor. ICF conducted the FWI calculations for PG&E that were used in the 2024 RAMP report. This metrics is influenced by variety of factors, from temperature, relative humidity, wind speed, and precipitation among others. This analysis was conducted using the publicly available data from the State's Fifth Climate Assessment (CMIP6) and followed best practices of analyzing long-term climate projections. Given the general acceptance that the FWI metric is valuable and appropriate wildfire metric, Eagle Rock Analytics, the manager of the State's Climate Data from the 5th California Climate Assessment report, has included the FWI metric as a derived index in the Analytic Engines (Source: https://analytics.cal-adapt.org/data/about/).	2	Climate

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
BUSINESS PLANNING AND EXECUTION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
BUSINESS PLANNING AND EXECUTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
BUSINESS PLANNING AND EXECUTION

A. Introduction

Our Objective – We have taken action in our business planning to implement a decision-making framework that balances safety, reliability, and risk-reduction objectives with customer affordability. This framework includes:

- 1) Implementing our Simple Affordable Model to plan and complete the right work at costs that allow for stabilizing overall customer bills between 2 to 4 percent, while advancing the Business Priorities set forth in our True North Strategy; and
- 2) Utilizing risk-based decision-making through the Risk Assessment and Mitigation Phase (RAMP) and cost-benefit analysis as an input that informs the scope and mix of our proposed activities.

This chapter discusses Pacific Gas and Electric Company's (PG&E or the Company) annual enterprise-wide planning and budgeting process (referred to as Business Planning Deployment) that is used to determine the type, scope, timing, and cost of our work. We complete our Business Planning Deployment process annually so that we are able to modify our work plans as necessary, based on the evolving needs of our customers and business. Our process is designed to deliver for people, planet, and California's prosperity. We used this process to prepare the multi-year investment plan that is reflected in this 2027 General Rate Case (GRC) to stabilize bills and improve service. This chapter also addresses the use and reprioritization of funds approved in the 2023 GRC, and discusses the decisions we made in interest of affordability.

B. Our True North Strategy and Simple Affordable Model

Our True North Strategy organizes our work into three Business Priorities—Customers, Energy System, and Foundational Capabilities—discussed below:

- Customers: We will deliver affordable energy and excellent customer experiences every day. This Business Priority translates to planning for (1) Customer Affordability, (2) Customer Satisfaction, inclusive of reliability, and (3) Public Safety, inclusive of Asset Failure risks that may lead to public safety incidents, such as Wildfire Risk Reduction.

- 1 • Energy System: We will construct an electric system using an architecture
2 that is resilient to climate change, decarbonized, and optimized to local and
3 system needs. We will continue to invest in a safe and reliable gas system,
4 ready to transition to future needs. This Business Priority translates to
5 (1) public safety and reliability improvement, (2) planning for the state's net
6 zero GHG emissions goals, (3) enabling beneficial load growth, and
7 (4) energy system risk reduction.
- 8 • Foundational Capabilities: To deliver on our Customer and Energy System
9 Business Priorities, we will continue to improve the processes and platforms
10 we use throughout the Company. The Foundational Capabilities Business
11 Priority includes advancing our progress in areas such as: (1) Safety
12 Management System; (2) Lean Operating Model; and (3) Information
13 Technology platforms and work processes. These improvements enable us
14 to do our work more safely and at a lower cost for our customers.

15 The Company reviews these Business Priorities on an annual basis, and our
16 functional areas refine their plans to these priorities. These priorities are
17 reflected throughout this filing.

18 Our Simple Affordable Model is working. It is our approach to achieving
19 both our Business Priorities and Customer Affordability, making the right
20 investments, at the right time, at the right cost. As described in Chapter 1, this
21 model: (1) delivers consistent operation and maintenance (O&M) expense
22 savings, (2) promotes beneficial load growth, and (3) pursues efficient financing
23 opportunities. These three aspects allow for increased long-term capital
24 investments over time that are critical to delivering our Customer and Energy
25 System priorities such as timely customer connections and energization capacity
26 work that also put downward pressure on rates. The model limits customer bill
27 growth consistent with anticipated inflation, while allowing for these long-term
28 investments.

29 How do we know this works? Over the past three years, we have reduced
30 costs an estimated \$2.5 billion.

31 These cost-savings were achieved through the adoption of our Lean
32 Operating Model, which identified efficiencies, improved processes, and led to
33 new technologies, such as the use of drones to inspect our equipment, enabling
34 us to reinvest much of that back into our Energy System to drive risk reduction

and improve service. In addition to efficiency in operations, we have sought innovative ways to reduce the energy burden for customers in partnership with this Commission and stakeholders. We collaborated with customer advocacy groups on alternatives to purchasing wildfire and non-wildfire liability insurance from the commercial markets, saving customers up to \$800 million between 2022 and 2024, ramping to an estimated \$700 million in annual savings on-going.

Carried forward, these initiatives will contribute to future bill stabilization. And we are doing more, reflected in our 2027 GRC Plan and discussed further below.

We are also expecting to see savings from lower borrowing costs. For example, in early 2025, we closed a \$15 billion loan guarantee through the U.S. Department of Energy's (DOE) Loan Programs Office. The loan guarantee will provide lower-cost financing for projects to: (1) enhance California's grid, (2) help ensure reliability, and (3) boost the capabilities of the hydro power generation fleet. This lower-cost financing could save customers up to \$1 billion over the life of the financing.

C. How We Plan Our Work

1. Business Plan Deployment

The Business Plan Deployment (BPD) process is a Lean planning process that aligns all components of strategy with work execution to ensure that we are developing executable and aligned work plans across the business. As discussed, the BPD process considers the Business Priorities described above when developing functional area specific work and financial plans that will deliver on those priorities. It is an annual process that reassesses and adjusts our plans to ensure they adapt to emerging needs, while achieving our Business Priorities.

PG&E used this process to develop a multi-year work plan covering 2025 through 2030, following the four steps described below:

- Step 1 – Confirmation of our Business Priorities: During this step, we perform an annual review of our True North Strategy to confirm the business priorities described above continue to reflect the needs of our customers and communities. As an example, during the 2024 BPD

process, which developed the 2025-2030 plan for the GRC, this step not only confirmed the existing priorities, but it also escalated increasing climate risk to our system through the weather events in 2022 and 2023, leading a strategic need to further prioritize resiliency.

- Step 2 – Establish Planning Guidelines: This step includes setting financial targets, which provide planning guidelines that ensure we are stabilizing bills and planning investments within the framework of our Simple Affordable Model. For the 2027 GRC, we assigned functional areas across PG&E initial expense budget targets based on their 2024 O&M expense actual spending, and capital targets based on the 2023 GRC authorized spending through 2026, which were then escalated to derive initial capital forecasts for 2027-2030.
- Step 3 – Prioritization of Initial Work Plans: Our BPD process uses several tools to prioritize the right work at the right time. One tool is the Risk Assessment and Mitigation Phase (RAMP) filing, which is used to analyze our top safety risks and our controls and mitigations to better optimize risk reduction. Another tool is our Risk Based Portfolio Prioritization Framework (RBPPF), which is an enterprise-wide prioritization framework consistent with the California Public Utilities Commission's (CPUC or Commission) Risk-Based Decision-Making Framework. A third tool is our Regional Considerations, adding prioritized weighting to work escalated by our communities. Finally, we use Integrated Grid Planning, a multi-year investment optimization tool. These tools are further described below in Subsection C.3.
- Step 4 – Strategic Affordability Decisions: While we work through the prioritization steps, we are ensuring that the work cost assumptions reflect both actual and anticipated operational efficiencies to optimize the amount of work that we can plan for within an affordable envelope for customers. First and foremost, our plan must deliver on our obligation to provide safe, reliable, resilient, and clean gas and electric service to customers, without compromise, and as owners of affordability we ensure that our operational cost assumptions reflect market conditions and our commitment to reducing costs. Additionally,

1 we evaluate non-operational cost savings opportunities, which are
2 described below.

3 As a result of this BPD process, in the 2027 GRC we are proposing
4 new, or accelerated, work for key areas including but not limited to:

- 5 • Electric Distribution new business connections and work at the request
6 of others to align to updated economic models and align with customer
7 energization demands;
- 8 • Completion of Electric Distribution's corrective maintenance tags in High
9 Fire Threat Districts (HFTD) and increased risk reduction in non-HFTD
10 locations;
- 11 • Hydro programs, including dam and water conveyance safety
12 mitigations;
- 13 • Gas Transmission programs, including additional work to comply with
14 new federal regulations commonly referred to as "Mega Rule"
15 requirements which emphasize Integrity Management, Materials
16 Traceability, Maximum Allowable Operating Pressure Reconfirmation,
17 and Pipeline Material Verification; and
- 18 • Fleet vehicle lifecycle replacements and adoption of California Air
19 Resources Board (CARB) Advanced Clean Truck (ACT) regulation.

20 Similarly, as a result of the BPD process, in the 2027 GRC we are
21 proposing reduced programmatic spend in vegetation management, due to
22 lower tree volumes from past tree removals, undergrounding work and
23 enhanced risk-based prioritization.

24 Due to the time necessary to review the results of PG&E's Results of
25 Operations (RO) model and prepare the necessary workpapers and
26 documentation, PG&E had to freeze the inputs to the RO Model as of
27 March 14, 2025. The reasonableness of PG&E's forecast should thus be
28 judged based on the information available to the Company as of this date.
29 PG&E continued to make slight modifications to its forecast through
30 approximately April 14, 2025. Any differences between the RO Model and
31 the forecasts contained in PG&E's testimony and workpapers will be
32 corrected in future runs of the RO Model.

2. Affordability

Customer Affordability is at the heart of how we prioritize our work. We use our Simple Affordable Model as a guide for stabilizing bills and our Lean Operating Model and operational decision-making tools to drive affordability into our day-to-day work. During the BPD process,¹ we challenged ourselves regarding how we could enhance customer affordability. This included purposeful decisions to reduce our forecast by incorporating savings identified through our Lean Operating Model, above and beyond the reoccurring savings achieved to date.

We discuss our cost-savings measures in further detail below.

a. Lean Operating Model and Operational Decision-Making

Our Lean Operating Model was described in detail in the 2023 GRC, focusing on problem solving, waste elimination, standardization of work, and visual management to improve operations. Where we have line-of-sight to improvements, we have included them in our 2027 GRC plan. For instance, in 2024, we developed and implemented 250 cost-saving initiatives using Lean problem solving and waste elimination tools. These initiatives saved \$1.1 billion in operating and capital costs to reduce materials, labor and other costs and more efficiently plan, execute and automate our work to deliver for our customers.

For example, by integrating technology into our Comprehensive Pole Inspection Program, leveraging drones and improving intrusive pole testing, we have been able to more accurately assess the health of our assets and better optimize the prioritization, scheduling, bundling, and timing of asset repairs and replacements. This work collectively delivered approximately \$150 million in efficiencies in 2024. These savings are carried forward into the 2027 GRC forecasts.

Another example includes streamlining our new service application and work-delivery process, which reduced customer cancellations. This improvement reduced new business unit costs, resulting in \$100 million of annual efficiencies incorporated into the 2027 GRC within Electric Operations.

¹ See Section C.1

Lean tools are not only applicable to our operations teams; we have incorporated saving elsewhere. In 2024, we had 15 back-office cost-saving initiatives, including most notably improvements to our insurance program, procurement collateral commitments, and consulting guidance. We also optimized our tax credits. These efforts delivered an additional \$350 million in reduced costs that are carried forward into our 2027-2030 plans.

b. Strategic Affordability Decisions

To further demonstrate our commitment to customer affordability in the 2027 GRC, we made additional, specific reductions to our initial forecasts. Through these adjustments, we have reduced our GRC request by approximately \$750 million in the test year, ramping up to an approximately \$1.3 billion decrease by 2030. These decisions maintain our ability to deliver safe and reliable service, while further stabilizing customer bills.

In the 2027 GRC, we made specific adjustments to the following costs:

- Depreciation Expense Request: We reduced our request by \$546 million annually, essentially carrying forward from 2027-2030 the depreciation expense methodology adopted in the 2023 GRC, with certain exceptions.
- Hydro Decommissioning Collection: We have reduced our request by \$75 million annually by extending the timeframe to collect funds for the Potter Valley Project Decommissioning over an 8 year time period rather than 4 years.
- Tax: We reduced our forecast by \$50 million annually based on a service cost optimization change being pursued.
- Active Medical: We reduced our request by \$50 million annually. To account for uncertainties, we have requested a two-way balancing account consistent with the ratemaking treatment provided to Southern California Edison Company.

In the 2027 GRC, we also have closely examined programs that have been experiencing significant variability in demand to ensure our request does not simply assume the high end of our forecast. In certain

1 cases, we have also lowered our forecast. An example of this is Electric
2 New Business. Our internal forecast for Electric New Business
3 suggests a 15 percent growth rate year over year for this GRC period,
4 based on the demand we are seeing. This would create a significant
5 increased forecast, and we recognize demand could ultimately be lower
6 or higher than 15 percent. As such, we have reduced our forecast to be
7 in-line with our Post Test Year Ratemaking (PTYR) chapter and are
8 seeking a two-way balancing account in the event that customer
9 demand is higher.

10 Further, we have lowered our PTYR proposal by approximately
11 \$200 million a year, to reflect continued efficiency identification above
12 what is already embedded in forecasts. This amount will not result in a
13 reduction in work completed, but a reduction in the cost of the work
14 being proposed. As stated, our Lean Operating Model is working and
15 our 2027 GRC proposal reflects the efficiencies it has produced to date
16 and where we have line of sight to achieving additional savings. These
17 examples show where we believe our progress will continue.

18 **c. Accessing Non-GRC Funding Sources**

19 Similar to efficient financing, our affordability strategy expands to
20 optimizing our funding sources. Our GRC forecast assumes that a
21 portion of Diablo Canyon Power Plant (DCPP) Volumetric Performance
22 Fees (VPF) can be used to fund critical work, consistent with the
23 public-purpose priorities listed in Public Utilities Code
24 Section 712.8(s)(1). As shown in Tables 2-1 and 2-2 below, our GRC
25 expense forecasts for Electric Distribution and Energy Supply for
26 2027-2030 reflect a reduction of \$205 million in expense eligible for
27 recovery through VPF revenues rather than recovered through GRC
28 rates. As required by Decision (D.) 23-12-036, PG&E will submit a
29 separate application setting forth the planned use of VPF revenues prior
30 to using them for these activities.

31 During the BPD process, we evaluated the programs in our
32 work-plan portfolio that deliver the key public-purpose benefits
33 enumerated in Section 712.8(s)(1) and are otherwise eligible for VPF
34 funding. This included various activities in Electric Distribution and

Energy Supply. While we reduced our 2027 GRC forecast, PG&E may revise the total VPF revenues ultimately used depending on circumstances at the time of their use.

Table 2-1 shows the 2027 Electric Distribution and Energy Supply expense forecasts with, and without, the costs assumed to be recovered through VPF revenues.

TABLE 2-1
GRC FORECAST WITHOUT VPF ADJUSTMENTS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	VPF Program	2027 Forecast	2027 VPF Reduced Forecast
1	Energy Supply (Exhibit (PG&E-5))	\$398,630	\$374,630
2	Electric Distribution (Exhibit (PG&E-4))	\$2,569,950	\$2,388,003

Note: The total Electric Distribution expense forecast is \$2,139,674: This table shows only the amount the Electric Distribution forecast was reduced from 2024 recorded levels by application of VPF revenues—there are other elements of the Electric Distribution expense forecast that contributed to the overall reduction from 2024 recorded.

1 Table 2-2 shows only the VPF forecast assumptions for
 2 2027-2030.²

TABLE 2-2
VPF PROGRAM FORECAST
(MILLIONS OF NOMINAL DOLLARS)

Line No.	VPF Program	Forecast			
		2027	2028	2029	2030
1	<u>Energy Supply (Exhibit PG&E-5)</u>				
2	Power Generation Asset Management, Inspections and Maintenance	\$22.10	\$22.10	\$22.10	\$22.10
3	Power Generation Communications	0.20	0.20	0.20	0.20
4	Power Generation Workforce Safety Initiatives	0.40	0.40	0.40	0.40
5	Zero-Carbon Energy Activities, Renewable Energy Activities	1.30	1.30	1.30	1.30
6	<u>Electric Distribution (Exhibit PG&E-4)</u>				
7	Electrification: BE Weatherization EIE portion in GRC	0.63	0.65	0.67	0.70
8	New Business	11.96	11.96	11.96	11.96
9	EVA – Service Inquiry	3.79	3.79	3.79	3.79
10	EVB – OK to Serve	8.17	8.17	8.17	8.17
11	Technology and System of Record	13.50	13.50	13.50	–
12	Overhead Inspections (BFB) Overhead Inspections	31.93	31.29	30.66	30.05
13	Wildfire Situational Awareness and Forecasting	36.27	36.81	37.64	–
14	Customer Battery Programs	30.00	29.14	29.16	28.66
15	Inspection, Prev and Corr Maintenance	57.66	58.03	57.67	–
16	Total	\$205.9	\$205.4	\$205.3	\$95.4

3. Prioritization During the Business Plan Deployment Process

4 To ensure we are investing in the right work at the right time, we used
 5 the following prioritization tools to develop the 2027 GRC workplan.

a. RAMP

7 We filed our 2024 RAMP Report on May 15, 2024 (A.24-05-008).

8 The 2024 RAMP Report identified mitigations and controls associated
 9 with each of our top safety risks and included estimated costs for these

² For the Electric Distribution exhibit, the VPFs are forecast to cover the entire programs identified in Table 2-2, except for the Customer Battery Programs. For the Customer Battery Programs, which are given special attrition treatment, VPF funds are forecast, in 2027, to cover a portion of the programs' expense forecasts. In the attrition years, however, VPF funds are forecast to cover the entire expense forecast for all Customer Battery Programs.

measures. Funding these risk mitigations was a top consideration in our BPD process for developing the 2027 GRC forecast.³

In the RAMP filing, we presented baseline risk levels for RAMP risks, and CBRs developed in accordance with the Risk-Based Decision-Making Framework (RDF). The baseline risk levels set a neutral baseline to compare the impacts of risk mitigation activities. The CBRs indicate effectiveness and affordability of risk mitigating activities.

Throughout the BPD process, we have exercised our best judgment and professional expertise as a prudent operator to select and present in this GRC a portfolio of risk mitigation programs that meets our legislative duty to place safety as the top priority. Of course, we are also mindful that we must meet this mandate in a manner that balances safety, reliability, and risk-reduction objectives with customer affordability, which is why this GRC represents a lower forecasted percentage increase than in recent GRCs.

Accordingly, as a prudent operator, PG&E uses the BPD process to consider many factors, including CBRs, to select the appropriate work portfolio that provides safe, reliable, and clean energy at affordable rates while meeting the growing demand of California and our customers.

b. Risk-Based Portfolio Prioritization Framework (RBPPF)

The risk reduction programs included in our 2027 GRC forecast were all vetted and selected under the Risk-Based Portfolio Prioritization Framework (RBPPF). We rely on our RBPPF to establish a consistent approach for categorizing and scoring proposed investments consistent with the Commission's Risk-Based Decision-Making Framework.

The RBPPF is a planning standard used by all functional areas. It uses a 1-5 scoring criteria based on level of urgency and impact across five categories: Risk Reduction, Compliance, Capacity, Reliability, and Other Customer Objectives. A top score of "5" in any of these categories signals that the work is of highest urgency and will have the highest impact on that specific category. In contrast, a score of "1" represents the lowest urgency and impact.

³ See Exhibit (PG&E-2), Ch. 1 for additional information on the RAMP process.

1 As part of the annual BPD process, our functional areas assess
2 annual work plans based on the level of urgency and impact that work
3 has on each of these five categories. We then use the scores (5 to 1) to
4 prioritize our work within a functional area, as well as across functions to
5 determine our Company-wide plans.

6 As an example of how RBPPF was used for the BPD planning
7 process, the functional area planning teams initially identified \$1.8 billion
8 of desired investments to further reduce risk and improve service that
9 was above our financial planning guardrails. Using the RBPPF tool, we
10 determined that \$500 million of the total was Level 4, signaling flexibility
11 in the urgency of the work. The \$1.3 billion remaining was scored at
12 Level 5, indicating highest urgency and impact for 2025. Of that
13 \$1.3 billion, an additional \$500 million was determined to be flexible in
14 timing, which allowed us to prioritize and plan for \$800 million of
15 high-urgency compliance work. As this example shows, RBPPF is a
16 valuable tool to ensure we make the right investments at the right time.

17 **c. Regional Considerations**

18 Our Regional Service Model gives us insights into the specific needs
19 and challenges of our hometowns beyond what might otherwise show
20 up in our energy system data and models. For instance, our regional
21 teams interact with customers and community leaders every day, and
22 their input is critical to ensure we are not missing important work in our
23 plan.

24 As an example, during our planning process for the 2027 GRC,
25 circuit 2119 in San Ramon was identified as having high impact
26 reliability challenges for the local community. This project was not
27 prioritized with the tools we used to identify high urgency projects,
28 however through regional engagement and insight, we flagged the
29 project as high urgency and it is now reflected in our plan. Similar
30 projects were flagged through our regional engagement, including the
31 reconfiguration of circuit SRA1106 to support a housing development in
32 Santa Rosa, Yolo County reliability improvements on circuit Grand
33 Island 2224, and economic development projects in Placer County.

These are but a few examples of how our Regional Service Model is improving how we plan and prioritize our work for customers.

d. Integrated Grid Planning

Our electric system faces complex, multi-dimensional issues such as wildfire risk, climate change, asset health, overloading and other related safety, reliability, and resilience issues. Given the complexity of these issues, planning and scheduling work requires tools beyond those we describe above.

Our Integrated Grid Planning tool helps us derive innovative and efficient electric work plans, improving customer affordability while getting more safety and risk reducing work on the system. Integrated Grid Planning is a data-driven approach that allows us to locally optimize our work plans—across multiple-years as well as the current year—and better use resources to deliver accelerated operational outcomes at lower costs. We can do this through: (1) bundling circuit-specific work, (2) advancing plans for materials and contracts procurement, (3) removing low-impact investments, and (4) optimizing the sequence of work across a multi-year timeframe. The efficiencies we can achieve through Integrated Grid Planning are central to our True North Strategy and enable us to achieve operational metric performance within our 2027 GRC forecast.⁴ This planning approach is resulting in unit cost reductions across multiple programs, including 24 percent unit cost efficiencies on bundling pole replacements, and 14 percent unit cost efficiencies for non-pole bundles.

D. Reprioritization of Work

1. PG&E Prioritizes Spending to Balance Existing and Emerging Needs and to Provide Safe and Reliable Service

The Commission has stated:

*A reprioritization process is expected and is necessary for the Utility to manage its operations in a safe and reliable manner.*⁵

⁴ This approach is described in further detail in Exhibit (PG&E-4), Ch. 2.

⁵ D.11-05-018, p. 82, Finding of Fact 10 (emphasis added).

1 As a prudent operator, PG&E stands by our obligation to manage
 2 authorized funding reasonably, consistent with our responsibility to provide
 3 safe and reliable service.⁶ We use our planning and budgeting processes
 4 discussed above to meet this obligation.

5 Our need to reprioritize work and associated investment decisions is
 6 typically driven by three factors:

- 7 1) Emergent Work: The obligation to perform additional or changing work
 8 in response to critical emerging needs, including events beyond our
 9 control (such as storms and other emergencies);
- 10 2) Underfunded Programs: The need to perform critical programs above
 11 what was authorized by the Commission in the 2023 GRC or other
 12 proceedings; and
- 13 3) Approved Additional Spending: The flexibility provided by the
 14 Commission in approved memorandum and balancing accounts to allow
 15 funding for certain programs with uncertain or fluctuating work
 16 requirements.

17 In response to these drivers, PG&E forecasts to spend approximately
 18 \$801 million more in expense and \$3,255 million more in capital than
 19 authorized by the Commission for the 2023-2026 GRC cycle.

⁶ The Commission has said: “It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the Utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled, and there may be reprioritization. This process is expected and is necessary for the Utility to manage its operations in a safe and reliable manner.” D.11-05-018, p. 27.

TABLE 2-3
COMPARISON OF TOTAL ACTUAL AND PLANNED SPENDING TO IMPUTED ADOPTED
LEVEL FOR 2023 GRC PERIOD
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023			2024			2025			2026			Total Planned Over/(Under) Spending	Percent Over/(Under) Spending
		Adopted	Recorded	Adopted	Recorded	Adopted	Forecast	Adopted	Forecast	Adopted	Forecast	Adopted	Forecast		
1	Expense	\$6,430	\$6,440	\$6,510	\$6,611	\$6,332	\$6,519	\$6,231	\$6,734	\$6,231	\$6,734	\$6,231	\$6,734	\$801	3%
2	Capital	\$6,523	\$7,632	\$7,968	\$8,577	\$8,767	\$9,839	\$8,365	\$8,828	\$8,365	\$8,828	\$8,365	\$8,828	\$3,255	10%

Notes:

- The adopted dollars in the above table are adjusted to include all adopted funding from GRC and other proceedings, in order to show a more accurate comparison with the recorded total. At the program level views in the deferred work table below and individual exhibit-level discussions, adopted values are unadjusted.
- 2023 and 2024 recorded and 2025 and 2026 forecast values in this table vary from the values listed in the RO Model provided with PG&E's GRC filing due to timing differences. The RO will be updated to incorporate these differences.
- Corporate Services reflect 100 percent of total Company costs.
- Companywide Expenses are included in the expense amounts and reflect 100 percent of total Company costs.
- 2023-2026 Adopted Expense and Capital Expenditures include programs that are adopted and approved by the Commission in the separate proceedings:
 - \$2,263 million capital expenditure adopted in the Final Decision of 2023 GRC Phase 2 Energization (D.24-07-008).
 - \$993 million capital and \$208 million expense adopted in the Final Decision of Oakland General Office (OGO) Petition for Modification (D.24-08-009).
 - \$420 million capital and \$4 million expense related to Gas AMI Replacement included in the Joint Motion for Adoption of Settlement (A.24-03-011).

We set forth below some of the key elements of our differences in recorded and forecast spending, grouped by driver.

a. Expense Reprioritization

As shown in the table below, the functional areas with increased spending are Electric Distribution, A&G, Shared Services, and Companywide Expenses offset by decreased spending in People (Human Resources), Gas Operations, Customer and Enterprise Solutions, and Energy Supply.

**TABLE 2-4
EXPENSE OVER/UNDER SPEND
(MILLIONS OF DOLLARS)**

Line No.	Area	Over/(Under) Spend	Exhibit
	<u>Functional Area</u>		
1	Administration & General	\$178	Exhibit (PG&E-9)
2	Electric Distribution	\$145	Exhibit (PG&E-4)
3	Shared Services & IT	\$49	Exhibit (PG&E-7)
4	Energy Supply	\$(9)	Exhibit (PG&E-5)
5	People	\$(84)	Exhibit (PG&E-8)
6	Customer and Enterprise Solutions	\$(134)	Exhibit (PG&E-6)
7	Gas Operations	\$(663)	Exhibit (PG&E-3)
	<u>Total Company</u>		
8	Companywide Expenses	\$1,320	Exhibit (PG&E-8, 9)

1) Emergent Work

In Electric Distribution, we are incurring increased spending above GRC-authorized for Routine Emergency expense activities (MWC BH). A Routine Emergency exists when there is an immediate safety hazard or customer outage. In response to these emergencies, PG&E troublemen and crews make the situation safe, restore power to customers, and isolate the problem so repairs can be made. The 2023 GRC forecast was based upon a 3-year average of historical costs but has proved insufficient to cover costs. We must complete this work to maintain safety and reliability for our customers. Exhibit (PG&E-4), Chapter 11 provides further information regarding our activities and costs.

1 Aerial Inspections, using drones and other aerial means to
2 inspect our overhead electric distribution facilities is a new program
3 not forecast in the 2023 GRC. Successful pilots conducted in 2022
4 and 2023 demonstrated that aerial inspections capture a variety of
5 asset conditions that are challenging to see from a ground vantage
6 point, including emergency conditions. Expanding this program in
7 the 2023 GRC period is also resulting in increased spending above
8 GRC-authorized for Overhead Inspections (MWC BF).
9 Exhibit (PG&E-4), Chapter 14 provides further information on this
10 new program.

11 **2) Underfunded Programs**

12 In Electric Distribution, we are incurring increased spending
13 above GRC-authorized for Vegetation Management (MWCs HN
14 and IG), which for the 2023-2026 period includes work for routine
15 vegetation management, wildfire mitigation activities, and hazard
16 patrol to meet Commission General Orders and our internal
17 standards. The overspending is due to additional costs incurred for
18 addressing work constraints (permitting issues, customer refusals to
19 allow work, etc.); implementing new technology solutions to
20 enhance and streamline our vegetation management inspections,
21 execution, and record keeping; completing wood management
22 (disposal); and managing program activities. We must complete this
23 work to meet regulatory standards, and to maintain safety and
24 reliability. Exhibit (PG&E-4), Chapter 8 provides further information
25 regarding our vegetation management activities and costs.

26 In Companywide Expenses (Exhibit (PG&E-8, 9)), we are
27 spending above GRC-adopted levels in critical employee benefit
28 and compensation programs, including the following: (1) Medical;
29 (2) Dental; (3) Mental Health; (4) Retirement Savings; (5) Short
30 Term Disability Supplemental Benefits and Voluntary Paid Family
31 Leave; and (6) Short-Term Incentive Plan. We anticipate that the
32 combined spending above adopted levels for Companywide
33 Expenses will be approximately \$1.3 billion for the 2023-2026 GRC
34 period.

We have a number of employee benefit programs that are critical to the health and welfare of our represented and non-represented employees. These costs were generally known and forecasted in our last GRC⁷ and were denied funding.⁸ Our represented workforce comprises more than 60 percent of our population of co-workers, and benefits for these persons are negotiated and established through collective bargaining agreements that mandate the Company to provide a specified level of benefits. The benefits we provide contribute to employee health and safety and are a significant factor in attracting and retaining a qualified workforce.⁹ Exhibit (PG&E-8), Chapter 4 provides further information regarding our benefits costs.

We are also spending above GRC-adopted levels for employee compensation. This area received significant reductions in the 2023 GRC.¹⁰ Despite the reductions, we continued to fund our market-based employee compensation programs, as likely expected by the Commission and parties.¹¹ This funding is based on, and directly tied to, delivering outcomes for our customers. The funding of these programs is critical to attracting and retaining the necessary talent to successfully operate the Company. Exhibit (PG&E-8), Chapters 3 and 7 provide further information regarding employee compensation costs.

3) Approved Additional Spending

We are incurring increased spending for Overhead Maintenance (MWC KA), which is subject to the Overhead and Underground

⁷ A.21-06-021, Exhibit PGE-8, Ch. 5, Sections C and E.

⁸ D.23-11-069, Section 8.4.

⁹ Exhibit (PG&E-8), Ch. 4.

¹⁰ D.23-11-069, Section 8.3.

¹¹ See D.14-08-032, p. 524 (“We do not believe that our adopted reductions in ratepayer funding of STIP will necessarily cause PG&E to reduce the overall level of compensation for STIP-eligible employees... Moreover, a reduction of ratepayer funding does not automatically mean that PG&E must [] reduce the underlying STIP benefit to employees. Shareholders may find it in their interest to replace the funds that ratepayers do not cover.”).

1 Maintenance Balancing Account (OUMBA), except for certain
2 activities that are wildfire mitigations subject to Wildfire Mitigation
3 Balancing Account (WMBA). The OUMBA is a two-way balancing
4 account that authorizes us to spend above our GRC forecasts so
5 that we can complete pending overhead maintenance work critical
6 to safety and reliability and complying with the Commission's
7 General Orders for overhead maintenance and PG&E's internal
8 standards. The Commission-approved OUMBA therefore provides
9 flexibility to account for this variability as we complete overhead
10 maintenance tags to reduce risk and enhance reliability on our
11 system. We anticipate overspending in this area for the 2023-2026
12 period as we continue to resolve pending maintenance items
13 identified during our system inspections. Exhibit (PG&E-4),
14 Chapter 15 provides further information regarding our overhead
15 maintenance activities, costs, and operation of the OUMBA.

16 We are also spending above authorized in Major Emergency
17 (MWC IF), which is subject to the Major Emergency Balancing
18 Account (MEBA). The MEBA is a two-way balancing account that
19 authorizes us to spend above our GRC adopted forecast as
20 necessary to respond to major emergencies not declared as
21 catastrophic events. The frequency and severity of major
22 emergencies (storms and other weather events, wildfires,
23 earthquakes, etc.) are unpredictable from year to year. In 2024
24 alone, we incurred approximately \$222 million of costs to respond to
25 major emergencies, significantly higher than authorized. For the
26 2023-2026 GRC period, we anticipate overspending in this area due
27 to these higher-than-average costs. We must complete this work to
28 restore service following major emergencies and to maintain safety
29 and reliability. Exhibit (PG&E-4), Chapter 11 provides further
30 information regarding our emergency response activities, costs, and
31 operation of the MEBA.

b. Capital Reprioritization

As shown in the table below, the functional areas with increased spending are Electric Distribution, Shared Services & IT, Customer & Enterprise Solutions, Energy Supply, and Gas Operations.

**TABLE 2-5
CAPITAL OVERSPEND
(MILLIONS OF DOLLARS)**

Line No.	Area	Overspend	Exhibit
1	Electric Distribution	\$2,327	Exhibit (PG&E-4)
2	Shared Services & IT	\$325	Exhibit (PG&E-7)
3	Customer & Enterprise Solutions	\$276	Exhibit (PG&E-6)
4	Energy Supply	\$276	Exhibit (PG&E-5)
5	Gas Operations	\$60	Exhibit (PG&E-3)

1) Emergent Work

Similar to expense, in Electric Distribution we are incurring increased capital spending above GRC-authorized for Routine Emergency work (MWC 17). As discussed above, we experienced a significant increase in routine emergency response work in 2024. We must complete this capital work to restore power and maintain safety and reliability for our customers. Exhibit (PG&E-4), Chapter 11 provides further information regarding these activities and costs.

In addition, we are spending above GRC authorized for Work Requested by Others (WRO) (MWC 10). This work involves relocating electric distribution and service facilities at the request of a government agency or other third party (e.g., private parties and developers). PG&E is required to perform this work under Rules 13, 15, and 16, and franchise agreements with local governments. WRO projects and associated costs can vary greatly depending on the scope of the customer request. For the past several years (including 2023-2024), customer requests requiring WRO work have increased in frequency and complexity. Exhibit (PG&E-4), Chapter 10 provides further information regarding WRO activities and costs.

2) Underfunded Programs

In Electric Distribution, we are also incurring increased capital spending above GRC-authorized for pole replacement activities (MWC 07) for damaged or deteriorated poles. We must resolve pending pole maintenance tags identified during inspections to address this safety and reliability issue. Our pole replacement activities in High-Fire Threat Districts (HFTD) also meet commitments made in our Wildfire Mitigation Plans (WMP). Exhibit (PG&E-4), Chapter 15 provides further information regarding these activities and costs.

In Shared Services, we incurred increased capital spending for electrical vehicle (EV) infrastructure work at our facilities to allow for the increased use of EVs by employees. On a related note, we also incurred capital spending for Corporate Real Estate Strategy & Services (CRESS) work to prepare facilities for employees returning to work after the end of the pandemic. Exhibit (PG&E-7), Chapter 4 provides further information regarding Shared Services CRESS activities and costs.

In Customer & Enterprise Solutions, we are incurring increased capital spending for IT work to upgrade PG&E.com, Contact Center Service Platform, and other various customer-experience and engagement platforms. Exhibit (PG&E-6), Chapter 11 provides further information regarding this work and costs.

In Energy Supply, we are incurring increased capital spending for various Hydro work, including implementing RAMP mitigation investments for safety and non-RAMP water delivery and storage infrastructure upgrades. Our Hydro work also includes work to address aging/obsolete generation equipment and infrastructure. In the 2023 GRC, the Commission adopted funding levels that reflected a significant decline year-over-year in capital between 2023-2026. Exhibit (PG&E-5), Chapter 3 provides further information regarding our Hydro work and costs.

In Gas Operations, we are incurring increased capital spending in the In-Line Inspection Upgrades capital program (MAT 98C) due

1 to several factors, including lower-than-requested unit costs adopted
2 in the 2023 GRC. Exhibit (PG&E-3) Chapter 5 provides further
3 information regarding this program and costs.

4 **3) Approved Additional Spending**

5 In Electric Distribution, we are incurring increased capital
6 spending for Overhead Maintenance (MWC 2A). These costs are
7 recorded to the Overhead Underground Maintenance Balancing
8 Account (OUMBA), except for certain activities recorded to the
9 WMBA. As noted above, the OUMBA is a two-way balancing
10 account that authorizes us to spend above our GRC forecasts for
11 overhead maintenance work critical to safety and reliability. The
12 OUMBA provides flexibility to account for variability in the amount of
13 work we will need to complete based on our system inspections.
14 We anticipate overspending in this area for the 2023-2026 period as
15 we continue to resolve pending maintenance items identified during
16 these inspections. Exhibit (PG&E-4), Chapter 15 provides further
17 information regarding our capital investments for overhead
18 maintenance and operation of the OUMBA.

19 In addition, we are overspending in Plug-in Electric Vehicle
20 (PEV) New Business (MWC 16) capital infrastructure work covered
21 by Rule 29 PEV. This work includes distribution transformer,
22 secondary, and service upgrade work to serve increased loads
23 related to PEVs. The Commission authorized PG&E to establish a
24 AB841 Memorandum Account (AB841MA) to track and record these
25 costs until a Rule 29 PEV forecast was adopted in a future general
26 rate case. The Commission did not adopt a forecast for this work in
27 the 2023 GRC. The amounts incurred for this work are recorded to
28 the AB841MA for review in this GRC, in accordance with
29 D.24-07-008. Exhibit (PG&E-4), Chapter 10 provides further
30 information regarding our Rule 29 PEV activities and costs.

31 Finally, we are also incurring costs above authorized for Major
32 Emergency (MWC 95) capital costs, which is subject to the Major
33 Emergency Balancing Account (MEBA). As noted above, the MEBA
34 is a two-way balancing account that authorizes spending above the

GRC adopted forecast as necessary to respond to major emergencies not declared as catastrophic events. In 2024 alone, we incurred major emergency response costs significantly higher than authorized. We must complete this emergency work to restore service, and to maintain safety and reliability. Exhibit (PG&E-4), Chapter 11 provides further information regarding our emergency response activities, costs, and operation of the MEBA.

2. Complying with the 2020 GRC Settlement Agreement on Deferred Work

As discussed above, following adoption of funding for safety and reliability programs in the GRC, we continue to reprioritize work and make associated investment decisions typically driven by three factors: (1) Emergent Work; (2) Underfunded Programs; and (3) Approved Additional Spending. This reprioritization of spending results in over- and under-spending on safety and reliability programs as compared to GRC adopted funding levels and, in some cases, fewer units than forecast are performed leading to “deferred work” as defined by the Commission.

In the 2023 GRC decision, the Commission directed PG&E to make a showing on deferred work in the 2027 GRC consistent with the requirements of the 2020 GRC deferred work settlement.¹² The settlement defines “deferred work” as any work proposed in the GRC where: (1) the work was requested and authorized based on representations that it was needed to provide safe and reliable service; (2) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and (3) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

As summarized in Table 2A-1 (Attachment A), PG&E identified deferred work in both the Gas Operations and the Electric Distribution functional areas. The table identifies each program with deferred work, summarizes the reasons for the deferred work, including if the funding was reallocated to

¹² “[T]he Commission directs PG&E to continue to follow the directives in the [2020 GRC] Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Pub. Util. Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities.” D.23-11-069, p. 49.

1 higher priority work, and where the functional area has provided the required
2 showing in opening testimony.¹³

3 The 2020 GRC settlement also lists six “principles of deferred work” that
4 were reflected in prior GRC decisions. The settlement requires that for all
5 work meeting the definition of deferred work PG&E demonstrate how the
6 specific funding request is consistent with the principles.¹⁴

7 The six principles are aligned to the enterprise planning and budgeting
8 processes discussed in this chapter, in that both acknowledge the need to
9 reprioritize work to address changed or emergent circumstances and
10 maintain safe and reliable service. Accordingly, in addition to being
11 addressed in each functional area’s testimony where specific deferred work
12 is identified, we also discuss the six principles below in the context of
13 PG&E’s overall, enterprise-level processes.

14 The six principles should be viewed in totality and not in isolation, at
15 both the enterprise level and the functional area level.¹⁵ They balance
16 factors that should be considered when determining whether PG&E’s
17 decisions are reasonable for the safe and reliable operation of its systems.

- 18 • Principle 1: Where funds are originally collected from ratepayers based
19 on representations that the work is necessary to provide safe and
20 reliable service and, yet, PG&E does not perform all of the designated
21 work, the fact that PG&E must pay for a higher priority activity or
22 program does not nullify or extinguish its responsibilities to fund

13 The Settlement requires that for its identified deferred work, PG&E’s direct showing explain:

- a) Why the authorized work was not performed in the time forecasted;
- b) Whether the deferral of the authorized work resulted in lower than authorized spending for the authorized work;
- c) How the funding was reallocated and whether such reallocation related to the provision of safe and reliable service; and
- d) To the extent that authorized funding for safety related work was used for other purposes, the reasonableness of the alternative work for the purpose of evaluating the appropriateness of the new funding request.

14 2020 Settlement Agreement adopted in the final GRC Decision, D.20-12-005, p. 37.

15 “The Settling Parties agree to the following six principles (Principles), which will be applicable to PG&E’s next GRC. The Settling Parties agree that the Principles should be viewed in totality.” 2020 Settlement Agreement adopted in the final GRC Decision, D.20-12-005, p. 36.

1 forecasted and authorized work unless such work is no longer deemed
2 necessary for safe and reliable service.¹⁶

3 We understand the intention of this principle is to require funding of
4 all work needed to deliver safe and reliable service, regardless of other
5 funding demands. We agree. We have and will continue to use the
6 funds adopted in the 2023 GRC to provide safe and reliable service in
7 2023-2026.

8 As discussed throughout this chapter, following adoption of funding
9 for safety and reliability programs in the GRC, we continue to reprioritize
10 work and make associated investment decisions typically driven by
11 three factors: (1) Emergent Work; (2) Underfunded Programs; and
12 (3) Approved Additional Spending. This reprioritization is done through
13 the Company's BPD and functional area change-control processes.
14 Within a given year, consistent with our responsibility and discretion to
15 adjust priorities to accommodate changing conditions (see Principle 5
16 below) each functional area manages and reprioritizes its spending.
17 These processes—at the individual functional area level and at the
18 enterprise level—align our spending to fund work that is deemed
19 necessary for safe and reliable service.

20 For the current GRC period, identified deferred work comprises a
21 small percentage of the safety and reliability work for which funding was
22 adopted between 2023-2026. Expense deferred work programs that
23 underspent amounted to approximately \$122 million, or 0.97 percent of
24 all Gas and Electric safety and reliability funded expense work. This
25 underspending was reprioritized as explained in the functional area
26 testimony referenced in Table 2A-1. Over the same time period, as
27 discussed in Section D.1.a above, driven largely by Emergent Work,
28 Underfunded Programs, and Approved Additional Funding, PG&E
29 expects to exceed overall adjusted adopted expense spending by
30 approximately \$801 million.¹⁷

¹⁶ The Principles stated in this discussion are directly taken from the 2020 Settlement Agreement adopted in the final GRC Decision, D.20-12-005, pp. 36-37.

¹⁷ See Table 2-3 above.

Capital deferred work programs that underspent amounted to approximately \$987 million, or 5.1 percent of all Gas and Electric safety and reliability funded capital work. This underspending was reprioritized as explained in the functional area testimony referenced in Table 2A-1. Over the same time period, as discussed in Section D.1.b above, driven largely by Emergent Work, Underfunded Programs, and Approved Additional Funding, PG&E expects to exceed overall adjusted adopted capital spending by approximately \$3.3 billion.¹⁸

- Principle 2: PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates.

We understand this principle to mean that our responsibility to provide safe and reliable service is independent of our overall spending level. This principle should be read in conjunction with Principles 3 and 6 that acknowledge that there is a limit to how much overspending can occur before damaging the Utility's financial health to the detriment of both customers and investors.

As discussed under Principle 1, we meet this principle by utilizing the BPD process to reprioritize spending consistent with our responsibility to provide safe and reliable service. As discussed above in Section D.1, for the 2023 GRC period, our spending exceeds adopted funding. While we have done so as part of our commitment to maintain safe, reliable service, we are also cognizant of the limits to overspending, as will be discussed further below.

- Principle 3: PG&E bears the risk that, as a result of meeting spending obligations necessary to provide safe and reliable service, the earned rate of return may be less than the authorized return.

We aim to earn our authorized rate of return over the course of the GRC. However, we understand that, under this principle, we are not guaranteed our authorized rate of return and that our obligation to provide safe and reliable service may cause our earnings to be less than

¹⁸ See Table 2-3 above.

authorized. Thus, consistent with Principle 6 below, this principle should be balanced over time.

- Principle 4: While PG&E has finite funds to meet capital and operational needs, PG&E is not restricted to spending only up to the forecast adopted in a GRC.

We understand this principle to be closely related to Principles 1, 2, and 6, with the important additional acknowledgment that we do have finite funds to meet our capital and operational needs. Over the 2023-2026 period, driven largely by Emergent Work, Underfunded Programs, and Approved Additional Funding, reprioritization occurred using the BPD process described above. This led to our spending above authorized amounts.¹⁹

- Principle 5: PG&E bears the responsibility—and has discretion—to adjust priorities to accommodate changing conditions after test year forecasts are adopted. Readjusting spending priorities, however, only involves the ranking and sequence of spending. Reprioritizing spending for new projects does not automatically justify postponing projects previously deemed necessary for safe and reliable service.

We understand this principle to be very similar to Principles 1-3, adding the explicit acknowledgment of PG&E's responsibility and discretion to readjust its spending priorities.

As described in Section D.1 and under Principle 1, using the BPD and functional area change-control processes driven largely by Emergent Work, Underfunded Programs, and Approved Additional Funding, we adjusted our spending plans. This process uses risk-informed planning and does not automatically postpone previously prioritized work when competing demands and emerging requirements arise. In addition, underspending on identified deferred work comprises a small percentage of the funding adopted for safety and reliability work between 2023-2026 and we expect to exceed the overall adopted expense and capital funding in order to support our safety and reliability goals.

¹⁹ See Table 2-3 above.

- Principle 6: The GRC process is a tool in supporting PG&E's ongoing ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs. Adopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E's ability to provide safe and reliable service while maintaining its financial health and ability to raise capital.

We understand that this principle recognizes that the GRC provides the funding levels PG&E needs to provide safe and reliable service while providing a reasonable opportunity to attract capital to California. This principle recognizes that PG&E is entitled to an opportunity to earn a return on its property that provides service to ratepayers, which ensures confidence in the financial soundness of the utility to support its credit and enables the utility to raise the money necessary for the proper discharge of its public duties.²⁰ It is critical that the Commission provide funding levels that provide the opportunity to attract capital in California to support PG&E's financial health as we undertake substantial and necessary investments for customers that will improve the safety and reliability of our service at the lowest cost to customers. While we are not guaranteed our authorized rate of return and have not achieved it in recent years, PG&E should be provided revenue sufficient to provide a reasonable opportunity to do so in accordance with Commission policy. This will support our creditworthiness and allow us to provide safe and reliable service at lower costs of financing for customers.

E. Conclusion

We are firmly committed to implementing a decision-making framework that balances safety, reliability, and risk-reduction objectives with customer affordability, as we plan the type, scope, timing, and cost of our work. We look forward to engaging with the Commission regarding these issues.

²⁰ See D.19-12-056, pp.15–16 ((citing *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923)); D.23-11-069, p. 707 (this includes the post-test years)).

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT A
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE
2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC
AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
Exhibit (PG&E-3) Gas Operations Deferred Work							
1	Exhibit (PG&E-3), Chapter 4: Asset Family – Gas Distribution Mains and Services	Gas Pipeline Replacement Program (MAT 14A)	PG&E does not expect to complete 156,358 feet (29.6 miles) out of the imputed units of 515,328 feet (97.6 miles). The program is expected to spend \$43.8 million less than imputed funding. <u>Reasons:</u> Reprioritization of funding to capital programs that received additional funding above adopted. For instance, MWC 50 programs such as MAT 50B (Reliability Service Replacement Program) and MAT 50J (Encroachment Program) forecasted overspend from adopted amounts to fund other higher priority safety and compliance work.	515,328 Feet of Main	\$416,928	358,970 Feet of Main	\$373,151
2		Gas Plastic Pipe Replacement for Mains/ Services (MAT 14D)	PG&E does not expect to complete 812,411 feet (153.9 miles) out of the imputed units of 2,935,680 feet (556 miles). The program is expected to spend \$45.7 million less than imputed funding. <u>Reasons:</u> Actual unit cost being higher than the adopted unit cost and reprioritization of funding to capital programs that received additional funding above adopted. For instance, MWC 50 programs such as MAT 50B (Reliability Service Replacement Program) and MAT 50J (Encroachment Program) forecasted overspend from adopted amounts to fund other higher priority safety and compliance work.	2,935,680 Feet of Main	\$1,658,736	2,123,269 Feet of Main	\$1,612,994
3		Reliability Main Replacement (MAT 50A)	PG&E does not expect to complete 98,875 feet of main (18.7 miles) out of the imputed units of 316,800 feet (60 miles). The program is expected to spend \$24.8 million less than imputed funding. <u>Reasons:</u> Unit costs higher than adopted amounts and reprioritization of funding to capital programs that received additional funding above adopted. For instance, other MWC 50 programs such as MAT 50B (Reliability Service Replacement Program) and MAT 50J (Encroachment Program) forecasted overspend from adopted amounts to fund other higher priority safety and compliance work.	316,800 Feet of Main	\$211,789	217,925 Feet of Main	\$186,983

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
4		New Valve Program (MAT 50R)	PG&E expects to complete 260 New Valve Installations out of the 400 imputed units, or 140 fewer units. The deferral of the authorized work is expected to result in spending of approximately \$1.6 million less than the imputed funding amount to the New Valve Program. <u>Reasons:</u> Unit costs higher than adopted amounts and reprioritization of funding to capital programs that received additional funding above adopted. For instance, other MWC 50 programs such as MAT 50B (Reliability Service Replacement Program) and MAT 50J (Encroachment Program) forecasted overspend from adopted amounts to fund other higher priority safety and compliance work.	400 Valves Installed	\$23,501	260 Valves Installed	\$21,924
5		Cross Bore Program (MAT JQK)	PG&E does not expect to complete 36,312 inspections out of the imputed units of 77,252 inspections. The program is expected to spend approximately \$1.8 million more than imputed funding. <u>Reasons:</u> This program is forecasted to be overspent and was prioritized to receive funding. It was important to spend additional funding on this program because PG&E strongly believes that the Cross Bore Program is an important safety initiative that PG&E should continue to pursue based on consideration of the catastrophic consequences and the limitations inherent in the risk modeling related to low frequency, high consequence outcomes. PG&E put an effort towards completion of the remaining accessible inspections within San Francisco to substantially complete the program in San Francisco leading to higher unit costs which resulted in under performing on the units.	77,252 Inspections	\$55,679	40,940 Inspections	\$57,494
6	Exhibit (PG&E-3), Chapter 5: Asset Family - Transmission Pipe	Valve Automation Program (MAT 75I)	PG&E does not expect to complete 43 valves out of the imputed units of 72 valves. The program is expected to spend \$53.2 million less than imputed funding. <u>Reasons:</u> Primarily due to the reprioritization of funding to capital programs that received additional funding above adopted. These programs included ILI Upgrades (MAT 98C), Pipe Replacement – Other (MAT 75O), and Casing Mitigations (MAT 3K5).	72 Valves Automated	\$92,605	29 Valves Automated	\$39,441
7		Fault Crossings Program (MAT 75L)	PG&E does not expect to complete 25 projects out of the imputed units of 32 projects. The program is expected to spend approximately \$22.1 million less than imputed funding. <u>Reasons:</u> Primarily due to the reprioritization of funding to capital programs that received additional funding above adopted. These programs included ILI Upgrades (MAT 98C), Pipe Replacement – Other (MAT 75O), and Casing Mitigations (MAT 3K5).	32 Projects	\$53,120	7 Projects	\$31,000

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
8		Shallow Pipe (MAT 75M)	PG&E does not expect to complete 9 projects out of the imputed units of 16 projects. The program is expected to spend approximately \$33.6 million less than imputed funding. <u>Reasons:</u> Due to the reprioritization of funds to Water and Levee Crossings (MAT 75K), and to other capital programs that received additional funding above adopted.	16 Projects	\$39,926	7 Projects	\$6,371
9		Exposed Pipe (MAT 75T)	PG&E does not expect to complete 11 projects out of the imputed units of 16 projects. PG&E expects to spend approximately \$11.2 million less than imputed funding. <u>Reasons:</u> Due to the reprioritization of funds to Water and Levee Crossings (MAT 75K), and to other capital programs that received additional funding above adopted.	16 Projects	\$39,926	5 Projects	\$28,728
10		Gas Gathering (MAT 84D)	PG&E does not expect to complete 21 meters out of the imputed units of 44 meters. PG&E expects to spend approximately \$16.7 million less than the imputed funding. <u>Reasons:</u> Primarily due to the reprioritization of funding to capital programs that received additional funding above adopted. These programs included ILI Upgrades (MAT 98C), Pipe Replacement – Other (MAT 75O), and Casing Mitigations (MAT 3K5).	44 Meters	\$48,211	23 Meters	\$31,553
11		ILI Upgrades (MAT 98C)	PG&E does not expect to complete 2 projects out of the 16 imputed units. PG&E expects to spend approximately \$210.6 million more than the imputed funding. <u>Reasons:</u> Primarily due to two upgrades being canceled because the line was operating at less than 20 percent SMYS, making it a suitable candidate for downrating as part of PG&E's Transmission Definition initiative. While PG&E has identified additional projects that could be performed if one is canceled, accelerating these project timelines can be very costly and inefficient due to project maturity in the planning process.	16 Projects	\$239,832	14 Projects	\$450,417
12		Casings Mitigation (MAT 3K5)	PG&E does not expect to complete 4 units out of 44 imputed casings mitigations. PG&E expects to spend \$32.1 million more than the imputed amount. <u>Reasons:</u> Primarily due to an anticipated high-cost casing pipeline replacement project in 2026. The program pace has been reduced to fund the anticipated high-cost casing project.	44 Projects	\$57,930	40 Projects	\$90,041

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
13		Close Interval Survey (CIS) (MAT GJE)	PG&E does not expect to complete 1,125 units out of the 1,804 imputed units. PG&E expects to spend approximately \$9.1 million less than the imputed amount. <u>Reasons:</u> Primarily due to the reprioritization of funds to other expense programs that received additional funding above adopted. Programs that spent more than adopted include Cathodic Protection Expense (MAT GJC), LNG/CNG (MAT GMD), Class Location – Strength Tests (MAT JT9), Pipeline WRO Expense (MAT JTA), and Geo-Hazard Mitigations (MAT JTT).	1,804 Various	\$16,916	679 Various	\$7,817
14		Casings (MAT GJM)	PG&E does not expect to complete 792 units out of the 3,932 imputed units. PG&E expects to spend approximately \$6.6 million less than the imputed amount. <u>Reasons:</u> Primarily due to fewer casings required for accelerated monitoring due to the casing mitigation or less contacts, leading to the lower number of casing leak survey units. The remaining spending below imputed for the Casings Program (MAT GJM) was reprioritized to other expense programs that received additional funding above adopted. Programs that spent more than adopted include Cathodic Protection Expense (MAT GJC), LNG/CNG (MAT GMD), Class Location – Strength Tests (MAT JT9), Pipeline WRO Expense (MAT JTA), and Geo-Hazard Mitigations (MAT JTT).	4,724 Various	\$17,466	3,932 Various	\$10,834
15		Shallow and Exposed Pipe – Expense (MAT JT4)	PG&E does not expect to complete 13 projects out of the 16 imputed units. PG&E expects to spend approximately \$8.9 million less than the imputed amount. <u>Reasons:</u> Primarily due to the reprioritization of funds to other expense programs that received additional funding above adopted. Programs that spent more than adopted include Cathodic Protection Expense (MAT GJC), LNG/CNG (MAT GMD), Class Location – Strength Tests (MAT JT9), Pipeline WRO Expense (MAT JTA), and Geo-Hazard Mitigations (MAT JTT).	16 Projects	\$11,264	3 Projects	\$2,342
16	Exhibit (PG&E-3), Chapter 6: Asset Family - Facilities	GD Regulator Station Rebuild (MAT 50C)	PG&E does not expect to complete 42 regulator station units out of the 100 imputed units. PG&E expects to spend approximately \$51.9 million less than the imputed amount. <u>Reasons:</u> Increased average unit cost: The average unit cost has increased at a rate faster than normal escalation. Higher-costs projects: 2025-2026 scope of work forecast to include only the rebuilds of GD District Regulator stations that follow the H-14 standard. Those rebuilds are more expensive than the stations that follow the H-10 standard. Reprioritization/higher risk work : Programs that spent more than adopted include the GD OPP program and the GD HPR program.	100 Regulator Stations	\$202,985	58 Regulator Stations	\$151,125

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
17		GD Regulator Station Component Replacement (MAT 50L)	PG&E does not expect to complete 205 regulator station components replacements out of the 600 imputed units. PG&E expects to spend approximately \$1.3 million less than the imputed amount. <u>Reasons:</u> Increased average unit cost: The average unit cost has increased at a rate faster than normal escalation. Higher-cost projects: In 2023 and 2024, many projects were fire valves projects that are more expensive than the average unit costs for other component replacements projects. Reprioritization/higher risk work: Programs that spent more than adopted include the GD OPP program and the GD HPR program.	600 Regulator Station Components	\$43,412	395 Regulator Station Components	\$42,080
18		Physical Security (MAT 76Z)	PG&E does not expect to complete 3 stations out of the 8 imputed units. PG&E expects to spend approximately \$19.5 million less than the imputed amount. <u>Reasons:</u> Reprioritization/higher risk work: In 2022, reprioritization of funds to higher risk work did not allow for the engineering of new projects, so those could not be executed in 2023. Operational issues: Projects started in 2024 will take two years to complete due to the need for additional infrastructure, particularly electrical power, and network infrastructure to meet the TSA requirements. The \$19.5 million of spending less than imputed was reallocated to other capital programs that received additional funding above adopted.	8 Regulator Stations	\$37,871	5 Regulator Stations	\$18,413
19	Exhibit (PG&E-3), Chapter 8: Operations and Maintenance	Casings (MAT 50Q)	PG&E does not expect to complete 5 casings out of the 40 imputed units. PG&E expects to spend approximately \$1.1 million more than the imputed amount. <u>Reasons:</u> Increased unit cost due to more complex casing mitigation projects resulting in overall spend exceeding imputed funding.	40 Casings	\$10,980	35 Casings	\$12,042
20		Install Casing Test Stations (MAT DGG)	PG&E does not expect to complete 358 casing test stations out of the 560 imputed units. PG&E expects to spend approximately \$3.1 million less than the imputed amount. <u>Reasons:</u> Reallocation of funding to other expense programs that received additional funding above imputed. An example of a program that spent more than adopted is the Atmospheric Corrosion Remediation Program (MAT GJB) that is higher priority.	560 Casing Test Stations Installed	\$13,431	202 Casing Test Stations Installed	\$10,325

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
21		Casing short mitigation <100 feet (MAT DGH)	PG&E does not expect to complete 79 casings out of the imputed units of 132. PG&E expects to spend approximately \$10.4 million less than the imputed amount. <u>Reasons:</u> Reallocation of funding to other expense programs that received additional funding above imputed. An example of a program that spent more than adopted is the Atmospheric Corrosion Remediation Program (MAT GJB) that is higher priority.	132 Casings Mitigated	\$17,621	53 Casings Mitigated	\$7,258
22		Leak Survey Meter Repair (MAT FIS)	PG&E does not expect to complete 78,664 meter repairs out of the 320,000 imputed. PG&E expects to spend approximately \$1.2 million more than the imputed amount. <u>Reasons:</u> Increased unit cost due to more complex jobs resulting in overall spend exceeding imputed funding.	320,000 Meters Repaired	\$39,845	241,336 Meters Repaired	\$41,006
23	Exhibit (PG&E-3), Chapter 9: Gas System Operations	Gas Capacity, Mains (MAT 47B)	PG&E does not expect to complete 145,445 (27.5 miles) out of the imputed units of 184,800 feet (35.0 miles). PG&E expects to spend approximately \$98.7 million less than the imputed funding. <u>Reasons:</u> 1) Reprioritization of funds to higher risk work. Programs that spent more than adopted include SCADA Gas Distribution Remote Terminal Units (MAT 4AM), which received zero funding in the 2023 GRC. It was reasonable to fund Gas Distribution Remote Terminal Units because SCADA is required for real time data visibility at regulator stations, which informs everything from system performance monitoring by our control room operators which enables emergency response, to long term design; and that SCADA visibility is necessary to monitor slam-shut devices, which are installed as part of the Overpressure Protection Enhancement Program, providing significant risk reduction benefits. 2) The ability to compensate for Capacity, Mains work by planning to use manual operations, sometimes including the injection of CNG or LNG into the system as an alternative to main installation for meeting increased demand.	184,800 Feet of Main	\$145,507	39,355 Feet of Main	\$46,850

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
(THOUSANDS OF DOLLARS)
(CONTINUED)

Line No.	Exhibit and Chapter	Deferred Work Program(s)	Reason for Deferred Work	Volume and Cost of Work			
				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
24		Gas Capacity, Regulator Stations (MAT 47C)	PG&E does not expect to address 5 regulator stations out of the 12 imputed units. PG&E expects to spend approximately \$14.2 million less than the imputed funding. <u>Reasons:</u> This is attributed primarily due to challenges regarding permitting and implementation, as well as a limited backlog of projects to draw into the year in cases where permit delays and other project implementation factors prevented the completion of units in the planned years. The need for additional Regulator Station units to meet capacity demands is dependent on evolving system needs. The delay in completing the additional five units will not prevent PG&E from meeting capacity needs during the 2023 GRC period.	12 Regulator Stations Addressed	\$23,933	7 Regulator Stations Addressed	\$9,713
25		Gas Capacity, Replace Regulator Station Component (MAT 47D)	PG&E does not expect to complete 1 regulator station component out of the 16 imputed units. PG&E expects to spend approximately \$0.32 million more than the imputed funding. <u>Reasons:</u> This is a capacity driven activity. We do not expect demand for this unit to arise until 2027, and if it does, we will complete this unit.	16 Regulator Station Components	\$523	15 Regulator Station Components	\$849
26		GD SCADA Visibility, ERX Pressure Monitoring (MAT 4AF)	PG&E does not expect to complete the installation of 17 electronic pressure recording devices (ERXs) out of the 40 imputed units. PG&E expects to spend approximately \$0.57 million more than the imputed funding. <u>Reasons:</u> The reason for not completing all imputed units in the 2023 GRC period is a combination of unanticipated technology changes, land acquisition process update, and higher than anticipated unit costs.	40 Electronic Pressure Recorders Installed	\$2,159	23 Electronic Pressure Recorders Installed	\$2,730
27		GT SCADA Visibility (MAT 76M)	PG&E does not expect to complete the installation of 14 remote terminal units out of the 32 imputed units. PG&E expects to spend approximately \$3.1 million less than the imputed funding. <u>Reasons:</u> First, there were multiple factors impacting project execution in 2023-2024 including internal resource constraints, permitting delays, difficulty getting electric service to SCADA RTU units in rural areas, and a change in internal design requirements. Second, in 2025-2026 we forecast to complete fewer units than adopted because of a higher actual unit cost in addition to funds being reprioritized to higher priority work. Capital transmission programs that received more funding than imputed include Gill Ranch (MAT 762) and Capacity for Load Growth (MAT 73A).	32 Remote Terminal Units Installed	\$12,184	18 Remote Terminal Units Installed	\$9,098
Exhibit (PG&E-4) Electric Distribution Deferred Work							

TABLE 2A-1
DEFERRED WORK IN PG&E'S 2027 GRC AS DEFINED BY THE 2020 GRC SETTLEMENT AGREEMENT, SECTION 5.2
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				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
28	Exhibit (PG&E-4), Chapter 14: Distribution Inspections	Underground (UG) Manhole Inspection Annual (MAT BFF)	PG&E does not expect to complete 3,137 units of manhole/vault inspections out of the imputed 6,184 units. The program will be underspent by \$318 thousand compared to imputed funding. <u>Reasons:</u> Reprioritization. PG&E reallocated funds for manhole inspections to other higher priority compliance work in MWC BF, including aerial inspections in MAT BF1. MAT BF1 is a new program that was not forecast in the 2023 GRC. Manhole inspections are still performed in accordance with GO165 compliance requirements.	6,184 Manholes Inspected	\$2,040	3,047 Manholes	\$1,722
29		OH Equipment Test (MAT BFG)	PG&E does not expect to complete 25,318 units of equipment inspections out of the imputed 102,305 units. Program will be overspent by \$558 thousand compared to imputed funding. <u>Reasons:</u> Unit costs for Overhead Equipment Tests were higher than anticipated in 2023 and 2024. In 2023 and 2024 PG&E completed all of the required equipment tests according to standard. 2025 and 2026 budget for this program is lower than 2023 and 2024, and accordingly PG&E is evaluating ways to complete all units to standard at a lower unit cost.	102,305 Equipment Inspections	\$10,683	76,987 Equipment Inspections	\$11,241
30	Exhibit (PG&E-4), Chapter 15: OH Maintenance and Poles	Pole Test & Treat (MAT GAA)	PG&E does not expect to complete 842,934 units of pole inspections out of the imputed 1,039,331 units. PG&E expects to spend approximately \$44.3 million less than the imputed funding. <u>Reasons:</u> PG&E's execution strategy has changed from what was authorized in the 2023 GRC for Pole Test and Treat, with the program prioritizing Comprehensive Pole Inspections (CPIs) which help inform and prioritize EC notifications to determine if the work needs to be performed. CPIs can be more costly on a per unit basis than routine inspections because work cannot be performed as efficiently as through routine inspections. As a result of this change in strategy, a portion of the inspections originally forecast for the 2023 GRC will need to be completed after 2026. The Pole Test and Treat program still maintains compliance with GO 165 requirements. PG&E reallocated funds for Pole Test and Treat inspections to other high priority inspection work such as Aerial Inspection in MAT BF1.	1,039,331 Inspections	\$86,456	196,397 Inspections	\$42,131

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				Imputed Adopted		Recorded + Forecast	
				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
31		Pole Analyze Loading (MAT GAC)	PG&E does not expect to complete 555,154 units of pole loading analysis out of the imputed 800,000 units. PG&E expects to spend approximately \$39.3 million less than the imputed funding. <u>Reasons:</u> PG&E's work in 2023 and 2024 in MAT GAC was focused on poles in HFTD locations. During that analysis, we identified a population of poles that required additional data to perform the analysis. In order to complete those higher priority HFTD units, we paused additional analysis and focused on performing more detailed calculations on the HFTD populations. We anticipate continuing to work on that population through 2026, at which point we will switch to prioritized non-HFTD analysis.	800,000 Poles	\$90,607	244,846 Poles	\$51,354
32	Exhibit (PG&E-4), Chapter 16: UG Maintenance And Infrastructure Replacement	UG Cable Other Replacement (MAT 56A)	PG&E does not expect to complete 32 miles of cable replacement out of the imputed 70 miles. PG&E expects to spend approximately \$78.6 million less than the imputed funding. <u>Reasons:</u> Reprioritization. PG&E is reprioritizing work in 56A to higher priority work in emergency replacements (MWC 17), underground/network maintenance replacements (MWCs 2B & 2C), capacity improvements (MWC 06), and addressing wildfire commitments (various MWCs).	70 Circuit Miles	\$162,355	38 Circuit Miles	\$83,731
33		Network Cable Replacement (MAT 56N)	PG&E does not expect to complete 227,557 feet of cable replacements out of the imputed 227,557 units. PG&E expects to spend approximately \$134.9 million less than the imputed funding. <u>Reasons:</u> Reprioritization. PG&E is reprioritizing work in 56N to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), pole replacements (MWC 07). Network cable replacement work is expected to ramp up beginning in 2029, once PG&E's wildfire commitments have been completed.	227,557 Circuit Feet	\$135,552	0 Circuit Feet	\$644
34		Replace Obsolete UG Switches (MAT 56S)	PG&E does not expect to complete 142 units of Load Break Oil Rotary (LBOR) switch replacements out of the imputed 308 units. PG&E expects to spend approximately \$3.0 million less than the imputed funding. <u>Reasons:</u> Reprioritization. PG&E is reprioritizing work in 56S to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06, 46), and pole replacements (MWC 07).	308 LBOR Switch Replacements	\$35,672	166 LBOR Switch Replacements	\$32,679
35		Install Temperature Indicator (MAT 56T)	PG&E does not expect to complete 4,276 units of temperature alarm devices (TAD) installations out of the imputed 4,276 units. PG&E expects to spend approximately \$17.3 million less than the imputed funding. <u>Reasons:</u> Reprioritization. PG&E is reprioritizing work in 56T to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	9,176 Installations	\$37,204	4,900 Installations	\$19,875

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				2023 GRC Cycle Imputed Adopted Units (2023-2026)	2023 GRC Cycle Imputed Adopted Costs (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast Units	2023-2024 Recorded + 2025-2026 Forecast Costs
36	Exhibit (PG&E-4), Chapter 17: OH Infrastructure Replacement and Reliability	Replace Deteriorated OH Conductor (MAT 08J)	PG&E does not expect to complete 255 miles of conductor replacement out of the imputed 295 miles. PG&E expects to spend approximately \$165.7 million less than the imputed funding. <u>Reasons:</u> PG&E is reprioritizing work in MAT 08J to System Hardening work in HFTD areas in order to reduce ignition risk.	295 Circuit Miles	\$188,965	39 Circuit Miles	\$23,313
37		OH Fuses Install/Replace (MAT 49C)	PG&E does not expect to complete 255 units of fuse replacements out of the imputed 515 units. PG&E expects to spend approximately \$275 thousand more than the imputed funding. <u>Reasons:</u> PG&E spent more than imputed in this program in 2025 and 2026, however realized unit costs were higher than anticipated, resulting in fewer units being completed than forecast in the 2023 GRC. Recent updates to the standard requirements for this program have triggered additional work, such as the full replacement of the pole. Historically, the installation of fuses did not require a pole replacement. One of the benefits of these updates is that replacement enables easier upgrade to a Fuse Saver for future work.	515 Fused Cut-Out Locations	\$6,849	260 Fused Cut-Out Locations	\$7,125
38		Electric Reliability Install Fault Location, Isolation, and Service Restoration (FLISR) Systems (MAT 49S)	PG&E does not expect to complete 41 units of circuit activations out of the imputed 48 units. PG&E expects to spend approximately \$13.2 million less than the imputed funding. <u>Reasons:</u> PG&E is reprioritizing work in 49S to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	48 FLISR Circuit Activations	\$16,341	7 FLISR Circuit Activations	\$3,131
39	Exhibit (PG&E-4), Chapter 18: Substation Asset Management	Replace Distribution Substation Breakers (MAT 48D)	PG&E does not expect to complete 144 units of breaker replacements out of the imputed 160 units. PG&E expects to spend approximately \$108.6 million less than the imputed funding. <u>Reasons:</u> PG&E is reprioritizing substation breaker replacements in order to support higher priority substation work in MWC 59. Rescheduling of these proactive replacements does not compromise safety or reliability.	160 Circuit Breakers Replaced	\$125,423	16 Circuit Breakers Replaced	\$16,805
40		Distribution Substation Animal Abatement (MAT 48X)	PG&E does not expect to complete 66 units of animal abatement locations out of the imputed 68 units. PG&E expects to spend approximately \$25.1 million less than the imputed funding. <u>Reason:</u> PG&E is reprioritizing substation breaker replacements in order to support higher priority substation work in MWC 59. Rescheduling of these proactive replacements does not compromise safety or reliability.	68 Locations	\$25,292	2 Locations	\$211