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PACIFIC GAS AND ELECTRIC COMPANY

2020 RISK ASSESSMENT AND MITIGATION PHASE REPORT

PACIFIC GAS AND ELECTRIC COMPANY
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INTRODUCTION

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully submits its 2020 Risk Assessment and Mitigation Phase (RAMP) Report to the California Public Utilities Commission (Commission or CPUC) pursuant to the Commission's direction in Decision (D.) 20-01-002.[1] This RAMP Report constitutes the initial phase of PG&E's 2023 General Rate Case (GRC), which will incorporate matters formerly considered in the Gas Transmission and Storage rate case. PG&E will file our 2023 test year GRC application in June 2021.[2]

The 2020 RAMP Report represents progress on the joint efforts of the Commission and its Safety and Enforcement Division (SED), Safety Policy Division (SPD),[3] PG&E, California's other large investor-owned utilities (IOU), and other stakeholders over the past several years to enhance risk-informed decision-making through the Safety Model Assessment Proceeding (S-MAP) and RAMP Reports. These joint efforts recently culminated in the CPUC's Decision accepting, with modifications, the S-MAP Settlement Agreement (S-MAP Settlement Decision).[4] This Report reflects PG&E's first implementation of the methodologies adopted in that decision.

This Report reflects the continued evolution of PG&E's Enterprise and Operational Risk Management (EORM) Program. The EORM Program enables PG&E to: (1) identify those risks that could lead to catastrophic safety consequences, (2) implement the actions that have the highest and most cost-effective potential to reduce risk, and (3) transparently monitor and report results. Consistent with Commission direction and stakeholder feedback, we

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[1] D.20-01-002, p. 3.

[2] D.20-01-002, p. 3.

[3] The SPD assumed the role of developing and recommending safety policy concerning risk assessment and risk mitigation from the SED.

[4] D.18-12-014.

have made important changes to the EORM Program from the Risk Management Program described in 2017 RAMP Report and PG&E's 2020 GRC. The most significant of these improvements are:

- Moving from a subject matter expert (SME) informed 7x7 risk selection tool to an event-based risk register grounded in repeatable risk events;
- Using PG&E-specific and relevant industry data in risk analysis, whereas the 2017 RAMP often used proxy or incomplete data;
- Developing risk tranche analysis that reveals which aspects of a risk have a disproportional impact on likelihood or consequences of risk events;
- Breaking out risk events into multiple outcomes to better determine which drivers could lead to more severe risk events; and
- Increasing consistency in the evaluation of risk and mitigations and beginning to deepen our understanding of compliance-based controls across PG&E's lines of business (LOB).

We will continue to refine and improve the EORM Program by implementing future guidance provided in this and other proceedings, other IOUs' RAMP proceedings, and PG&E's GRC proceedings. Our EORM Program will also continue to benefit from and carefully consider stakeholder input.

Our implementation of the S-MAP Settlement Decision is explained in Chapters 3 and 4 of this Report.[5] We developed our Multi-Attribute Value Function (MAVF)[6]—a foundational element of the S-MAP Settlement Decision—based on the principles articulated in that decision.[7] Using that methodology, we performed a risk analysis and produced risk scores, and then used them to: (1) identify top risks, of which there are 12, to be evaluated in this Report and (2) develop the proposed mitigations to address those risks to advance our mission to deliver safe, reliable, affordable clean energy to our customers every day.

We include in this Report a high-level discussion of other safety risks, including key drivers and mitigations. We have included a separate chapter in

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[5] D.18-12-014.

[6] 2018 S-MAP Revised Lexicon (D.18-12-014, p. 17) defines a MAVF as:

> [a] tool for combining all potential consequences of the occurrence of a risk event, and [it] creates a single measurement of value.

[7] See Chapter 3, "Risk Modeling and Risk Spend Efficiency."

which we describe relevant cross-cutting factors that impact PG&E's risks. Finally, we provide a qualitative discussion of potential pandemic impacts and our plans for incorporating the pandemic risk in future risk assessments. These components, together with the RAMP risk evaluations, provide a holistic view on how we are continually assessing our system and refining our risk management processes.

B. Background

This is PG&E's second RAMP Report. It advances our work over the last decade to continuously improve the EORM Program. The Report also demonstrates progress in our understanding, analysis, quantification and mitigation of risk. This is another significant step in our ongoing effort to address the risks inherent in providing gas and electric service.

PG&E has enhanced its ability to identify and mitigate risk over the past decade. In 2012, following the San Bruno tragedy, we transitioned our then-existing Enterprise Risk Management Program to a more comprehensive program with improved operational focus, increased use of analytics and greater integration with the Company's planning processes.[8] In subsequent years, we began incorporating risk and mitigation analyses into our integrated planning processes.[9] Our goal is to be a leading utility in adopting and advancing rigorous risk management practices.

More recently, we have been working to address feedback regarding our first RAMP Report and our integration of the RAMP Report in the 2020 GRC. These efforts have primarily focused on data and integration. As discussed more fully below, we have improved our data collection and analysis and have moved to integrate risk analysis and evaluation of mitigations across multiple LOBs. Specifically, we have moved to an event-based formulation of RAMP risks and the identification and analysis of cross-cutting factors, which are drivers and/or consequences that may affect multiple event-based risks.

These improvements in data, integration and analysis are in response to this feedback. Our heightened focus on data acquisition and analysis has led to greater transparency and a more strategic application of subject matter

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8 2014 GRC, Application (A.) 12-11-009, Exhibit (PG&E-1), p. 4-1 to p. 4-3.

9 2017 GRC, A.15-09-001, Exhibit (PG&E-2), p. 4-5 to p. 4-6.

expertise, two areas of concern raised by SED. In addition, PG&E has replaced general industry data with more PG&E-specific data, consistent with feedback from SED and intervenors. While there is more work to be done on PG&E-specific data collection, this Report reflects progress in the analysis of data informing event-based risks. Going forward, we will continue to gather more granular data and disseminate it so it is used in risk-informed decision-making.

Leading up to this Report, PG&E conducted three workshops with stakeholders to transparently describe how PG&E would incorporate the S-MAP Settlement Decision methodology into our risk management practices, propose risks for evaluation in this Report, and solicit feedback received from the Commission and parties.[10] We reiterated our focus on tail events and explained why this focus is both appropriate and necessary to retain line-of-sight on high consequence tail events while using expected values in prioritization and decision-making. We achieve this focus on tail events through the MAVF scaling function, which enables us to "captur[e] aversion to extreme outcomes."[11]

At the third workshop, held on February 4, 2020, we presented our preliminary list of 12 RAMP risks[12] shown in Table 1-1 below. PG&E explained at this workshop that the preliminary list was developed starting with the risks in PG&E's Corporate Risk Register (CRR).[13] PG&E's presentation included Risk Event definitions, bowtie analyses, and documentation of data sources for each risk on the preliminary list.

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[10] For a discussion of the contents of the three workshops, see Chapter 4.

[11] D.18-12-014, Attachment A, MAVF Principle 5 – Scaled Units, p. A-5.

[12] This public workshop is a requirement set forth in the S-MAP Settlement Decision. (D.18-12-014, p. 32.) The previous two workshops were not required. For a description of the workshops and the process for identifying the preliminary RAMP risks, see Chapter 4.

[13] PG&E recently renamed its Enterprise Risk Register to Corporate Risk Register. The CRR consists of event-based risks with potential for severe or catastrophic outcomes to the company. The purpose of the CRR is to provide visibility and focus on these to facilitate leadership attention, monitoring, and oversight.

TABLE 1-1
RAMP RISKS AS PRESENTED IN FEBRUARY 4, 2020 WORKSHOP

Line No.	Risk Event
1	Wildfire
2	Third-Party Incident
3	Motor Vehicle Incident
4	Employee Safety Incident
5	Contractor Safety Incident
6	Real Estate and Facilities Failure
7	Loss of Containment (LOC) – Gas Distribution Pipeline – Non-Cross Bore
8	Large Uncontrolled Water Release (Dam Failure)
9	LOC – Gas Transmission Pipeline
10	Failure of Electric Distribution Network Assets
11	Failure of Electric Distribution Overhead Assets
12	Large Gas Over-pressurization Downstream

The 12 RAMP risks analyzed in this Report are the risks identified above. PG&E modified the scope or risk definition of certain risks following the third workshop. Any change to the risk is addressed in the risk-specific chapter.

We acknowledge and appreciate the significant contributions from SED, SPD and other CPUC staff and intervenors at the workshops, and throughout the decade-long journey to improve the methodology employed for systematic and quantitative risk assessment and mitigation. This Report incorporates feedback from the Commission and other stakeholders in a variety of forums since PG&E's 2017 RAMP Report, including the three workshops discussed above. The Report also incorporates insights derived from our peer utilities' RAMP Reports, including Southern California Edison Company's RAMP proceeding (Investigation (I). 18-11-006) and Sempra's 2019 RAMP proceeding (I.19-11-010) which was the first RAMP Report to implement the S-MAP Settlement Decision methodology.

We have strived to implement the S-MAP Settlement Decision within the compressed timeline for production of this RAMP Report. In D.20-01-002, the Commission reduced the available preparation time of the Report by five months. This change required us to be innovative, creative and flexible in achieving the goals of the S-MAP Settlement Decision on a more compressed timeframe. The analysis in this Report includes information as of May 2020. Certain events after May 2020 are not reflected in this Report but will be included in the risk analysis presented in the 2023 GRC.

The reduced preparation time, and the need to advance urgent wildfire safety work, precluded PG&E from completing the evaluation of risk reduction achieved through existing controls. As a start on this process, we have piloted two control programs RSEs: Leak Management and Enhanced Inspection Program.[14] We appreciate feedback on our approach to quantifying these controls as we will expand this analysis to additional control programs. Deepening our understanding of existing controls is an essential next step in advancing our risk management and we remain committed to completing this effort.

The material that follows shows the improvements we have made and the areas where further improvements are planned. As discussed more fully in Chapter 2, we will present additional information and refinements in our 2023 GRC testimony.[15] This Report presents both a snapshot of the current state of our work and our commitment to further expanding our quantitative operational risk modeling.

C. PG&E's Approach to Risk Management and the RAMP Report

1. Risk Management Is Driven by Data

PG&E's risk management efforts and this RAMP Report are increasingly data-driven. In our 2017 RAMP Report, we identified the need to gather better data as a critical next step for most risks. Since that time, we have focused on developing, analyzing and refining PG&E-specific risk data. This effort is reflected in this Report.

Improvements to our data have enabled a transition from a risk management process that primarily relied on the judgment of SMEs and industry data to a process driven largely by PG&E-specific data from historical events, supplemented as necessary with SME and industry data. All the RAMP risks incorporate PG&E-specific data, which most accurately captures both the consequences and likelihood of trigger events in our service area.

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[14] See Loss of Containment Distribution Main or Service (Chapter 8) and Failure of Electric Distribution Overhead Assets (Chapter 11).

[15] See Chapter 2 for a discussion of lessons learned and next steps. PG&E will provide RSEs for additional programs not included in this Report consistent with the thresholds in the S-MAP Settlement Decision.

We have improved data collection in areas having the greatest impact on risk analysis. For example, in addition to using failure data to model the frequency of risk events, our bowtie analysis incorporates root cause analyses and data feedback loops, making the analysis more robust. We also have begun collecting data on the causes of failure to help develop more effective mitigations. The Company is broadening our focus to understand "what happened" and "why it happened," and using both to anticipate and mitigate future occurrences.

This transition is ongoing. Our data collection efforts revealed gaps and the need for additional data, including more granular data on the frequency of specific drivers, failure modes, and the consequence of events.

Many of our data gathering processes are compliance-focused and, as such, data collection and review have historically been directed at annual reporting requirements rather than risk analysis. While keeping an accurate count of events for reporting purposes is necessary, it is insufficient for the purpose of analyzing risk. Therefore we are intensifying our efforts to better understand failure modes, irrespective of whether a specific failure constitutes a reportable event. For example, we are recording all ignitions associated with PG&E equipment regardless whether an ignition meets the CPUC reporting requirements. We can still learn from and reduce risks by incorporating in our data events that caused an ignition, irrespective of whether the event was of a sufficient magnitude to trigger a reporting requirement. We can more effectively reduce wildfire risk if we understand the cause of every ignition, which requires collecting and analyzing the data necessary to do so.

Better risk-informed decision-making requires both better data and better data analysis. PG&E is committed to continue to identify data gaps and gather increasingly granular data to better inform our risk analysis. We will continue to build on these data enhancements as we build our 2023 GRC.

2. The Current Event-Based Risk Register Allows for More Transparent and Consistent Identification and Ranking of Risks

PG&E has transitioned to an event-based risk register that is developed on an enterprise-wide basis governed and supported by the EORM

Department.[16] This transition has enabled the consistent examination of the likelihood and consequences of risk events across the Company.

PG&E consolidated a list of over 200 individual risks that informed the 2017 RAMP Report which resulted in 35 "event-based risks"[17] at the end of 2019. This new list was the starting point for the risks addressed in this Report. Some of the 200 individual risks previously identified were recharacterized as drivers to, or controls for, risk events. For example, "emergency preparedness and response risk," (the risk resulting from failing to appropriately prepare for and respond to emergent situations) is now primarily viewed as a control for reducing the impact of specific Risk Events, such as a "Wildfire" or "Loss of Containment – Gas Transmission Pipeline." Similarly, "Cyber-Attack" risk is now viewed as a potential driver for Risk Events, such as Failure of Electric Distribution Network Assets or Large Gas Over-pressurization Downstream.[18]

Each Risk Event has a risk definition and a scope that defines what qualifies as a Risk Event. Each Risk Event is then broken out into Tranches to allow for more granular risk analysis.[19] A data range sets the period considered to establish the frequency of the Risk Event. These elements are summarized in a Risk Event Summary for all the 12 RAMP risks. Each of the 12 RAMP risks is discussed in its own chapter of this Report.

A consequence of adopting an event-based view of risk is that certain risk drivers, controls, and/or mitigations may cut across multiple events. Items that are not themselves Risk Events, but that can affect multiple Risk Events, are identified as cross-cutting factors. These factors can affect Risk

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16 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 18) defines a "risk event" as:

> An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address. In particular, the occurrence of a Risk Event changes the levels of some or all of the Attributes of a risky situation.

17 As described in Chapter 4, "RAMP Risk Selection," PG&E has made additional refinements to its CRR since 2019. As of May 2020, there are 33 event-based risks on the CRR.

18 See Chapter 20, "Cross-Cutting Factors."

19 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 18) defines a "tranche" as:

> A logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment.

Events in several ways. A cross-cutting factor can be a unique risk driver or a component of an existing driver; it can impact the likelihood of an event and/or its consequence. For example, Records and Information Management (RIM) was a risk in the 2017 RAMP Report. RIM is now considered a cross-cutting factor for several risks, including those involving LOC and failure of electric distribution assets.

A reality of these cross-cutting factors means that some aspect of risk management (e.g., controls or mitigations) that impact a Risk Event may be managed by someone other than that Risk Event's owner. As such, the identification and management of these cross-cutting factors are critical components of our EORM success. As discussed in Chapter 2, PG&E has formed a Vice President Risk Committee with representation from various LOBs, which has taken on oversight of cross-cutting factors to ensure they receive the same sort of rigorous review as is done for the Risk Events themselves.

In Chapter 20, "Cross-Cutting Factors," we identify eight cross-cutting factors that are evaluated in this RAMP Report. They are:

1) Climate Resilience;
2) Cyber Attack;
3) Emergency Preparedness and Response;
4) Information Technology (IT) Asset Failure;
5) Physical Attack;
6) RIM;
7) Seismic; and
8) Skilled and Qualified Workforce.

We analyzed many of these cross-cutting factors separately as individual risks in the 2017 RAMP Report.[20] While these cross-cutting factors are now incorporated into the bowtie analysis of the risk events, it remains difficult to fully model their impacts and understand the consequences of these factors. Given the condensed timeline to prepare this RAMP Report, this is an area in which we did not achieve the level of

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[20] PG&E described the weakness of the cross-cutting modeling approach in its 2017 RAMP Report and also received criticism from SED. See Chapter 20, "Cross-Cutting Factors."

analysis we had hoped. Chapter 20 summarizes the cross-cutting factors, shows how they map to and affect the RAMP risks. In addition, many RAMP risks have set forth a “climate focused” alternative mitigation plan to identify the potential impacts that future climate factors may have on the risk event and potential mitigations to address those impacts. We will continue working to incorporate these factors into the risk event bowties and we look forward to feedback from the Commission and stakeholders on this issue.

3. PG&E Has Implemented the MAVF and Risk Analysis Methodologies Pursuant to the S-MAP Settlement Decision

a. MAVF

PG&E selected its list of Preliminary RAMP Risks by applying the methodology in the S-MAP Settlement Decision.[21] We started by including the top 40 percent of Risk Events in our Corporate Risk Register based on Safety Risk Score (rounding up as necessary). We then examined Risk Events below the 40 percent threshold to determine if they had a Safety Risk Score within 20 percent of the lowest scoring Risk Event in the top 40 percent. If so, we added that Risk Event to the list. This process yielded 12 Event Risks for the preliminary list. These 12 Event Risks are the RAMP risks shown in Table 1-1 above.

Consistent with the S-MAP Settlement Decision, we are implementing a MAVF for each RAMP risk together with a bowtie analysis. In the S-MAP Settlement Decision, the Commission agreed with the SED that using a MAVF is:

> … a big improvement [that] dramatically advances [a] utility’s ability to assess and prioritize risks, and offers many advantages … .[22]

The bowtie analysis facilitates the calculation of a risk score, which reflects the probability of a risk event occurrence given the historical frequency of key risk drivers and the potential consequences of the risk event.

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[21] D.18-12-014, Attachment A, Step 2A, p. A-8 to p. A-9.

[22] D.18-12-014, p. 44.

A MAVF measures risk consequences in terms of Attributes.[23] PG&E uses four Attributes: (1) Safety, (2) Gas Reliability, (3) Electric Reliability, and, (4) Financial (excluding shareholders' financial interests).[24] Environmental attributes are accounted for financially (i.e., within the financial Attribute) because there are no commonly accepted measures of non-monetary environmental consequences. We believe these four attributes incorporate the essential elements to deliver safe, reliable, and affordable service, which are also key elements in driving customer satisfaction.

For each attribute there are natural units of measurement and a range of potential values for these units that go from the smallest to the largest observable value.[25] Using the Electric Reliability attribute as an example, the natural units are Customer Minutes Interrupted per event and the range of potential values goes from zero to 4 billion.

Each attribute is assigned a weight in the MAVF. The Commission determined in the S-MAP Settlement Decision that potential safety consequences of a risk event should be assigned:

> … a minimum … weight of 40% to ensure that the safety attribute is weighted most heavily.[26]

PG&E's risk scoring methodology is consistent with this direction in assigning a 50 percent weighting for safety consequences, a 20 percent weighting for electric reliability consequences, a 5 percent weighting for gas reliability consequences, and a 25 percent weighting for financial consequences. This weighting reflects our focus on safety and is consistent with the weighting used by the other large IOUs.

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23 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 16) defines an "attribute" as:

> An observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability. Changes in the levels of attributes are used to determine the consequences of a Risk Event. The attributes in an MAVF should cover the reasons that a utility would undertake risk mitigation activities.

24 D.18-12-014, p. 29.

25 Ranges are defined on a per-event basis. Pursuant to the 2018 S-MAP Revised Lexicon (D.18-12-014, pp. 17-18), "… the largest observable value [of an Attribute] is the high end of the range." PG&E interprets this to be based on historical and/or plausible worst-case scenarios.

26 D.18-12-014, p. 45.

We use a scaling function to assign a score between zero (for the most favorable outcome) and 100 (for the least favorable outcome) to the natural units associated with each attribute. This scaling allows attributes with different natural units of measurement to be combined into a single risk score.[27] Converting each attribute to a common scale also shows which attributes are the primary drivers of each risk.

We use a non-linear scaling function that has the effect of increasing the risk scores associated with catastrophic outcomes.[28] This approach is consistent with the S-MAP Settlement Agreement, which permits both linear and non-linear scaling functions.[29] The non-linear scaling function supports our risk management philosophy which seeks to avoid low frequency, high consequence events that can have catastrophic consequences. Chapter 3 provides additional explanation of why this is the appropriate lens to use in scoring risks and mitigations.

b. Risk Analysis

Consistent with the S-MAP Settlement Decision, risk scores are the product of the Likelihood of a Risk Event (LoRE), and the Consequence of a Risk Event (CoRE) (i.e., ”Risk Score = LoRE x CoRE”). The Safety Risk Score only considers safety consequences. The Overall Risk Score considers safety, electric and gas reliability and financial consequences using the weights and scaling functions discussed above. The likelihood is based on frequency data, which are reported as expected number of risk events caused by a risk driver, per unit of exposure, per unit of time.

Figure 1-1 below shows a simplified bowtie analysis, which illustrates the relationship between a Risk Event and its Drivers and Consequences. In the center of the bowtie is the Risk Event, which is a well-defined, single, observable, and measurable event caused by the

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27 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 18) defines a “risk score” as a:

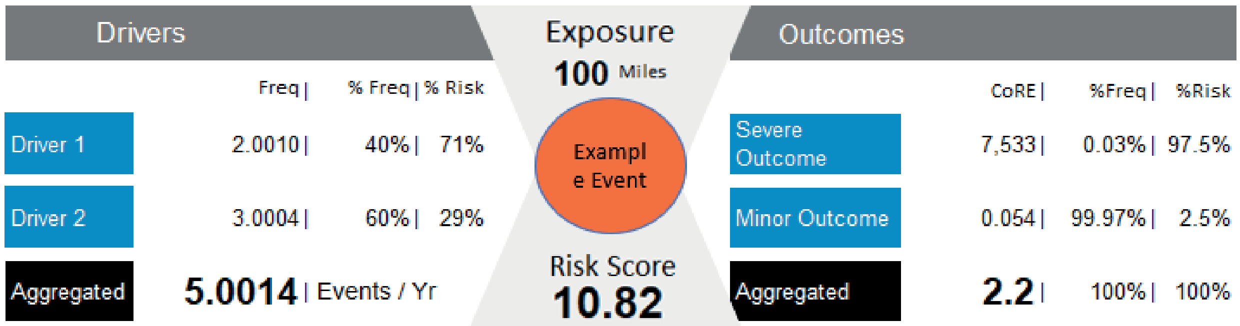
> Numerical representation of qualitative and / or quantitative risk assessment that is typically used to relatively rank risks and may change over time.

28 The S-MAP Settlement Agreement explicitly allows for the use of either linear or non-linear scaling factors. (D.18-12-014, Attachment A, No. 6, p. A-6.)

29 D.18-12-014, Attachment A, No. 6, p. A-6.

Drivers (characterized by Exposure and Frequency) on the left-hand side, which brings about the Consequences on the right-hand side.

FIGURE 1-1
ILLUSTRATIVE BOW TIE



To develop a distribution of consequences, we performed Monte Carlo simulations of a consequence distribution for each attribute in natural units specific to each outcome for each tranche of a Risk Event. We use these simulations to produce CoRE as expected values of scaled units for CoRE each tranche of each Risk Event. CoRE values are multiplied to LoRE to produce Risk Scores per unit of exposure of each tranche. The Overall Risk Score for a Risk Event is a summation of the expected values that represent the individual tranche risk score. Like the attribute analysis, the tranche analysis further magnifies which conditions have a disproportionate risk impact.

This is the first RAMP Report where we have divided risks into tranches. We acknowledge that this initial effort is only the first step in disaggregating risk. Parties have suggested methods for further disaggregation such as tranches based on asset condition and further geographic segmentation. We support the tranches approach and expect to incorporate further refinements to achieve greater risk granularity when we have better data relevant to mitigation opportunities.

This risk analysis considers only direct safety consequences in computing Risk Scores. The Utility Reform Network (TURN) suggested that indirect safety consequences must be included to obtain accurate

Risk Scores.[30] We disagree. We cannot find a reliable methodology to distinguish between those indirect consequences appropriate for inclusion and those which are too remote in terms of time, distance and/or causality. Without such a methodology, we cannot develop reliable data on indirect consequences and, without such data, the indirect consequences would be little better than a guess.

For the purposes of preliminary risk list identification, the scores shown are 2019 annual scores. In recent months, we have incorporated 2019 recorded incident data, revised the models based on internal and external feedback, and forecasted risk reduction based on planned work for the current GRC cycle. We present these updated risk scores throughout this Report, as the 2023 Baseline Risk Scores.

4. Mitigations, Controls and Risk Spend Efficiency

In addition to evaluating risk, the RAMP Report evaluates proposed Mitigations:[31]

> … to provide the Commission and parties the kind of information that is needed to direct limited utility resources and ratepayer dollars to the mitigations and groups of assets that can produce the most risk reduction benefit.[32]

The data and risk model enhancements discussed above have improved our ability to develop and analyze mitigation strategies.

PG&E has proposed a Mitigation Plan for each RAMP risk. The Mitigations proposed are designed either to reduce one or more of the risk driver frequencies or to modify the consequence outcomes of one or more attributes. The connection between the Mitigation and the risk driver(s) or consequence attribute(s) each Mitigation addresses is illustrated in each chapter.

Each Mitigation is evaluated by comparing the overall risk score associated with the Risk Event being mitigated before and after the

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30 See WP 3-4 for TURN's February 19, 2020 letter.

31 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 17) defines a "mitigation" as a:

> Measure or activity proposed or in process designed to reduce the impact / consequences and / or likelihood / probability of an event.

32 D.18-12-014, p. 21.

application of the Mitigation. For each Mitigation, we calculate a Risk Spend Efficiency (RSE), dividing the reduction in risk score by the cost of the Mitigation (excluding any shareholder funded cost). This calculation is done on a present value basis using the same discount factors for both the numerator and the denominator.[33] While our previous RAMP model used a 6-year time horizon to evaluate benefits from mitigations, our 2020 model includes benefits from proposed mitigations over their entire useful life.

We bundle individual Mitigations to create Mitigation plans. Each Mitigation plan may include both Mitigations and "foundational" activities. Foundational activities are programs or activities that do not have a stand-alone risk mitigation effect but enable multiple Mitigations. They can be thought of as initial work needed to implement future Mitigations such as investments in IT infrastructure. Because foundational activities generally do not themselves reduce risk, they do not have associated RSE calculations. However, their costs are included with an associated Mitigation in calculating that Mitigation's RSE.

PG&E primarily reduces risk through controls. Controls are currently established measures that modify risk.[34] Controls include operations, plans and standards, emergency response procedures and other programs required by law or policy to operate our LOBs. They are often associated with compliance requirements. While the controls currently in place reduce risk, we did not calculate RSE for all controls.

We see value in calculating RSE for controls, despite the challenges inherent in this effort. During 2019, we redesigned our compliance driven inspection processes to be risk based. This change enhanced identification of risk factors and failure modes, which demonstrates the value of assessing compliance-based controls through a risk lens. It is crucial that we better understand both the mitigations and controls that may reduce the inherent

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33 The use of a single discount factor is a change from the approach PG&E used in its workshops. TURN suggested that a single discount rate be used because PG&E proposed use of different discount rates for numerator and the denominator in the RSE calculation would bias the results. PG&E accepted this suggestion and has used a single discount rate for RSE calculations in the 2020 RAMP Report.

34 The 2018 S-MAP Revised Lexicon (D.18-12-014, p. 16) defines a "control" as a: "Currently established measure that is modifying risk."

risks on our system. But no system of controls can eliminate risk from the dynamic open environment where the utility operates. Our risk program is designed to continually learn from incidents, make conditional assessments to evaluate the effectiveness of our processes and controls, and adjust those processes in response to new data and incidents.

D. Organization of this Report

The remainder of this Report is organized as follows:

TABLE 1-2
SUBSEQUENT RAMP REPORT CHAPTERS

Line No.	Chapter	Contents
1	2	Risk Management Framework
2	3	Risk Modeling and RSE
3	4	Risk Selection
4	5	Safety Culture and Compensation
5	6	Pandemic Impact Evaluation
6	7-18	Individual Risk Chapters
7	19	Other Safety Risks
8	20	Cross Cutting Factors
9	21	Steady State Replacement

This RAMP Report includes a separate chapter for each of the 12 RAMP risks is presented in Table 1-2 above. Each risk is presented in a standard format with the same elements. Each chapter ends with an alternatives analysis showing the proposed mitigation plan and two alternative plans. Each risk-specific chapter addresses the first eight of the 10 steps in the Cycla 10-step Risk-informed Resource Allocation Process with the final two steps to be addressed following issuance of the GRC decision.[35]

E. Conclusion

The foregoing demonstrates our substantial progress in developing our EORM Program. To summarize, we have:

- Transitioned to an event-based RAMP Risk Register;

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35 D.18-12-014, p. 33. The two steps this process does not address are: Step 9: Adjusting mitigations following CPUC decision on allowed resources; and, Step 10: Monitoring the effectiveness of risk mitigations. These last two steps will be addressed after receiving the GRC decision, and in the submission of the Accountability Report, respectively.

- Collected and analyzed more PG&E-specific risk data;
- Integrated risk evaluation methodologies across the Company's LOBs;
- Identified cross cutting factors and begun incorporating them in risk evaluation;
- Redesigned compliance-based inspection processes to incorporate risk; and,
- Begun the work to develop RSE for control measures.

While all these efforts will help reduce risk, no system of controls and mitigations can eliminate risk in utilities' dynamic, open operating environment. Therefore, the goal of our risk program is to continually learn from incidents, investigations, condition assessments, industry operational experience and other risk professionals in order to continually improve our risk-mitigating processes controls and efforts.

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CHAPTER 2

RISK ASSESSMENT AND MITIGATION PHASE

PG&E'S ENTERPRISE RISK MANAGEMENT FRAMEWORK

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PG&E'S ENTERPRISE RISK MANAGEMENT FRAMEWORK

A. Introduction

Pacific Gas and Electric Company's (PG&E or the Company or the Utility) Enterprise and Operational Risk Management (EORM) Department has centrally governed the Company's processes for identifying, assessing, mitigating and monitoring risk since its inception in 2012. Our approach has evolved since that time as a result of lessons learned, feedback from external stakeholders, benchmarking, and risk management best practices. This chapter provides an overview of the current state of the EORM Department and our practices, including:

- PG&E's Enterprise Risk Management (ERM) Framework;
- Changes since PG&E's 2017 Risk Assessment and Mitigation Phase (RAMP) Report; and
- Additional focus areas for improvement going forward.

B. PG&E's ERM Framework

1. Objective of PG&E's EORM Program

The objective of PG&E's EORM program is to facilitate risk-based, data-driven decision-making that results in measurable risk reduction. EORM's processes are based on the principles of the widely-used International Organization for Standardization (ISO) 31000[1] risk management standard and help the Company to systematically identify,

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1 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.

evaluate, prioritize, mitigate, and monitor risks inherent in its operations. PG&E uses bowtie analyses[2] to accomplish this objective.

EORM provides central coordination of risk mitigation with local execution. Through application of the EORM framework and continual improvements thereto, PG&E comprehensively identifies risks that could lead to significant safety consequences at an enterprise level, and then implements the actions that have the best potential to reduce risk at a local level. EORM effectively and transparently monitors and reports results from operations throughout PG&E's service area.

At its inception, the EORM program largely relied on a qualitative approach to assessing and evaluating risks. Over time, however, particularly with the significant developments from the Safety Model Assessment Proceeding (S-MAP) and RAMP proceedings, PG&E's EORM program has become increasingly data-driven and quantitative at all stages of this iterative process.

2. Purpose

The EORM Department (Department) provides governance for PG&E's EORM program and supports the Lines of Business (LOB), who are responsible for identifying, evaluating, mitigating and monitoring the risks. The Department is responsible for assessing those risks that have the potential to be severe or catastrophic to PG&E and designating these as risks on the Corporate Risk Register. Additionally, the Department provides oversight by monitoring the status of the Company's EORM activities.

The EORM Program is an integral part of how we provide safe and reliable utility service. The Department works with LOBs to:

- Identify and evaluate risks using a blend of qualitative and quantitative techniques;

[2] Bowtie analysis provides the framework for all risk assessments within scope of the EORM program. The bowtie analysis starts with the risk event at the knot of the bowtie and identifies risk drivers (threats) with their likelihood of leading to a risk event on the left side of the bowtie, and the potential outcomes with their magnitude of consequence of a risk event on the right side of the bowtie. The analysis is then used to quantify risk reduction from mitigations that reduce the likelihood of a risk event from each risk driver (left side of the bowtie) and/or reduce the magnitude of consequences as a result of the event occurring (right side of the bowtie). For a detailed discussion of our approach, see Chapter 3 of this Report.

- Develop risk response plans based on an analysis of reasonable alternative mitigation strategies;
- Establish metrics to monitor risks and measure the effectiveness of mitigations;
- Provide oversight to ensure the LOBs follow the standards and procedures established and maintained by the Department;
- Implement the outcomes of regulatory risk proceedings such as the S-MAP and RAMP;
- Facilitate cross-functional risk meetings to promote consistency, continuous improvement, and sharing of best practices;
- Report to senior management on the status of EORM at PG&E, including whether the LOBs have dedicated and qualified resources to manage risks on the Corporate Risk Register consistent with their mitigation strategies; and
- Manage a database to store the Company's EORM process records.

The Department provides strategy, analysis, and support for LOBs as PG&E completes quantitative risk assessments.

3. Organization Structure

PG&E's risk governance structure is led by the Chief Risk Officer (CRO) who, effective June 30, 2020, will report directly to the CEO of PG&E Corporation. The CRO will also directly report to the Safety and Nuclear Oversight (SNO) Committees of the Board of Directors[3] and the Audit Committees of the Board. The CRO will be the enterprise risk officer for PG&E with oversight of risk assessment and mitigation. The CRO will have oversight of risks associated with PG&E's operations and the environment related to public safety. This will include, but not be limited to, nuclear risk, wildfire risk, and risks of other natural disasters as well as new strategic risks confronting utilities such as business interruption from attack, storms, and other catastrophic events.

The Department consists of three groups: (1) Risk Quantification, (2) Regulatory, and (3) Governance. Since the last RAMP, the size of PG&E's Risk Quantification team has expanded from one PhD assisted by

[3] The CRO reported to the Chief Financial Officer until June 30, 2020.

consultants, to a team of five risk professionals—four of which have PhDs in a quantitative field.[4] The Regulatory team supports EORM's efforts to meet its regulatory commitments including preparation of the RAMP, the General Rate Case (GRC), and participation in other regulatory proceedings. The Regulatory team includes two employees and has one vacancy. The Governance team supports the governance of the EORM Program (see below for description). The Governance team includes two employees and has two vacancies.

In the Plan of Reorganization Order Instituting Rulemaking ("I.") 19-09-016 ("POR OII")[5] PG&E committed to a more regionalized structure in its business operations. Regionalization will help PG&E improve risk management by: (1) identifying local risks in each region;[6] (2) improving knowledge of the condition of local assets; (3) focusing on the needs of local customers; and (4) improving local operations. This enhanced information will then be used to assess the effectiveness of regional controls and mitigations. A Regional Safety Director in each region will help improve PG&E's risk management by improving the gathering and analysis of data regarding regional safety incidents including root cause analysis.

PG&E also has begun collecting data on the causes of failure for assets in service, broadening our focus to include not only "what happened" but "why it happened." The intent of this effort is to better understand asset conditions and take proactive steps to mitigate future occurrences.

While we have made significant strides by integrating tranche analysis into our risk models, we do not yet have a deep understanding of local asset conditions. Regional staff will have better insight into the condition of the assets and the needs of the region. By understanding the local needs of

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4 Please see WP 2-1 for a list of qualifications.

5 *See Order Instituting Investigation on the Commission's Own Motion to Consider the Ratemaking and Other Implications of a Proposed Plan for Resolution of Voluntary Case filed by Pacific Gas and Electric Company, pursuant to Chapter 11 of the Bankruptcy Code, in the United States Bankruptcy Court, Northern District of California, San Francisco Division, In re Pacific Gas and Electric Corporation and Pacific Gas and Electric Company, Case No. 19-30088,* I.19-09-016 (Sept. 26, 2019).

6 EORM plans to conduct a bottom up risk survey in each region to hear from front line employees on the condition of the assets, local issues that can lead to safety risks and barriers that prevent controls and mitigations from effectively reducing risk.

customers and the risk factors to our assets specific to that region, system planners and engineering can design a more resilient system that is better able to meet local needs and improve the risk management and safety of the system.

4. Governance

Our risk management governance structure has remained largely unchanged since the 2017 RAMP however EORM's role has increased within the Company to reflect PG&E's heightened focus on reducing risk in our operations. Our focus on risk is reflected at every level of the Company, from the Board of Directors to individual contributors. We conduct "horizon scanning" in different forums at different levels of the organization. These forums where risk is evaluated, discussed and monitored throughout the Company include:

Board Committees: Three Board of Director-level committees (Audit, Finance, and SNO) provide oversight of Enterprise Risks and associated mitigation activities. Board Committees receive updates on the risk management program, approve the designation of Enterprise Risks[7] and Enterprise Cross-Cutting Factors[8] and provide oversight to these Enterprise Risks and Enterprise Cross-Cutting Factors at least every 12 months.

Vice President (VP) Risk Committee: An enterprise risk committee comprised of VPs from each of the LOBs meets monthly, to oversee progress made on risk focus areas and actions to reduce risk exposure. The Committee also oversees risk management program strategy and performs deep dives and challenge sessions into specific top risks. Since the last RAMP, this Committee expanded its responsibilities to oversee the cross-cutting factors to ensure these receive the same rigorous review as event-based risks. The VP Risk Committee also provides a forum for raising and resolving cross-functional issues.

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7 "Enterprise Risks" are risks identified through the EORM Program as potentially catastrophic and recommended by senior management for Board-level review at least once every 12 months.

8 "Enterprise Cross-Cutting Factors" is the term used to describe cross-cutting risk drivers or controls associated with one or more Enterprise Risks.

Session D: PG&E's CRO and Chief Ethics and Compliance Officer jointly lead Session D, with Risk Owners and Compliance Requirement Owners presenting specific risk and compliance topics related to their organization.

During PG&E's annual Session D meeting, senior officers identify those risks that could be most potentially catastrophic to PG&E, and therefore, qualify as Enterprise Risks, which are then subject to Board Committee oversight. Senior Officers also set annual risk management priorities for measurable risk reduction for the Company's top risks (i.e., those on the Corporate Risk Register). The information derived from Session D, as well as all other risk information from the other risk and compliance forums, inform PG&E's strategy and execution plans that ultimately form the basis of PG&E's GRC forecast and LOB work plans. There is also an annual horizon-scanning survey as part of Session D.

Session D begins with an assessment of how the Utility performed against the risk and compliance commitments made in the prior year. It then transitions to a focus on the top risks and associated compliance items for the Company, leveraging the outputs from the forums outlined above and input from the most recent risk assessments and RAMP. For each of the risks and associated compliance requirements identified for discussion during Session D, key drivers and associated controls, mitigation strategies, and any potential challenges are discussed and decisions, if necessary, are made. The session ends with a look ahead through "Horizon Scanning" to determine how prepared the Utility is to manage new or changing risks or compliance requirements. The key outcome of Session D is leadership alignment on the areas of focus for the coming year and an initial assessment of the adequacy of resources to execute against the proposed mitigation plans for the top Company risks.

Risk Management Community (RMC) Meetings: RMC meetings are held monthly, where EORM leads a discussion with Risk Managers from all LOBs, Compliance Liaisons, and other interested parties on various risk management topics. Although PG&E follows an internal standard based on the ISO 31000 standard, which helps achieve a consistent approach to risk management throughout the organization, there is always room for debate and interpretation. The RMC is the forum used to have this discussion, share best practices, discuss challenges, and encourage employees to speak up and raise issues as needed.

LOB Risk and Compliance Committees (RCCs): Each LOB conducts RCC meetings chaired by the most senior Officer in the LOB to provide oversight for risk and compliance performance and initiatives for which they have ownership, raise and resolve issues, and share best practices. These take place throughout the year, at least quarterly but most are monthly. Each LOB RCC oversees the actions taken to actively manage the operational and strategic risks inherent to that LOB.

If a pertinent issue is raised that requires further investigation, an owner is designated with the understanding that the item will be tracked and brought to the appropriate LOB's RCC for further review and resolution.

Dedicated Risk Managers in each LOB manage all risk-related activities within that LOB, which includes: risk assessments and quantification, reporting and governance, and tracking metrics and mitigations. EORM is increasing the level of support it is providing to LOB risk managers by embedding risk professionals in key areas to ensure: (1) the data, models, assumptions and calculations used for decision-making have integrity; (2) there are feedback loops to assess the risk reducing impact of executed work; (3) the level of risk reduction achieved through compliance driven processes and controls is understood; and (4) that there is "line of sight" from the top risks to executed work.

In addition to the governance structure and forums described above, there are additional tools we use to monitor and evaluate risk.

Guidance documents outline the ERM process including roles and responsibilities for governance, oversight, execution, and support. These documents were updated to reflect the change in methodology in the S-MAP Settlement Agreement.[9]

The Enterprise Performance Huddle (EPH) risk dashboard tracks key metrics and associated performance by LOBs. The EPH keeps the senior management team apprised of the progress on the Company's most

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[9] See Phase Two Decision Adopting S-MAP Settlement Agreement with Modifications, Attachment A, Element No. 8, Risk Identification and Definition, D.18-12-014, p. A-7, (D.18-12-014).

important risk priorities, including the management of Enterprise Risks and Enterprise Cross-Cutting Factors throughout the organization. The risk discussion at the EPH focuses on risk reduction of PG&E's Enterprise Risks and Cross-Cutting Factors and other risk-related commitments made by LOBs.

The Corrective Action Program (CAP) enables employees and contractors to identify and track equipment and safety issues, ineffective and inefficient work processes and procedures, and provide suggestions on how to execute work more safely or efficiently. All employees and contractors with access to PG&E's computer network can enter an issue into the CAP system via the intranet and mobile devices, phone and paper. A similar system has been in place for decades at the Diablo Canyon Power Plant and has been instrumental in supporting a speak-up culture.

C. Key Improvements Since PG&E's 2017 RAMP

1. Multi-Attribute Value Function (MAVF) Methodology

After the California Public Utilities Commission (CPUC or the Commission) adopted the S-MAP Settlement Agreement in Decision (D.) 18-12-014, PG&E constructed an MAVF and implemented in 2019 the methodology for risk and mitigation analysis to be consistent with the S-MAP Settlement Agreement. A description of how PG&E implemented this methodology is found in Chapter 3.

2. New Risk Models

PG&E upgraded its first-generation RAMP risk models used in the 2017 RAMP. The 2017 RAMP risk models were based in Excel with the off-the-shelf @ Risk add-in, commercial software for performing Monte Carlo Simulation. While these models were tremendously useful for the first RAMP, there were numerous challenges for scaling up to meet the needs for increased modeling requirements under the S-MAP Settlement Agreement and companywide adoption and usage. PG&E developed a new Python-based model and implemented MAVF and risk and mitigation analysis methodologies. The methodology implemented in this new risk model is further discussed in Chapter 3. Key benefits of the new models include:

- Capability to scale up the granularity of the bowtie modeling in terms of number of tranches, drivers, sub-drivers, and outcomes, and the number of mitigations modeled;
- Significantly faster runtime than Excel-based simulation models;
- No need to purchase license for each user since Python is free;
- Capability of defining a custom timeframe and modeling as many future years as desired, allowing PG&E to account for factors such as climate change and to model long-term benefits from mitigations such as capital investments;
- Capability of performing sensitivity analysis;
- Usage of the same code for modeling all risks, with standardized input and output formats;
- Easier aggregation of modeling inputs and results across the enterprise; and
- Improved technical quality of simulation results that address high sampling error for rare events.

3. Event-Based Risk Register

Shortly after filing its 2017 RAMP, PG&E began its transition from an individual department-centric view of risk to a Companywide event-based view of risk. LOBs throughout the Company identified the risk events the Company should be concerned about given the Company's objectives. The LOBs also identified that certain of the previously-identified risks would be more accurately characterized as drivers to, or controls for, those risk events. At the end of the process, PG&E consolidated over 200 individual risks to 33 risk events and 10 cross-cutting factors on the Corporate Risk Register.

Key changes resulting from the transition to an event-based risk register include:

- Some stand-alone risks became drivers to one or many event-based risks. For example, "Cyber Attack" was previously a stand-alone risk; however, in an event-based view, Cyber Attack is a driver to several risk events, including "System-wide Electrical Disturbance (Blackout)" and "Data Loss Event."

- Some stand-alone risks became controls for one or many event-based risks. For example, "Emergency Preparedness and Response Risk" was previously a stand-alone risk resulting from failing to appropriately prepare and respond. Now, it is viewed as a control or mitigation for reducing the impact of a risk event, such as a "Loss of Containment on Gas Transmission Pipeline Rupture" or a "Wildfire," and is assessed in its ability to respond to any severe event.
- Several LOBs must work together to reduce Company risk. Due to the cross-cutting nature of elements of the event-based risk register (i.e. in some instances there are risk drivers, controls, or mitigations that may be managed by someone other than the risk owner), risk owners must coordinate all risk management activities across LOBs to effectively control, mitigate, and track risk performance.

Key benefits of the event-based risk register include:

- Improved ability to perform quantitative risk assessments;
- More objective comparisons between risks;
- Line of sight between desired risk reduction goals, planned actions, and results achieved, including calculations of Risk-Spend Efficiency (RSE) scores;
- Less overlap of risks, drivers, and controls;
- Pervasive drivers and controls can now be focused on specific risk events, which will enable prioritization of cross-Company efforts, such as records management and cybersecurity; and
- Consistency with the S-MAP Settlement Agreement.

4. Commitments Following the 2017 RAMP Report

In PG&E's 2020 GRC, PG&E provided next steps to improve its Risk Management Program. PG&E reports on the progress of these next steps below:

a. Quantitative Operational Risk Modeling

PG&E has met its goal to quantify all risks in its Corporate Risk Register except for two (Business Model Risk-Gas and Business Model Risk-Electric). Completing the modeling of these risks required the development of new skills, techniques, and data sources. The EORM team has individuals with quantitative skill sets with the ability to develop mathematical and statistical models using various modeling techniques, and knowledge and experience in financial and market risk management.

The risk models used to complete quantitative operational risk modeling have significantly improved as described earlier, the new models allow PG&E to model risks at a more granular level and also provide the capability to roll up the risk scores at an aggregated level.[10]

b. Modeling Mitigations and Controls

PG&E also committed in the 2020 GRC to calculate RSE scores for proposed control programs for the 2023 GRC. RSE scores will be used for prioritization of programs that mitigate safety and/or reliability risks identified on the Corporate Risk Register. This will include: (1) proposed new risk mitigation programs; (2) continuation of existing risk mitigation programs; (3) continuation of existing risk control programs (both mandatory and discretionary); and (4) enhancing existing mitigations and control programs.

c. Data Quality Improvements

PG&E has also made significant progress in utilizing PG&E-specific data as much as possible to better understand the risks. The quantitative risk assessments completed with the risk models have allowed PG&E's LOBs to develop mitigation strategies informed by data and analysis, rather than relying exclusively on qualitative assessment and Subject Matter Expert (SME) judgment.

d. Risk Model Governance, Oversight, and Evolution

RAMP and the risk assessment methodologies developed following the S-MAP Settlement Agreement have accelerated PG&E's progress in risk management. Today, the Company has plans to further develop and improve its risk models to improve decision-making. PG&E's risk models now enable PG&E to look beyond the six-year time horizon in the 2017 RAMP models. Benefits realized by proposed mitigations are

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[10] Model improvements are discussed further in Chapter 3

no longer bounded by any time frame in the model used for the 2020 RAMP. PG&E is creating a governance structure for the development, maintenance and use of operational risk models, so that PG&E uses consistent methodology for representing risk across the enterprise for better risk-informed decision making. PG&E is also working on centralizing inputs and outputs; model validation and acceptance; and development of additional analytical tools for making decisions within programs to further enhance its ability to identify, model, and manage risk. All of these efforts are designed to enhance and improve risk modeling repeatability and transparency.

e. Commitments in PG&E's Plan of Reorganization

PG&E seeks to continually improve its EORM program in addition to these recent advances. PG&E discussed its plans to progress its EORM program in testimony in the Plan of Reorganization OII in the following areas:

Risk Evaluation: Imposing additional rigor around risk reporting, continuing and improving the use of the Bowtie Analysis as a standard way of quantitatively evaluating risk and communicating the key drivers of risk, the performance of critical controls, and the effectiveness of risk reduction activities. Risk reviews will include, at a minimum: (i) a deep dive view of the risk or risk topic centered on a Bowtie Analysis; (ii) metrics that illustrate progress and effectiveness of mitigations over time; and (iii) descriptions of any associated open high-risk audit items.

Risk Accountability: Each "enterprise risk" on PG&E's "risk register" will have an identified "risk owner" who provides a progress update at least once every 12 months.

Risk Data and Spending: EORM will focus on developing the right data sources to better inform decision-making and to make clear when risk mitigation decisions are data-driven or based on subject-matter expertise.

Organizational Structure: EORM will seek alternative perspectives on how risk management is organizationally structured, how the EORM program compares to out-of-industry best practices such as the practices of airlines and other non-utility entities, and the quality of the staff performing risk management functions.

Data regarding non-conformance: EORM will analyze data regarding non-conformance events to improve the understanding of why the non-conformance occurred -- not just identification of failure but understanding the cause.

f. Interrelationships Between Risks

As PG&E continues to refine its approach to risk modeling, it will make additional improvements to identify and understand how risks interrelate. A more granular understanding of risk drivers obtained through fault tree/event tree analysis, for example, may enable PG&E to better understand how different failure modes interact with one another to cause a risk event to occur. This may provide additional insights into effective mitigation options for managing risk.

At this point, PG&E is still seeking to better understand the interrelationship between risks and looks forward to working with the CPUC, other utilities, and other parties to further explore this topic.

Chapter 20 of this Report discusses PG&E's cross-cutting factors, which are drivers and/or consequences that may affect more than one event-based risk. PG&E faced challenges capturing the impact of these factors.

g. Tracking of Associated Financials

PG&E's accounting system (SAP) was not set up to track costs associated with risk mitigations. The Company has adjusted SAP to incorporate RAMP-related identifications to track mitigation costs for use in future accountability reporting.

Additionally, one of the commitments made in PG&E's 2020 Session D was to develop and implement a process to access risk-mapped financial data for each risk on the Corporate Risk Register and related cross-cutting factors. This functionality will allow PG&E to know how much money is being spent on each risk.

h. Risk-Informed Budget Allocation

As stated in the 2020 GRC, the goal for Risk-Informed Budget Allocation (RIBA) is to use the outputs of the quantitative operational risk modeling to enable consistent data-driven, risk-informed decision making. By the end of 2020, RIBA scores will be based on the MAVF, which will allow for this goal to be met.

i. Next Steps

As contemplated in D.18-12-014, there are various issues that will be addressed among the Commission, other utilities, and interested stakeholders in a future S-MAP rulemaking. These include portfolio optimization, risk tolerance, and comparability across utilities. The outcomes of that rulemaking, like its predecessor, will likely result in an impactful change to our risk assessment methodologies. We look forward to working with parties on integrating the lessons learned and achievements of this RAMP Report into that upcoming rulemaking.

D. Lessons Learned

As described throughout this Report, we have significantly improved in our abilities to identify, assess and mitigate risk. However, through this RAMP process, we have further identified additional areas of opportunity to improve our processes going forward. Many of these are interrelated and improvements in one area will cascade into others. Our primary lessons learned for this proceeding include:

<u>Data Quality:</u> PG&E's ability to execute critical work, as well as make risk-informed, data-driven decisions may be limited due to poor data quality and an absence of effective data management and data governance practices.

An enterprise-wide data governance initiative is currently underway at PG&E. One facet of this initiative is to improve the quality of data used for modeling and other purposes. Improving the quality of data available to be used in risk modeling will take many years. PG&E is working on a framework for how to proceed in times when insufficient data is available or available data is low quality.

<u>Risk Spend Efficiency:</u> RSE scores are dependent on the data and methodology that we use to estimate them, and they are also geared towards

programs that mitigate tail risks. While PG&E believes this is the right approach currently, it highlights the different dimensions of risk management that should be considered as we further develop the risk management framework.

Different units are used for planning work and modeling risks. Assumptions made to translate those units to a common denominator introduce additional uncertainty into the RSE. For instance, work units may be planned by determining the number of assets to be replaced, whereas the risk modeling considers the number of miles of exposure. In this example, conversion from units to miles is based on the system average. In the future, efforts will be made to have more granular work unit to risk exposure conversion. This will be difficult, given that work plans are not established more than a few years in the future.

<u>Modeling – distributions and simultaneous events:</u> Having a broader set of distributions, including empirical distributions, will allow us to integrate the output of asset-level integrity management models directly.

PG&E experienced a challenge in estimating conditional consequence distributions for this Report due to a lack of data. Because extreme tail events are rare, and in some cases, have not occurred to date, it is difficult to select the correct probability distributions to use for consequences. Consequence distributions impact the Consequence of Risk Event and therefore are an important driver of the Risk Score. However, PG&E's Scaling Function caps extreme events at a score of 100 Scaled Units, so the effects of large over-estimation of extreme events is alleviated.

PG&E used common, well-defined distributions for consequences to prepare this Report. For example, the lognormal distribution was selected for financial risks and the zero-truncated Poisson distribution for Serious Injuries and Fatalities. PG&E expects to do more work on estimating conditional distributions by developing and, or, enhancing its data set of consequences and reviewing and calibrating consequence distributions across the Risk Events on its Corporate Risk Register.

PG&E looks forward to collaboration between the other utilities and other stakeholders on the best way to model an event when more than one risk event happens simultaneously.

Cross-Cutting Factors: PG&E has incorporated cross-cutting factors directly into each risk bowtie to show the link between each cross-cutting factor and the risk events. However, modeling cross-cutting factors remains a challenge. Cross-cutting factors add to the complexity of each risk model. It is very hard to represent explicitly the impact cross-cutting factors have on each specific risk event due to the lack of data and the added complexity the cross-cutting factor introduces to the bowtie. The fact that the cross-cutting factors and mitigations are managed by cross-cutting LOBs rather than risk LOBs also complicates the risk modeling and management. PG&E looks forward to working with stakeholders to improve the way it models cross-cutting factors.

IT Asset Failure: PG&E has made progress in identifying IT assets that relate to event-based risks but is not yet able to leverage the current assessment of asset health to determine the likelihood of IT asset failure in the same way as with other physical assets (e.g., electric or gas assets). As such, it is not yet possible to meaningfully and systematically identify all high-risk IT assets (high likelihood of failure and/or high consequence of failure). As IT Asset Failure modeling is improved, the Cyber Attack risk assessment will also benefit, since Cyber Attacks can drive IT Asset Failures and therefore impact risk events. The current Cyber Attack modeling does not fully incorporate the relationship between IT asset failures and risk events.

Granularity of Tranche Analysis: More granular use of tranches is an improvement PG&E will implement in the future. A homogenous risk profile across all assets in a tranche is the goal. As PG&E has more data to characterize the likelihood of failure and consequence of failure across assets, PG&E will be able to further refine our tranche definitions. For some models, only consequence of failure was a consideration in tranche development.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

RISK ASSESSMENT AND MITIGATION PHASE

RISK MODELING AND RISK SPEND EFFICIENCY

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A. Introduction

This chapter provides a detailed discussion of the Multi-Attribute Value Function (MAVF), Risk Score, and Risk Spend Efficiency (RSE) methodology used to quantitatively assess risks and mitigations throughout this report. It also includes numerical examples to illustrate how these methods are applied.

The Safety Model Assessment Proceeding (S-MAP) Settlement Agreement Decision (the S-MAP Settlement Decision)[1] established minimum requirements that satisfy and expand on Steps 1, 2 and 3 of the Cycla 10-step risk evaluation process.[2] The Commission directs the large Utilities to implement the following steps to analyze risk and mitigation choices in Appendix A of the S-MAP Settlement Decision:[3]

- Building a MAVF – Step 1A
- Identifying Risks for the Enterprise Risk Register[4] – Step 1B
- Risk Assessment and Risk Ranking in Preparation for Risk Assessment Mitigation and Phase (RAMP) – Step 2A
- Selecting Enterprise Risks for RAMP – Step 2B
- Mitigation Analysis for Risks in RAMP – Step 3

Each of the Steps, and the associated sub-steps or “elements” are described in detail in Attachment A, Appendix A to the S-MAP Settlement Decision.

This chapter describes Steps 1A and 3. Steps 1B, 2A, and 2B are described in Chapter 4.

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1 Decision (D.) 18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with Modifications.

2 The Cycla Corporation 10-Step Evaluation Method was adopted in D.16-08-018 as a common yardstick for evaluating the maturity of utility risk assessment and mitigation models. D.18-12-014, pp. 12-14.

3 D.18-12-014, p. 22.

4 PG&E recently renamed its Enterprise Risk Register to its Corporate Risk Register (CRR).

The terms used to describe the different elements of Pacific Gas and Electric Company's (PG&E or the Company) risk model and risk analysis efforts are based on the definitions provided in the S-MAP Settlement Decision.[5] Terms that are not defined in the S-MAP Settlement Decision are defined in this Chapter the first time they are used.

B. Risk Management Approach

PG&E's risk modeling, analysis and mitigation strategy is focused on reducing the potential for catastrophic risk events and the consequences of those events. In terms of risk modeling, this strategy entails paying special attention to tail risk—the low frequency, high consequence events. We achieve this in the 2020 RAMP by using a non-linear scaling function which gives a greater weight in the risk model to low frequency, high consequence events than to high frequency, low consequence events.[6]

PG&E is risk-averse in the sense that term is used in economics. Given a choice between two mitigations that theoretically reduce the same expected amount of loss, one of which is targeted at catastrophic (low frequency, high consequence) risk events and another that is targeted at routine (high frequency, low consequence) risk events, our preference is to select the mitigation that targets the catastrophic events because of the uncertainty of their frequency and consequence. Catastrophic events can have a more severe impact than multiple routine events for numerous reasons, including:

- The maximum scope and consequences of certain catastrophic events, such as a wildfire, are very hard to determine;
- The effects of catastrophic events have the potential to be concentrated in one place and one time, disproportionately affecting communities;
- Catastrophic events can also overwhelm emergency facilities and infrastructure; and
- Catastrophic events can have significant, unforeseen consequences that are not factored into everyday operations and contingency planning, and therefore have a greater potential to disrupt PG&E's operations (compared to multiple low consequence events).

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5 D.18-12-014, Attachment A, pp. A-2 to A-4.

6 PG&E's use of a non-linear scaling function is described in Section C.5, below.

We have learned through experience that the biggest risk events—those that disrupt the lives of our customers, their communities and PG&E itself—are the ones we need to avoid by clearly understanding what drives these events and then taking the right steps to prevent them in the future.

C. Multi-Attribute Value Function

Step 1A in D.18-12-014 requires utilities to build a MAVF to evaluate and rank alternative risk mitigation programs.[7] PG&E's MAVF reflects our focus on low-frequency/high-consequence risk events without neglecting operational risks (high-probability/low-consequence events).

Appendix A lists the six principles according to which the MAVF should be constructed.[8] The six principles are shown in rows 2 through 7 in Table 3-1 below.

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[7] D.18-12-014, p. 22.

[8] D.18-12-014, Attachment A, pp. A-5 to A-6.

TABLE 3-1
STEP 1A, PRINCIPLE 1 – BUILDING A MULTI-ATTRIBUTE VALUE FUNCTION

Row No.	Element Name	Element Description and Requirements
1	MAVF	A utility's MAVF should be constructed by following these six principles (see Rows 2-7, below). The MAVF is required to be built once, but the utility may adjust its MAVF over time. Any changes to the MAVF must adhere to the principles of construction set forth in Rows 2 through 7 below.
2	MAVF Principle 1 – Attribute Hierarchy	Attributes are combined in a hierarchy, such that the top-level Attributes are typically labels or categories and the lower-level Attributes are observable and measurable.
3	MAVF Principle 2 –Measured Observations	Each lower-level Attribute has its own range (minimum and maximum) expressed in natural units that are observable during ordinary operations and as a consequence of the occurrence of a risk event.
4	MAVF Principle 3 – Comparison	Use a measurable proxy for an Attribute that is logically necessary but not directly measurable. This principle only applies when a necessary Attribute is not directly measurable. For example, a measure of the number of complaints about service received can be used as a proxy for customer satisfaction.
5	MAVF Principle 4 – Risk Assessment	When Attribute levels that result from the occurrence of a risk event are uncertain, assess the uncertainty in the Attribute levels by using expected value or percentiles, or by specifying well-defined probability distributions, from which expected values and tail values can be determined. Monte Carlo simulations or other similar simulations (including calibrated subject expertise modeling), among other tools, may be used to satisfy this principle.
6	MAVF Principle 5 – Scaled Units	Construct a scale that converts the range of natural units (from Row 3) to scaled units to specify the relative value of changes within the range, including capturing aversion to extreme outcomes or indifference over a range of outcomes. The scaling function can be linear or non-linear. For example, the scale is linear if the value of avoiding a given change in Attribute level does not depend on the Attribute level. Alternatively, the scale is non-linear if the value of avoiding a given change in Attribute level differs by the Attribute level.
7	MAVF Principle 6 – Relative Importance	Each Attribute in the MAVF should be assigned a weight reflecting its relative importance to other Attributes identified in the MAVF. Weights are assigned based on the relative value of moving each Attribute from its least desirable to its most desirable level, considering the entire range of the Attribute. One means of incorporating a weighting process was presented in the February 17, 2017 Report of Joint Intervenor Test Drive Step 1 Results, "Specifying the Multi-Attribute Value Function," by Drs. Feinstein and Lesser. Weights are assigned based on actual Attribute measurement ranges, not a fixed weight arbitrarily assigned to an Attribute. *However, given the California Public Utilities Commission's (CPUC or Commission) focus on safety, a minimum of 40 percent safety weight is established unless the Utilities can justify a lower weight based on their respective analyses. This requirement supersedes the other specifications stated above.* For example, the Attribute weights will reflect the relative importance of moving the safety outcomes from the least to the most desirable levels as compared with moving financial outcomes from the least to the most desirable levels in a risky situation.

1. Implementing MAVF Principle 1 – Attribute Hierarchy

Principle 1 requires that Utilities identify Attributes that are combined in a hierarchy such that the top level Attributes are categories and the lower level Attributes, or sub-Attributes, are observable and measurable.[9]

PG&E identified four Attributes: (1) Safety, (2) Electric Reliability, (3) Gas Reliability, and (4) Financial, each with one lower-level Attribute.

1) "Safety" has one lower-level observable and measurable attribute: Equivalent Fatalities (EF).
2) "Electric Reliability" has one lower-level observable and measurable attribute: Customer Minutes Interrupted (CMI).
3) "Gas Reliability" has one lower-level observable and measurable attribute: Number of Customers Affected.
4) "Financial" has one lower-level attribute: U.S. Dollars. Pursuant to D.18-12-014 and D.16-08-018, shareholders' financial interests are excluded.[10]

2. Implementing MAVF Principle 2 – Measured Observations

MAVF Principle 2 requires that each lower-level Attribute have its own minimum and maximum range expressed in natural units that are observable during ordinary operations and as a Consequence of a Risk Event (CoRE).[11] Table 3-2 below summarizes PG&E's Attributes and associated ranges.

TABLE 3-2
STEP 1A, PRINCIPLE 2 – MEASURED OBSERVATIONS

Line No.	Attribute	Natural Unit of Attribute	Range
1	Safety	EFs	0 – 100
2	Electric Reliability	CMI	0 – 4 billion
3	Gas Reliability	Number of Customers Affected	0 – 750 thousand
4	Financial	Dollars	0 – 5 billion

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9 D.18-12-014, Attachment A, p. A-5, No. 2.

10 D.18-12-014, p. 29, and D.16-08-018, p. 193, Conclusion of Law (COL) 37.

11 D.18-12-014, Attachment A, p. A-5, No. 3.

The S-MAP Settlement Decision defines the low and high end of the Range of the Natural Unit to be a smallest and largest observable value from a risk event.[12] PG&E uses the term Upper Bound to denote the highest value in a Range. However, given the uncertainty in what the largest observable outcome of a risk event might be, PG&E defines the Ranges based on historical events and plausible high-consequence scenarios. PG&E defines each of the natural units of the Attribute as follows:

- An Equivalent Fatality is defined as the sum of Fatalities and Serious Injury Equivalents per event occurrence. Serious Injury is defined as an injury that requires in-patient hospitalization of an individual pursuant to existing Federal and State reporting guidelines.[13,14] Fatalities and Serious Injuries are converted to EFs using the factors shown in Table 3-3. The conversion rate from Serious Injury to EF is based on the disutility factors for Serious Injuries relative to Fatality available from Federal sources.[15] The Upper Bound of the Range for the Safety Attribute is based on EFs resulting from the Camp Fire rounded up to 100.

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12 D.18-12-014, Attachment A, p. A-3.

13 Pipeline and Hazardous Materials Safety Administration (PHMSA) § 191.3, Definitions: Incident. See also: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-facility-incident-report-criteria-history>, accessed June 25, 2020.

14 D.98-07-097, Appendix B, Accident Report Requirements, par. 3. See also, <https://www.cpuc.ca.gov/General.aspx?id=2090>, accessed June 22. 2020.

15 See Federal Aviation Administration (FAA) Office of Aviation Policy and Plans, Treatment of the Values of Life and Injury in Economic Analysis, p. 2-3, Table 2-3, Updated September 2016, aaccessed June 19, 2020, at: <https://www.faa.gov/regulations_policies/policy_guidance/benefit_cost/media/econ-value-section-2-tx-values.pdf>.

TABLE 3-3
EQUIVALENT FATALITY CONVERSION FACTORS
SIMULATED FATALITY OR SERIOUS INJYRY QUANTITIES

Line No.	Type	Equivalent Factor
1	Fatality	1.00
2	Serious Injury	0.25

- The Electric Reliability Upper Bound is based on the October 26-29, 2019 Public Safety Power Shutoff event consequence of approximately 3.6 billion CMI rounded up to 4 billion.
- The Gas Reliability Upper Bound is based on a scenario of an outage at a critical gas facility.
- The Upper Bound of the Financial Range represents a financial loss commensurate with a 2000-2001 Energy Crisis-type event. Costs related to recent wildfires were not used to set the Upper Bound because, pursuant to D.18-12-014, utility shareholders' financial interests are excluded from consideration.

3. Implementing MAVF Principle 3 – Comparison

MAVF Principle 3 directs Utilities to use a measurable proxy for any Attribute that is logically necessary, but not directly measurable.[16] Since all PG&E's Attributes are directly measurable, proxies are not used.

4. Implementing MAVF Principle 4 – Risk Assessment

MAVF Principle 4 states that when Attribute levels resulting from the occurrence of a risk event are uncertain, the utility should assess the uncertainty in the Attribute levels using expected values or percentiles, or by specifying well-defined probability distributions from which expected values and tail values can be determined. Monte Carlo simulations may be used to satisfy this principle.[17]

PG&E employs a probabilistic approach to modeling Attribute levels. The Attributes are specified by well-defined conditional probability distributions with parameters derived from data and/or calibrated subject

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16 D.18-12-014, Attachment A, p. A-5, No. 4.

17 D.18-12-014, Attachment A, p. A-5, No. 5.

matter expert (SME) input. Monte Carlo methods are used to simulate Attribute levels from these distributions. Details about PG&E's Risk Assessment methodology and a numerical example are presented in Section D.

5. Implementing MAVF Principle 5 – Scaled Units

MAVF Principle 5 requires Utilities to construct a scale that converts the range of natural units to scaled units to specify the relative value of changes within the range.[18]

The S-MAP Settlement Decision defines the Scaled Unit of an Attribute as a value that varies from 0 and 100. The Scaled unit is set to 0 for the most desirable level, and 100 for least desirable level.[19] For any level of the attribute between the most desirable and least desirable levels, the Scaled Unit is between 0 and 100. Consistent with the S-MAP Settlement Decision, PG&E's Scaled Units reflect a 0-to-100-point scale, where zero reflects no adverse consequences (i.e., no EFs, no reliability impact, or no financial loss) and 100 corresponds to the Upper Bound of the Attribute Range.

MAVF Principle 5 provides that the scale described above can be constructed so as to "captur[e] aversion to extreme outcomes or indifference over a range of outcomes"[20] and that the "scaling function can be linear or non-linear."[21] As described in Section B, above, PG&E's risk management objective is to prioritize the mitigation of risks characterized as low frequency/high consequence (LFHC) events, even though their expected loss might be the same as multiple high frequency events with low consequences. To reflect this objective, PG&E uses a non-linear scaling function that captures aversion to extreme outcomes, rather than using a linear Scaling Function that would yield indifference over a range of outcomes.

In the 2017 RAMP Report, PG&E used two measures of risk, the Mean (i.e., the average of simulated losses), and the 90-100 percent Tail Average

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18 D.18-12-014, Attachment A, pp. A-5 to A-6, No. 6.

19 D.18-12-014, Attachment A, p. A-3.

20 D.18-12-014, Attachment A, p. A-5, No. 6.

21 D.18-12-014, Attachment A, p. A-6, No. 6.

(i.e., the average of the worst 10 percent of simulated losses).[22] We considered the 90-100 Tail Average to be an important metric because of our desire to focus on the identification, evaluation and reduction of catastrophic risks, given our past experience with risks.[23] Events since the 2017 RAMP Report, especially the Camp Fire, have highlighted and validated the need for a continued focus on high consequence, low probability risk.

The S-MAP Settlement Decision that sets forth the requirements for the 2020 RAMP does not give PG&E the opportunity to use the Tail Average as a metric. The S-MAP Settlement Decision adopted a single measure of risk—the Risk Score— which is the product of the Likelihood of a Risk Event (LoRE) and the Consequence of a Risk Event (CoRE). The S-MAP Settlement Decision further defines CoRE to be the weighted sum of the scaled values of the level of the individual Attributes using the MAVF.[24]

One effect of using the Expected Value of Attributes as the sole measure for CoRE is that the tail risk of risk events may be obscured, depending on what scaling function is used. A linear scaling function essentially adopts the average of risk event outcomes as the measure of the risk. It is indifferent to the distribution of those outcomes. Consider the scenarios shown in Figure 3-1 and Figure 3-2 below, which represent the potential safety consequence of two hypothetical risk events:

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22 PG&E’s 2017 RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017) (PG&E’s 2017 RAMP Report), pp. B-15 to B-16.

23 PG&E’s 2017 RAMP Report, p. B-16.

24 D.18-12-014, Attachment A, p. A-11, No. 13.

FIGURE 3-1
HIGH FREQUENCY, LOW CONSEQUENCE EVENT WITH MEAN LOSS OF $150

FIGURE 3-2
LOW FREQUENCY, HIGH CONSEQUENCE EVENT WITH MEAN LOSS OF $150

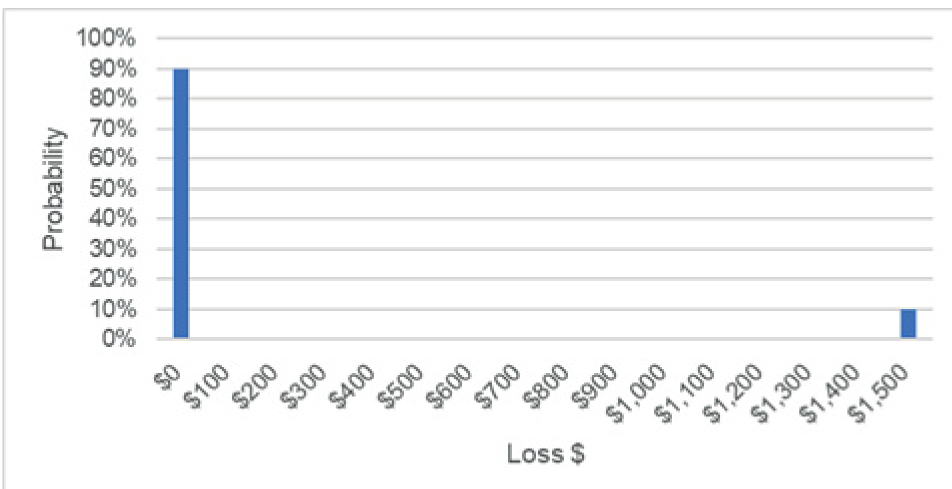

Figure 3-1 represents a high frequency, low consequence event. 75 percent of the risk events result in a loss, but the losses are small ($100-300 in this example). Figure 3-2 represents a low frequency, high consequence (i.e. catastrophic) event. Only 10 percent of the risk events result in a loss, but that loss is large ($1,500). In both cases, the mean loss for all the risk events considered together is the same—$150.[25] Because their mean loss is the same, a linear scaling function would treat these two

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[25] (0.25 x $100) + (0.25 x $200) + (0.25 x $300) = $150 = 0.10 x $1500.

risks similarly, despite the large difference in the distribution of risk outcomes.[26] By contrast, as described below, a non-linear scaling function assigns a greater weight to low frequency high, consequence risk events, so that mitigations for the risk in Figure 3-2 would be prioritized over mitigations for the risk shown in Figure 3-1. PG&E uses non-linear scaling function because it allows us to better understand tail risk and prioritize mitigations for low frequency, high consequence events, consistent with our risk management objectives.

In academic settings, MAVFs are used in conjunction with a utility function[27] when extending standard, single-attribute utility theory to a multi-attribute setting. The MAVF first establishes an ordering preference for all the different combinations of attribute levels. The utility function, either on its own or together with the MAVF, is then used to express risk preference (i.e., risk-aversion, risk-seeking or risk-neutral). However, that possibility does not exist in the framework of the S-MAP Settlement Decision, which requires expected values to be used for the CoRE,[28] basically giving CoRE the role of the utility function. The S-MAP Settlement Decision further requires that, "The CoRE is the weighted sum of the scaled values of the levels of the individual Attributes using the utility's full MAVF."[29] Mathematically, this implies $U(V(a)) = V(a)$, where U is the utility function and V is the expected value of the multi-attribute value function. The utility function is risk-neutral and, in the context of the S-MAP Settlement Decision, cannot be used to express risk aversion. Therefore, the only way to express aversion to catastrophic risk is through the Scaling Function, consistent with MAVF Principle 5.

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26 In Economics theory, Figure 3-2 is a Mean-Preserving Spread of Figure 3-1. Risk-averse individuals will prefer Figure 3-1 to Figure 3-2.

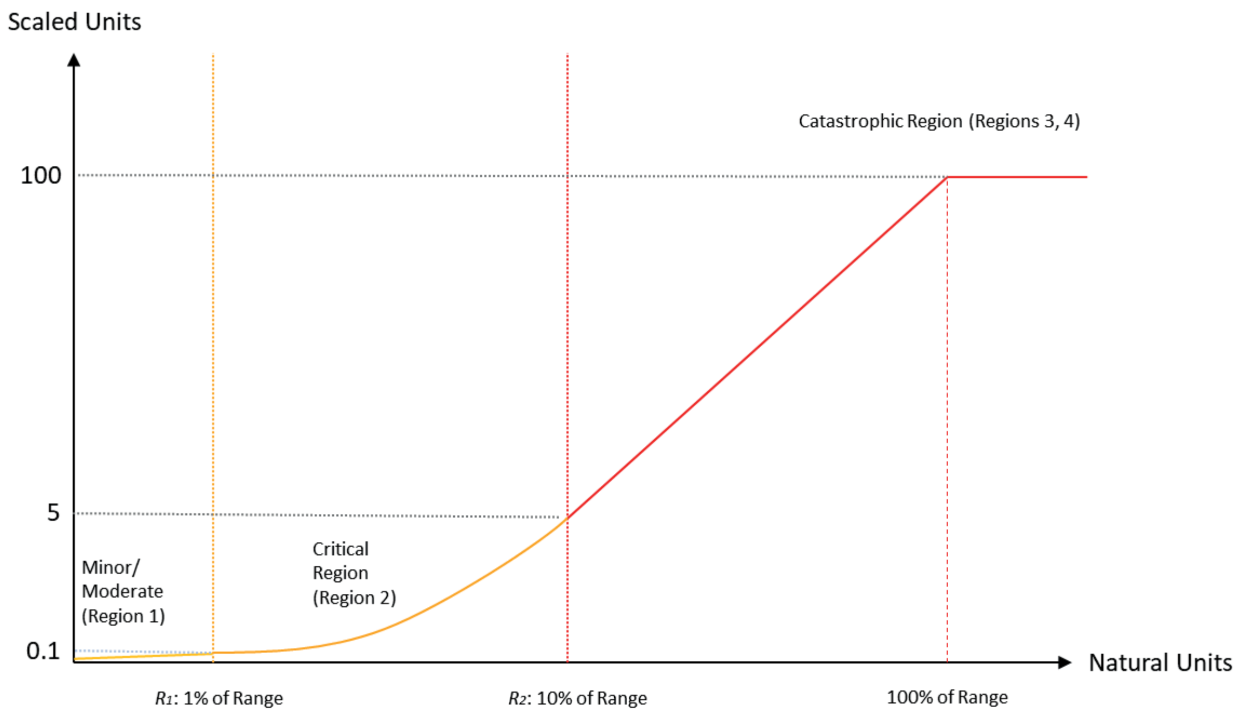
27 In general economics, a utility function measures preferences concerning a set of alternatives. Here, utility refers to the general sense of the word (i.e., "utility: fitness for some purpose or worth to some end"). Merriam-Webster.com Dictionary, s.v. "utility," accessed June 19, 2020, at <https://www.merriam-webster.com/dictionary/utility>.

28 D.18-12-014, Attachment A, pp. A-12 to A-13, No 24.

29 D.18-12-014, Attachment A, p. A-11, No 13.

The non-linear Scaling Function used by PG&E consists of three regions that define its overall shape, illustrated in Figure 3-3. Each of the regions is described below.

FIGURE 3-3
NON-LINEAR SCALING FUNCTION FOR PG&E'S MAVF



a) Minor/Moderate Region: Linear for natural unit consequence from 0 percent to 1 percent of the Range. Events whose consequence result in this region are assigned Scaled Units between 0 and 0.1.

b) Critical Region: Quadratic for natural unit consequence from 1 percent to 10 percent of the Range. Events whose consequence result in this region are assigned Scaled Units between 0.1 and 5.

c) Catastrophic Region: Linear for natural consequence from 10 percent to 100 percent of the Range (catastrophic events). Events whose consequence results in this region and beyond 100 percent of the Range are assigned Scaled Units between 5 and 100.

Mathematically, the Scaling Function, *S(r)*, used for all Attributes is defined in Equation 1.

FIGURE 3-4
EQUATION 1: SCALING FUNCTION FOR ALL ATTRIBUTES

$$S(r) = \begin{cases} 10r, & \text{Region 1: } r \le R_1 \\ 10r + \frac{1}{2}.\frac{100(0.99 - 0.10)}{(R_2 - R_1)}(r - R_1)^2 & \text{Region 2: } R_1 < r \le R_2 \\ \frac{100 - S_2}{(1.0 - R_2)}(r - R_2) + S_2, & \text{Region 3: } R_2 < r \le 100\% \\ 100, & \text{Region 4: } r > 100\% \end{cases}$$

where

a: *Attribute Level (e.g. $ loss)*
R: *Upper Range of Attribute (e.g. $5billion for Financial)*
$r = \frac{a}{R}$: *Normalized Attribute Level*

R_1 *=1% (Upper bound of Minor/Moderate Region)*
R_2 *=10% (Upper bound of Critical Region)*

S_1 *=0.1 (Maximum value in Minor/Moderate Region)*
S_2 *=5 (Maximum value in Critical Region)*

For consequences in the minor/moderate region (Region 1), representing high-frequency/low-consequence events, a linear function with a relatively small coefficient is adequate because the resulting low consequence value is multiplied by a relatively high frequency of occurrence when risk scores are calculated.

As the consequence from a risk event enters the critical level (defined as 1 percent of the Upper Bound), PG&E's Scaling Function reflects growing risk aversion through a quadratic function. In the Critical region (Region 2), PG&E assigns an incremental value of between approximately 1 to 10 times the value of an incremental loss in a minor/moderate situation. This increase in Scaled Units can be seen in the increasing slope of a scaling function:

- Going from an Attribute level of 2 percent to 2.1 percent is approximately twice the increase in Scaled Units going from 0.0 percent to 0.1 percent;
- The increase in Scaled Units going from an Attribute level of 5 percent to 5.1 percent is approximately five times the increase when going from 0.0 percent to 0.1 percent; and,

- The increase in Scaled Units going from an Attribute level of 9.9 percent to 10 percent is approximately 10 times the increase when going from 0.0 percent to 0.1 percent.

These increases were achieved by calibrating the quadratic coefficient.

Throughout the Catastrophic region (Region 3), incremental losses are assigned approximately 10 times the value of an incremental loss in a minor/moderate situation. The increase in Scaled Units (i.e. slope) going from an Attribute level of either 10 percent to 10.1 percent or 99.9 percent to 100 percent is about 10 times more than the increase going from 0.0 percent to 0.1 percent. This consistent increase is illustrated by the constant slope of the scaling function in the Catastrophic region in Figure 3.4. The linear coefficient for Region 3 was set to be approximately 105.6 to achieve this consistent increase.

PG&E places a maximum value of 100 on the Scaled Units and does not constrain the underlying Attribute level to the Range. For consequences above the Attribute Range, the Scaled Unit is capped at 100. Capping the scaled units has the effect of treating all extreme tail end results the same in the risk model even though it is possible that the consequences of an extreme event could exceed the maximum value of the Attribute Range.

6. Implementing MAVF Principle 6 – Relative Importance

MAVF Principle 6 states that each Attribute should be assigned a weight reflecting its importance relative to other Attributes defined in the MAVF.[30] PG&E uses the Attribute Weights shown in Table 3-4.

TABLE 3-4
ATTRIBUTE WEIGHTS

Line No.	Attribute	Weight
1	Safety	50%
2	Electric Reliability	20%
3	Gas Reliability	5%
4	Financial	25%

[30] D.18-12-014, Attachment A, p. A-6, No. 7.

PG&E assigned the Attribute Weights to reflect the relative importance of moving each Attribute from its least desirable level (i.e., Upper Bound) to its most desirable level (i.e., zero). For example, the Attribute Weights reflect PG&E's view that it is twice as valuable to move the Safety Attribute from 100 to 0 EFs as it is to move the Financial Attribute from $5 billion to $0. Assigning 50 percent weight to the Safety Attribute is in line with PG&E's emphasis on safety and is also consistent with the S-MAP Settlement Decision's requirement for a minimum 40 percent weighting for Safety.[31]

D. Risk Assessment

This section describes how PG&E implemented Step 3, Mitigation Analysis for Risks in RAMP. The objective of this section is to explain the methodology used to develop the 12 models which probabilistically assess the likelihood and consequence of various risks events reported in PG&E's 2020 RAMP Report, Chapters 7 through 18. Each of these models produces a 2023 Baseline Risk Score, which is calculated using the methodology discussed in Section D.1.d, below.

1. Bow Tie Methodology

All RAMP risk chapters include a Bow Tie illustration, which gives a visual summary of the drivers and CoRE. In the center of the Bow Tie is the risk event, which is a well-defined, single, observable and measurable event. In the example Bow Tie below, Figure 3-5, the Risk Event is a Loss of Containment (LOC) on a Gas Transmission Pipeline.

In the following sections PG&E describes each of the Bow Tie elements: drivers/frequency; outcomes/consequences; the risk score; and the cross-cutting factors.[32]

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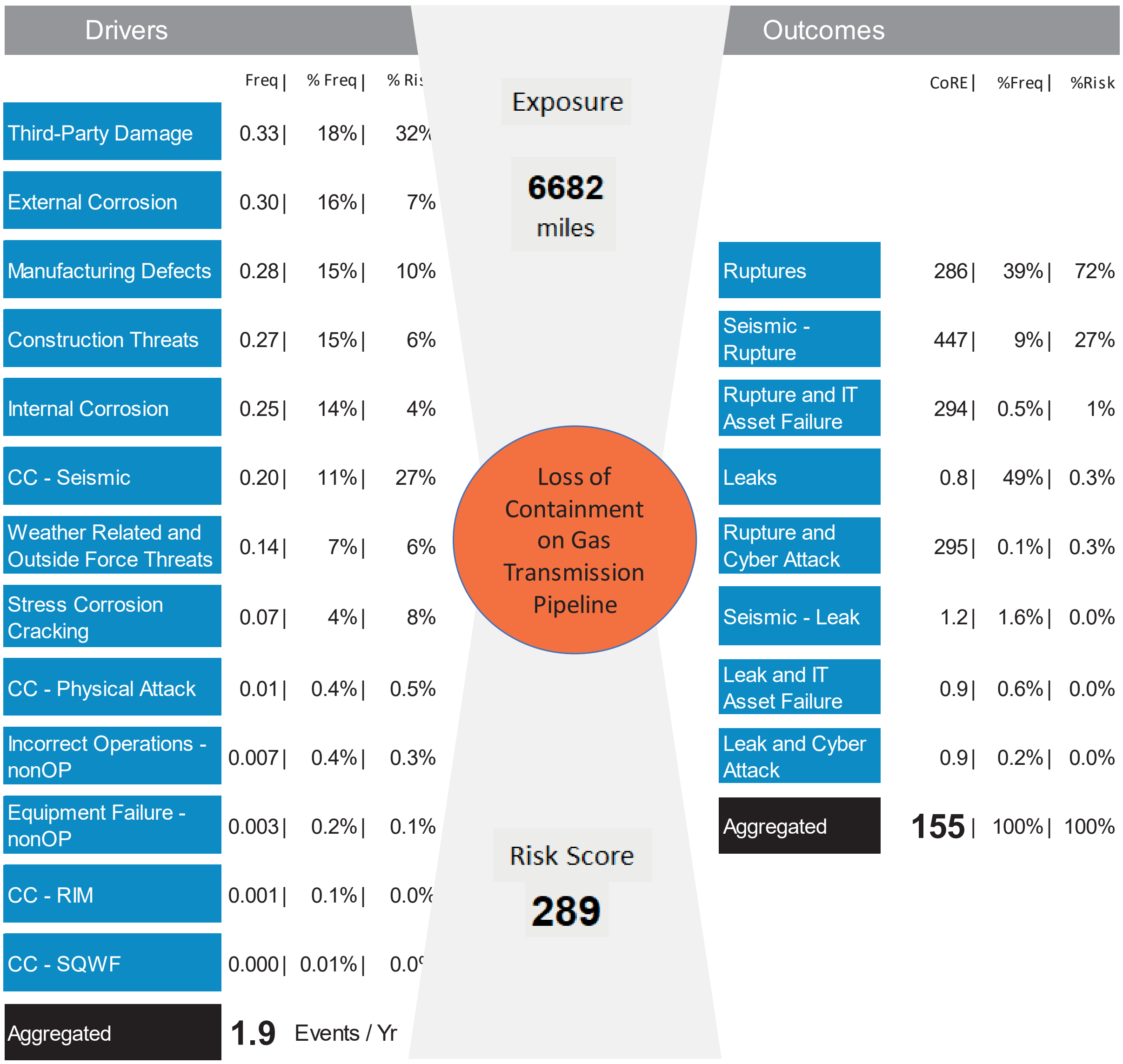
[31] D.18-12-014, p. 66, COL 5.

[32] Cross-cutting factors are not risk events themselves but rather they impact either the likelihood or consequence of other risk events. The cross-cutting factors are shown on the left side of the Bow Tie preceded by the letters "CC." On the right side of the Bow Tie they are shown in combination with other consequence events (i.e., Leak and Cyber Attack where leak is a loss of containment outcome and cyber attack is the cross-cutting factor).

The risk score shown at the bottom of the Bow Tie, in the center, is calculated as the likelihood of the risk event multiplied by the consequence of the risk event (LoRE x CoRE). Calculating the risk score is described in more detail below.

Please note the CoRE shown in the Bow Tie includes a scaler of 1,000.

FIGURE 3-5
RISK EVENT BOW TIE: LOSS OF CONTAINMENT ON A GAS TRANSMISSION PIPELINE



a. Frequency of a Risk Event

On the left-hand size of the Bow Tie are the Risk Event drivers and their associated frequencies. The set of drivers includes the causes or threats identified for the Risk Event. Drivers are measurable events. The annual frequency of a risk driver leading to a Risk Event is informed by PG&E event data that is supplemented with industry data and/or SME input when necessary. Certain drivers are further divided into multiple sub-drivers (components of a risk driver),[33] where the further division is useful and where data are available. Risk and mitigation analysis can also be done at a sub-driver level.

Drivers are expressed as the frequency of occurrence of a Risk Event per exposure *per year*, the time unit for the analysis. For example, Figure 3-5 shows a frequency of 0.33 for the Third-Party Damage driver (top left side of the figure) which means that in 2023 PG&E expects to have 0.33 loss of containment events on a gas transmission pipeline due to third-party damage events if no mitigations are implemented starting in 2023. The frequency of a Risk Event associated with each driver is summed to establish the risk-level frequency. Without implementing any mitigations starting in 2023, PG&E expects to have 1.9 loss of containment events—the aggregated number of events shown in the lower left corner of the Bow Tie.

b. Potential Consequence of a Risk Event

On the right-hand side of the Bow Tie, PG&E introduces Outcomes to differentiate manifestations of a risk event that have significantly different consequences (changes in Attribute levels representing the impact of the outcome). Each Outcome is characterized by different probability distributions over the applicable Attributes, determined from PG&E data, industry data, and/or SME input. The consequences of the Risk Event are shown in more detail in the Consequence Table in each RAMP risk chapter. Figure 3-6 below is the Consequence Table for the LOC on a Gas Transmission Pipeline risk.

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33 For example, the risk driver "Vegetation" in the Failure of Electric Distribution Overhead Assets risk event includes three sub-drivers: tree contract; right-of-way encroachment; and, tree trimming.

FIGURE 3-6
CONSEQUENCE TABLE: LOSS OF CONTAINMENT ON A GAS TRANSMISSION PIPELINE

					Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial
Ruptures	286	39.0%	72%	0.7	1.0	41,573	5.3	115.0	164.8	5.8	0.7	30,234	3.9	83.6	119.9	4.2
Seismic - Rupture	447	9.2%	27%	0.2	1.7	48,067	8.5	247.2	189.0	11.0	0.3	8,261	1.5	42.5	32.5	1.9
Rupture and IT Asset Failure	294	0.5%	1%	0.0	1.0	42,149	5.4	119.7	169.0	5.5	0.0	403	0.1	1.1	1.6	0.1
Leaks	0.8	48.7%	0.3%	0.9	0.0	22	1.2	0.2	0.0	0.6	0.0	20	1.1	0.2	0.0	0.5
Rupture and Cyber Attack	295	0.1%	0.3%	0.0	1.0	42,059	5.6	120.4	168.4	6.0	0.0	106	0.0	0.3	0.4	0.0
Seismic - Leak	1.2	1.6%	0.0%	0.0	0.0	33	1.7	0.3	0.0	0.9	0.0	1	0.1	0.0	0.0	0.0
Leak and IT Asset Failure	0.9	0.6%	0.0%	0.0	0.0	23	1.3	0.2	0.0	0.6	0.0	0	0.0	0.0	0.0	0.0
Leak and Cyber Attack	0.9	0.2%	0.0%	0.0	0.0	22	1.3	0.2	0.0	0.6	0.0	0	0.0	0.0	0.0	0.0
Aggregated	**155**	100%	100%	1.9	0.6	20,939	3.5	69	83	4	1.0	39,025	6.6	128	154	7

For reference, the attribute ranges are shown again below – Table 3-2 (above):

Line No.	Attribute	Natural Unit of Attribute	Range
1	Safety	EFs	0 – 100
2	Electric Reliability	Customer Minutes Interrupted	0 – 4 billion
3	Gas Reliability	Number of Customers Affected	0 – 750 thousand
4	Financial	Dollars	0 – 5 billion

In the LOC on a Gas Transmission Pipeline risk above, the consequences of a LOC event include the potential for serious injury or fatality (Safety), loss of gas service (Gas Reliability), and property damage (Financial). The manifestation of these consequences depends on the Outcome that causes the loss of containment. A leak is sufficiently different from a rupture that modelling them both with a single consequence attribute distribution does not fairly characterize either. Having different sets of Attribute distributions for each Outcome more precisely models the potential consequences of the Risk Event.

The probability distributions characterizing Safety, Financial and Gas Reliability Consequence for the leak outcome are lower in mean and variance across the attributes than the set of distributions for a rupture. Furthermore, some drivers are more or less likely to lead to lower or higher severity outcomes. For example, the Third-Party Damage driver leads only to the rupture outcome, not a leak. In contrast, External Corrosion, an important driver of LOC events, is more likely to lead to a leak than to a rupture. Through this analysis, PG&E can better identify and mitigate drivers strongly tied to the more severe outcomes when elements on the left- and the right-hand side of the Bow Ties are presented as specifically as possible, given the available information.

The Bow Tie illustrated in each RAMP risk chapter lists drivers and outcomes of the Risk Event, as well as the associated summary quantities such as frequency, consequence and contribution to risk score. Within PG&E's enterprise risk model, those elements can vary by one or more of: time, tranche, sub-driver, outcome, and attribute as summarized in Table 3-5.

TABLE 3-5
SUMMARY OF BOW TIE ELEMENT UNITS AND DIMENSIONALITY

Line No.	Bow Tie Element	Quantification Unit	Can Vary By
1	Exposure	Depends on risk event (e.g., miles of pipe, number of high hazard dams, number of employees)	• Time • Tranche
2	Driver	Expected number of risk events per year (frequency)	• Time • Tranche • Sub-driver • Outcome
3	Outcomes	CoRE	• Time • Tranche • Attribute

c. Tranches

For each Risk Event, underlying the Bow Tie structure is a set of tranches over which driver frequencies and Outcome attribute distributions vary both in applicability and magnitude. Each tranche includes a group of assets, a geographic region or other grouping that is intended to have a similar risk profile. For example, the Employee Safety Incident Risk includes two tranches—Office Employees and Field Employees—distinct groups of employees with similar risk profiles within each tranche. The Bow Tie is essentially defined at a tranche level which provides a more granular view of risk and how mitigations will reduce risk.

d. Calculating the Risk Score

Each RAMP risk has an associated Risk Score that is the product of the LoRE and the CoRE.[34]

Risk Score per Unit of Exposure = LoRE x CoRE

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[34] D.18-12-014, Attachment A, p. A-11, No. 13.

CoRE is the weighted sum of Scaled Units representing the consequence from an occurrence of a Risk Event on each Attribute using the MAVF. To calculate CoRE using Attribute Weights and Attribute Scaled Units, PG&E applies a Scaler of 1000. Specifically,

CoRE = Safety CoRE + Electric Reliability CoRE+ Gas Reliability CoRE + Financial CoRE

Where:

- *Safety CoRE = Scaler (1,000) x Safety Weight (50%) x Safety Scaled Unit*
- *Electric Reliability CoRE = Scaler (1,000) x Electric Reliability Weight (25%) x Electric Reliability Scaled Unit*
- *Gas Reliability CoRE = Scaler (1,000) x Gas Reliability Weight (5%) x Gas Reliability Scaled Unit*
- *Financial CoRE = Scaler (1,000) x Financial Weight (20%) x Financial Scaled Unit*

PG&E treats LoRE as specified per unit of exposure and expresses Risk Scores equivalently as Frequency x CoRE at a Tranche or System level:

Tranche Risk Score = Tranche Exposure x LoRE x CoRE

= Tranche Frequency x CoRE

Risk Score = Sum of Tranche Risk Scores over all Tranches for the Risk Event

Frequency (the number of occurrences per year) is directly observable and easily understood. For events that are expected to happen less than once per year per unit of exposure, the likelihood of the risk event happening in a year for a Tranche and the frequency of the risk event happening are equivalent (e.g., a 100-year flood has an annual probability, or LoRE, of 0.01, and, the expected number of floods per year, Frequency, is 0.01). For risk events that are expected to happen more often than once per year per unit of exposure, the likelihood of the risk event is 1 though the frequency of the risk event is greater than 1. Frequency captures the difference between a risk event that happens twice per year and 1,000 times per year, whereas likelihood, as a metric, is unable to do so given a one-year time period for analysis.[35]

e. Test Year Baseline Risk Score

Throughout this RAMP report, all Bow Ties show the Test Year (TY) Baseline Risk Scores for 2023—the TY for PG&E's next General Rate Case (GRC). Test-Year Baseline Risk Scores for 2023 are calculated based on Frequency and Consequence of the Risk Event and may be adjusted for estimated increases due to factors such as climate change and cyber attacks and adjusted for estimated reductions in Frequency and Consequence due to the effectiveness of mitigations that are implemented prior to the start of 2023 GRC period.

2. Modeling the Cross-Cutting Factors

Cross-cutting factors are not risk events themselves but rather they impact either the likelihood or consequence of other items (risk events) on PG&E's CRR.

PG&E presented three cross-cutting factors in its 2017 RAMP. The cross-cutting risk model was dependent on the outputs from the other stand-alone risk models. The cross-cutting models were not specific risk events, but an aggregation of the associated stand-alone risk; each of the stand-alone risks estimated what portion of the risk could be attributed to a cross-cutting factor issue.

For the 2020 RAMP PG&E uses a new approach for presenting and modeling cross-cutting factors. This new approach is responsive to feedback from the Safety Enforcement Division (SED) that PG&E's approach to modelling cross-cutting factors in the 2017 RAMP lacked specificity and transparency into the impact of the drivers and how they are

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35 A potential approach to this issue would be to vary the period for analysis (i.e., a month, a day) in order to compute a LoRE < 1. However, PG&E believes that varying the analysis period from a year would add complexity without substantial benefit, especially since PG&E's enterprise risks have frequencies ranging in order of magnitude from 10^{-3} to 10^{4}.

causally linked to the risk event.[36] In the 2020 RAMP, PG&E is now integrating each applicable cross-cutting factor into the appropriate RAMP risk models as a driver, driver component or consequence of that specific risk. This new approach increases transparency and demonstrates how the cross-cutting factors contribute to the frequency and/or consequence of the RAMP risk events.

As described in Chapter 20, Cross-Cutting Factors, there are four ways the cross-cutting factors are included in the event-based risk models.

a) Driver: Appears on the left-hand side of the Bow Tie as a driver and is modeled identically to other drivers. Frequency of a Risk Event associated with cross-cutting drivers is identified in the same manner as for the other drivers based on historical frequency of those events, or SME judgement if historical data is not available or sufficient.

b) Consequence Multiplier: When a cross-cutting factor affects a consequence of an event for an Outcome regardless of drivers, it is modeled as a Consequence Multiplier to the Natural Unit of the simulated risk event outcome, affecting the CoRE.

c) Outcome: Where the impact of a cross-cutting driver differs from the impact of the non-cross cutting drivers on the consequences of a Risk Event (e.g., the severe Seismic outcome is driven solely by the Seismic driver).

d) Escalating Frequency: Is applied as a Frequency Multiplier over time to one or more applicable risk drivers (e.g., climate change).

3. Modeling the Mitigations and Control Programs

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. The adequacy and effectiveness of a mitigation is assessed based on how much of the exposure is affected (i.e., scope of mitigation), the impact on specific driver/sub-driver

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[36] SED noted that PG&E's 2017 approach to modelling cross-cutting risks lacked the specificity and transparency into the impact of the drivers and how they are causally linked to the risk event. SED noted that it might be best to include the cross-cutting drivers in the appropriate stand-alone risk chapter to prevent duplication and better show how these components of risk contribute to the frequency of the risk event. PG&E, Risk and Safety Aspects of RAMP Report, I.17-11-003 (Mar. 30, 2018), p. 24.

frequencies (and how those frequencies may change over time), the impact on the consequence of specific attributes, and the associated cost.

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, or an enhancement to an existing one.[37] Controls have no end date.

The benefits of applying mitigations and controls are represented by percentage reductions in driver/sub-driver frequencies by tranche and outcome, and/or consequence magnitude (e.g., the number of customer minutes interrupted per risk event outcome as simulated) by tranche and outcome. Mitigations are further defined by the duration of risk reduction benefits once mitigation is complete, and effectiveness degradation with time.

PG&E developed mitigation effectiveness workpapers for each mitigation (excluding foundational mitigations that support risk reduction activities but do not reduce risk themselves) and two controls (Gas Operations Leak Management and Electric Operations Enhanced Inspections). The mitigation effectiveness workpapers outline the effectiveness of each mitigation, justification for that effectiveness, the mitigation benefit length and the justification for the benefit length. The mitigation effectiveness workpapers are included as part of the workpapers for each RAMP risk.

4. Risk Spend Efficiency

Risk Spend Efficiency is a metric for representing the benefit to cost ratio of a mitigation, where benefit is described in terms of risk reduction. The S-MAP Settlement Decision states that RSE should be calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate. Further, the values in the numerator and denominator should be present values and, for capital programs, the mitigation costs in the denominator should include incremental expenses made necessary by the capital investment.[38]

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[37] D.18-12-014, p. 16 (see, 2018 S-MAP Revised Lexicon, pp. 16-19).

[38] D.18-12-014, Attachment A, p. A-13, No. 25.

PG&E's RSE results shows the risk reduction achieved per 1 million dollars ($M) spent. For example, a risk event with Frequency of one event per year and Consequence of 40 million CMI has a risk score of 20.[39] If a mitigation that costs $10 million reduces the Frequency of this risk event by 50 percent (from 1 event per year to 0.5 events per year), then then risk reduction (the difference between pre- and post-mitigation scores) is 10 and RSE is 1.[40]

When the benefit of a mitigation lasts more than one year, risk reduction is aggregated by the present value of risk reduction over the benefit years and the cost is aggregated as the present value of the costs over the spend years. Equation 2 shows the RSE calculation:

$$RSE = \frac{\text{NPV(Pre-mitigation Risk Scores)} - \text{NPV(post-mitigation Risk Scores)}}{\text{NPV(Program Costs)}}$$

Where:

- NPV (Risk Scores) and NPV (Program Costs) are the Net Present Value of the Risk Score and Program Costs.

The following sections discuss how PG&E has implemented the S-MAP Settlement Decision requirements for calculating RSE.

a. Discounting

As noted above, in compliance with the S-MAP Settlement Decision, PG&E shows the numerator and denominator of the RSE as present values.[41] PG&E uses a single discount rate, its After Tax Weighted Average Cost of Capital (ATWACC) to calculate the present value of all future costs and attributes. The base year for all discounting is 2020.

PG&E focused on two core principles when discounting:

1) Costs and benefits occurring over different time periods should be assessed on an equal basis. Principle 1 implies a non-zero discount rate for costs to account for the time value of money.

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39 Risk Score = Frequency x CoRE = Frequency (1) * Scaler (1000) * Attribute Weight (50%) * Scaled Unit (0.1) = 50.

40 Risk Reduction = Pre-mitigation Risk Score (50) – Post-mitigation Risk Score (25) = 25.

RSE = Risk Reduction / Cost = 25/ 25M = 1 /$M spend.

41 D.18-12-014, Attachment A, p. A-13, No. 25.

2) All else being equal, RSEs should not change if both costs and mitigations are offset by a period of time.[42]

To achieve Principle 2, the discount rate for Attributes (i.e., in the numerator of the RSE) must not only be the same across all Attributes but also must be the same as the discount rate for costs (i.e., the denominator). The ATWACC was derived as follows:

TABLE 3-6
2020 AFTER TAX WEIGHTED AVERAGE COST OF CAPITAL CALCULATION

Line No.	Component	Weight	Cost of Capital (%)	WACC		After Tax WACC
1	Debt	48%	5.2	2.5	x (1 - tax rate)	1.8
2	Common Stock	52%	10.3	5.3		5.3
3						7.1

Note: The ATWACC used in the risk model is based on PG&E's cost of capital as of the June 30, 2020 filing date for the RAMP. On April 22, 2019 PG&E filed its Cost of Capital Application (A.19-04-015) for TY 2020. When a decision is issued in that proceeding, PG&E will make updates to its risk model as required.

This discount rate was determined solely based on the Principles and considerations above. Therefore, it is only valid in the context of calculating RSEs in this RAMP Report and should not be extended to other applications without further consideration.

b. Mitigation and Control Program Mitigation Costs

The basis of the program costs used to calculate the RSE are high level capital and expense cost estimates developed by the RAMP risk teams. PG&E used the best available information when calculating and

[42] As an example of why Principle 2 is necessary, consider a program that starts immediately and runs for a set number of years, with costs only incurred during that period. All else being equal, the program should have the same RSE if it started one year later, otherwise one could simply defer or expedite the work to increase the RSE score with no fundamental improvement in the program.

estimating the costs associated with each mitigation. These costs are included in the workpapers supporting this RAMP report.[43]

Because PG&E's GRC forecasting process is still in the early stages, the mitigation forecast costs to be included in the 2023 GRC may be different from the estimates included in this RAMP Report, including potential changes as a result of SPD and intervenor feedback in this proceeding.

c. Treatment of Capital Costs

To account for the incremental expenses associated with the capital investments such as depreciation and return on equity over the book life of an asset, PG&E is considering using an estimated Revenue Requirement associated with capital spend. Using the Revenue Requirement to calculate NPV would allow for a direct comparison between the RSEs for capital programs and the RSEs for expense programs by normalizing the risk reduction per dollar spent. Using an estimated revenue requirement will lead to lower RSEs for capital programs because the revenue costs will be included. PG&E would like SPD's and intervenor feedback on this approach and suggests that this issue should be considered in the forthcoming S-MAP rulemaking.

d. Pre-Mitigation and Post-Mitigation Risk Scores

Pursuant to the S-MAP Settlement Decision, PG&E calculated pre- and post-mitigation risk scores for each year that proposed mitigations are in effect.[44]

For this 2020 RAMP, PG&E defines the different periods as:

- Pre-mitigation: For programs planned for the GRC period (2023-2026) PG&E calculates a pre-mitigation program score that accounts for the benefits from any mitigations that are planned for 2020–2022.

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43 Each RAMP risk chapter (Chapters 7 to 18) and the Cross-Cutting Factor chapter (Chapter 20) includes cost tables and supporting financial workpapers that show the costs from 2020 through 2026 used to develop the RSE.

44 D.18-12-014, Attachment A, p. A-11, No. 13.

- 2023 TY Baseline: PG&E's upcoming GRC TY.
- Post-Mitigation: The benefits from proposed mitigations for the 2023-2026 GRC period are accounted for in the Post-mitigation Risk Scores.

e. Risk Reduction

The Risk Reduction Score captures all the program's benefits and is not limited by the GRC time period. For example, gas pipeline replacement assumes a capital life of 80 years so the benefits are assumed to accrue over all 80 years.

Certain programs in this RAMP Report benefit multiple risks. For example: (1) PG&E proposes mitigations (e.g., Enhanced Vegetation Management) that will reduce the risk of both a Wildfire and a Failure of Distribution Overhead Asset Failure risk event; and (2) PG&E proposes a mitigation (3A and 4C Line Reclosers) that will reduce risk of both an Electric Distribution Overhead Asset Failure and a Third-Party Safety Incident.

For mitigations that benefit multiple risks, PG&E includes the impact of the mitigation in the calculation of the Risk Reduction score for each RAMP risk that benefits from the mitigation. When calculating RSE, however, in instances where a mitigation benefits more than one risk, the mitigation budget is only aligned to the primary RAMP risk event.[45] For example, the budget for the Enhanced Vegetation Management is aligned to the primary RAMP risk of Wildfire and PG&E only calculates an RSE for the risk to which the budget is aligned. This approach avoids counting a single mitigation spend twice.

Many of the cross-cutting mitigations (mitigations aligned to the cross-cutting factors) address multiple RAMP risk events. The Risk Reduction for these mitigations is calculated at the risk level and then summed across each risk. The risk reduction is presented at the cross-cutting factor level (e.g., a Risk Reduction score is provided for all

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[45] The one exception is related to the Skilled and Qualified Workforce (SQWF) cross-cutting factor. The costs for implementing the SQWF mitigation is divided equally between the Failure of Electric Distribution Overhead Assets risk event and the Failure of Electric Distribution Network Assets risk event.

Records and Information Management mitigations combined) and then allocated to each RAMP risk the cross-cutting factor impacts.

Some mitigations in the RAMP risk portfolios also benefit risks included as Other Safety Risks (Chapter 19) and/or additional PG&E risks not included in this RAMP Report. PG&E considers these mitigations' risk reduction value for the RAMP risks only.

The S-MAP Settlement Decision states that utilities should provide the pre- and post-mitigation values for the effects of a mitigation at the tranche level.[46] PG&E provides pre- and post-mitigation values for each RAMP risk at the tranche level in supporting workpapers.[47]

f. Tranche-Level RSE

The S-MAP Settlement Decision states that Utilities should provide RSEs at the tranche level. PG&E provides RSEs at the tranche level for each risk in supporting workpapers.[48]

To calculate tranche-level RSEs, the risk model requires a tranche-level cost estimate for each mitigation and control. The risk owners provided the mitigation and/or control costs at the tranche level.[49] This approach is consistent with the S-MAP Settlement Decision which requires RSEs to reflect the full set of benefits that result from the incurred costs.[50]

Many of the cross-cutting mitigations address multiple RAMP risk events, but the costs cannot be meaningfully separated or allocated. Therefore, the RSEs for the cross-cutting mitigations are provided at the cross-cutting factor level (e.g., one RSE is provided for all Records and Information Management mitigations combined).

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46 D.18-12-014, Attachment A, p. A-12, No. 16.

47 See WP 3-5.

48 See WP 3-19.

49 The modeling workpaper input files show the tranche-level costs. Modeling input files will be provided July 17, 2020.

50 D.18-12-014, Attachment A, p. A-13, No. 25.

g. Foundational Mitigations

PG&E defines foundational mitigations as those programs that support multiple mitigations that reduce risk, but do not reduce the risk themselves. PG&E does not allocate the costs of foundational mitigations among the mitigations they support because the costs cannot be allocated in a meaningful way.

Foundational mitigations are, by definition, assigned an RSE of 0 and marked as such in the analyses.

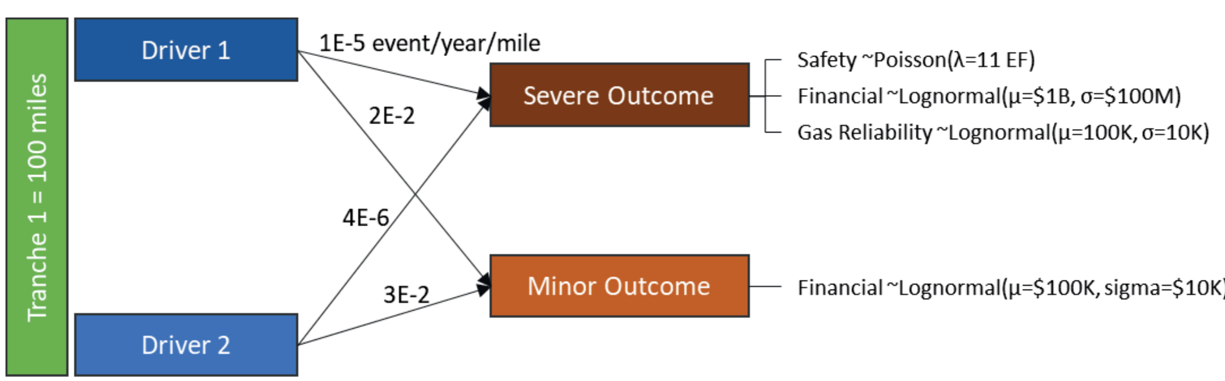
Certain actions that could be considered foundational mitigations are necessary to support a *single* mitigation program. PG&E includes the costs for these actions as part of the cost of the mitigation program they enable and does not consider them foundational mitigations.

5. Risk Analysis Example: MAVF, Risk Score, Risk Reduction, and RSE

This section walks through an example of how a simple Bow Tie model (shown in Figure 3-7 below) is used to compute Risk Spend Efficiency values for two proposed mitigations and addresses:

a) LoRE;
b) CoRE;
c) Expected Value from simulated CoRE;
d) Risk Score;
e) Risk Reduction; and
f) Risk-Spend Efficiency.

FIGURE 3-7
EXAMPLE BOW TIE INPUT ASSUMPTIONS



Note: Poisson and Lognormal refer to the parametric probability distributions used to model the outcome of the risk event.

The example Bow Tie in Figure 3-7 includes:

- Two drivers – Driver 1 and Driver 2;
- Two Outcomes – Minor and Severe;
- One tranche, Tranche 1, defined by an exposure of 100 miles of an asset;
- The risk event is characterized by potential Safety, Gas Reliability, and Financial consequences;
- The Minor outcome has only Financial consequences; and
- The Severe outcome has greater Financial consequences, as well as Safety and Reliability impacts.

The two distinct outcomes for this single risk event, allows the model to capture the low frequency high consequence outcome and the high frequency low consequence outcome, each of which have uncertainty regarding the magnitude of the consequences.

a. Likelihood of Risk Event

Likelihood of Risk Event is calculated per tranche-outcome-driver. The example Bow Tie in Figure 3-7, with one tranche, two drivers, and two Outcomes requires (1*2*2 = 4) four frequency values.

Where there is more than one tranche, PG&E calculates as many sets of tranche-driver-outcome frequencies and Outcome Attribute distributions as there are tranches. Risk Events that are presented in this RAMP report include tens or hundreds of frequency values per Risk Event.

For the sample Bow Tie, the LoRE occurring per year, per unit of exposure (LoRE) is the sum of the four frequencies shown in Table 3-7.

TABLE 3-7
SAMPLE BOW TIE: SUMMARY OF LORE BY DRIVER, OUTCOME AND RISK EVENT

Line No.	Calculation	Minor Outcome	Severe Outcome	LoRE by Driver	Percent of Frequency by Driver
1	LoRE for Driver 1	0.02	0.00001	0.02001	40%
2	LoRE for Driver 2	0.03	0.000004	0.030004	60%
3	LoRE (/yr/mile) =	0.05	1.4E-05		
4	Freq (#/year) =	5	0.0014		
5	% of Freq =	99.97%	0.03%		100%

- LoRE for each Driver = Minor Outcome + Severe Outcome;
- LoRE per year per mile = LoRE for Driver 1 + LoRE for Driver 2;
- Frequency (number of events per year) = LoRE per year per mile x 100 (exposure);[51] and,
- Percent of Frequency = Frequency of Each Outcome / Total Frequency – For example, 5/(5+0.0014) = 99.97%

Therefore, the model expects 0.050014 events per year per mile, which is equivalent to a probability of 0.050014 that the event will happen each year on a given mile of exposure.

Given 100 miles of exposure on the tranche, the risk event frequency is:

Frequency = Exposure x LoRE = 100 x 0.050014 = 5.0014 events per year

Of these 5.0014 events:

- 99.97% of the time the outcome is Minor; and
- 0.03% of the time (1 in 714 years) the outcome is Severe.

b. Consequence of Risk Event (CoRE) for one Trial

Risk event consequences are calculated per tranche-outcome-attribute combination. The Severe Outcome is illustrated in this example given its complexity relative to the Minor Outcome.

The Severe Outcome has Safety, Reliability, and Financial attributes, each defined using a parametric probability distribution (two Lognormal, one Poisson). This example of the CoRE calculation using the MAVF assumes that these attributes are deterministic (the model does not include elements of randomness and the results will be the same every time you run the model) to simplify the application of the MAVF. A description of the probabilistic case (i.e., a model that includes elements of randomness and presents results that vary each time you run the model) follows in Section D.5.c, CoRE as Expected Value.

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51 The value “100” is used here because the Tranche is defined as 100 miles and the LoRE is measured per mile.

The Consequences of a Risk Event in Natural Units for the Severe Outcome are listed in Column A of Table 3-8. The step-by-step calculation below computes all quantities for the Safety Attribute to illustrate the Safety CoRE calculation. Identical steps are performed for each of the other Attributes.

TABLE 3-8
SAMPLE BOW TIE: MAVF DATA FOR SEVERE OUTCOME ASSUMING DETERMINISTIC CONSEQUENCE

		Column			
		A	B	C	D
Line No.	Attribute	Consequence of Risk Event in Natural Unit	Normalized Natural Unit (0-1)	Scaled Unit	Attribute CoRE
1	Safety	11 EF	0.11	6.1	3,027
2	Gas Reliability	100K Customers	0.133	8.5	426
3	Financial	$1B	0.2	15.6	3,889

Calculating the Safety CoRE

Column A has values in Natural Units for each Attributes. The expected values of the distributions are assumed to be a deterministic consequence. The Safety consequence is 11 EFs.

Column B is an intermediate step applying the scaling function characterized in Equation 1 (Figure 3-4), specifically calculating parameter *r*. It results from normalizing the Natural Unit values in Column A using the Attribute Ranges in Table 3-2. This step determines which scaling function Region the Natural Units fall within.

Normalized Unit (Safety) = Natural Unit (Safety)/(Upper Bound – Lower Bound)

= 11 / (100 – 0) = 0.11

Column C shows the results of applying the scaling function to the Natural Unit. Given Normalized Natural Units, *r*, the scaling function returns Scaled Units.[52] The Safety outcome is “catastrophic”, r = 0.11 >

[52] If a linear scaling function had been used, Column C would simply be 100*Column B.

R_2, so the equation corresponding to Region 3 from Equation 1 and Figure 3-3 is used ($S_2 = 5$, $R_2 = 0.1$).

$$\text{Scaled Unit (Safety)} = \frac{100 - S_2}{1.0 - R_2}(\text{Normalized Unit} - R_2) + S_2$$

$$= \frac{100 - 5}{1.0 - 0.1}(0.11 - 0.1) + 5 = 6.1$$

Column D is the Attribute CoRE, calculated as scaled units multiplied by the appropriate weight x a Scaler of 1000. The Attribute weights are as defined in Table 3-4. The Safety CoRE is calculated as:

Safety CoRE = Scaler x Safety Weight x Scaled Unit (Safety)

$$= 1000 \times 0.5 \times 6.1 = 3{,}027$$

Finally, all Attribute-level CoREs (Column D) are summed to compute the CoRE at the risk level:

CoRE = Safety CoRE + Gas Reliability CoRE + Financial CoRE

$$= 3027 + 426 + 3889 = 7{,}343$$

Following the same steps, the CoRE of the Minor Outcome is 0.05.

c. CoRE as Expected Value

PG&E’s risk model simulates the Natural Units for relevant tranche-outcome-attribute combinations. Table 3-9 below shows the simulated natural unit values for all Severe Outcome attributes for 10 trials,[53] based on the calculations described in Section D.5.b above.

[53] PG&E’s model runs 10,000 trials per distribution.

TABLE 3-9
SAMPLE BOW TIE: SIMULATED SEVERE OUTCOMES VALUES IN NATURAL UNITS AND ATTRIBUTE CORE CALCULATIONS[(a)]

Trial	Safety				Reliability				Financial			
	Sim Natural Unit (EF)	Normalized	Scaled	Total CoRE	Sim Natural Unit (1k Cust)	Normalized	Scaled	Total CoRE	Sim Natural Unit ($M)	Normalized	Scaled	Total CoRE
1	5	0.05	1.3	646	84	0.11	6.3	315	871	0.17	12.8	3,207
2	8	0,08	3.2	1,611	86	0.12	6,6	330	871	0.17	12.8	3,209
3	8	0.08	3.2	1,611	91	0.12	7.2	362	982	0.20	15.2	3,791
4	10	0.10	5.0	2,503	96	0.13	8.0	400	987	0.20	15.3	3,819
5	12	0.12	7.1	3,556	97	0.13	8.0	401	1,006	0.20	15.7	3,923
6	12	0.12	7.1	3,556	104	0.13	8.1	406	1,028	0.21	16.2	4,039
7	13	0.13	8.2	4,083	104	0.14	9.1	453	1,031	0.21	16.2	4,053
8	14	0.14	9.2	4,611	108	0.14	9.1	456	1,051	0.21	16.6	4,158
9	14	0.14	9.2	4,611	108	0.14	9.6	481	1,119	0.22	18.1	4,517
10	15	0.15	10.3	5,139	109	0.14	9.7	486	1,134	0.23	18.4	4,594
11	**Safety CoRE 3,193**				**Reliability CoRE 409**				**Financial CoRE 3,931**			
Sum of Attribute Values: 7,533												

(a) The Attribute CoRE is the average of the CoRE per trial for that Attribute.

The additional step required to compute the Attribute CoRE (compared to the steps required to calculate the CoRE for one trial described in Section D.5.b) is to take the average of all Trial CoRE values.

Therefore, the CoRE for the Severe Outcome is the average sum of the three Attribute CoRE values: 3,193 + 409 + 3,931 = 7,533.

The CoRE using the probabilistic values is greater than the CoRE computed using deterministic values because of the non-linear scaling function, which places greater weight on those trials having the least favorable outcomes (e.g., Row 10 in Table 3-9).

Following the identical process, PG&E calculated the CoRE for the Minor Outcome (based only on the Financial Attribute because it is the only outcome of a minor event). The Minor Outcome CoRE is 0.054.

TABLE 3-10
SAMPLE BOW TIE: CORE PER OUTCOME

Line No.	Outcome	CoRE
1	Severe	7,533
2	Minor	0.054

Using these outcome-based CoRE values, the CoRE at the risk-level is calculated as a weighted sum of CoRE based on the frequency percentage of each outcome.

CoRE = % Freq (Minor Outcome) x CoRE (Minor Outcome)
+ % Freq (Severe Outcome) x CoRE (Severe Outcome)

CoRE = 0.03% (Table 3-7) x 7,533 (Table 3-9) + 99.97% (Table 3-7) x 0.054 (Table 3-10) = 2.2

d. Risk Score

The Risk Score is computed at the tranche-outcome level. Given a single tranche for this example risk, the risk scores per outcome are:

Risk Score (Minor Outcome) = Frequency (Minor Outcome) x CoRE (Minor Outcome)
= 5 (Table 3-7) x 0.054 (Table 3-10) = 0.27

Risk Score (Severe Outcome) = Frequency (Severe Outcome) x CoRE (Severe Outcome)
= 0.0014 (Table 3-7) x 7,533 (Table 3-9) = 10.55

Risk Score = Risk Score (Minor Outcome) + Risk Score (Severe Outcome)
= 0.27 + 10.55 = 10.82

The sample risk Bow Tie, Figure 3-8 below, shows that the Severe Outcome contributes 97 percent of the total risk though it represents only 0.03 percent of the frequency of a risk event.

FIGURE 3-8
SAMPLE BOW TIE: EXAMPLE RISK EVENT SUMMARY

e. Risk Reduction Score

To calculate the Risk Reduction score PG&E uses data supplied by the RAMP risk teams that outline the effectiveness of the proposed mitigation and the duration of the mitigation benefit.

Table 3-11 is information for two mitigations used in the example calculation.

TABLE 3-11
SAMPLE BOW TIE: CHARACTERISTICS FOR MITIGATION 1 AND MITIGATION 2

Line No.	Target	Effectiveness Percentage	Scope	Benefit Duration	Effectiveness Degradation
1	Frequency of Drivers 1 and 2	20%	17 miles in Year 1	4 Years	20% annually
2	Safety Consequences of Severe Outcome	10%	100 miles each year from Year 1 to Year 4	1 Year	0%

1) Mitigation 1 – Program Frequency

Proposed mitigation M1 targets all risk drivers for the risk event and is 20 percent effective at reducing event frequency. Effectiveness of M1 is provided per unit of exposure to which the mitigation is applied. Using the scope and effectiveness of the mitigations, the model calculates the average effectiveness at the tranche level:

Average effectiveness = Effectiveness x Scope / Tranche Exposure

= 20% x 17 miles/ 100 miles = 3.4%

Because M1 affects all risk drivers equally applied to the single risk tranche, Risk Reduction is equal to 3.4% of the Risk Score (10.82 x 0.034 = 0.37). Risk Reduction can also be calculated as:

Pre-Mitigation Risk Score = 10.82 (Section D.5.d)

Post-Mitigation Risk Score = (1 – 3.4%) x 10.82 = 10.45

Risk Reduction Score (M1) = Pre-Mitigation Risk Score – Post-Mitigation Risk Score

= 10.82 – 10.45 = 0.37

2) Mitigation 2 – Consequence Mitigation

Proposed mitigation M2 reduces the magnitude of the Safety consequence by 10 percent, but only for the Severe Outcome. The mitigation effectiveness is applied to the entire project scope, so the average effectiveness at a tranche level is the same as the effectiveness at a program exposure level:

Average effectiveness = Effectiveness x Scope / Tranche Exposure

= 10% x 100 miles / 100 miles = 10%

The average effectiveness is applied to the simulated Natural Units (Table 3-9, Severe Outcomes Values in Natural Units) to determine the post-mitigation consequence as shown in Table 3-12 below.

TABLE 3-12
SAMPLE BOW TIE: SIMULATED SEVERE OUTCOME VALUES IN MITIGATED NATURAL UNITS AND ATTRIBUTE CORE CALCULATIONS

Trial	Pre-Mitigation Consequence in Natural Units (EF)[a]	Post-Mitigation Consequence in Natural Units (EF)[b]	Normalized	Scaled	Trial CoRE
1	5	4.5	0.045	1.1	528
2	8	7.2	0.072	2.6	1,310
3	8	7.2	0.072	2.6	1,310
4	10	9.0	0.090	4.1	2,032
5	12	10.8	0.108	5.8	2,922
6	12	10.8	0.108	5.8	2,922
7	13	11.7	0.117	6.8	3,397
8	14	12.6	0.126	7.7	3,872
9	14	12.6	0.126	7.7	3,872
10	15	13.5	0.135	8.7	4,347
11				Safety CoRE	2,651

(a) Values from Table 3-9, Severe Outcomes Values in Natural Units.
(b) Reflects value after 10 percent effectiveness applied to the Pre-Mitigation Consequence in Natural Units.

Mitigation M2 reduces Safety consequence by 10 percent but the Safety CoRE is reduced by 17 percent—from 3,193 (Table 3-9) to 2,651—as a result of the non-linear scaling function. Risk Reduction is calculated as follows:

Pre-Mitigation Risk Score = 10.82 (Section D.5.d)

Post-Mitigation CoRE (Severe Outcome) =
2,651 (Table 3-12) + 409 (Table 3-9) + 3,931 (Table 3-9) = 6,991

Post-Mitigation Risk Score (Severe Outcome)
= Frequency (Severe Outcome) x Post-Mitigation CoRE (Severe Outcome)
= 0.0014 (Table 3-7) x 6,991 = 9.78

Post-Mitigation Risk Score =
Post-Mitigation Risk Score (Severe Outcome) + (Post-Mitigation) Risk Score (Minor Outcome)
= 9.78 + 0.27 (Section D.5.d) = 10.05

Risk Reduction Score (M2) = Pre-Mitigation Risk Score - Post-Mitigation Risk Score

= 10.82 (Section D.5.d) – 10.05 = 0.77

TABLE 3-13
SAMPLE BOW TIE: RISK REDUCTION SCORE BY MITIGATION

Line No.	Mitigation	Risk Reduction Score	Post-Mitigation Risk Score
1	M1	0.37	10.45
2	M2	0.77	10.05

f. Risk Spend Efficiency

Risk Spend Efficiency (Equation 2) is the risk reduction per dollar spent:

$$RSE = \frac{\text{NPV(Pre-mitigation Risk Scores)} \; - \text{NPV(post-mitigation Risk Scores)}}{\text{NPV(Program Costs)}}$$

PG&E calculated the RSEs shown in Table 3-14 for the two sample mitigations using: the risk reduction scores in Table 3-13; the discounting factor discussed in Section C.4.a to calculate the NPV; and sample program costs

TABLE 3-14
SAMPLE BOW TIE: RISK REDUCTION SCORE BY MITIGATION

Line No.	Risk Reduction Score and Cost by Mitigation	Year 1	Year 2	Year 3	Year 4	NPV
1	Risk Reduction Score (M1)	0.37	0.30	0.24	0.19	1.01
2	Risk Reduction Score (M2)	0.77	0.77	0.77	0.77	2.79
3	M1 Program Cost ($M – Capital)	$2.00	–	–	–	2.00
4	M2 Program Cost ($M – Expense)	$0.50	$0.50	$0.50	$0.50	1.81

RSE (M1) = NPV of Risk Reduction Score (M1) / NPV of Program Costs (M1)

= 1.01 / 2.00 = 0.50

RSE (M1) = NPV of Risk Reduction Score (M2) / NPV of Program Costs (M2)

= 2.79 / 1.81 = 1.54

E. Workpapers Supporting PG&E's RAMP Risk Models

The S-MAP Settlement Decision requires that PG&E provide in its RAMP Report a ranking of all RAMP mitigations by RSE.[54] This ranking is provided in supporting workpapers (WP 3-1).

A list of the 12 RAMP risks with the final safety risk score and final total risk score for each is also included in workpapers (WP 3-3).

PG&E has developed workpapers supporting each of its 12 RAMP risk models and a risk model User Guide. The workpapers consist of a risk model input file and a risk model output (Bow Tie) file.[55]

- User Guide – The User Guide provides information about how to input data into the files in order to run the risk model. It also provides calculations, distributions and other information so users can better understand the different elements driving the risk model.
- Source Documents Index and Source Documents – The source documents index lists all of the data used in the risk model. It includes a reference to the source file that is available in soft copy and/or a link to publicly available information. The index number for each file listed on the source document index is also used in the risk model to reference the data used in the model.
- Input Files – This file includes the inputs into the risk model for each of the 12 RAMP risks. It lists the drivers, sub-drivers, tranches and consequences for each risk. Modeling information includes frequency inputs by sub-driver, frequency multipliers, consequence multipliers, program exposure, program costs, program effectiveness on consequences and frequencies, and escalation methods. Input files will be made available in soft copy.
- Bow Tie File – This file includes the outputs from the risk model for each of the 12 RAMP risks. It includes the Bow Tie and Consequence Table graphics included in each RAMP risk chapter (Chapters 7 to 18), the risk

54 D.18-12-014, Attachment A, p. A-14, No. 26.

55 Modeling workpapers will be submitted on July 17, 2020.

scores, RSE, and risk reduction score for each mitigation and the RSE and risk reduction score for each alternative mitigation plan. In addition, the file includes detailed output for driver frequency, outcome frequency, tranche level exposure, risk score by outcome, risk score by tranche, risk score by outcome by attribute, and driver contribution to risk scores. Bow Tie files will be made available in soft copy.

PG&E has prepared mitigation effectiveness workpapers that describe each mitigation program, the effectiveness of each program, the justification for the effectiveness percentage, the mitigation benefit duration, and reason for selecting that duration, and the annual degradation rate of effectiveness. These workpapers are part of the modeling source documents package that will be provided following the RAMP Report. PG&E is also providing a courtesy copy of these workpapers with the RAMP Report.[56]

F. Response to TURN's Feedback Regarding PG&E's 2020 RAMP Methodology

PG&E presented our risk modeling methodology at public workshop hosted by the SPD on January 13, 2020 and February 4, 2020. We received feedback from The Utility Reform Network (TURN) about our RAMP risk modeling methodology and other RAMP-related topics in a letter dated February 19, 2020.[57] This section addresses modeling-related concerns raised by TURN, following the outline of TURN's February 19, 2020 letter. Other concerns raised by TURN are addressed elsewhere in this Report and in the responsive letter that PG&E sent TURN on February 25, 2020.[58]

Concerns with PG&E's MAVF

TURN states that the MAVF tool is fundamental to accurately and comprehensively capture all the pre- and post-mitigation consequences of risk events and thus it must be well-designed in order to yield reliable results.[59]

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56 See workpapers starting at WP 3-6.

57 Legal Director Thomas J. Long, TURN, letter to Tessa Carlberg and PG&E 2020 RAMP Team, February 19, 2020. (TURN's February 19, 2020 Letter). A copy of the letter is included as WP 3-9.

58 Senior Director Janaize Markland, PG&E Enterprise & Operational Risk & Insurance, letter to Legal Director Thomas J. Long, TURN, February 25, 2020 (PG&E's February 25, 2020 letter).

59 TURN's February 19, 2020 Letter, p. 2.

TURN then describes four specific areas of concern with PG&E's MAVF, each of which PG&E addresses below.

1. Scaling Function

TURN raises several issues with respect to the scaling function used in PG&E's MAVF to convert attribute levels from natural units to scaled units. In general, TURN's criticisms stem from its opinion that PG&E should use a linear scaling function instead of a non-linear scaling function.[60]

PG&E and TURN disagree on this issue. As explained in Section B above, PG&E's risk management philosophy is risk-averse, i.e., PG&E is focused on reducing the risk of catastrophic (low frequency, high consequence) events. A linear scaling function yields a risk score that effectively treats all outcomes as "average." By contrast, a non-linear function is sensitive to the distribution of consequences, not just the mean, which allows PG&E to better understand and manage the tail-risk associated with catastrophic events.

PG&E responds to TURN's specific concerns about the scaling function below.

a. TURN Issue 1a: Scaling Function for Financial Consequences Attribute

TURN states that PG&E's use of a non-linear scaling function for financial consequences violates: (1) the concept that the value of one dollar is always one dollar; and, (2) the idea that financial benefits should be additive because "it permits the financial value of a single project to change if that project is divided arbitrarily into two or more parts."[61]

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[60] TURN's February 19, 2020 Letter, p. 2, Item 1.a.

[61] TURN's February 19, 2020 Letter, p. 2, Item 1.a.

PG&E's Response:

While in the abstract one dollar is the same as another, the purpose of the MAVF is to measure Risk (in Scaled Units), not dollars. The MAVF measures the effect on PG&E and our customers of losing a certain amount of money. In economics, this is expressed as utility theory, which is based on the idea that individuals assign different levels of satisfaction values to the original monetary values and use the utility values, not direct monetary values, when making decisions. A dollar when an individual has two dollars can be valued more than a dollar when the individual has 100 dollars. The utility function translates monetary values into the amount of satisfaction and its curvature is different by the preference of a decision maker. Risk-averse decision makers have concave utility function while risk-seeking decision makers have convex utility functions.[62]

PG&E treats the MAVF scaling function as a form of a utility function applied to a consequence from a risk event. PG&E's non-linear scaling function has non-decreasing slope within the Attribute Range that is, in principle, consistent with a risk-averse decision maker.[63] As permitted by MAVF Principle 5, PG&E captures its aversion to catastrophic outcomes through the use of a non-linear scaling function.[64]

TURN's concern that use of a non-linear function could permit the financial value of a single project to change if that project is divided arbitrarily into two or more parts is unfounded. The financial consequence attribute measures the financial consequences of *risk events*, not projects. Consistent with the S-MAP Settlement Decision, PG&E has defined risk events in terms of logical units such as fire

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62 Eeckhoudt et al., Economic and Financial Decisions Under Risk (2005), Chapter 1.

63 Traditional utility functions measure the amount of satisfaction, well-being, etc. from *receiving* amounts of an attribute (e.g., dollars), and risk-aversion is expressed by a concave utility function. The MAVF, however, measures the loss in utility from *losses* of an attribute, so a risk-averse individual would have a convex MAVF.

64 D.18-12-014, Attachment A, pp. A-5 to A-6, No. 6.

ignitions or outages.[65] PG&E has not “arbitrarily” divided (or combined) risk events in a way that would change risk scores. While PG&E would consider any input TURN might have about how to improve risk event definition, the suggestion that PG&E hypothetically could define the same risk events in multiple ways (leading to different risk scores) is not a good reason to force PG&E to use a linear scaling function that does not capture our aversion to catastrophic risk.

b. TURN Issue 1b: Scaling Function for Safety Consequences Attribute

TURN states that PG&E’s non-linear scaling function for the safety attribute indicates that the value of reducing equivalent deaths from 1 to zero is less than one-tenth as much as reducing the equivalent deaths from 100 to 99. TURN argues that this is both counterintuitive and inconsistent with industry-wide practice and that PG&E’s non-linear scaling function should be modified.[66]

<u>PG&E’s Response</u>:

As discussed in Section B, PG&E’s risk management focus is on reducing catastrophic events with potentially extreme consequences because of the disparate impact that a single catastrophic even can have relative to multiple lower consequence events. PG&E’s use of a non-linear function allows it to understand and manage the tail risk of catastrophic events. In addition, PG&E believes that 10 different

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65 The S-Map Settlement Decision is clear about how likelihoods and consequences should be defined and does not provide discretion for arbitrary divisions of risk events and consequences. Under Step 2A, Row No 10 of Appendix A, p. A-8, it requires “[f]or each enterprise risk, the utility will use actual results, available and appropriate data … and/or Subject Matter Experts (SMEs) to identify potential consequences of the risk event … .” Similarly at Row No 11, p. A-11, it requires “[f]or each enterprise risk, the utility will use actual results and/or SME input … .” Under Global Items, p. A-17, Row No 29, it requires “[t]he sources of inputs should be clearly specified. When SME judgment is used, the process that the SMEs undertook to provide their judgement should be described.” Further on, it states, “[t]he methodologies used by the utility should be mathematically correct and <u>logically sound.</u>” (Underscore added.) In D.18-12-014, the CPUC also agreed that emphasis should be placed on developing comparable risk scores (which would require consistent risk event definitions) across utilities. PG&E looks forward to participation in this topic in a future OIR.

66 TURN’s February 19, 2020 Letter, pp. 2-3, Item 1.b.

non-catastrophic events are unlikely to result in the same level of impact as one catastrophic event.

c. TURN Issue 1c: Statistical Value of Life Given by Weights and Attribute Ranges

TURN states that the implied Value of Statistical Life (VSL) given by the weights and the attribute ranges for safety and financial impacts is $100 million which is ten times higher than statistical values used by the U.S. Environmental Protection Agency to evaluate health risk and the U.S. Dept. of Transportation to evaluate vehicle safety features. TURN is concerned that PG&E's use of this higher value may result in skewing the ranking of different risks and misallocating risk management dollars.[67]

PG&E's Response:

To a large extent, the implied statistical value of a life that TURN identifies is a result of required elements of the MAVF calculation process, particularly the emphasis on safety.

PG&E's MAVF is "a tool for combining all potential consequences of the occurrence of a risk event, and creat[ing] a single measurement of value."[68]

MAVF Principle 2 requires that each lower-level Attribute of the MAVF (i.e., safety, reliability, financial impact) has its own minimum and maximum range expressed in natural units that are observable during ordinary operations and as a CoRE.[69] The S-MAP Settlement Decision defines the low and high end of the range of natural units to be the smallest and largest observable value from a risk event, respectively.[70] Consistent with this definition, PG&E set the ranges of the safety and financial consequence Attributes based on historical events and plausible high-consequence scenarios. For the safety Attribute, the high end of the range was based on EFs from the Camp Fire, rounded up

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67 TURN's February 19, 2020 Letter, p. 3, Item 1.c.

68 D.18-12-014, Attachment A, p. A-3.

69 D.18-12-014, Attachment A, p. A-5, No. 3.

70 D.18-12-014, Attachment A, p. A-3.

to 100. For the financial Attribute, the high end of the range, $5 billion, represents a financial loss commensurate with a 2000-2001 Energy Crisis-type event, recognizing that shareholder losses are not considered.

Consistent with the S-MAP Settlement Decision, PG&E assigned Attribute weights in the MAVF based on the relative value of moving each Attribute from its least desirable to its most desirable level, considering the entire range of the Attribute.[71] Attribute weights reflect the relative importance of moving the safety outcomes from the least to the most desirable level as compared to moving financial outcomes from the least to the most desirable levels. PG&E's MAVF combines the Safety, Electric Reliability, Gas Reliability, and Financial attribute consequences of a risk event using the 50 percent, 20 percent, 5 percent and 25 percent weights, respectively, so that safety consequences throughout the attribute range are given twice the weight of financial consequences. This weights 100 EFs (the high end of the Safety consequence range) as comparable to $10 billion (which is twice the $5 billion high end of the Financial consequence range). This relationship could be adjusted by changing the relative weights of the Safety and Financial attributes, but the S-MAP Settlement Decision requires that the safety attribute be set at 40 percent or higher, so any adjustment would not reduce the implied VSL to published values.[72] As it stands, the S-MAP Settlement Decision framework is not directly compatible with VSL. Furthermore, PG&E believes the 50 percent weighting of the safety Attribute provides an appropriate focus on safety.

2. Number of Attributes

TURN believes that there appear to be too few attributes in PG&E's MAVF and strongly doubts that the four attributes considered (Safety, Electric Reliability, Gas Reliability and Financial) cover all the reasons for

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71 D.18-12-014, Attachment A, p. A-6, No. 7.

72 D.18-12-014, p. 67, Ordering Paragraph (OP) 2. Based on the ranges PG&E established, the lowest VSL that could be achieved is approximately $33.3 million, by eliminating the Reliability Attributes, reducing Safety to 40 percent, and assigning 60 percent to the Financial Attribute.

engaging in risk mitigation. TURN claims that PG&E failed to take customer satisfaction into account by failing to include a customer satisfaction attribute.[73]

PG&E's Response:

The four attributes PG&E includes in its risk model incorporate the essential elements required to deliver safe, reliable, and affordable service to our customers. Providing safe, reliable and affordable service is the foundation of customer satisfaction, and PG&E does not believe that adding a customer satisfaction attribute would significantly change its risk analysis.

3. Risk Aversion

TURN states that one of PG&E's motivations for non-linear scaling functions is "risk aversion," which TURN claims is inconsistent with long-standing economic principles. TURN believes that risk-averse behavior in the face of uncertainty does not apply with multi-attribute scaling functions because the purpose of scaling functions is to reflect known tradeoffs and states that PG&E's MAVF reflects PG&E's preference for reductions in worst-case outcomes over equivalent reductions in other, non-worst-case outcomes.[74]

PG&E's Response:

PG&E has explained in Section B above why we are risk-averse, i.e., why we prefer mitigations that reduce the potential for risk events with catastrophic outcomes over mitigations that reduce a similar amount of high frequency, low consequence risk. Due to the greater potential uncertainty surrounding catastrophic events, and their potential to disrupt communities and PG&E's operations, these two types of risk reduction are not truly "equivalent." TURN claims that "risk averse behavior in the face of uncertainty doesn't apply with multi-attribute scaling functions,"[75] but MAVF Principle 5 – Scaled Units, explicitly contemplates use of scaling functions, including non-linear functions to "captur[e] aversion to extreme outcomes."

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73 TURN's February 19, 2020 Letter, p. 3 Item 2.

74 TURN's February 19, 2020 Letter, p. 4, Item 3.

75 TURN's February 19, 2020 Letter, p. 4, Item 3.

4. Initial Modeling Results

TURN writes that PG&E stated in its January 13, 2020 workshop that another motivation for the non-linear scaling function selected was that the Company did not like the initial results of its modeling, and so adjusted the scaling function to reflect Company intuition regarding the levels of different risks. As a result, PG&E may not, in fact, select the most cost-effective set of risk mitigation measures.[76] This is a misinterpretation of PG&E's workshop comments.

PG&E's Response:

PG&E's objective for its S-MAP Settlement Decision implementation, including use of a non-linear scaling function, has always been to focus on tail risk. PG&E stated this objective in the January 13, 2020 workshop. PG&E did not arbitrarily "place its thumb on the scale" to favor one risk over another.

PG&E also mentioned that it tested various scaling functions (i.e., "scales") against real-world risk events to see how they represented tail risk. PG&E tested a linear scaling function on its risk Bow Ties. The results agreed with PG&E's assumption that a linear scaling function would not did not adequately represent tail risk.

Concerns with the Calculation of RSE

5. Discount Rates

TURN writes that, at the January 13, 2020 workshop, PG&E stated that it was using three different discount rates: a zero discount rate for the Safety and Reliability attributes; a market-based discount rate for the Financial attribute; and, PG&E's utility discount rate for all program costs. TURN claims that using different discount rates is inconsistent with basic economic concepts for project evaluation.[77]

PG&E's Response:

Upon consideration PG&E agreed with TURN's feedback and has used a single discount rate for all risk model calculations.

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[76] TURN's February 19, 2020 Letter, p. 4, Item 4.

[77] TURN's February 19, 2020 Letter, p. 5, Item 5.

Failure to Account for All Consequences of Risk Events

TURN notes that under the S-MAP Settlement Decision it is critical that all consequences of a risk event be included in the analysis. TURN identifies two instances where it claims that PG&E has improperly failed to include potential consequences of a risk event in its analysis. PG&E responds to TURN's concerns below.

6. Indirect Impacts or Consequence of the Risk Event

TURN claims that PG&E ignores "indirect" impacts or consequences of risk events, which could lead to underestimating CoRE values or inaccurate RSE values. In particular, TURN notes that PG&E's risk modeling of safety consequences does not account for "death or injuries caused by the failure of electrical equipment caused by a widespread planned or unplanned outage—such as non-functioning traffic lights, breathing machines, and other medical equipment—even though these are known consequences of outages."[78] TURN believes that this may lead to inaccurate RSEs due to "the failure to consider adverse safety impacts from Planned Shutoffs."[79] TURN notes that Row 31 of the S-MAP Settlement Decision states that "SME judgment should be used if the methodology requires use of data that is not available."[80] TURN further indicates that PG&E "has subject matter experts who should be able to develop estimates of these indirect impacts [and] can also intensify its efforts to seek out data about the safety impacts of power outages."[81]

PG&E's Response:

PG&E's risk assessment only includes direct safety consequences. TURN claims that outages have known safety consequences—such as deaths or injuries due non-functioning traffic lights, breathing machines, and other medical equipment—but PG&E does not have sufficient data to determine whether these safety consequences actually materialize (or if

78 TURN's February 19, 2020 Letter, p. 6, Item 6.

79 TURN's February 19, 2020 Letter, p. 6, Item 6.

80 TURN's February 19, 2020 Letter, p. 5, Failure to Account for All Consequences of Risk Events.

81 TURN's February 19, 2020 Letter, p. 6, Item 6.

they do, how often). Under these circumstances, PG&E believes that any estimate using SME judgment would only make PG&E's risk analysis more speculative and uncertain.

7. Excluding Safety Impacts from Outages From Third-Party Safety Incident

TURN states that PG&E's failure to include the safety impacts from outages as discussed in Item 6 above also affects the Third-Party Safety Incident risk. TURN suggests that one way to address its concern is "to distinguish between outage-related and non-outage-related outcomes on the right side of the [Bow Tie], and include potential safety consequences associated with the outage outcomes."[82]

<u>PG&E's Response</u>:

PG&E incorporated TURN's feedback and distinguished outage-related and non-outage-related outcomes as 'Public Interaction with Reliability Impact" and "Public Interaction." However, PG&E did not include potential safety consequences associated with the outage outcomes for the reasons responded to Item 9.

<u>Insufficient Granularity of Analysis</u>

TURN notes that the S-MAP Settlement Decision requires that risk analyses be disaggregated by tranches to ensure that the highest risks in the system get the requisite attention and that mitigations are not too broadly scoped. TURN is concerned that PG&E's risk analysis is not sufficiently granular.[83] PG&E responds to TURN's specific concerns below.

8. Granularity Related to the Wildfire Risk

TURN states that the Wildfire risk should have more granularity, specifically tranches that reflect asset condition, whether the asset has been upgraded, and geographic locations.[84]

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82 TURN's February 19, 2020 Letter, p. 6, Item 7.

83 TURN's February 19, 2020 Letter, p. 6.

84 TURN's February 19, 2020 Letter, pp. 6-7, Item 8.

PG&E's Response:

PG&E discusses the tranches used to model Wildfire in Chapter 10, Section B.4. PG&E is continually evaluating how it defines its tranches to find the right balance between too few and too many tranches.

9. Developing Tranches to Account for Differences in Consequences Owing to Geographic Locations of Assets

TURN states that PG&E should account for differences in consequences of the occurrence of risk events owing to geographic locations, and references the Loss of Containment on a Gas Transmission Pipeline risk event.[85]

PG&E's Response:

PG&E addresses this issue in Chapter 7, Section B.4.

10. Incorporating Asset Condition when Specifying Tranches

TURN states that PG&E should incorporate asset condition when it specifies tranches of assets involved in specific risks and references the Loss of Containment on a Gas Transmission Pipeline risk event as an example.[86]

PG&E's Response:

PG&E addresses this issue in Chapter 7, Section B.4.

Incorrect Baseline for Risk Analysis

11. Baseline for Risk Selection Should have been 2022 and not 2019

TURN notes that using the correct baseline for risk analysis is necessary to ensure PG&E is not double-counting risk reduction benefits.[87]

TURN states that the S-MAP Settlement Decision requires PG&E to use 2022 as the baseline and not 2019 in order to capture the effects of risk mitigation benefits expected to be achieved prior to the next GRC period. TURN claims that PG&E's scoring of risks for the February 4, 2020 workshop is not consistent with the requirements of the S-MAP Settlement

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85 TURN's February 19, 2020 Letter, p. 7, Item 9.

86 TURN's February 19, 2020 Letter, p. 7, Item 10.

87 TURN's February 19, 2020 Letter, p. 8.

Decision and may have resulted in the incorrect ranking and selection of risks.[88]

PG&E's Response:

PG&E addresses this issue in Chapter 4, Section C.

PG&E's Intentions Regarding Calculation of Risk Reduction for "Controls"

12. Inability to Calculate Control RSEs in RAMP Submission

TURN notes that PG&E stated at the January 13, 2020 workshop that it may not calculate RSEs for controls (mitigations currently in place). TURN views this position as inconsistent with the S-MAP Settlement Decision (Row 26) that requires RSE scores for all RAMP mitigations without distinguishing between new or existing mitigations. PG&E's claimed lack of "counterfactual" data is not a legitimate excuse because Row 31 of the S-MAP Settlement Decision states that "SME judgement should be used if data are not available."[89]

PG&E's Response:

PG&E agrees with SED and TURN that RSE calculations for existing controls can facilitate the evaluation of the overall effectiveness of risk reduction work. However, modeling the controls, which is a precondition to developing RSEs, is not required by D.18-12-014 and PG&E was unable to complete this work for most control programs in time for this RAMP.

TURN describes controls as "mitigations currently in place," and implies that there is no distinction between mitigations and controls in the S-MAP Settlement Decision. However, when it updated the risk lexicon in D.18-12-014, the Commission retained the distinction between mitigations and controls.[90]

Given the accelerated schedule for RAMP, PG&E was not able to model most of its control programs. However, as described at the workshops, PG&E performed pilot evaluations of select control programs in this RAMP. PG&E hopes parties will provide feedback on the pilot methodology used to

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88 TURN's February 19, 2020 Letter, p. 8, Item 11.

89 TURN's February 19, 2020 Letter, p. 8, Item 12.

90 D.18-12-014, 2018 S-MAP Revised Lexicon, pp. 16-17.

evaluate these controls, and PG&E will incorporate that feedback and lessons learned into future risk assessments. We believe that gaining a better understanding of these programs is an essential next step in our risk management evolution.

Insufficient Transparency

TURN states that PG&E has not provided transparency in its calculations and inputs to those calculations as required by Row 29 of the S-MAP Settlement Decision. TURN lists six items that it requires to verify PG&E's risk selection and analysis.[91]

PG&E's Response:

PG&E will provide workpapers supporting its risk models that address each of the six items TURN needs to verify PG&E's risk selection and analysis.[92] Regarding the six items (a-f) requested by TURN, PG&E will provide:

a. The probability distributions on the levels of all attributes in natural units as a consequence of the occurrence of the risk event;
b. The likelihood of occurrence of the risk event;
e. Supporting details showing how the LoRE was calculated; and
f. Supporting details that show how the CoRE was calculated (right side of Bow Tie).

The other two items TURN identified (item c, the likelihood of occurrence of each driver (left side of Bow Tie), and item d, the conditional probability of the occurrence of the risk event, given the occurrence of each driver (left side of Bow Tie)) are not available because PG&E calculates the left side of the Bow Tie directly without going through the two steps TURN calls out. TURN is asking for:

$$\text{LoRE(risk event and driver)} = \text{LoRE(risk event} \mid \text{driver)} \times \text{LoRE(driver)}$$

Because PG&E calculates the left-hand side directly without going through the two steps, PG&E does not have data for items c or d, but does have data for item e (likelihood of occurrence of the event by each driver).

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91 TURN's February 19, 2020 Letter, pp. 8-9, Insufficient Transparency, Item 13.

92 Modeling workpapers will be provided on July 17, 2020.

For example: for the vegetation driver of an ignition event:

a. LoRE(driver) is the probability of having vegetation contact;

b. LoRE(risk event | driver) is the probability of having ignition when there is vegetation contact; and,

c. LoRE(risk event and driver) is the probability of having ignition from vegetation contact.

Other Concerns and Recommendations

TURN identifies three additional concerns and recommendations related to: cyber-related risks; inadequate and/or inaccurate recordkeeping; and weather conditions related to wildfire risk. Weather related issues related to wildfire are addressed in Chapter 10. Cyber-related risk is addressed in Chapter 20, Attachment A, Section B. Recordkeeping is addressed in Chapter 20, Attachment A, Section F.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

RISK ASSESSMENT AND MITIGATION PHASE

RISK SELECTION

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A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E or the Company or the Utility) describes the process for selecting the safety risks evaluated within this Risk Assessment and Mitigation Phase (RAMP) Report in accordance with the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement (S-MAP Settlement Decision) process, including hosting a public workshop to introduce the proposed RAMP risks. This chapter will also discuss significant changes to the RAMP risks following the public workshop and compares PG&E's 2020 RAMP risk selection with the risks included in its 2017 RAMP report.

B. Risk Identification and the Enterprise Risk Register (Step 1B of the Settlement Agreement)

As directed in the S-MAP Settlement Decision, the utility's Enterprise Risk Register (ERR) is the starting point for selecting risks to be evaluated in RAMP.[1] PG&E transitioned to an event-based risk register shortly after filing its 2017 RAMP.[2] This change resulted in PG&E having many fewer risks on its register, all the risk events being similarly scoped throughout the Company, and a consistent methodology being used by each line of business.

Following the issuance of the S-MAP Settlement Decision in December 2018, PG&E began refining our risk assessment methodology and risk models to incorporate the principles of the S-MAP Settlement Decision. This process included evaluating, selecting, and refining the consequence attributes, scaling function, and ranges discussed in Chapter 3. PG&E applied these principles to our Corporate Risk Register (CRR) which contained 35 risk events at the end of

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1 Phase Two Decision Adopting S-MAP Settlement Agreement with Modifications, Attachment A, Element No. 8, Risk Identification and Definition, D.18-12-014, p. A-7, (D.18-12-014).

2 See Chapter 2, Enterprise Risk Management Framework.

2019.[3] The revised CRR list was finalized and approved by the Vice President Risk Committee on January 16, 2020.[4] Since that time, we have continued to assess the scope and definition and incorporate feedback from internal and external stakeholders. There are currently 33 risks on PG&E's CRR.

C. Risk Assessment, Risk Ranking, and Risk Selection for RAMP Evaluation (Steps 2A and 2B of the S-MAP Settlement Agreement)

Of those risk events on the 2019 CRR, 26 had a Safety Risk Score greater than zero. The S-MAP Settlement Decision requires utilities to compute a Safety Risk Score using only the safety attribute for those risks with a safety risk component, and -- for the top 40 percent of those risk events -- compute a Multi-Attribute Risk Score (MARS).[5] Using the S-MAP Settlement Decision process, there were 11 risks with a Safety Risk Score that required further analysis and computation of a MARS.

For purposes of determining the proposed risks to be evaluated in RAMP, PG&E applied the above steps. In addition, PG&E added another step: for any risk below the 40 percent threshold, if the Safety Risk Score was within 20 percent of the minimum safety score of the risks within the top 40 percent, then that risk was included on the Preliminary RAMP Risk list. For the 26 safety risks, PG&E calculated MARS for the top 11 of those risks, which is slightly higher than 40 percent. At the time the RAMP risk selection occurred, the minimum safety score for these top 11 risks was 8 for the "Failure of Electric Distribution Overhead Assets" risk event. The next highest safety risk, "Large Overpressure Event Downstream of a Measurement and Control Facility," had a score of 7, which was within 20 percent of 8, thus PG&E calculated a MARS for

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3 PG&E recently renamed the ERR to the CRR.

4 For a list of the 35 risk events, see WP 4-48 to 4-49, PG&E's 2020 RAMP Preliminary Risk List (January 21, 2020).

5 D.18-12-014, Step 2-A, Risk Assessment and Risk Ranking in Preparation for RAMP, pp. A-8 to A-9.

that additional safety risk. Together, those 12 risks constituted PG&E's Preliminary RAMP risk list.[6]

TABLE 4-1
PG&E'S PROPOSED RISKS FOR 2020 RAMP

Line No.	Safety Risk Event	Safety Risk Score	MARS
1	Wildfire	8403	20041
2	Third Party Safety Incident	1592	1642
3	Motor Vehicle Safety Incident	217	218
4	Employee Safety Incident	120	124
5	Contractor Safety Incident	116	116
6	Real Estate and Facilities Failure	104	142
7	Loss of Containment (LOC) – Gas Distribution Pipeline - Non-Cross Bore	86	108
8	Large Uncontrolled Water Release (Dam Failure)	42	71
9	Loss of Containment – Gas Transmission Pipeline	23	49
10	Failure of Electric Distribution Network Assets	12	12
11	Failure of Electric Distribution Overhead Assets	8	453
12	Large Gas Overpressure Event Downstream of a Measurement and Control Facility	7	8
13	Failure of Electric Distribution Underground Assets	5	
14	LOC - Customer Connected Equipment	3	
15	Aviation - Helicopter Incident	3	
16	LOC - Gas Storage Facilities	3	
17	LOC - Distribution Pipeline - Cross Bore	2	
18	Aviation Fixed Wing Incident	2	
19	LOC - Gas M&C or C&P Facilities	2	Not
20	Nuclear Core Damaging Event	< 0.001	Calculated
21	LOC - CNG Station Equipment	< 0.0001	
22	LOC - LNG/CNG Portable Equipment	< 0.0001	
23	Failure of Substation Assets	< 0.0001	
24	Failure of Transmission Overhead Assets	< 0.0001	
25	Failure of Transmission Underground Assets	< 0.0001	
26	Hazardous Material Release	< 0.0001	

Scoring of Safety Risk Events consists of: (1) The Safety Risk Scores for each Risk with a non-zero Safety Score in PG&E's CRR and (2) MARS for the top 40 percent of CRR risks with a non-zero Safety Risk Score. Scores are rounded to the nearest significant digit. These scores represent the model outputs as of January 16, 2020..

6 PG&E considers all its safety risks important and, as such, monitors and manages them through its normal course of business. While 13 of the 26 risks with a Safety Risk Score on the CRR are not being assessed as a 2020 RAMP risk, PG&E is providing an overview of these risks and the work PG&E is doing to mitigate these risks in Chapter 19, Other Safety Risks..

Once the utility has determined the Preliminary RAMP Risks to be included in the upcoming RAMP report, the S-MAP Settlement Decision directs the utilities to host a public workshop to introduce the proposed RAMP risks and 14 days prior to the workshop, provide parties with a list of the preliminary risks.[7] PG&E served its 2020 RAMP Preliminary Risk List on parties on January 21, 2020 in advance of the February 4, 2020 workshop.[8]

It should be acknowledged that PG&E was not able to comply with one aspect of the S-MAP Settlement Agreement in its presentation of the 2020 RAMP Preliminary Risk List. The risk scores calculated above, which were approved on January 16, 2020 and released publicly on January 21, 2020, could only include data available as of December 2019. The risk scores thus do not include complete 2019 recorded information (including risk events and consequences) and they do not incorporate subject matter expert-informed "benefits of any mitigations that are expected to be implemented prior to the GRC period under review in the RAMP submission," as envisioned by the S-MAP Settlement Decision.[9] The difference in approach is due to the condensed timeline to produce this Report, and the Rate Case Plan being issued just a few days prior to the dissemination of the 2020 RAMP Preliminary Risk List.[10] PG&E used the 2019 CRR scores as the baseline for determining the preliminary RAMP risk list. The purpose of sending the 2020 RAMP Preliminary List and hosting a workshop in early February was to enable PG&E to have adequate time to incorporate feedback and make changes to its risks for this Report. This approach was shared with parties during the January 13, 2020 workshop.[11]

Following the issuance of the 2020 RAMP Preliminary Risk List, PG&E updated its models to incorporate the entirety of 2019 recorded data and the

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[7] D.18-12-014, p. A-10.

[8] WP 4-47 and 4-52.

[9] D.18-12-014, p. A-8 to A-9.

[10] Decision Modifying the Commission's Rate Case Plan for Energy Utilities, was issued on January 16, 2020, (D.20-01-002)

[11] PG&E 2020 Risk Assessment and Mitigation Phase Workshop #2, January 13, 2020, WP 4-19 to WP 4-26.

benefits of mitigations that will be performed from 2020-2022.[12] With these additional inputs, PG&E reranked all the safety risks. The twelve preliminary risks proposed in January remained the top safety risks, although there was some shift in rank among the top twelve risks. The risk scores included throughout this Report represent a 2023 test year baseline.

D. Public Workshops and Evolution of Risks

1. PG&E's Public Workshops in Advance of the 2020 RAMP Report

As described in Chapter 1, Introduction, PG&E jointly hosted three public workshops with the Safety Policy Division in advance of this RAMP Report. The purpose of these workshops was to bring interested parties along on PG&E's journey of implementing the S-MAP Settlement Decision into our risk assessment practices and to provide an early opportunity to receive feedback from parties. These workshops also allowed parties to hear about PG&E's progress jointly and publicly rather than in separate meetings. In this way, the participating parties continued the cooperative spirit adopted in the S-MAP proceeding of continuous improvement in risk assessment methodologies.

PG&E's first workshop was held on November 12, 2019. This workshop focused on PG&E's implementation of the S-MAP Settlement Agreement and provide updates to commitments made in PG&E's 2020 General Rate Case proceeding related to risk management.[13]

PG&E's second workshop was held on January 13, 2020. This workshop detailed PG&E's proposed modeling approaches including: the choice of attributes; assigned weightings and ranges; the discount rate for the attributes; the non-linear scaling function for capturing low-probability, high-consequence events; and the use of 2023 baseline for this RAMP Report.[14]

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12 As described in Ch 6, Pandemic Impacts, PG&E has not accounted for any potential delays or rescoped work as a result of the COVID-19 pandemic as it is too premature to understand the entire breadth of impacts at this time. The 2020 forecasted work in this report reflect the forecast as of March 2020.

13 See WP 4-1 to WP 4-18, PG&E 2020 Risk Assessment and Mitigation Phase Overview, Workshop #1, November 14, 2019.

14 PG&E 2020 Risk Assessment and Mitigation Phase Workshop #2, January 13, 2020, WP 4-19 to WP 4-26.

PG&E's third workshop was held on February 4, 2020. This workshop was held two weeks following the dissemination of PG&E's 2020 RAMP Preliminary Risks list. The purpose of this workshop was "to gather from SED, CPUC staff, and other interested parties to inform the determination of the final list of risks to be included in RAMP."[15] This is the only workshop of the three that is required under the S-MAP Settlement Agreement. In this workshop, PG&E presented the data, assumptions, and bowtie elements for each of the 12 preliminary RAMP risks. PG&E also provided a discussion of the cross-cutting factors that influence the risk events and a comparison of the 2017 RAMP risks to the 2020 RAMP preliminary risks.[16]

2. Incorporating Feedback and Significant Changes Since Workshop 3

PG&E incorporated the feedback it received from the stakeholder participation process into its risk assessment methodology and the feedback directly improved it. This includes improvements to the overall risk scoring methodology, such as the use of a consistent discount rate for each attribute,[17] and revisions to individual risks, such as including the cross-bore tranches to the Loss of Containment on Distribution Main or Service event.[18] There were other suggestions, such as expanding the list of Attributes of the Multi-Attribute Value Function, that PG&E ultimately decided not to adopt. The S-MAP Settlement Decision directs the utility to include "the rationale for taking or disregarding input during the workshop" in its RAMP report.[19] We have identified throughout this report where PG&E has changed its methodology as a result of intervenor feedback or provided justification for the suggestion if it was not ultimately included.

This RAMP report is better because of the feedback that we have received and have been able to incorporate. Even where we did not ultimately adopt a suggestion, we were able to challenge our assumptions

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15 D.18-12-014, , p. A-10.

16 See WP 4-86 to 4-145, PG&E 2020 Risk Assessment and Mitigation Phase Workshop #3, February 4, 2020.

17 See Chapter 3, Risk Modeling Risk Spend Efficiency, Section F.5.

18 See Chapter 8, Loss of Containment of Gas Distribution Main or Service, Section B.4.

19 D.18-12-014, p. A-10.

and ensure that our stance is the right one. PG&E hopes that this report provides another opportunity for PG&E and the broader risk management community to improve our risk assessments, and in turn, improve the safety of our communities.

PG&E welcomes stakeholder input but acknowledges that PG&E and stakeholders may be coming from very different perspectives given the differing roles we have. PG&E must do what it believes to be in the best interest of the multiple stakeholders the Utility represents including the customers and communities we serve.

E. Comparison Between 2017 and 2020 RAMP Reports

As described throughout this Report, there have been a number of changes from the methodologies employed in the 2017 RAMP report. These include a move to an event-based risk register, recharacterizing cross-cutting risk factors, and the development and implementation of the risk assessment methodologies articulated in the S-MAP Settlement Decision. As a result, certain risks that were analyzed as a 2017 RAMP risk are no longer evaluated as a RAMP risk in this Report. Importantly, the scope of the risks have also changed since the 2017 RAMP risk. For a discussion of the comparison of the scope changes between reports, see the Changes Since 2017 Section in each RAMP risk chapter. Table 4-2 below identifies where the 2017 RAMP risks appear in this Report.[20]

[20] See also WP 4-165.

TABLE 4-2
2017 RAMP REPORT RISKS IN THE 2020 RAMP REPORT

Line No.	2017 RAMP Risk	2020 RAMP Report Location
1	Transmission Pipe Failure with Ignition	Chapter 7, Loss of Containment on Gas Transmission Pipeline
2	Failure to Maintain Capacity for System Demands	No longer a safety risk
3	Measurement and Control Failure – Release of Gas with Ignition Downstream	Chapter 19, Other Safety Risks
4	Measurement and Control Failure – Release of Gas with Ignition at Measurement and Control Facility	Chapter 19, Other Safety Risks
5	Release of Gas with Ignition on Distribution Facilities – Cross Bore	Cross Bores are included in the Loss of Containment on Gas Distribution Main or Service risk (Chapter 8)
6	Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility	Chapter 19, Other Safety Risks
7	Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore	Cross Bores are included in the Loss of Containment on Gas Distribution Main or Service risk (Chapter 8)
8	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility	Chapter 19, Other Safety Risks
9	Distribution Overhead Conductor Primary	Incorporated into Failure of Distribution Overhead Assets (Chapter 11) and Third Party Safety Incident (Chapter 15)
10	Transmission Overhead Conductor	Chapter 19, Other Safety Risks
11	Wildfire	Chapter 10, Wildfire
12	Nuclear Core Damaging	Chapter 19, Other Safety Risks
13	Hydro System Safety – Dams	Chapter 13, Large Uncontrolled Water Release (Dams)
14	Contractor Safety	Chapter 17, Contractor Safety Incident
15	Employee Safety	Chapter 16, Employee Safety Incident
16	Motor Vehicle Safety	Chapter 18, Motor Vehicle Safety Incident
17	Lack of Fitness for Duty	Incorporated into Employee Safety Risk (Chapter 16)
18	Cyber Attack	Chapter 20, Cross-Cutting Factors
19	Insider Threat	Incorporated into Cyber Attack (Chapter 20)
20	Records and Information Management	Chapter 20, Cross-Cutting Factors
21	Skilled and Qualified Workforce	Chapter 20, Cross-Cutting Factors
22	Climate Resilience	Chapter 20, Cross-Cutting Factors

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CHAPTER 5

RISK ASSESSMENT AND MITIGATION PHASE

SAFETY CULTURE AND COMPENSATION

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SAFETY CULTURE AND COMPENSATION

A. Introduction

Nothing is more important than safety to Pacific Gas and Electric Company (PG&E, or the Company, or the Utility). Our goal is to continually reduce risk to keep our customers, the communities we serve and our workforce (employee and contractor) safe. Our focus is to continue building an organization in which we have designed every work activity to facilitate safe performance, every member of our workforce knows and practices safe behaviors, and every individual is encouraged to speak up if they see unsafe or risky behavior and has confidence that their concerns and ideas will be heard and followed up on. A strong safety culture is fundamental to our operations and is consistent with PG&E's Mission, Vision, and Values. Our business is founded on safety.

Our performance during the past few years has fallen short of that aspiration. We have experienced a number of tragic incidents and too many people are still getting hurt. We have not always practiced what we preach and have identified a number of gaps we need to close. We know we can do better and we have to do better. We are committed to changing our Company and safety culture. We will do this through the implementation of a comprehensive long-term strategy that will span several years. We will link every initiative to a specific outcome, challenging us to work on the most important things that will give us the greatest improvements. We will have various programs specifically addressing cultural topics. We will resource the work appropriately, closely track progress, and emphasize the sustainability of the various initiatives. We will also listen to external experts and observers, and adjust course when necessary.

FIGURE 5-1
PG&E'S MISSION, VISION, AND CULTURE

This chapter describes PG&E's safety culture including executive board engagement, organizational structure, and discusses PG&E's compensation policies related to safety performance.

B. PG&E's Safety Culture

1. Safety Leadership

PG&E recognizes that we must improve the Company's safety culture and performance. We are working to transition from a compliance-focused organization to a risk-focused organization that holds each other accountable for safety, resolves issues promptly, and has engagement at all levels. As stated above, protecting the safety of the public, our employees and contractors must come before anything else, all the time, everywhere. This commitment needs to be reflected in the decisions we make, our behavior, and how we invest our time and resources.

Effective March 9, 2020, Francisco Benavides joined PG&E as Vice President and Chief Safety Officer (CSO) of the Enterprise Health and Safety line of business. Hiring Mr. Benavides is an important part of strengthening our safety culture. He brings 30 years of industrial safety, health and environmental experience to his new role. Mr. Benavides has demonstrated experience in reducing injury rates 40 to 90 percent, eliminating fatalities, and reducing the rate of high-potential incidents.[1]

Mr. Benavides reports to the Corporation Chief Executive Officer (CEO) and is responsible and held accountable for:

- Protecting the safety of PG&E's customers, communities, and workforce;
- Setting the Company's workforce and public safety strategy;
- Establishing governing standards and expectations for safety across the Company;
- Ensuring adherence to those standards;
- Supporting the Company's operational safety execution;
- Working to hone and mature PG&E's safety culture; and
- Identifying areas of safety risk, and developing preventive and corrective action plans.

In the proposed regionalization of operations, each region will have a Safety Director who reports to the CSO and who is accountable for safety at the local level. Each Regional Safety Director will be in place no later than May 2021. The Directors will work with the leadership in their region on identifying region-specific hazards and assessing risk, verifying critical field controls, coaching on positive safety interactions, and coordinating the implementation of enterprise-wide safety programs within their region.

2. Workforce Safety Strategy

Mr. Benavides is responsible for developing and implementing the Company's workforce safety strategy that will be shared with and reviewed by PG&E's Board of Directors Safety and Nuclear Operations (SNO) Committee. He will draw upon his experience implementing safety culture-related programs and Safety Management Systems to finalize the strategy which will be presented to the SNO Committee at the end of July 2020.

To develop the strategy Mr. Benavides gathered data from various sources, including interviews, field visits, incident investigations, and internal and external audits and assessments. The strategy includes two major

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[1] Incident that has the potential to cause a serious injury or fatality.

pillars: systems and culture. Systems refers to risk management, equipment, processes, and procedures. Culture refers to employee engagement, adherence to established requirements, sense of urgency for safety, and leadership. Focus areas of the safety strategy will include:

Enterprise Safety Management System (ESMS): PG&E has committed to implementing an ESMS that consists of a series of capabilities (people, process, governance, and technology systems) required to define, plan, implement, and continuously improve workforce safety. The ESMS will become the way PG&E "delivers the business of safety" and will be based on a consistent and comprehensive enterprise safety controls framework reinforced with system assurance.[2]

In the last quarter of 2019 and first quarter of 2020, PG&E developed a draft set of policies and standards to define the ESMS (e.g., policies for ESMS and Management of Change and standards for Workforce Safety and Safety Values and Actions). The intent of these set of policies and standards is to define the ESMS and reinforce PG&E's commitment to reducing safety risks to keep our customers, the communities we serve, and employees safe.[3]

Enhanced Safety Risk Management: PG&E will develop an enhanced safety risk management program to evaluate and improve safety and risk management at three levels:

- <u>Company Level</u>: Understand, manage, and mitigate catastrophic safety risks;
- <u>Department Level</u>: Understand, manage, and mitigate critical safety risks associated with a particular job family, such as the risk of falling when working at heights, the risk of a collision when driving a vehicle, or the risk of electrocution when working around electrical conductors; and

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2 PG&E first proposed the ESMS in its 2017 RAMP filing, but has struggled to implement it due to multiple changes within the organization. PG&E's RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017) (PG&E's 2017 RAMP Report), p. C-1.

3 Governance documents will be updated to reflect the regionalization plan and the Plan of Reorganization before they are published.

- Task Level: Understand, manage, and mitigate safety risks associated with a specific task, such as the safety risk associated with welding sections of pipe as part of a pipeline replacement project.

PG&E will identify safety risk and control owners and determine who is responsible for the oversight of them. The risk assessment processes will be more detailed than what has been done in the past, and risk mitigation actions will be closely tracked and reported.

Standards: PG&E will improve our safety technical standards by simplifying them, clarifying them, and making them more protective, consistent with leading industry practice.

Contractor Safety Management: Improve contractor safety management by increasing on-site supervision and safety officer presence; stronger safety criteria in the contractor selection process; requiring safety plans along with project bids; holding strategic contractor meetings with the PG&E leadership focused on safety performance; strengthening requirements for number of observations the contractors must conduct and sharing observation findings with PG&E; and updating safety-focused training for PG&E employees engaging contractors.

Musculoskeletal Disorder (MSD) Programs/Ergonomics: PG&E will work with employees and supervisors and use injury data to develop a proactive approach for identifying high-risk physically-demanding field jobs for detailed evaluations conducted by trained ergonomic experts. Additionally, PG&E will increase field employee awareness about the benefits of using sports medicine professionals (Industrial Athletes) to assist with assessment and assistance with strengthening exercises. By using data, Office Ergonomic Specialists will work with employees to proactively address ergonomic needs prior to the employees experiencing discomfort. This is particularly important during the current COVID-19 stay at home situation.

Safety Audits: We will implement a comprehensive program for conducting safety audits across the various departments in the Company, with scope and frequency based on risk. Audit participation will include both operations and management, and will be conducted by qualified auditors with a qualified Safety Lead Auditor.

Data Management, Systems and Reporting: PG&E will improve data capture by including more detail about the reasons behind the most serious incidents. We will feed a database to manage ergonomic risk assessments, and further enhance our ability to digitize checklists, reports, and communications, making those available to supervisors in the field.

Since Mr. Benavides's arrival, he has acted in collaboration with the operations leaders to make immediate improvements in Serious Injury and Fatality (SIF) incident management.[4] Actions have included: implementing executive reviews of SIF incidents; eliminating extension of SIF corrective action due dates; requiring contractors to report potential SIF events to PG&E; and implementing joint investigations (PG&E and contractor) for the incidents.

Culture: Examples of programs designed to strengthen our safety culture include an initiative to take officers and directors to the field to have informal safety conversations with hourly employees, establishing a requirement that safety be part of the hiring criteria for all jobs, developing and communicating a set of principles around safety beliefs, requiring that every employee have a safety-related performance objective in their annual plan, deploying safety leadership training, and measuring our safety culture using detailed perception surveys. PG&E is also revising the current Values & Actions standard to make it more specific and focused. The implementation of the standard will be mandatory and audited.

Public Safety: A number of departments, people, and work are related to Public Safety in PG&E. This includes vegetation management, electric grid sectioning, process safety for gas operations, transportation safety, and asset management. Under the new strategy, the planning for those different components will be coordinated, the reporting will be integrated, and the Chief Safety Officer will be part of the "public safety power shut-off" or PSPS process, playing an oversight role.

Governance Accountability Model: PG&E is establishing a Governance Oversight Execute Support (GOES) accountability model (Figure 5-2) to

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4 Incident that resulted in a person experiencing a serious injury or fatality (SIF-A) and incidents that had the potential (SIF-P) to result in a SIF-A.

clarify roles and responsibilities. GOES will focus on functions where clarity of roles and responsibilities would make a meaningful difference. Safety is one of those functions. PG&E expects to implement GOES after it emerges from bankruptcy.

FIGURE 5-2
GOES ACCOUNTABILITY MODEL

Accountability	Definition
(G)overnance	▪ Accountability to define what good is, what the rules are, and who is accountable
(O)versight	▪ Accountability to critically monitor adherence to the rules to assure the desired outcomes are attained
(E)xecute	▪ Accountability to develop plans, implement procedures and deliver results
(S)upport	▪ Accountability to provide resources and tools to executing functions

3. External Governance

PG&E values engagement and oversight from external experts to help us improve our safety culture and performance. PG&E implemented an Independent Safety Oversight Committee (ISOC), and hired an Independent Chief Safety Advisor to the Corporation CEO and President. The ISOC is comprised of members with relevant and diverse safety and operational expertise, including expertise in the utility industry. The ISOC members are independent and external to PG&E. The ISOC reviews and assesses the design and operation of PG&E’s systems and processes to identify improvement areas for risk reduction and better safety performance. The ISOC is responsible for advising senior leadership on recommendations to improve public, workforce, and environmental safety. The committee also provides an independent review to confirm if safety controls are in place, functioning, and meet internal and external requirements.

The initial ISOC visit to PG&E took place in December 2019 and was focused on the processes and programs related to wildfire safety in Electric

Operations. The ISOC members found four major concerns in their initial visit. First, ISOC noted a lack of effective collaboration, both among PG&E departments and between PG&E and other California stakeholders. Second, this deficit was compounded by a lack of effective work and resource planning, leading to delays and backlogs on work critical to PG&E's infrastructure and safety conditions. Third, ISOC members noted an absence of effective, accurate, and trustworthy data for leadership to obtain an accurate picture of PG&E's historical and current system health. Fourth, there was an overall need for more effective change management.

PG&E leadership acknowledged the ISOC members' concerns and assigned Action Owners to closing gaps on each major concern. The Action Owners developed gap closure plans and Enterprise Health and Safety tracked progress. In the most recent ISOC visit conducted in June 2020, the ISOC members did not consider their major concerns closed yet, but they did note PG&E's progress on closing them. The actions taken for the concerns include:

a) Effective Collaboration: PG&E presented a single intake platform and process for encroachment permitting that replaced the previous nineteen non-standardized processes as well as the results of a pilot on effective external engagement with San Mateo City and County. PG&E is in the process of scaling the initial successes of effective internal and external collaboration.
b) Lack of Effective Work and Resource Planning: PG&E presented a roadmap to more effective work and resource planning based around standardized work processes and health metrics to complete critical infrastructure work.
c) Data Improvements: PG&E presented on a mix of near-term data improvements for electric operations ahead of the 2020 wildfire season and a longer term enterprise data governance framework.
d) Effective Change Management: PG&E acknowledged the importance of effective management of change capabilities and implemented an Electric Operations Management of Change standard. Elements of the Change Management, inclusive of Management of Change are being assessed to scale across PG&E.

PG&E is currently awaiting the report for the most recent June 2020 ISOC visit that covered Electric and Gas Operations inclusive of public, workforce, and environmental safety.

4. Governance Framework: Board of Directors

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

- Enterprise risks and cross-cutting factors,[5] 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 Utility'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 the Utility's nuclear and other operating facilities. The Board holds regularly-scheduled meetings, and the SNO Committee must meet at least six times per year. Members of PG&E management regularly attend Board and Committee meetings. The SNO Committee's charters specifically require regular review, with the CSO, of the Company's long-term safety goals and objectives, as well as current staffing and budgeting needs.

C. Compensation Policies Related to Safety

PG&E's compensation policies reflect our mission to provide safe, reliable, affordable, and clean energy for our customers by promoting positive outcomes in line with those objectives. This section describes PG&E's compensation

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5 Cross-cutting factors are not risk events themselves, but rather, they impact either the likelihood or consequence of other risk events on PG&E's Corporate Risk Register.

structure and how safety metrics are established, evaluated, and incorporated into employees' compensation.[6]

1. Foundational Compensation

PG&E's employee compensation consists of two broad categories: foundational and at-risk compensation. Foundational compensation includes an employee's base pay, benefits, and pension. This portion of compensation provides a stable income as well as health, wellness, and retirement benefits. The proportion of foundational compensation in an employee's total compensation depends on the level of an employee. For a majority of PG&E's represented employees, foundational compensation is 100 percent of their overall compensation; for executive employees, foundational compensation averages only about 36 percent of overall compensation. Benefits programs that promote health maintenance and disease prevention are essential to the Company's ability to keep a diverse, skilled, experienced, and dedicated staff healthy and focused on delivering safe and reliable service to customers.

2. At-Risk Compensation

At-risk compensation, or incentive compensation, is designed to be conditioned on one or more aspects of the employee's and/or the Company's level of performance against set goals. Two main at-risk components of compensation will apply upon PG&E's emergence from Chapter 11—the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The new STIP and LTIP were developed as part of a rigorous re-evaluation of existing incentive compensation plans and will consist of objectively-measurable, primarily outcome-based, risk reduction measures that promote customer and workforce welfare (especially public and employee safety) and financial stability, consistent with the requirements of Assembly Bill 1054 and the California Public Utilities Commission's (Commission) decision approving PG&E's Plan of Reorganization (POR) (Decision (D.) 20-05-053).

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6 This section describes the compensation structure for all employees. For a more detailed discussion of executive compensation, please see John Lowe's January 31, 2020 testimony in The CPUC Order Instituting Investigation PG&E's Plan of Reorganization 2019, I.19-09-016, Vol. 1, (I.19-09-016).

a. **STIP**

Salaried employees, those hourly employees who are not represented by a labor agreement, and salaried employees represented by the International Brotherhood of Electrical Workers and the Engineers and Scientists of California participate in PG&E's STIP, which is PG&E's variable pay program tied to annual Company performance. The participation rates vary by employee level, from 6 percent for support-level employees to 30 percent for Senior Director-level employees.[7]

STIP metrics are established each calendar year by the Compensation Committee of the PG&E Corporation Board of Directors. In 2020, 75 percent of the STIP performance metrics will be focused on customer welfare (especially public and employee safety) and the remaining 25 percent on financial stability. The 2020 STIP's metrics will be almost entirely outcome-based as opposed to activity- or effort-based.[8] The metrics selected for the STIP are informed by the Enterprise and Operational Risk Management Program at PG&E, and the Safety Model Assessment Proceeding and Risk Assessment and Mitigation Phase proceedings before the Commission.

STIP payouts are affected by the Company's performance against the established metrics. The STIP score can range from 0 percent to 150 percent of target each year. Each employee receives an individual modifier each year that can result in an adjustment of the payout, depending on how the individual performs relative to his or her individual job performance goals. Before the STIP score is finalized, the Compensation Committee reviews and approves the results, and has discretion to reduce the score (including to zero) if it believes it

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7 Executive STIP participation level is approved annually by the Compensation Committee or Board of Directors, and ranges year-over-year.

8 See Testimony of John Lowe, I.19-09-016, Vol. 1, p. 7-10, for a description of metrics and associated weightings that will be in place in 2020 for executives.

appropriate to do so under the totality of the circumstances.[9] Further, per the Commission's decision in D.20-05-053, there is a presumption that a material portion of the Utility executives' compensation shall be withheld if PG&E is the ignition source of a catastrophic wildfire, unless the Commission determines that such withholding would be inappropriate.

b. LTIP

Approximately 400 senior employees are eligible for PG&E's LTIP, which is PG&E's variable pay program tied to long-term Company performance. The target values vary by employee level, increasing by level within the Company.

The 2020 LTIP awards, to the extent payable, will consist of performance shares. LTIP awards will be calculated based on performance on three objective performance metrics for a three-year performance period: (1) system hardening (which promotes reduction in wildfire risk); (2) substation enablement (which promotes reduction of the scope of Public Safety Power Shutoffs (PSPS)); and (3) customer experience (which promotes customer welfare). The customer experience metric has two components: customer satisfaction (as objectively measured through administration of a customer survey), and PSPS Notification Accuracy (which relates to the number of PSPS-affected customers who receive notifications at least 12 hours in advance).[10] In this way, PG&E's long-term compensation focuses on the achievement of safety and other important objectives.

The LTIP score can range from 0 percent to 200 percent of target. Also, to take into account the long-term financial health and stability of the Company, the LTIP score will be multiplied by a Total Shareholder Return modifier, which can impact the total award to LTIP participants by a range of 0.75 to 1.25, based on the total performance of PG&E

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[9] The Compensation Committee and the Board exercised their discretion to reduce 2018 STIP payouts to zero in light of the devastating 2018 Camp Fire, the hardships incurred by communities, and PG&E's financial circumstances, including the need to seek relief under Chapter 11.

[10] I.19-09-016, John Lowe testimony Vol 1, p. 7-16.

Corporation stock (price appreciation or depreciation, plus dividends (if any)), relative to the total performance of the stocks of a comparator group of peer companies.[11]

Before the LTIP score is finalized, the Compensation Committee and the independent members of the Utility Board, as applicable, review and approve the results, and have discretion to reduce or eliminate LTIP awards for any reason—subject to certain legal restrictions—with respect to any particular employee or more broadly.[12] Additionally, as noted, there is a presumption that a material portion of the Utility executives' compensation shall be withheld if PG&E is the ignition source of a catastrophic wildfire, unless the Commission determines that such withholding would be inappropriate.

PG&E recognizes and remains committed to improving safety culture and safety performance. The focus is building an accountable, transparent organization that embraces raising issues and ideas, and acts upon resolving them. PG&E is focused on moving quickly and efficiently, without risking the safety of our customers, our workforce, or the community.

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11 The comparator group of companies is established by the Compensation Committee at the time of the grant annually to ensure its appropriateness.

12 The Compensation Committee has this discretion for LTIP participants other than the CEO of the Utility, for whom the independent members of the Utility Board have sole discretion.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

RISK ASSESSMENT AND MITIGATION PHASE

PANDEMIC IMPACT ASSESSMENT

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A. Executive Summary

In December 2019, a novel strain of coronavirus (COVID-19) was reported to have surfaced in Wuhan, China, resulting in significant disruptions to manufacturing, supply chain, markets, and travel world-wide. On January 30, 2020, the International Health Regulations Emergency Committee of the World Health Organization (WHO) declared the COVID-19 outbreak a public health emergency of international concern and on March 12, 2020, announced the outbreak was a pandemic. On March 16, 2020, the CPUC directed electric utility companies to follow customer protection measures including a moratorium on service disconnections, retroactive to March 4, 2020. On March 19, 2020, California instituted state-wide shelter-in-place measures.

At Pacific Gas and Electric Company (PG&E or the Company), our hearts go out to all those who have been affected by this outbreak. At the time of this writing more than two million Americans have tested positive for the virus, more than one hundred thousand have died and more than forty million have lost their jobs. PG&E understands that many of our customers are facing severe personal and economic challenges because of this crisis as many businesses, schools and community facilities have closed to slow the spread of the virus. Throughout this crisis, PG&E has taken steps to address not only the health and safety needs of customers and employees but also to ensure that critical energy services are available to the public so that every customer can have confidence that, during this time of unprecedented economic and personal stress, they can turn on their lights, keep their heat and air conditioning running, cook on their stoves and power appliances that are needed to maintain their health, safety and comfort.

Emergency response, critical maintenance, work associated with our Wildfire Mitigation Plan and our preparedness for Public Safety Power Shutoff (PSPS) and new customer connections has continued with a commitment to minimize customer impacts to the extent possible. As the situation evolves, we will continue to adjust our work as needed to deliver safe, reliable energy and to keep our customers, communities and employees safe.

In order to better prepare for future pandemics and improve our current suite of risk analysis models PG&E has begun the task of reaching out to our risk management teams to gather feedback on their experience during the current pandemic and their thoughts about how the risks they are responsible for managing could more fully incorporate the potential impacts of a pandemic going forward. The main themes that have emerged from these initial feedback sessions are:

- A concern regarding how human performance may be impacted by the various stresses placed upon employees due to the pandemic. Human performance is a driver in a number of PG&E's safety risk models.
- A potential decrease in third-party contact with PG&E electric and gas system assets due to extended shelter-in-place and social distancing orders. Third-party contact with PG&E assets is a driver in a number of PG&E's safety risk models. And,
- Concerns regarding the impact of prolonged deferral of non-essential work. While this concern is less explicit than human performance and third-party contact with assets there was an concern expressed that the efficacy of some discretionary risk control programs could be less than what is currently included in models due to lack of skilled and qualified workforce availability for deployment in the field because of shelter-in-place and social distancing orders, supply chain disruptions or the inability of partnering organizations to provide support services that PG&E relies upon for risk control.

Over the next several months PG&E will be reviewing the data that informs our current set of risk model drivers to determine how those drivers have been impacted by the COVID-19 pandemic. In addition, PG&E will be exploring potential new data sources and new drivers that could help us to better understand the impacts on key safety risks. At the same time PG&E will be assessing whether the current structure of risk models is appropriate to capture the potential impacts of future pandemics. PG&E looks forward to working with other stakeholders to gather their insights into how future pandemics might be included in safety risk models so that we can continue to keep the public and employees safe in the face of future pandemic episodes.

1. Introduction

The intent of this chapter is to describe PG&E's responses to the current novel COVID-19 pandemic and PG&E's initial efforts to explore potential qualitative impacts of this and future pandemics on PG&E's key safety risks. The analysis described in this chapter is not meant to be exhaustive, but rather an initial qualitative assessment of the items having the largest impact on PG&E's key safety risks at the time of publication. The insights captured here are based in large part on interviews conducted with the PG&E subject matter experts who manage these key safety risks for the Company. The observations herein are subject to change as the COVID-19 pandemic progresses and PG&E gains more knowledge of its longer-term impacts. PG&E intends to leverage this initial qualitative pandemic assessment as a foundation to improve future quantitative modeling of safety risks.

The COVID-19 pandemic is the fifth major United States (U.S.) pandemic recognized by the Centers for Disease Control and Prevention (CDC) since the Spanish Flu pandemic of 1917-1918. In response to this pandemic, local and state governments have ordered residents to shelter-in-place and have curtailed non-essential business in an attempt to reduce the spread of infection. Likewise, PG&E has enacted many safety measures and operational changes to promote the health and safety of our employees and the communities we serve. The disruptions to daily life and economic activity brought on by COVID-19, and the attempts to combat it, have been almost unprecedented. However, there is no guarantee that they will not occur again.[1] As such, this Chapter ends with a discussion of PG&E's current plans to refine its pandemic-related risk analysis to plan for future pandemics.

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1 The CDC has noted that the risk of local outbreaks turning into pandemics has grown due to an increased risk of infectious pathogens "spilling over" from animals to humans, development of antimicrobial resistance, spread of infectious diseases through global travel and trade, acts of bioterrorism and weak public health infrastructures. CDC, Global Health Protection and Security, Why It Matters: The Pandemic Threat, accessed June 18, 2020, at <https://www.cdc.gov/globalhealth/healthprotection/fieldupdates/winter-2017/why-it-matters.html>.

Pandemic Definition

TABLE 6-1
PANDEMIC OVERVIEW

Pandemic Definition[(a)]	A pandemic is a global disease outbreak. Three conditions must be met for a viral outbreak to become a pandemic • A new virus subtype must emerge for which there is little or no human immunity; • The virus must infect humans and cause illness; and • The virus must spread easily and sustainably (continuing without interruption) among humans. Historically, pandemics though rare, are recurring events.
In Scope	Qualitative assessment of pandemic impacts to PG&E risk drivers, controls consequences and mitigations based on current PG&E and industry experiences during the COVID-19 Pandemic.
Out of Scope	Quantitative assessment of pandemic risk is currently not in scope for this risk chapter. Given that the current pandemic is on-going and prior pandemics are poor proxies for COVID-19 risk modeling at this time, PG&E would be forced to rely on incomplete data and conjecture and therefore this assessment has been determined to be out of scope.
Data Sources	CDC, WHO, Edison Electric Institute, PG&E data and subject matter experts.

(a) CDC, 2009 HIN1: Overview of a Pandemic April 2009 - August 2010, slide 27, accessed June 23, 2020, at https://www.cdc.gov/h1n1flu/yearinreview/2009_H1N1-Overview_of_a_Pandemic-12_06_2010.pptx.

It is challenging to extrapolate pandemic outcomes into models or forecasts due to significant projected variances in infection rates, fatality rates and susceptible populations.[2] For example, the table below shows the broad range of global and U.S. fatalities for each the five major pandemics to occur in the U.S. since 1917.

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2 Maggie Koresh et al., FiveThirtyEight, ABC News, “Why It’s So Freaking Hard To Make A Good COVID-19 Model” (Mar. 31, 2020), accessed June 18, 2020 at <https://fivethirtyeight.com/features/why-its-so-freaking-hard-to-make-a-good-covid-19-model/>.

TABLE 6-2
MAJOR PANDEMIC OUTBREAKS IMPACTING THE U.S.

Line No.	Year	Pandemic Name	Virus Name	Global Fatalities	U.S. Fatalities
1	1917-1918	Spanish Flu	H1N1	50,000,000	675,000
2	1957-1958	Asian Flu	H2N2	1,100,000	116,000
3	1968	Hong Kong Flu	H3N2	1,000,000	100,000
4	2009	Swine Flu	H1N1pdm09	151,700 to 575,400	12,500
5	2019-2020	COVID-19	SARS-CoV-2	479,144[a]	120,955[b]

(a) World Health Organization as of June 25, 2020.
(b) *Id.*

As a result, there is significant variation and uncertainty in the experts' COVID-19 projections for both infections and fatalities at the time of this report. Therefore, at the time of filing this report, PG&E cannot reasonably estimate the duration or severity of the COVID-19 pandemic or its impact to on-going PG&E operations and key safety risks.

B. PG&E's Response to COVID-19

On March 27, 2020, PG&E issued a letter in response to Safety and Enforcement Division's request, dated March 20, 2020, for information on the actions PG&E is taking to protect the health and safety of its customers and workforce and to ensure continuity of service.[3] The letter detailed specific PG&E steps, including initiating an Incident Management Team (IMT) to monitor and respond to the virus, activating the Emergency Operations Center (EOC), implementing policies for Safety and Continuity of Service and prioritizing essential work to maintain regulatory compliance, safety and system integrity while minimizing discomfort to the service territory through the minimization of unnecessary outages and curtailments. PG&E continues to monitor the situation and will make adjustments as necessary. We briefly review PG&E's response below.

3 Senior Director Meredith Allen, PG&E Regulatory Relations, letter to Director Leslie Palmer, CPUC Safety and Enforcement, March 27, 2020 (PG&E's March 27, 2020 Letter).

1. Incident Management Team and Emergency Operations Center Activation

PG&E set up an IMT to monitor and respond to the virus on February 27, 2020 and formally activated its EOC on March 16, 2020 to facilitate and coordinate the company's response to the spread of the virus in accordance with PG&E's Emergency Response Plan. Early actions of the IMT included providing information to employees, taking social-distancing and remote work actions, and hiring an infectious disease and pandemic expert to support education and preparedness action development.

2. Safety and Continuity of Service

On March 12, 2020, several days before the Bay Area counties' shelter-in-place orders, PG&E asked its office-based workforce to work from home. PG&E took additional measures to promote social distancing, including cancelling all PG&E-hosted conferences, suspending all business travel and transitioning all in-person meetings to calls. In response to counties' and the state's shelter-at-home orders, PG&E directed employees to follow state and local shelter-in-place guidelines and not report to work locations unless their roles directly support the delivery, maintenance and restoration of gas or electric service while further prioritizing which operational work was currently essential. For employees who could not work from home or who could not work because of family needs, PG&E implemented interim time recording policies. PG&E established a Human Resources helpline to respond to employees' questions in connection with the pandemic. For employees and contractors that still report to work locations, PG&E enacted pandemic safety related practices which include social distancing, extensive, regular site cleaning, and other precautions recommended by medical experts.

PG&E also took several actions related to vulnerable customers. Effective March 12, 2020, PG&E suspended disconnections for non-payment for residential and small-business customers. On March 19, 2020, PG&E filed Advice Letter 4227-G/5784-E in compliance with Decision 19-07-015, to present its Emergency Consumer Protection Plan for customers affected by COVID-19. This plan extends PG&E's moratorium on disconnections and waives deposit and reconnection fees on customers affected by COVID-19 until March 4, 2021, implements flexible pay-plan options for affected customers, and provides additional support to affected low-income and medical-baseline customers. Pay plans for customers affected by COVID-19 will be relaxed to 12 months, and affected customers will be exempt from standard and high-usage post-enrollment verification for Coronavirus Aid, Relief, & Economic Security Act eligibility. In addition, PG&E will suspend all customer removals from the medical baseline program and waive all medical baseline recertification requirements through March 4, 2021. PG&E will communicate these changes to customers through partner community-based organizations and non-profits, targeted messaging, customer contact centers, social media communications, and a dedicated website.

3. Essential Work

PG&E's Electric Operations will continue performing electric work consistent with the Governor's priorities for essential services and for the safety of our customers and communities including:

- Emergency response to restore electric service;
- Work to further the preparedness for PSPS events as directed by the California Governor's Office of Emergency Services, California Department of Forestry and Fire Protection and the California Public Utilities Commission (CPUC);
- New customer connections and Work Requested by Others (WRO)
- Enhanced and routine vegetation management;
- Critical maintenance;
- Work associated with PG&E's Wildfire Mitigation Plan.

PG&E's Gas Operations will continue essential work to support its ongoing commitment to safely and reliably deliver natural gas to customers. Some examples of essential gas work include:

- Emergency response to restore gas service;
- Service restoration and relights;
- Regulatory code compliance work including safety surveys and patrols of gas pipelines, maintenance essential to the safe operation of the system, and fulfilling 811 requests to locate and mark PG&E infrastructure;

- New customer connections and Work Requested by WRO; and
- Butte County Rebuild work.

PG&E's Power Generation and Energy Procurement Operations will continue essential work to support its ongoing commitment to safe and reliable operation of generation assets and infrastructure. Some examples of essential energy supply work include:

- Ensuring dam safety;
- Maintaining environmental stewardship;
- Meeting water delivery commitments needed to support public health and welfare; and
- Maintenance on conventional, hydro, renewable and nuclear generation facilities needed to support grid safety and stability.

PG&E's Customer Service Operations will continue essential work to support its ongoing commitment to keep customers informed and help them resolve issues related to energy services. Some examples of essential customer service work include:

- Providing key Contact Center services such as emergency, outage and other field services related calls from customers; and
- Providing credit and customer billing support services to ensure customers receive timely and accurate bills and that customer questions regarding pandemic related policy changes such as the moratorium on shut-offs are answered promptly.

PG&E will evaluate and proceed with new electric and gas customer-requested work that cannot be reasonably postponed and that supports essential infrastructure and businesses. This work includes projects immediately necessary to the construction of, maintenance, reliable operation or repair of essential infrastructure, affordable housing, homeless shelters, healthcare operations provided that such construction is directly related to COVID-19 response, and qualifying agriculture and food services. Essential infrastructure also includes facilities such as critical telecommunications and water sanitation. PG&E will comply with all known local county construction restrictions, will seek local jurisdiction input on essential infrastructure evaluation, and will balance planned outage requirements related to new business construction.

Additional information for our COVID-19 related actions and programs is contained on PG&E's website and in Company news releases.

C. PG&E Current Efforts to Assess the Effects of a Pandemic

PG&E does not yet fully understand the pandemic's ultimate effect on its operations and key safety risks as we are still in the midst of the COVID-19 pandemic. However, PG&E recognizes the need to evaluate how this pandemic and future pandemics could potentially impact key safety risks and how those impacts could be modeled within the current framework. Given the ongoing and evolving nature of the COVID-19 pandemic and the limited data to evaluate this situation, PG&E is unable to develop a quantitative perspective for this 2020 Risk Assessment and Mitigation Phase (RAMP) report. Instead, PG&E has attempted to qualitatively evaluate the potential effects of a pandemic on its key safety risks based on current experiences related to COVID-19, to identify key actions taken to mitigate the safety risk impact and to prepare for future quantitative analysis and modeling of a pandemic. These actions and the outputs of this qualitative assessment are described in the following sections.

1. Qualitative Evaluation Process

PG&E performed a qualitative evaluation of its risk bowties, based on the COVID-19 experience, to assess the potential effect of a pandemic on its key safety risks. As part of this evaluation, PG&E undertook the following steps:

a) Hosted a virtual meeting with the CPUC's Safety Policy Division, TURN and the Public Advocates Office at the California Public Utilities Commission on April 2, 2020 outlining the qualitative approach to be taken in discussing COVID-19 in this 2020 RAMP filing. During this meeting, PG&E received valuable feedback from various parties on items to consider in this qualitative evaluation process.

b) Conducted digital surveys and telephonic interviews with the RAMP risk bowtie and cross-cutting factor owners for insights on the current and potential impacts from COVID-19 on various risk bowtie elements (i.e., risk drivers, exposure, consequences), and controls and mitigation programs.

c) Included a discussion of potential impacts of COVID-19 during online challenge sessions with key PG&E leaders reviewing RAMP risk assessments.

d) Reviewed PG&E's draft Infectious Disease and Pandemic Response Plan and telephonically interviewed members of the Emergency Planning and Response and EOC teams to assess how actions identified within this plan could impact RAMP safety bowties.

Based on this evaluation process, PG&E has identified three broad areas where a pandemic can impact risk that, ideally, will be explored further by stakeholders in the Safety Model Assessment Proceeding deliberations. As stated earlier, this list is not exhaustive and is subject to change as we learn more about the impacts of COVID-19. PG&E welcomes feedback on these themes in this RAMP proceeding.

2. Pandemic Impact Themes

Through our qualitative evaluation process, we have identified three main areas where a pandemic could impact key safety risks: (a) new working conditions present human performance concerns; (b) changes in the public's contact with PG&E's assets; and, (c) concerns over prolonged delays in non-essential work. Certainly, this is not an exhaustive list as there are many issues that may arise as the pandemic continues and as we begin to transition back to a new normal post pandemic environment at work, schools, home, transportation, shopping, etc. Nevertheless, PG&E feels that the insights gained through our initial inquiries are worth sharing with stakeholders.

a. New Working Conditions Present Human Performance Concerns

Like most U.S. corporations and government entities, PG&E has enacted 'social distancing' and has followed California's 'shelter-in-place' orders. PG&E has enabled remote working for as much of its workforce as practical given role requirements and has enacted new safety procedures for employees that still must physically report to work. In addition, PG&E has recognized employees may have increased family care needs as daycares and schools close or as family members become ill. For these matters, PG&E is allowing employees to work flexible hours when possible. Additionally, to support our workforce with these challenges, between March 19, 2020 and June 30, 2020 PG&E provided additional paid time off for employees who were unable to report to work or work from home due to school closure, were 65 years of age or older or had a medical condition which made them more susceptible to severe complications from the virus.

PG&E's shifting of the majority of its workforce to locations outside of PG&E facilities, and its enactment of new safety procedures for employees in the field, presents challenges for PG&E employees and subcontractors. One key challenge is developing new routines to accomplish day-to-day activities and effective intra-company communication. These new routine challenges are further compounded by the potential for higher stress due to working without natural breaks, the uncertainty of how long shelter-in-place mandates will be in effect, and ongoing health, well-being and other concerns related to the COVID-19 virus itself. In this operating environment, employees may be more likely to make errors that would not have occurred under normal operating conditions.

A key driver in multiple RAMP risks is improper operations by its employees. Examples are:

- "Incorrect Operations" driver for Loss of Containment – Distribution Facilities;
- "Incorrect Operations" driver for Large Gas Over-pressurization – Downstream of M&C Facility risks;
- "Human Performance" driver for Failure of Distribution Overhead Asset; and
- "Human Performance" driver for Failure of Distribution Underground Network Asset risks.

These drivers reflect potential errors committed by employees under normal working conditions. However, employees in the field, following new social-distancing measures combined with potential health distractions or other pandemic-related concerns, may experience decreased situational awareness for certain tasks which could lead to additional performance errors. Additionally, elevated stress and pandemic-related distractions for employees working remotely could also contribute to increased incidence of improper operations, potentially contributing to a higher likelihood of safety-related risk events.

Conversely, the suspension of non-essential work due to COVID-19 may result in fewer opportunities for incorrect operations due to human error. Since operating errors sometimes occur during construction or maintenance projects. Going forward, PG&E will be examining the data used to inform the human performance and incorrect operations drivers used in its risk models to assess whether they have changed materially during the current pandemic. Evaluating these and similar metrics will help determine how the likelihood and consequences of safety risks may be affected during a pandemic.

b. Change in Third-Party Contact with PG&E Assets

'Shelter-in-place' measures have changed the daily activities and location of our customers. PG&E's customers have generally been confined to residential areas with reduced mobility in order to comply with COVID-19 public safety measures.[4] This behavioral change has the potential to change customer interactions with PG&E's assets in certain areas of the network. Recently published data from Google indicates that there is 53 percent less retail and recreation mobility activity, 42 percent less workplace mobility activity, and 27 percent less grocery and pharmacy mobility activity throughout California because of COVID-19.[5] In general, this data confirms that the public is abiding by 'shelter-in-place' orders which could result in fewer interactions between the public and PG&E assets reducing the likelihood of third-party related safety risk events while shelter-at-home orders are in place.

For example, PG&E's Third-Party Safety Incident risk, has a 'Car Pole/Guy' driver that represents incidents of the public coming into

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4 San Francisco, Santa Clara, San Mateo, Marin, Contra Costa and Alameda announced shelter-in-place requirements on Monday, March 16, 2020. A state-wide order was issued March 19, 2020. Governor's Exec. Order No. N-33-20 (Mar. 19, 2020).

5 Google, COVID-19 Community Mobility Report, mobility data, California April 5, 2020, accessed May 22, 2020 at <https://www.gstatic.com/covid19/mobility/2020-04-05_US_California_Mobility_Report_en.pdf>.

contact with PG&E poles and/or guy wires, usually in a vehicular accident. As ‘shelter-in-place’ orders and lower economic activity reduce vehicular travel, there is the potential for a reduction in the frequency of this driver during a pandemic. Similarly, with some parks and recreational areas closed to the public during shelter-in-place, including PG&E managed park and recreational facilities, there is a potential for a decrease in third-party contact with PG&E assets located in or near public and private parks and recreation facilities. Additionally, there could be a reduction in the number of incidents for the ‘Third-Party Damage’ driver for the Loss of Containment – Transmission Pipeline risk and ‘Excavation Damage’ for the Loss of Containment – Distribution Facilities risk as reduced economic activity and ‘shelter-in-place’ orders could impact third-party construction-related activity that results in these types of public contact with PG&E assets.

PG&E plans to study all data sources that have previously been used in the development of RAMP bowties to identify and quantify the public’s interactions with its assets across all RAMP risks. For example, PG&E plans to analyze the number of incidents of poles being struck by third parties during the COVID-19 pandemic to assess if there was a material change in this risk driver and why a change did or did not occur. Further, PG&E will be studying ‘811’ request data, along with third-party dig-in incident data, to evaluate the change in third party damage to our underground assets. Evaluating these and similar metrics will help determine how the likelihood and consequences of safety risks may be affected during a pandemic.

c. Prolonged Deferral of Non-Essential Work Raises Concern

While PG&E does not anticipate delaying essential work at this time, longer duration impacts of the pandemic on workforce and material availability and safety measures could result in unknown impacts on the execution of certain risk control and mitigation activities. Since the onset of the pandemic, in order to ensure public and employee safety, PG&E has deferred non-essential projects.[6] While the impact of a prolonged delay in non-essential work is unknown at this time, many of the subject matter experts who were interviewed expressed concern that the likelihood of risk events could increase if delays in non-essential work were to continue for the foreseeable future.[7]

In addition to the potential impacts on non-essential work, subject matter experts interviewed also expressed concern that a prolonged public health response to the pandemic may impact the supply chain for critical parts and equipment by requiring suppliers to remain closed. Permitting and other support services provided by Federal, State and local government agencies may also be affected as some state and local agencies curtail operations or furlough employees in order to sustain COVID-19 safety measures or due to budget issues that impact agency operations.

While it is too early to know what impact the delays in non-essential work, supply chain disruptions and reduced Federal, State and local government agency support services will have on the frequency of risk drivers or the efficacy of control and mitigation programs aligned to safety risks given the evolving nature of COVID-19, PG&E plans to evaluate the metrics associated with all drivers, controls and mitigation programs to understand the impact of deferred work on realized risk reduction.

3. Initial Quantitative Modeling Approach

As noted throughout this narrative, PG&E continues to adapt its response to COVID-19 as the pandemic evolves and progresses. In keeping with a data-driven modeling approach, PG&E will focus its initial efforts in three main areas

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6 See, PG&E's March 27, 2020 letter for a detailed description of PG&E categorization of essential and non-essential work.

7 California's Pandemic Roadmap gives no definitive timeline for the complete lifting of the stay-at-home order. Instead, it identified 6 Indicators and 4 Stages on the road to lifting the stay-at-home orders, occurring only when therapeutics are widely available. Accessed June 3, 2020, pp. 2, 5 and 12, at <https://www.gov.ca.gov/wp-content/uploads/2020/04/Update-on-California-Pandemic-Roadmap.pdf>.

- Analyzing Current Data for Trends: While the impact of COVID-19 are still preliminary and on-going, data supporting estimates of risk drivers and consequences will be updated and reviewed to identify and understand how these components of the risk models have been affected by the COVID-19 pandemic. Review and analysis of the existing data streams will help PG&E understand what enhancements to the models may need to be made to better capture the potential impacts of future pandemics.
- Identifying and Reviewing Additional Data: There may be a need to review and analyze additional data that will provide insight into the potential impact of future pandemics on PG&E's key safety risks. For example, as noted previously, there was a concern raised in the survey of risk mangers that prolonged deferment of non-essential work necessitated by shelter-in-place or other public health measures could impact risk control or mitigation programs which, in turn, could impact risk assessments. There have also been concerns raised regarding the impact of the pandemic on the State and local government's ability to fund public safety services at pre-pandemic levels, and lower levels of mutual aid being available during a crisis due to concerns regarding employee safety from industry partners, regional or Federal agencies. These concerns coupled with other issues like supply chain disruptions present a level of uncertainty in modeling for mitigation and control program effectiveness during a pandemic. As such, understanding these impacts and others will be a focus of study for PG&E as we develop a quantitative risk assessment of a pandemic.
- Evaluating Modeling Methodologies: Based on the findings from Steps 1 and 2 above, PG&E will develop risk modeling enhancements that better capture the potential impact of pandemics in future risk quantification efforts. For example, a threshold modeling question is whether a pandemic should be modeled as a stand-alone risk event or whether it is better modeled as a cross-cutting factor impacting multiple risks. Early indications are that the most fruitful approach may be to focus on how pandemics impact the following risk drivers:
  – Availability of skilled and qualified workforce;

   - Human performance/operating errors; and
   - Third-party contact with PG&E assets.

PG&E anticipates additional data analysis and modeling considerations will be identified as it conducts further analysis.

Fundamental to developing PG&E's quantitative pandemic risk assessment approach is the desire to collaborate with Utilities, the CPUC and other stakeholders to discuss, agree and develop a consistent and transparent pandemic-related modeling approach. PG&E suggests that a workshop could be scheduled in the upcoming SMAP proceeding which would allow stakeholders with detailed understanding of the current risk modeling framework to share their ideas in a collaborative setting on how to best model this pandemic risk. Some key items to discuss at that workshop would be:

- a review of the available data to assess the impacts of the COVID-19 pandemic on key risk drivers and cross cutting factors;
- a discussion of how a pandemic might impact the likelihood or consequences of risk events;
- definition and scope of a pandemic used for risk modeling purposes;
  - frequency of pandemic occurrence for risk modeling;
  - magnitude of pandemic occurrence for risk modeling; and
- is a pandemic a stand-alone risk event or a driver to a risk event and sub-driver to a driver to a risk event?

These are just an initial set of discussion items and modeling questions that PG&E believes would be of interest to multiple stakeholders and for which PG&E would like to receive input on prior to attempting to quantify pandemic impacts in future risk analysis.

D. Conclusion

As described in this chapter PG&E has taken several actions in response to the current pandemic to ensure the health and safety of our employees and the public we serve. PG&E understands the severe hardships that the pandemic has imposed on many of our customers and employees and has taken actions to ensure that customers continue to have access to energy services during this crisis and to continue with essential work that is needed to ensure system safety and reliability. In addition, PG&E has begun the process of assessing how we can learn from this current pandemic experience to inform future risk assessments. PG&E looks forward to working with stakeholders over the next several months to gather additional insights into how future pandemics can be captured on our risk assessment models.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
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RISK MITIGATION PLAN: LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE

A. Executive Summary

Loss of Containment (LoC) on Gas Transmission Pipeline refers to a failure of a gas transmission pipeline resulting in a LoC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, and the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture. The drivers for this risk event are: third-party damage; external corrosion; manufacturing defects; construction threats; internal corrosion; Weather-Related and Outside Force (WROF) threats; equipment failure; incorrect operations; and stress corrosion cracking (SCC). The cross-cutting factors Seismic, Physical Attack, Information Technology Asset Failure, Skilled and Qualified Workforce, and Records and Information Management also impact this risk.

Exposure to this risk is based on the 6,682 miles of transmission pipeline in the Pacific Gas and Electric Company (PG&E) system. A Loss of Containment on Gas Transmission Pipeline risk event is expected to occur two times a year, based on the risk model results. Third-Party Damage is the highest contributor to the frequency of this risk, accounting for 18 percent of the risk events. External corrosion, manufacturing defects, construction threats, internal corrosion and seismic are the remaining key drivers accounting for an additional 71 percent. Pipeline rupture accounts for 99 percent of the risk consequences and pipeline leak accounts for 1 percent of the risk consequences. The mitigations PG&E will implement from 2020-2026 are designed to address these key risk drivers and consequences.

PG&E identified four tranches for this risk. Each tranche represents a group of transmission assets that are intended to have a similar risk profile associated with leak and rupture LoC events. Assets were assigned tranches based on two criteria: percent Specified Minimum Yield Strength (%SMYS), defined as greater than or less than 20 percent; and areas with Impacted Occupancy Count with 10 or more people within the potential impact radius (IOC≥10). The two tranches with greater than 20 percent Specified Minimum Yield Strength (SMYS) accounts for 80 percent of the risk.

LoC on Gas Transmission Pipeline has the third highest 2023 test year baseline safety score (128) and fourth highest 2023 test year baseline total risk score (289) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 308, improves by 10 percent by 2026 when the planned and proposed mitigations are applied: the 2023 test year baseline risk score is 289 and the 2026 post-mitigation risk score is 277.[1]

PG&E is proposing a series of controls and mitigations to address LoC on Gas Transmission Pipeline risk. The Strength Testing and In-Line Pipeline Upgrades mitigations have both the highest Risk Spend Efficiency (RSE) scores and the highest total risk reduction scores.

TABLE 7-1
RISK OVERVIEW

Line No.	Risk Name	LoC on Gas Transmission Pipeline
1	In Scope	Failure of a transmission pipeline that leads to a significant LoC (leak or rupture). Significant is defined as a LoC that results in an injury requiring in-patient hospitalization, a fatality, or total costs valued at $50,000 or more, measured in 1984 dollars.
2	Out of Scope	A LoC driven by large overpressure events, LoC on distribution assets.
3	Data Quantification Sources[(a)]	Pipeline and Hazardous Materials Safety Administration (PHMSA) reports from 1984-2019

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

PG&E's natural gas transmission system consists of approximately 6,680 miles of transmission pipeline. Transmission pipeline and associated components transport gas from receipt points into PG&E's natural gas transmission system until the pipe arrives at a distribution center, a storage

1 The information herein is subject to those limitations described in Chapter 2, Section D.

facility or a large customer. The average age of PG&E's transmission pipe is approximately 50 years. About 43.5 percent of PG&E's transmission system miles are located in areas with estimated impacted occupancy count (IOC) of greater than or equal to 10 people (IOC >= 10). IOC refers to the count of people within the Potential Impact Radius (PIR).[2]

In the 2020 RAMP, PG&E transitions from considering transmission pipeline risk in terms of High Consequence Area (HCA) to considering it in terms of IOC. This allows for better alignment with PG&E's transmission integrity management risk model. HCA focuses on the potential consequence of a risk event by focusing on pipeline segments that pose the greatest risk to human life, property and the environment, primarily using structure counts. IOC, however, focuses on the potential impact of a risk event and is more focused on the safety of the individuals living and working around a transmission pipeline. PG&E is using IOC instead of HCA because it allows for a more accurate representation of potential safety impacts based on the presence of people in the pipeline vicinity.

Risks to transmission pipe include third-party damage, internal and external corrosion, construction threats, WROFs, manufacturing defects, SCC, equipment failure, and incorrect operations. These threats to the assets in the transmission pipe asset family could lead to LoC (leak or rupture) that would result in an uncontrolled gas release leading to potential public, contractor and/or employee safety issues, outages, and/or property damage.

PG&E manages transmission pipeline risk through its Transmission Integrity Management Program (TIMP). TIMP is the program in which PG&E identifies, prioritizes, assesses, evaluates, repairs and validates the integrity of its gas transmission pipeline that could, in the event of a leak or rupture, impact public safety.

Examples of the type of work PG&E performs in the TIMP to manage transmission asset risk include In-Line Inspection (ILI), Direct Assessment (DA), strength testing, vintage pipe replacement, earthquake fault crossing,

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[2] PG&E defines IOC in internal utility procedure TD-4127P-07 "Impacted Occupancy Count" and began incorporating this into its RAMP LOC – Transmission models in Q1 2020.

geo-hazard threat identification and mitigation, emergency response programs, class location changes, shallow and exposed pipe, gas gathering, programs to support integrity management and pipe investigations and field engineering.

PG&E also manages transmission asset risk through its leak survey programs. PG&E conducts leak surveys on the gas transmission pipeline system by implementing foot, aerial and mobile leak survey to meet regulatory requirements. While pipeline leaks only account for a small portion of the transmission pipeline risk (discussed in Section 7 below), it is important to include leak monitoring and management in the risk analysis so that PG&E has a holistic view of the potential risks to the gas transmission pipeline system.

2. Risk Definition

Failure of a gas transmission pipeline resulting in a LoC, with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, and the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture.

B. Risk Assessment

1. Background and Evolution

PG&E's 2017 RAMP included a Transmission Pipeline Rupture with Ignition risk[3] that is similar to the LoC on Gas Transmission Pipeline risk included in the 2020 RAMP.

In the 2017 RAMP, the risk event was specific to transmission pipeline failure with ignition whereas the 2020 RAMP risk event includes failure (rupture or leak) with or without ignition. The new event description more closely correlates with PG&E's TIMP risk model because it relies on data from PG&E assets and because the 2017 RAMP model excluded pipeline failure without ignition.

The risk event modelled in the 2017 RAMP was a lower probability risk, estimated to occur once every nine years, whereas the occurrence of the

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3 PG&E's RAMP Report, Investigation 17-11-003 (Nov. 30, 2017), Chapter 1.

risk event in the 2020 RAMP is estimated at almost two events per year. The 2020 model more accurately represents PG&E's transmission pipeline system because it is based on PG&E data (where available) and because LoC on a transmission pipeline without ignition is a significant contributor to the risk events because consequences from a rupture, even without ignition, can include serious injuries, fatalities, reliability and financial impacts. These elements were not accounted for in the 2017 RAMP model.

In the 2017 RAMP, PG&E identified nine risk drivers based on the American Society of Mechanical Engineers (ASME) B31.8S Standard that is designed to provide pipeline operators with the information necessary to develop and implement an effective integrity management program using proven industry practices and processes.[4] The same nine transmission pipeline risk drivers are included in the 2020 RAMP. The Equipment Failure and Incorrect Operations contribution to the LoC on Gas Transmission Pipeline risk only includes the portion associated with non-overpressure events. Two cross-cutting factors, Skilled and Qualified Workforce and Records and Information Management are sub-drivers of the Incorrect Operations driver,[5] and they make up a significant portion of the Incorrect Operations frequency.

PG&E's 2017 RAMP analyses were based on data contained in the PHMSA Annual Report and PHMSA Major Incident Reports. In 2020, PG&E's analysis is informed by PHMSA Major Incident Report data, Gas Transmission Incident Reports, and PG&E current transmission pipeline asset data (updated yearly) for pipeline integrity, people impacted (within the PIR) and customers impacted downstream.

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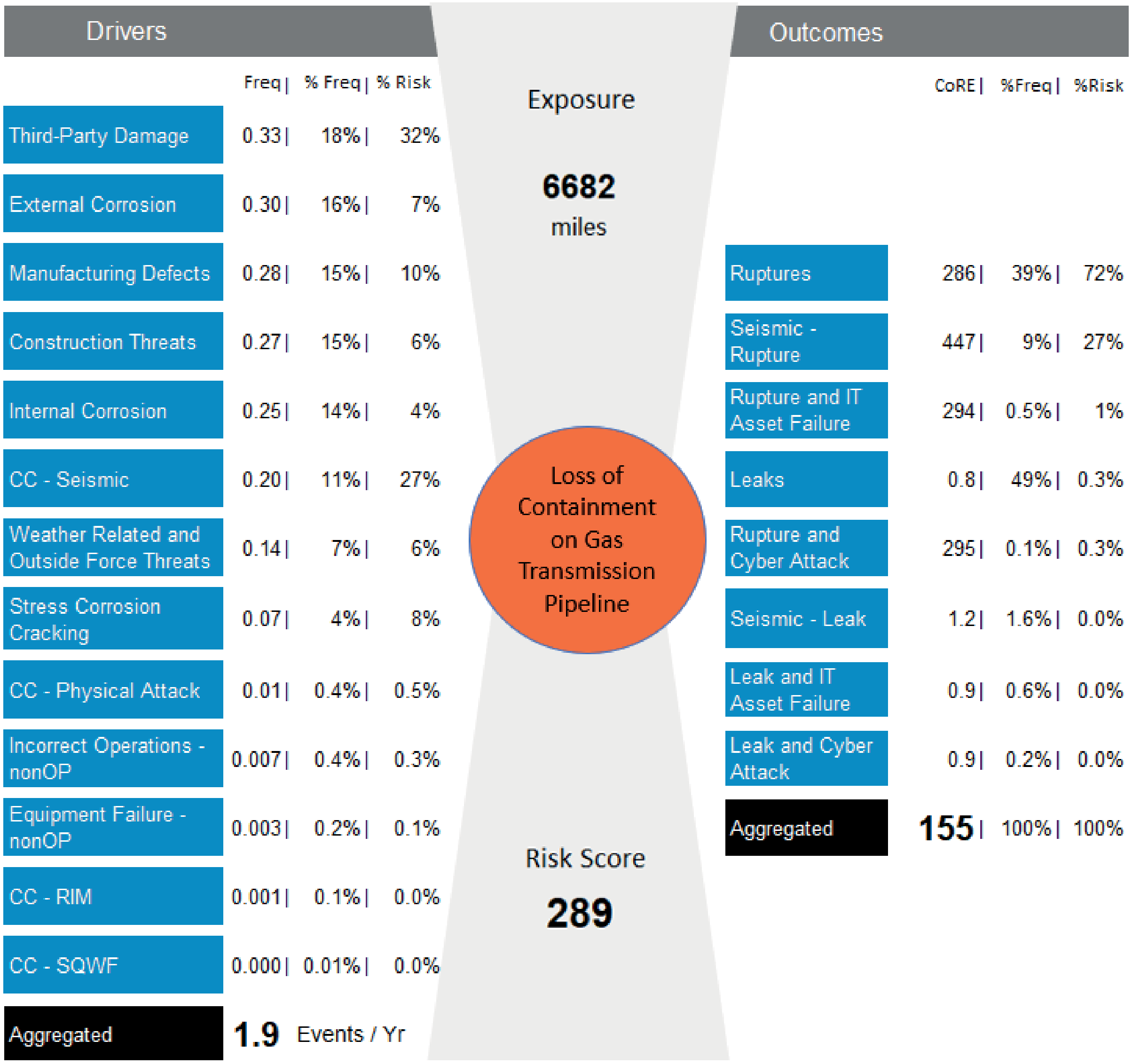
4 ASME B31.8S – 2018, "Managing System Integrity of Gas Pipelines," ASME https://primis.phmsa.dot.gov/rmwg/docs/ASMEB31%208S%20Risk%20Modeling%20Summary_RMWG0816.pdf (as of June 25, 2020).

5 See D8 – Incorrect Operations on page 7-10.

2. Risk Bow Tie

FIGURE 7-1
RISK BOW TIE



a. Difference from 2017 Risk Bow Tie

Drivers:

The 2020 bowtie includes the same risk drivers as the 2017 RAMP bowtie. However, for the Equipment Failure and Incorrect Operations risk drivers, only the non-overpressure contribution is included for this risk. The overpressure contribution of these risk drivers is included in the Large Overpressure Event Downstream of Gas Measurement and Control Facility risk to not double count the contribution of this risk driver. In addition, it includes cross-cutting risk drivers to help better illustrate individual cross-cutting driver contributions to the LoC on Gas Transmission Pipeline risk.

Outcomes:

The 2020 bowtie displays possible outcomes for each LoC event – this was not included in the 2017 RAMP model bowtie. Outcomes displayed not only include pipeline leak or pipeline rupture but also where there is a combination of the leak or rupture plus a cross-cutting risk event.

Consequences:

The 2020 bowtie does not include compliance, trust or environmental consequences. They were out of scope for this RAMP.

3. Exposure to Risk

PG&E's natural gas transmission system is inherently hazardous with the main risks associated with a LoC event. PG&E measured the risk exposure as the number of miles of transmission pipeline owned and operated by PG&E. The total exposure used in the model is 6,682 miles of transmission pipeline for 2020-2026. PG&E assumes that the exposure stays approximately constant over the 2020-2026 time period.

4. Tranches

PG&E identified four tranches for the LoC on Gas Transmission Pipeline risk. Each tranche represents a group of transmission assets, that are intended to have a similar risk profile associated with leak and rupture LoC events. Assets were assigned tranches based on two criteria: Percent Specified Minimum Yield Strength (SMYS) and IOC. SMEs expect that areas with a higher percent SMYS and IOC would have a higher risk.

Tranche 1: Greater than or equal to 20 percent SMYS with IOC greater than or equal to 10 (High Impact Areas), 2,089 miles;

Tranche 2: Greater than or equal to 20 percent SMYS with IOC less than 10 (Low Impact Areas), 2,949 miles;

Tranche 3: Less than 20 percent SMYS with IOC greater than or equal to 10 (High Impact Areas), 816 miles; and

Tranche 4: Less than 20 percent SMYS with IOC less than 10 (Low Impact Areas), 828 miles.

The 20 percent SMYS threshold is recognized by experts in the industry, based on PG&E's Transmission Pipe operating pressures, as the stress ratio below which events will more likely result in leaks, while events on pipelines operating at pressures above 20 percent SMYS have higher possibility to result in ruptures.[6] The stress ratio of 20 percent SMYS equates to a factor of safety equal to five, which means the maximum pressure the pipeline could hold without failure is five times the specified Maximum Allowable Operating Pressure.

The IOC boundary was based on PG&E IOC estimates data which showed a bi-modal distribution for estimated number of people impacted (those within the potential impact radius)) with 10 being the approximate boundary.

In developing the tranches for this risk, PG&E considered tranching by asset health attributes. Ultimately, it was difficult to determine which attributes were the best indicator of overall asset health, given the various unique attributes that inform asset health by the different asset management programs.

Even though asset health attributes are not used for tranching, they are considered in the model. For example, certain drivers incorporate ILI data, which provide a measure of pipeline health. PG&E will continue to explore asset health in tranching as risk modeling continues to mature.

Table 7-2 below shows the tranche-level results of the risk analysis.

TABLE 7-2
RISK EXPOSURE AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Percent Exposure	Safety Risk Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent Risk Score
1	< 20% SMYS and IOC < 10	12%	1.52	0.62	0.59	2.74	1%
2	< 20% SMYS and IOC >= 10	12%	47.32	4.88	1.53	53.73	19%
3	>= 20% SMYS and IOC < 10	44%	4.85	84.95	1.80	91.60	32%
4	>= 20% SMYS and IOC >= 10	31%	74.05	63.95	2.83	140.82	49%
5	Total	100%	127.74	154.40	6.75	288.89	100%

6 See workpaper WP 7-3: Leak vs. Rupture Thresholds for Material and Construction Anomalies. Husain M. Al Muslim, PhD; and Michael J. Rosenfeld, PE. December 15, 2013. INGAA/AGA. Final Report No. 13-180.

5. Drivers and Associated Frequency

PG&E has identified nine primary risk drivers for its gas transmission pipeline risk. Risk drivers eight and nine, Incorrect Operations and Equipment Failure, only include the contribution associated with non-overpressure events. The contribution associated with overpressure events is captured in the other gas risk model, Large Overpressure Event Downstream of Gas Measurement and Control Facility (Chapter 9). Each driver and its associated 2023 test-year estimated frequency and key sub-drivers are discussed below.

D1 – Third-Party Damage: Refers to pipeline damage inflicted by first, second, or third parties through digging activities. Third-party damage related rupture incidents accounts for 0.33 (18 percent) of the 1.9 expected annual number of LOC events.[7]

D2 – Internal Corrosion: Refers to corrosion of the internal wall of steel transmission pipelines following exposure to water and/or contaminants in the gas. The extent of the corrosion damage and resultant threat depends on the operating conditions of the pipeline and the particular corrosive constituents within the pipe. Internal corrosion accounts for 0.25 (14 percent) of the 1.9 expected annual number of LOC events.

D3 – External Corrosion: Refers to the deterioration of the outside of the steel pipe that results from reaction with the outside environment (i.e., soil, water). Over time, external corrosion can reduce the wall thickness of the pipe, making the pipe weaker and more susceptible to other threats. External corrosion accounts for 0.30 (16 percent) of the 1.9 expected annual number of LOC events.

D4 – Construction Threats: Refers to a connection between two segments of pipe. Construction Threats accounts for 0.27 (15 percent) of the 1.9 expected annual number of LOC events.

D5 –WROFs: Refers to water crossings, unstable soil, erosion, heavy rains and floods. WROFs accounts for 0.14 (7 percent) of the 1.9 expected

7 The risk model frequencies account for both leaks and ruptures under the broad description “loss of containment” event.

number of LOC events. Seismic activity was excluded from this driver, as it is considered a cross-cutting factor for the 2020 RAMP.

D6 – Manufacturing Defects: Refers to longitudinal seam defects caused by flaws in the welding of the pipe seam and/or pipe body defects caused by various steel impurities. It also includes Selective Seam Weld Corrosion. Manufacturing defects accounts for 0.28 (15 percent) of the 1.9 expected annual number of LOC events.

D7 – Stress Corrosion Cracking: Refers to cracking from the combined influence of tensile stress and a corrosive environment. SCC accounts for 0.07 (4 percent) of the 1.9 average expected number of rupture events.

D8 – Incorrect Operations[8]: Refers to any activity, or omission of an activity, by PG&E personnel that could adversely impact the safety or reliability of the pipeline. Failures due to incorrect operations result from work procedure errors or human performance factors. Only non-overpressure incidents were included in this driver. Incorrect operations accounts for 0.008 (0.4 percent) of the 1.9 expected annual number of LOC events. Two cross-cutting factors, Skilled and Qualified Workforce and Records and Information Management (RIM), are sub-drivers of Incorrect Operations and account for 17% of Incorrect Operations but broken out from Incorrect Operations driver in the bowtie for visibility.

D9 – Equipment Failure: Equipment refers to pipeline facilities, other than pipe and pipe components, such as gaskets and O-rings, and control valve failure. Only non-overpressure incidents were included in this risk driver. Equipment failure accounts for 0.003 (0.2) percent of the 1.9 expected annual number of LOC events.[9]

To model this risk, PG&E utilized internal gas frequency and consequence data (derived from PG&E's current transmission pipeline

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8 The Incorrect Operations driver contributions to this risk are minimal. Incorrect Operations mainly contribute to overpressure events which are captured under the Large Overpressure Event Downstream of Gas Measurement and Control Facility risk (Chapter 9).

9 The Equipment Failure driver contributions to this risk are minimal. Equipment Failure mainly contributes to overpressure events which are captured under the Large Overpressure Event Downstream of a Measurement and Control Facility risk (Chapter 9).

conditions and location) and PHMSA data from 1984-2019. The PHMSA data includes Gas Transmission incident reports from 1984-2002, 2002-2010, and from 2010-2019. The PHMSA data was used to supplement PG&E data in order to obtain driver frequencies not included in the TIMP risk model (1984 to 2018 data was used).

PG&E's data regarding failure likelihood for ruptures is derived from the current condition of the transmission pipeline system. The failure likelihood algorithm addresses the likelihood of failure due to each of the risk drivers. For some threats, such as External Corrosion and Internal Corrosion, failure likelihood is calculated using probabilistic methods when ILI data are available. Where it is not possible to estimate failure likelihood by using probabilistic methods, a quantitative estimate is derived by means of an adjustment factor approach, applied against base case industry or PG&E failure likelihood statistics.

PG&E's failure likelihood for leaks is derived using a similar approach as for ruptures but only for the External Corrosion and Internal Corrosion risk drivers. To obtain the remaining five risk driver frequencies, adjustment factors/ratios from PHMSA data were applied to the available PG&E rupture data.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the LOC on Gas Transmission Pipeline risk are shown in Table 7-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 7-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Cyber Attack		X
2	Emergency Preparedness and Response		X
3	Information Technology Asset Failure		X
4	Physical Attack	X	
5	Records and Information Management	X	X
6	Seismic	X	X
7	Skilled and Qualified Workforce	X	

When analyzing the LOC on Gas Transmission Pipeline risk, PG&E considered the cross-cutting factor Climate Change even though it is not listed in the table above. Climate-related drivers are mainly captured under the WROF driver (landslides, erosion, subsidence, wildfire). In the context of Climate Change, the Gas Transmission risk team discussed the potential impact that wildfires could have on this risk and concluded that the impact would be small given that transmission pipeline assets are mostly underground. PG&E also evaluated the possible impacts of climate change resulting in increased subsidence. PG&E commissioned a study that looked at a critical area (Line 186) and concluded that existing pipeline assets are fit for service and able to operate under expected subsidence by 2060 even when using conservative estimates. Potential increases in corrosion rates due to sea level rise were also evaluated concluding that existing mitigation programs are adequate and able to address any additional cathodic protection needs that may arise. Even though climate change is not a significant risk driver for this risk, PG&E does consider gas transmission pipeline impacted by climate change as one of its alternative mitigations (Section F.1).

PG&E carefully evaluated whether the Cyber Attack and/or IT Asset Failure cross-cutting factors could cause a loss of containment risk event. It was determined that there is no credible scenario for either cross-cutting factor to cause a loss of containment event, but they are considered to impact the consequences of a LoC on Gas Transmission Pipeline risk event if IT Asset failure or Cyber Attack happened concurrently with an LOC.

7. Consequences

The basis for measuring the consequences of this risk is: did a LoC on a transmission pipeline occur and if so, (1) did the LoC result in a leak; or (2) did the LoC result in a rupture.

The consequences of a LoC on Gas Transmission Pipeline risk event occurring are:

- The rate of occurrence of LoC events that resulted in a rupture is 49 percent, contributing more than 99 percent of the overall risk; and
- The rate of occurrence of LoC events that resulted in a leak is 51 percent, contributing less than 1 percent of the overall risk.

The consequences of this risk are measured in terms of serious injuries or fatalities; reliability and financial impacts.

PG&E's financial consequence was estimated from the PHMSA financial data which captures costs associated with property damage and emergency response. An adjustment factor of 2.31 for California was applied (to reflect higher cost expected in California), based on the ratio of median value of homes in California to the median value of homes in all states—this data was obtained from Zillow home value estimates. Since housing data includes extreme values, the median was used as it is a better representation of the general level of the housing market than the average.

PG&E's reliability consequence profiles are different for ruptures and leaks. For ruptures, reliability consequence was determined based on the expected number of impacted customers in the case of service being interrupted to the pipeline segment. To account for the higher likelihood of service loss when the pipeline segment is part of a radial feed system (no alternative feed), a multiplier is applied to the expected number of impacted customers:

- Multiplier = 1 if radial system
- Multiplier = 0.5 if non-radial (meaning half of the customers served will be affected)

From this data, the mean value was used as a 50th percentile probability input, and the max value as a 99th percentile probability input, to fit a lognormal distribution. In addition, for the tranches ≥20 percent SMYS, the rupture consequence distribution was modified because the described approach was leading to overly conservative values. For these tranches, the 50th percentile probability input was developed using subject matter expert judgment informed by consolidated radial system averages and expectation that ≥20 percent SMYS tranches should have at least a 50th percentile probability value higher than that of the less than 20 percent SMYS tranches. The max values (99th percentile probability inputs) were not modified for the ≥20 percent SMYS tranches.

Finally, for ruptures, a 75.5 percent probability of a rupture leading to a reliability incident (customer outage) was calculated from PHMSA data 2010-2019, assuming those incidents with an estimated cost of operator's emergency response were incidents that lead to a reliability event.

For leaks, the reliability consequence was determined based on PG&E Gas Quarterly Incident Report data from 2015-2019. From this historical data, the number of customers out of service was fit into a lognormal distribution. A 36.8 percent probability of a leak leading to a reliability incident (customer outage) was also calculated from this data.

PG&E's Safety consequence is calculated from the number of human occupants impacted (estimated number of people within the PIR). Conditional probabilities (from a hazard zone analysis presented in the October 2016 PHMSA Committee Meeting workshop[10]) of fatalities and injuries are applied. It assumes: (1) homogeneous distribution of the human occupants through the PIR covered area; and (2) hazard zone is equal to the PIR. The numbers used are as follows:

- Injury rate = 80 percent, Fatality rate = 8 percent for hazard zone < 100 ft (feet)
- Injury rate = 50 percent, Fatality rate = 5 percent for hazard zone between 100 ft and 50 percent of PIR
- Injury rate = 20 percent, Fatality rate = 2 percent for hazard zone between 50 percent and 100 percent of PIR

With the estimated injuries and fatalities, the PHMSA data was used to calculate potential injuries and fatalities for employees, contractors and the public for both ruptures and leaks.

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[10] See workpaper WP 7-43, Pipeline Risk Assessment/Management, Mini-Workshop.

Table 7-4 below shows the consequences of the risk event. Model attributes are described in Chapter 3, Risk Modeling and Risk Spend Efficiency.

TABLE 7-4
RISK EVENT CONSEQUENCES

	CoRE | %Freq | %Risk	Freq	Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
			Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial
Ruptures	286 | 39.0% | 72%	0.7	1.0	41,573	5.3	115.0	164.8	5.8	0.7	30,234	3.9	83.6	119.9	4.2
Seismic - Rupture	447 | 9.2% | 27%	0.2	1.7	48,067	8.5	247.2	189.0	11.0	0.3	8,261	1.5	42.5	32.5	1.9
Rupture and IT Asset Failure	294 | 0.5% | 1%	0.0	1.0	42,149	5.4	119.7	169.0	5.5	0.0	403	0.1	1.1	1.6	0.1
Leaks	0.8 | 48.7% | 0.3%	0.9	0.0	22	1.2	0.2	0.0	0.6	0.0	20	1.1	0.2	0.0	0.5
Rupture and Cyber Attack	295 | 0.1% | 0.3%	0.0	1.0	42,059	5.6	120.4	168.4	6.0	0.0	106	0.0	0.3	0.4	0.0
Seismic - Leak	1.2 | 1.6% | 0.0%	0.0	0.0	33	1.7	0.3	0.0	0.9	0.0	1	0.1	0.0	0.0	0.0
Leak and IT Asset Failure	0.9 | 0.6% | 0.0%	0.0	0.0	23	1.3	0.2	0.0	0.6	0.0	0	0.0	0.0	0.0	0.0
Leak and Cyber Attack	0.9 | 0.2% | 0.0%	0.0	0.0	22	1.3	0.2	0.0	0.6	0.0	0	0.0	0.0	0.0	0.0
Aggregated	**155** | 100% | 100%	1.9	0.6	20,939	3.5	69	83	4	1.0	39,025	6.6	128	154	7

C. Controls and Mitigations

Tables 7-5 and 7-6 list the controls and mitigations PG&E included in its 2017 RAMP, 2019 Gas Transmission and Storage (GT&S) Rate Case and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are on-going, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

TABLE 7-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP	2019 GT&S 2019-2022 Controls[(a)]	2020 RAMP 2020-2022 Controls	2020 RAMP 2023-2026 Controls
1	C1 – Corrosion Control	X	X	X	X
2	C2 – Direct Assessments (DA)	X	X	X	X
3	C3 –TIMP Pressure Tests	X	X	X	X
4	C4 – Leak Survey	X	X	X	X
5	C5 – Locate and Mark	X	X	X	X
6	C6 – Patrols	X	X	X	X
7	C7 – Public Awareness	X	X	X	X
8	C8 – ILI – Re-inspections	X	X	X	X
9	C9 – Pipe Replacement Program (formerly Other Pipeline Safety and Reliability Replacements)	X	X	X	X
10	C10 – Geohazard Control Program (formerly Earthquake Fault Crossings)	X	X	X	X
11	C11 – Other Operations and Maintenance (O&M)	X	X	X	X

(a) The controls PG&E proposed in the 2017 RAMP were incorporated by reference in the 2019 GT&S rate case filing. See Application (A.) 17-11-009, Prepared Testimony, p. 4-34, footnote 14.

TABLE 7-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2019 GT&S 2019-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1 – ILI Upgrades [(a) (b)]	X	X	X	X
2	M2 – Strength Testing	X	X	X	X
3	M3 – Vintage Pipe Replacement	X	X	X	X
4	M4 – Valve Automation	X	X	X	X
5	M5 – Shallow Pipe[(c)]	X	(d)	X	X
6	M6 – Exposed Pipe[(d)]	X	(d)	X	X
7	M (not numbered) – Upgrading Pipe to Make Pipelines Capable of ILI		X		

(a) In the 2017 RAMP, this mitigation was referred to as “ILI” and was described as including both pipeline upgrades and first-time inspections (See I.17-11-003, p. 1-15). In this 2020 RAMP the scope of the ILI program includes only pipeline upgrades.

(b) In the 2017 RAMP, the mitigations were numbered sequentially (M1, M2, M3, etc.) and then a letter was appended to the mitigation number to indicate the period during which certain work associated with that mitigation would occur. For example, M1A described the 2016 work, M1B described the 2017-2019 work, and M1C described the 2020-2022 work. In this table and the following sections PG&E refers to the mitigation number without the letter (year) designation as the description of the work did not change, only the volume of work.

(c) Previously referred to as “Shallow and Exposed Pipe” in the 2017 RAMP. This mitigation was divided into two separate mitigations in the 2020 RAMP.

(d) In the 2019 GT&S, this mitigation is described as an alternative mitigation. (See A.17-11-009, Prepared Testimony, p.4-37, lines 24-26).

1. 2019 Controls and Mitigations

a. Controls

C1 – Corrosion Control: Most of PG&E’s transmission pipelines are made of steel and are subject to corrosion, an electrochemical process where metal degrades due to its interaction with the environment. Corrosion control seeks to: (1) control/reduce the elements that lead to corrosion; or (2) minimize the natural corrosion process using electrical currents. Effective corrosion control monitoring programs are critical to provide timely data that represent pipeline conditions, allow for modifications in corrosion mitigation strategies, and update risk management tools. This control addresses the External Corrosion, Internal Corrosion and SCC drivers.

C2 – Direct Assessments (DA): DA is a method of conducting assessments of pipeline integrity, as outlined in Title 49 of the Code of Federal Regulations—Transportation (49 CFR) Part 192 Subpart O. DA is used to help address time dependent threats of external corrosion, internal corrosion, and SCC by allowing for identification of anomalies which, if not addressed, could grow and potentially affect the structural integrity of the pipeline. The assessment techniques are called: (1) External Corrosion Direct Assessment, used to identify and assess locations likely to have external corrosion; (2) Internal Corrosion Direct Assessment, used to identify and assess locations likely to have internal corrosion; and (3) SCC Direct Assessment, used to identify and assess the presence of a corrosive environment combined with sufficient tensile stress in the pipe material to initiate and grow stress corrosion cracks. This control addresses the External Corrosion, Internal Corrosion and SCC drivers.

C3 –TIMP Pressure Tests: TIMP Pressure Tests are a method of conducting pipeline integrity assessments, as outlined in 49 CFR Part 192 Subpart O. Pressure tests are the most suitable assessment method for assessing certain threats, such as when a pipe has a manufacturing threat or in some cases SCC, when ILI is not a feasible method. This control addresses the External Corrosion, Internal Corrosion, SCC, Manufacturing Related Defects, Construction Threats, and Third-Party Damage drivers.

C4 – Leak Survey: PG&E conducts leak surveys on the Gas Transmission pipeline system to meet the regulatory requirements of 49 CFR Part 192.706 and GO-112F. PG&E conducts leak surveys on the gas transmission pipeline system by implementing foot, aerial and mobile leak surveys.

– <u>Foot Survey</u>: Foot surveys require personnel to carry a portable gas leak detector in close proximity to the pipeline route.

– <u>Aerial Survey</u>: Aerial leak surveys using Light Detection and Ranging (LIDAR) Infra-Red technology are being used more frequently and are typically transported by helicopter along the pipeline right-of-way (ROW).

– Mobile Survey: Ground-based mobile technology is a portable gas detector transported on vehicles along the pipeline ROW.

For each case, leaks are detected and recorded on the instrument before being downloaded to a database for immediate or scheduled repair. This control addresses all the risk drivers.

C5 – Locate and Mark: PG&E's Damage Prevention Program includes the Locate and Mark Program with the goal of preventing excavation damage to PG&E transmission pipeline assets. This program includes responding to notifications in a timely manner, physically locating PG&E gas transmission pipeline assets near the proposed excavations and properly marking these assets and returning to the site when excavation activities are occurring near or over the gas transmission assets. This control addresses the Third-Party Damage driver.

C6 – Patrols: Pipeline patrol is an activity required by 49 CFR Part 192.705 to "observe surface conditions on and adjacent to the [pipeline's] right-of-way for indications of leaks, construction activity, and other factors affecting safety and operation". A secondary purpose of patrolling is to report new construction that may impact a pipeline's Class Location or classification as an HCA (49 CFR Part 192.613). This control addresses the Third-Party Damage and WROF drivers.

C7 – Public Awareness: PG&E is required to develop and implement public education programs that comply with American Petroleum Institute's Recommended Practice 1162, 1st Edition (RP 1162). The Public Awareness Program is part of the Damage Prevention Program and its goal is to enhance public safety, emergency preparedness and environmental protection through increased public awareness and knowledge. This control addresses the Third-Party Damage driver.

C8 – ILIs – Re-Inspections: ILI is the most reliable pipeline integrity assessment tool currently available to a natural gas pipeline operator to assess the internal and external condition of transmission line pipe. ILI enables a pipeline operator to assess the condition of its pipelines and to predict the integrity of those pipelines into the future to address time dependent, as well as other threats to pipeline integrity. ILI involves running technologically advanced inspection tools, often called "smart pigs" through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigation or repair. ILI is characterized as "traditional" or "non-traditional." The traditional ILI uses tools that move through the pipeline driven by pressure differentials generated by gas flow. The non-traditional tools move through the interior of the pipeline by means other than through the use of gas propulsion such as using robotic and tractor tools, winching a tool through the pipe with a cable or using specially designed low-friction tools. There are three major phases to an ILI program. The first involves modifying or updating the existing pipeline system to accommodate an ILI tool. PG&E refers to this as "traditional ILI upgrades" which involves capital improvements to make the pipelines piggable. The second phase of an ILI program involves cleaning and inspection "runs" in the pipeline. Inspection runs are generally divided into first-time inspection runs for initial assessment purposes and re-inspection runs conducted for reassessment purposes. The third phase of the ILI program is the direct examination and repair and is driven by the results of the data analysis. This remediation effort allows for the preventative repair and mitigation of anomalies before they result in a pipeline leak or rupture. PG&E defines the re-inspection runs as a control for this risk given that the ILI re-inspections are performed on a periodic basis. The upgrades and the first-time inspections are defined as mitigation and discussed in the mitigation section below. The ILI program addresses External Corrosion, Internal Corrosion, SCC, Manufacturing Related Defects, Construction Threats, WROFs, and Third-Party Damage.

C9 – Pipe Replacement Program (formerly Other Pipeline Safety and Reliability Replacements): PG&E expects to continue to replace pipe due to leaks, dig-ins, corrosion integrity issues, overbuilds and encroachments, and other pipeline safety and reliability issues that arise. The pipe replacement program addresses External Corrosion, Internal Corrosion, SCC, Third-Party Damage, Manufacturing Related Defects and WROFs.

C10 – Geohazard Control Program (formerly Earthquake Fault Crossings):[11] The Geohazard Control program addresses the specific threat of damage to a pipeline from land movement strains at known earthquake faults due to seismic events and other geohazards. California law requires natural gas operators to prepare for and minimize damage to pipelines from earthquakes as part of their integrity management programs. Since the inception of this program, PG&E has conducted detailed studies which have shaped the direction of PG&E's earthquake fault crossing program. The studies, which address both the anticipated geologic movement and pipeline mechanical properties, provide information that informs PG&E how to manage the integrity of these segments of pipe. This control addresses the WROF driver.

C11 – Other O&M:[12] Gas Transmission O&M activities are the actions planned, tracked and managed to ensure regulatory compliance and increase the useful lives of the Gas Transmission assets. Gas Transmission O&M expense includes costs to perform compliance, preventive and corrective tasks. Work in this control program also includes small-scale, routine safety and reliability capital work as well. This control addresses all drivers.

b. Mitigations

M1 – ILI Upgrades:[13] The purpose of this mitigation is to make one-time modifications to the pipeline to be able to run a smart pig unimpeded through the pipeline.

The pipeline upgrades enable the first-time inspection mileage. This mitigation addresses internal and external corrosion, SCC,

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[11] The name of the control program and description of the program has been modified since the 2017 RAMP to more appropriately describe the work performed in this control program.

[12] This description of this control program has been modified since the 2017 RAMP to more appropriately describe the work performed in this control program.

[13] In the 2017 RAMP this mitigation was referred to as "ILI" and was described as including both pipeline upgrades and first-time inspections. MAT codes HPB (Traditional ILI Runs), HPI (ILI Direct Exam and Repair), and 98C (ILI Upgrades) were associated with this mitigation. (See PG&E's 2017 RAMP Report, p. 1-15). In this 2020 RAMP the scope of the ILI program includes only pipeline upgrades. Only MAT code 98C is associated with this mitigation in the 2020 RAMP.

manufacturing defects, third-party damage, WROF and Construction Threats.

In the 2017 RAMP, PG&E proposed first time inspections of 673 miles (93 miles in 2017, 218 miles in 2018 and 362 miles in 2019) of transmission pipeline between 2017 and 2019. Through 2019, PG&E inspected 611.8 miles (123.1 miles in 2017, 243.0 miles in 2018 and 245.7 miles in 2019). In addition, PG&E upgraded 643.1 miles of transmission pipe for ILI.[14]

M2 – Strength Testing: PG&E strength tests pipe for several reasons, including to establish a Maximum Allowable Operating Pressure as a part of original construction, when there is a Class Location change, as an integrity assessment to meet regulatory requirements and to fulfill PG&E's obligation to the National Transportation Safety Board Safety Recommendation P-10-4. PG&E completed a high volume of mileage in 2017 and 2018 in order to meet the mandated mileage from the CPUC in Decision 16-06-056. This mitigation addresses internal and external corrosion, SCC, manufacturing defects, third-party/mechanical damage, WROF and welding/fabrication related defects.

PG&E proposed strength testing 585 miles of transmission pipeline between 2017 and 2019. PG&E completed strength testing for 253, 286, and 115 miles of pipe in 2017, 2018, and 2019, respectively. The 3-year total of 684 miles exceeds the 585 miles plan.

M3 – Vintage Pipe Replacement: PG&E considers "vintage pipe" to include pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today. PG&E plans to replace all the vintage pipe segments containing vintage fabrication and construction threats that are subject to a high risk of land movement and are in proximity to population. This proposed plan is partially based on assessment of site-specific land movement information collected through PG&E's Geohazard Threat Identification program. Additionally,

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[14] PG&E was initially on a 12-year pace to make pipelines capable of accepting an ILI tool. As a result of the 2019 GT&S decision (Decision 19-09-025), the program remained on a 12-year pace through 2018 and then switched to a 15-year program starting in 2019. In its decision, the CPUC noted that changing the pace of the program would not pose undue risks. D.19-09-025, p. 138.

PG&E was mandated to replace 20 miles in 2018. This mitigation addresses internal and external corrosion, SCC, manufacturing defects, construction threats, WROF and third-party/mechanical damage.

PG&E planned to replace 46 miles of vintage pipe–20 miles in 2017, 23 miles in 2018 and 3 miles in 2019. PG&E replaced 3.5, 20.6, and 2.1 miles of vintage pipe in 2017, 2018, and 2019 respectively, excluding vintage pipeline retirement only projects. The 3-year total miles replaced is less than the planned amount due to operational constraints that did not allow enough time for engineering and permitting. PG&E's 2015 GT&S Rate Case decision was not issued until the middle of 2016[15] and its 2019 GT&S Rate Case Decision was not issued until September 2019, creating uncertainty in the planning work.

M4 – Valve Automation: PG&E's Valve Automation program is designed to enhance emergency response in the event of a gas transmission pipeline rupture. Installation of automated isolation capability on major pipelines in heavily-populated areas increases emergency preparedness and may reduce the danger to emergency personnel and the public in the event of a pipeline rupture.[16] This mitigation addresses the consequences of the event by preventing further escalation.

PG&E automated 92 valves – 23 in 2017; 46 in 2018 and 23 in 2019. Fewer valves were automated in 2017 because funds were reprioritized to higher priority work. For 2019, the decrease was due to PG&E combining two Valve Automation projects (four valves) into one project, which was delayed to 2020.

M5 – Shallow and Exposed Pipe: The goal of this program is to identify, prioritize, and mitigate locations where pipeline has insufficient cover, is vulnerable to exposure from third parties, or has become

15 The 2015 GT&S Rate Case covers 2015-2018. The 2019 GT&S Rate Case cycle covers 2019-2022.

16 Given that the exposure defined in the model is in miles, the equivalent miles addressed by the number of valves automated each year was calculated by analyzing the sections of pipeline that will be influenced by the valves. Four valves are equivalent to approximately 10 miles.

exposed due to natural forces. This mitigation addresses internal and external corrosion, SCC, third-party damage, WROF, manufacturing defects and Construction Threats drivers.

In the 2017 RAMP, PG&E planned to replace 2.5 miles in 2017, 1.5 miles in 2018 and 1.4 miles in 2019. PG&E replaced 0.5, 1.0, and 0.7 miles of shallow and exposed pipe in 2017, 2018, and 2019 respectively, a total of 2.2 miles. PG&E replaced fewer miles because it chose to reallocate funds to higher priority work.

D. 2020-2022 Controls and Mitigation Plan

1. Changes to Controls

PG&E is not planning to change or add to the controls in the 2017 RAMP.

2. Changes to Mitigations

PG&E will continue to implement the five mitigations proposed in the 2017 RAMP.

Mitigation M5 is now two separate mitigations – M5, Shallow Pipe and M6 – Exposed Pipe. PG&E is not proposing any new mitigations.

The amount of work PG&E plans to complete is shown in Table 7-5 below.

TABLE 7-7
PLANNED MITIGATIONS 2020-2022

Line No.	Mitigation Name and Number	Rate Case Units[(a)]	Planned Units of Work			
			2020	2021	2022	Total
1	M1 – ILI Upgrades	# of projects	12	12	12	36
2	M2 – Strength Testing	Miles	38.00	36.8	36.8	111.60
3	M3 – Vintage Pipe Replacement	Miles	2.02	3.08	2.41	7.51
4	M4 – Valve Automation	Valves	23	24	24	71
5	M5 – Shallow Pipe	Miles	0.30	0.02	0.01	0.33
6	M6 – Exposed Pipe	Miles	0.76	0.61	0.45	1.82

(a) The units of work are presented in "rate case" units – the units referred to in PG&E's gas distribution and/or transmission rate cases. In certain cases, the units of work are represented differently in the RAMP model because the model requires that units of work are standardized. For example, in the General Rate Case PG&E reports feet of distribution main pipeline replaced whereas in the RAMP model PG&E inputs miles of distribution main replaced.

Tables 7-8 and 7-9 below show the forecast costs for the mitigation work planned for the 2020-2022 period.

TABLE 7-8
FORECAST COSTS[(a)]
EXPENSE 2020-2022
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M2	Strength Testing	MC1, JTC	$39,622	$39,521	$40,707	$119,850
2	Total			$39,622	$39,521	$40,707	$119,850

(a) See WP 7-1.

TABLE 7-9
FORECAST COSTS[(a)]
CAPITAL 2020-2022
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M1	ILI Upgrades	98C	$167,785	$144,000	$147,600	$495,385
2	M3	Vintage Pipe Replacement	75E	23,957	45,300	35,446	104,703
3	M4	Valve Automation	75I	24,056	28,800	29,520	82,377
4	M5	Shallow Pipe	75M	6,941	6,941	7,150	21,033
5	M6	Exposed Pipe	75T	10,311	18,126	19,835	48,272
6		Total		$233,052	$243,167	$239,551	$715,770

(a) See WP 7-1.

E. 2023 – 2026 Proposed Mitigation Plan

PG&E will continue to implement the same five mitigations. The amount of work PG&E plans to complete is shown in Table 7-10 below.

TABLE 7-10
PLANNED MITIGATIONS 2023-2026

Line No.	Mitigation Name and Number	Rate Case Units [(a)]	Planned Units of Work				
			2023	2024	2025	2026	Total
1	M1 – ILI Upgrades	# of projects	12	12	12	12	48
2	M2 – Strength Testing	Miles	79.31	79.31	79.31	79.31	317.22
3	M3 – Vintage Pipe Replacement	Miles	2.22	1.23	2.66	3.10	9.21
4	M4 – Valve Automation	Valves	27	27	27	26	107
5	M5 – Shallow Pipe	Miles	0.57	0.30	0.30	0.30	1.47
6	M6 – Exposed Pipe	Miles	0.19	0.42	0.42	0.42	1.44

(a) The units of work are presented in “rate case” units – the units referred to in PG&E’s gas distribution and/or transmission rate cases. In certain cases, the units of work are represented differently in the RAMP model because the model requires that units of work are standardized. For example, in the GT&S PG&E reports feet of distribution main pipeline replaced whereas in the RAMP model PG&E inputs miles of distribution main replaced.

Tables 7-11 and 7-12 below show the forecast costs, RSEs and risk reduction scores for the mitigation work planned for the 2023-2026 period.

TABLE 7-11
FORECAST COSTS, RSE AND RISK REDUCTION[b]
EXPENSE 2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M2	Strength Testing	MC1	$90,357	$93,067	$95,859	$98,735	$378,019	0.14	37.9
2		Total		$90,357	$93,067	$95,859	$98,735	$378,019		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
(b) See WP 7-1.

TABLE 7-12
FORECAST COSTS, RSE AND RISK REDUCTION[b]
CAPITAL 2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1	ILI Upgrades	98C	$151,290	$155,072	$158,949	$162,923	$628,234	0.10	44.0
2	M3	Vintage Pipe Replacement	75E	33,631	19,192	42,750	51,317	146,890	0.04	4.2
3	M4	Valve Automation	75I	34,040	34,891	35,764	35,472	140,167	0.08	8.7
4	M5	Shallow Pipe	75M	7,364	7,585	7,813	8,047	30,809	0.02	0.5
5	M6	Exposed Pipe	75T	7,643	11,653	12,002	12,362	43,660	0.02	0.6
6		Total		$233,969	$228,394	$257,278	$270,121	$989,761		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
(b) See WP 7-1.

Tables 7-11 and 7-12 above shows the planned cost, RSE and risk reduction score for each of the LOC on Gas Transmission Pipeline risk mitigation programs. PG&E's mitigation program proposes to focus spending on the two programs that reduce the greatest amount of risk:

- The ILI program provides the greatest risk reduction and has the second highest RSE. PG&E is proposing to allocate more than 60 percent of its capital mitigation spending on this program. ILI is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe.[17]
- Strength Testing has the highest RSE score of the proposed mitigations and the second highest risk reduction. PG&E is proposing to allocate approximately 28 percent of its total mitigation spending on this program.
- PG&E's planned mitigations are focused on addressing the tranche with the highest percent of risk. PG&E's 2023-2026 plan includes ILI Upgrade projects and Strength Testing focused on the Greater than or Equal to 20 percent SMYS and High Impact IOC tranche. Taken together, PG&E estimates that 69 percent of the total risk reduction from its proposed mitigation programs is focused in this highest risk tranche.[18]

PG&E is proposing to spend approximately $74 million dollars between 2023 and 2026 on two mitigations - Shallow Pipe and Exposed Pipe. While the RSE scores for these programs are low compared to the other planned mitigations, the programs help PG&E to address risks due to shallow and exposed pipe on both land and locations of levee/water crossings. The two programs identify, prioritize and mitigate pipeline that has insufficient cover, is vulnerable to damage or exposure from third parties, or has become exposed due to natural forces. The pipe segments addressed by these programs have a higher risk (especially for TPD and WROF drivers) relative to others within the tranches, leading to slight underestimations of RSE. There is not a tranche specific to these pipe segments because their exposure is less than 1 percent of

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17 "Report to the National Transportation Safety Board on Historical and Future Development of Advanced In-Line Inspection Platforms for Use in Gas Transmission Pipelines," INGAA, March 26, 2012.

18 See WP 7-205 Risk Reduction Tranche vs Program Heat Map.

the overall transmission pipeline system. This program enhances public safety and improves system reliability by identifying and evaluating hazards such as soil erosion, third-party damage threats, and other geohazards to buried pipeline installations located under waterways and within levee structures. This mitigation program is informed by several best practices.[19] Studies conducted after Hurricane Katrina on levee systems nationwide identified California levee systems as among the most vulnerable for failure and have the greatest potential risk for loss of life, property damage, and economic impact.

PG&E also implements shallow and exposed pipe mitigations to meet regulatory compliance requirements. 49 CFR 192.933 requires that PG&E take action to address integrity issues and 49 CFR 192.935 requires prevention and mitigation measures for identified hazards associated with shallow and exposed pipe.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: Mitigate Transmission Pipeline Impacted by Climate Change

To improve the resilience of PG&E's transmission pipeline to climate change, PG&E reviewed white paper CEC-500-2017-008 from California Energy Commission (CEC) Climate Change Center (assessment of California's natural gas pipeline vulnerability to climate change). This paper documents simulations of different flooding scenarios in three primary regions: the San Francisco Bay Area, the Sacramento-San Joaquin River Delta, and California's full coastline. It also includes analyses of the location of existing natural gas transmission pipelines and associated infrastructure

[19] These best practices are discussed in PG&E's 2019 GT&S Rate Case, A.17-11-009, Prepared Testimony, p. 5-101, line 25 to p.5-102, line 12.

to identify locations of possible vulnerability to inundation damage associated with extreme storms and various increments of long-term sea level rise (SLR).

Based on the worst-case scenario analysis of 1.41 meter sea level rise coupled with a near 100-year storm event (NESE 100), PG&E found that approximately 36 miles of transmission pipeline could be at levels of threat requiring specific interventions in the face of projected higher sea level and storm surge.

PG&E determined that 36 miles could be targeted for intervention over a 30-year period, targeting to complete by 2053. The program would prioritize replacement of pipe in those areas that present the higher risk first.

PG&E assumed the cost of intervention to address the 36 miles of pipeline would be equivalent to its vintage pipe replacement program. Based on the CEC report, 23 of the 36 miles may need to be replaced and secured, and the remaining miles may require other work (e.g., anchoring) which requires excavation—a significant contributor to the cost of replacing pipe.

This cost estimate is preliminary, based on information readily available and supplemented with SME judgment. A more in-depth analysis would be required to better estimate the costs associated with this program.

PG&E is not pursuing this alternative mitigation at this time because PG&E has prioritized its work plan to address more immediate concerns. PG&E would need to perform additional studies to obtain a better understanding of the potential impact to our transmission pipeline system due to rising sea level.

TABLE 7-13
FORECAST COSTS, RSE AND RISK REDUCTION[b]
EXPENSE 2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Mitigate Transmission Pipeline Impacted by Climate Change	$18,179	$18,724	$19,286	$19,864	$76,053	0.03	1.5
2		Total	$18,179	$18,724	$19,286	$19,864	$76,053		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See WP 7-1.

2. Alternative Plan 2: Mitigate Transmission Pipeline Third Party Damage Events

This mitigation uses new technology to reduce the risk of third-party/mechanical damage to transmission pipeline assets. This program would install active global positioning system (GPS) tracking devices on third-party excavation equipment and the device would alert PG&E when the excavation equipment is working near a pipeline, giving PG&E time to investigate the work against a valid USA ticket and potentially reduce the likelihood of excavation equipment impacting the pipeline.

To develop the initial cost estimate for this alternative, the total excavation equipment count in California was estimated from a California Air Resources Board (ARB) report, ARB No. 04-315 "Characterization of the Off-Road Equipment Population." The preliminary scope of this program is defined as 14,184 pieces of excavation equipment (e.g., backhoes, excavators, graders), of which PG&E assumes it would add tracking devices to 50 percent of the excavation equipment population over three years (2023 through 2025).

The effectiveness of this program would be based on the percentage of dig-ins with gas release involving excavation machinery and that do not have a valid (USA) 811 ticket, and the assumption that one out of five events (excavation machinery detected near transmission pipeline without a USA ticket) would be effectively mitigated, preventing a LoC event.

The cost estimate accounts for estimated 10 full-time employees for deployment of units and monitoring/response, who would be strategically placed across the PG&E service territory. It also accounts for the recurring monthly cost associated with the renting of the GPS units.

PG&E will continue to evaluate this program and may conduct a pilot program to further analyze the costs and benefits of this program given the favorable RSE and risk reduction.

Table 7-14 below lists the mitigation, RSE and estimated costs to install tracking devices on third-party excavation equipment.

TABLE 7-14
FORECAST COSTS, RSE AND RISK REDUCTION[b]
EXPENSE 2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A2	Mitigate Transmission Pipeline Third Party Damage Events	$3,556	$7,174	$11,007	$12,611	$34,348	0.14	3.4
2		Total	$3,556	$7,174	$11,007	$12,611	$34,348		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See WP 7-1.

Table 7-15 compares the proposed and alternative mitigation plans.

TABLE 7-15
MITIGATION PLAN ALTERNATIVES ANALYSIS[c]
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[a]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[b]	Total Spend (NPV)	RSE
1	Proposed	M1, M2, M3, M4, M5, M6	$378,019	$989,761	96	$1,003,351	0.096
2	Alternative 1	Proposed + A1	$454,072	$989,761	97	$1,059,229	0.092
3	Alternative 2	Proposed + A2	$412,367	$989,761	99	$1,027,866	0.097

(a) Plan Components refers to the Mitigations presented in Table 7-6.
(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.
(c) See WP 7-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: LOSS OF CONTAINMENT ON GAS DISTRIBUTION MAIN OR SERVICE

PACIFIC GAS AND ELECTRIC COMPANY
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RISK MITIGATION PLAN: LOSS OF CONTAINMENT ON GAS DISTRIBUTION MAIN OR SERVICE

A. Executive Summary

Loss of containment (LOC) on Gas Distribution Main or Service refers to a leak on a distribution main or service asset with the potential for migration and ignition. The drivers for this risk event are: corrosion, natural forces, excavation damage, other outside force damage, material weld or joint failure, equipment failure, incorrect operations, or other events that could threaten the integrity of the pipeline. LOC due to a cross bore event is a sub-driver of the incorrect operations driver. The cross-cutting factors including Climate Change, Emergency Preparedness and Response, Physical Attack, Records and Information Management, Seismic, and Skilled and Qualified Workforce (SQWF) also impact this risk event.

Exposure[1] to this risk is based on approximately 43,200 miles of distribution mains and approximately 3.6 million gas services and risers.[2] The risk model includes approximately 29,590 risk events each year. The majority of the risk events are minor LOC events (leaks) that account for 21 percent of the total risk. Those risk events which are defined as major LOC events make up 79 percent of the total risk.

The main risk driver, equipment failure, is responsible for 65 percent of the risk events. Corrosion, incorrect operations, excavation damage, and material/weld failure combined are responsible for 30 percent of risk events. The mitigations Pacific Gas and Electric Company (PG&E) will implement from 2020-2026 are designed to address the risk drivers noted above.

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1 Miles of distribution main and services, number of risers, and count of cross bore inspections are combined for the purpose of running the risk model, and exposure is expressed as 4.45 million units.

2 Service lines refers to gas lines operating at less than or equal to 60 pounds per square inch gauge connecting from the main to customer-connected equipment. Service lines include single customer and branch services. Risers connect underground service lines to the above-ground meter set.

PG&E identified 12 tranches for this risk event. Ten of the tranches are separated by asset type, material type and population density and two outcomes, major and minor. The other two tranches represent cross bore events inside and outside San Francisco. The highest tranche-level risk is associated with services and risers.

LOC on Gas Distribution Main or Service has the sixth-highest 2023 test year (TY) baseline safety score (72) and the fifth-highest 2023 TY baseline total risk score (99) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 110, improves by 15 percent when the planned mitigations are applied—the 2023 TY baseline risk score is 99 and the post-mitigation 2026 risk score is 93.

The New Valve Installation and Fitting Mitigation programs have the highest risk spend efficiency (RSE) scores, and the plastic and steel Pipeline Replacement Program have the highest total risk reduction scores.[3]

TABLE 8-1
RISK OVERVIEW

RISK NAME	LOC on Gas Distribution Main or Service
IN SCOPE	Failure of a gas distribution main or service resulting in a LOC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers.
OUT OF SCOPE	A LOC driven by large over pressure events and customer-connected equipment.
DATA QUANTIFICATION SOURCES[(a)]	RiskFinder Leak Data, Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data, Legacy Cross Bore program inspection data, PG&E's 2020 General Rate Case (GRC) application, PG&E Gas Distribution Geographic Information System (GD-GIS), PG&E Customer Outage Data, 2010 census block data, PG&E unit cost information from its 2020 GRC.

(a) Source documents will be provided with the workpapers on July 17, 2020.

3 The information presented herein is subject to the limitations described in Chapter 2, Section D.

1. Risk Overview

PG&E recently rescoped this risk. At the February 4, 2020 RAMP Workshop with the California Public Utilities Commission and interested parties (Workshop #3), this risk was presented as two risks: (1) Loss of Containment – Gas Distribution Pipeline – Non-Cross Bore; and, (2) Loss of Containment – Gas Distribution Pipeline – Cross Bore. The gas distribution risk is now called Loss of Containment on Gas Distribution Main or Service, combining both risks into a single risk event.

The exposure to this risk is based on approximately 43,200 miles of distribution mains, and approximately 3.6 million gas services and risers, which together provide natural gas to PG&E's 4.3 million residential, commercial and industrial customers.

LOC on a gas distribution main or service refers to a leak on a distribution main or service asset with the potential for migration and ignition. The drivers for this risk event are: corrosion; natural forces; excavation damage; other outside force damage; material weld or joint failure; equipment failure; incorrect operations; and, other events that could threaten the integrity of the pipeline. LOC on the gas distribution system due to a cross bore[4] is a sub-driver of the incorrect operations driver. The cross-cutting risks Records and Information Management, Seismic and SQWF also impact this risk event.

PG&E monitors the gas distribution system assets through operations and maintenance activities including atmospheric corrosion inspections, cathodic protection (CP) system monitoring, leak survey and excavation damage prevention efforts. PG&E performs additional monitoring, risk assessment and mitigation activities through the Distribution Integrity Management Program (DIMP).

Along with system monitoring, PG&E mitigates distribution main and service risk through additional corrosion control programs, fitting repair and replacement programs, emergency zone valve installations, and legacy

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4 A cross bore is an inadvertent placement of an underground utility through a wastewater or storm drain system during trenchless construction. Cross bores pose a risk as they can result in a gas leak into the sewer system if damaged during sewer cleaning operations.

cross bore inspections. PG&E also performs gas distribution pipeline replacement as part of the asset management strategy to mitigate the effects of aging infrastructure within the gas distribution system.

2. Risk Definition

Failure of a gas distribution main or service resulting in a LOC, with or without ignition, can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas to customers.

B. Risk Assessment

1. Background and Evolution

PG&E's 2017 RAMP included two gas distribution pipeline risks: (1) Release of Gas with Ignition on Distribution Facilities – Cross Bore[5]; and, (2) Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore.[6] In the 2020 RAMP, PG&E is presenting one combined gas distribution risk event that includes both cross bore and non-cross bore risk events. The LOC due to a cross bore is both a sub-driver of the incorrect operations driver and a driver of the cross bore tranche.

The risk events in the 2017 RAMP were defined as distribution asset LOC with ignition (non-cross bore) and release of gas with ignition cross bore. The risk event definition in the 2020 RAMP has been expanded to include both "with ignition" and "without ignition." By expanding the definition to include "without ignition" in the risk event, PG&E is able to improve risk model accuracy by using more PG&E historical system data, since most of the gas distribution LOC events do not result in an ignition, but contribute to the risk consequences.

In the 2017 RAMP, PG&E identified eight drivers for the non-cross bore risk event for categorizing and evaluating threats on distribution assets. PG&E has modeled the new combined risk event using the same eight drivers. The drivers are based on Title 49 of the Code of Federal Regulations – Transportation (CFR) Part 192, Subpart P. At RAMP

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5 PG&E's RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017) (PG&E's 2017 RAMP Report), Chapter 5.

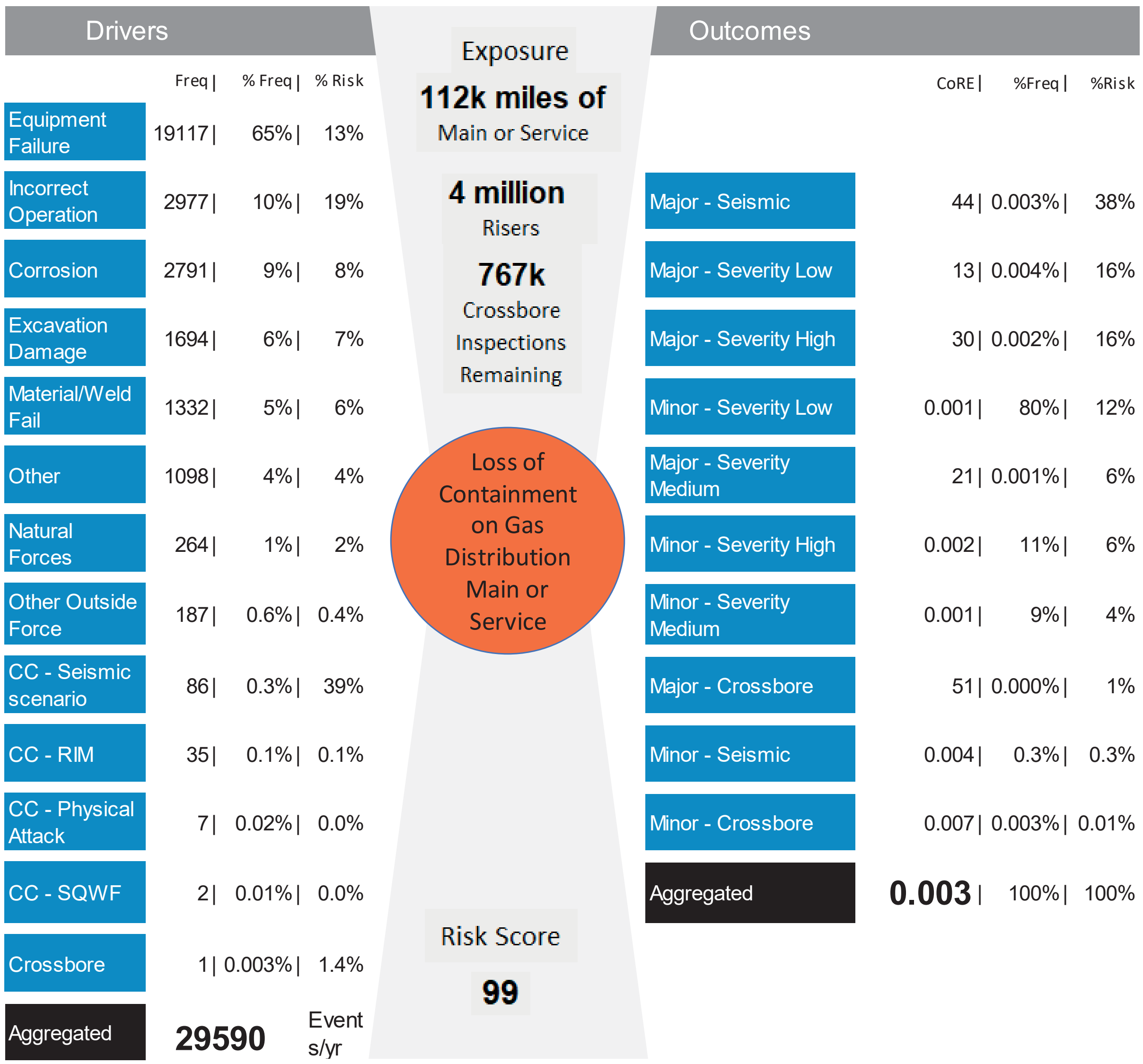
6 PG&E's 2017 RAMP Report, Chapter 7.

Workshop #3, PG&E presented its list of 12 proposed RAMP risks. The list excluded the Loss of Containment – Distribution Pipeline – Cross Bore risk because it did not meet the criteria to qualify as a RAMP risk.[7] During the workshop, the Safety and Enforcement Division (SED) and intervenors questioned why the cross bore risk was not identified as a RAMP risk, since PG&E identified cross bores as a top safety risk in the 2020 GRC. In response to this feedback, PG&E combined the cross bore risk into the LOC – Gas Distribution Main or Service risk event and maintained visibility to the cross bores through tranching. By including cross bores in the risk event, PG&E now has a holistic view of its gas distribution system, and a more complete picture of the potential drivers of a risk event on this system.

7 Consistent with the requirements set forth in the Phase Two Safety Model Assessment Proceeding (S-MAP) Settlement Agreement (Attachment A to Decision 18-12-014), PG&E selected its RAMP risks by evaluating all risks on its Enterprise Risk Register (ERR), identifying the safety risks and computing a Safety Risk Score for each one. PG&E sorted the list by the Safety Risk Score and selected the top 40 percent of the ERR risks with a safety risk score greater than zero. PG&E also selected risks for inclusion in RAMP whose Safety Risk Score was within 20 percent of the lowest top 40 percent Safety Risk Score. Safety risks that did not meet this S-MAP selection criteria are included in Chapter 19, “Other Safety Risks,” in this 2020 RAMP Report.

2. Risk Bow Tie

FIGURE 8-1
RISK BOW TIE



a. Difference from 2017 Risk Bow Tie

In the 2017 RAMP, PG&E presented two gas distribution LOC risks—one cross bore (Chapter 5) and one non-cross bore (Chapter 7). In the 2020 RAMP, PG&E is presenting one gas distribution LOC risk with cross bores represented at the tranche level.

In the 2017 RAMP, both of the risk events were defined as LOC with ignition. In the 2020 RAMP, the risk event includes both with and without ignition to better align with PG&E's history with distribution LOC events. By redefining the risk event to include without ignition, PG&E is able to rely on PG&E data to model the risk event and consequences as opposed to relying on industry data.

The risk drivers for both the 2017 RAMP non-cross bore event and the 2020 risk event are the same, and are based on 49 CFR Part 192, Subpart P.

3. Exposure to Risk

For the LOC on Gas Distribution Main or Service risk event, exposure to risk is measured by the total distribution equipment units. This is based on approximately 43,200 miles of PG&E distribution mains, approximately 3.6 million services and approximately 3.6 million risers.[8] Because the unit of measure is different for the different Gas Distribution asset types, exposure is defined in the risk model as 112,000 miles of main or service, 4 million risers and 767,000 cross bore inspections remaining.

For the cross bore tranches, risk exposure is based on an estimated number of potential legacy cross bores remaining in PG&E's system. The exact number of cross bores on the system is unknown. PG&E estimated the number of cross bores by multiplying PG&E's historic cross bore find rate by the number of inspections remaining based on information through February 2020.

4. Tranches

PG&E identified 12 total tranches for the Loss of Containment on Gas Distribution Main or Service risk event, 10 of which (Tranches 1-10 in Table 8-2 below), have been separated by three factors: asset type, material type, and population density. These tranche-defining factors represent different risk profiles.[9]

The factors provide a reasonable foundation for evaluating the likelihood of a LOC risk event based on asset and material type and the consequences of a risk event considering major/minor outcome, severity

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8 For RAMP risk model purposes, it is assumed that there is one riser for every service.

9 At Workshop #3, PG&E presented five distribution gas pipeline risk tranches based on the likelihood of failure (material type) and the consequence of failure (asset type). Following the workshop, PG&E expanded the number of tranches by including material type, asset type and population density and added cross bores as unique tranches.

grouping, asset type, and population density. Based on feedback received during RAMP Workshop #3, PG&E added cross bores into the LOC on Gas Distribution Main or Service risk event and maintained visibility to the cross bores through tranching (Items 11 and 12 in Table 8-2 below). There are two tranches for cross bores based on the potential for a cross bore inside or outside San Francisco. This tranche design acknowledges the increased risk of cross bores in San Francisco due to the relatively high amount of pipeline replacement activity combined with the high population density.

PG&E will continue to improve its model over time. One change that PG&E is evaluating is to further divide the pipeline tranches by the classifying pipe by the years in which it was installed: steel pipe, pre- and post-1941; and plastic pipe, pre- and post-1985. These divisions will better represent the current state of the gas distribution system as there are known differences in the risk profile of the pipe depending on the installation date.

Table 8-2 shows the percent exposure and percent risk by asset type at the tranche level.

TABLE 8-2
PERCENT EXPOSURE AND PERCENT RISK BY TRANCHE AND ASSET TYPE
LOC – GAS DISTRIBUTION MAIN OR SERVICE

Line No.	Tranche	Percent Exposure	Safety Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent Risk
1	Main-Plastic-Population Density High	13%	7.9	0.6	0.7	9.1	23%
2	Main-Plastic-Population Density Low	41%	3.2	0.7	1.9	5.8	14%
3	Main-Steel-Population Density High	11%	10.3	0.8	1.6	12.7	31%
4	Main-Steel-Population Density Low	35%	6.4	1.7	4.6	12.7	31%
5	Total	100%	27.8	3.8	8.6	40.3	100%
6	Service-Steel-Population Density High	12%	8.3	0.1	1.4	9.8	23%
7	Service-Steel-Population Density Low	22%	1.9	0.2	2.2	4.4	10%
8	Service-Plastic-Population Density High	23%	16.8	0.2	2.6	19.6	45%
9	Service-Plastic-Population Density Low	44%	4.6	0.5	4.3	9.3	22%
10	Total	100%	31.6	1.1	10.5	43.1	100%
11	Riser-All-Population Density High	37%	10.9	0.0	1.4	12.4	85%
12	Riser-All-Population Density Low	63%	0.7	0.0	1.5	2.2	15%
13	Total	100%	11.6	0.1	3.0	14.6	100%
14	Cross Bore-San Francisco	4%	0.2	0.0	0.0	0.2	12%
15	Cross Bore-Non-San Francisco	96%	1.2	0.0	0.0	1.2	88%
16	Total	100%	1.4	0.0	0.0	1.4	100%
17	Grand Total	100%	72.4	4.9	22.1	99.4	100%

5. Drivers and Associated Frequency

PG&E identified eight drivers and 30 subs-drivers for the LOC on Gas Distribution Main or Service risk event. The drivers are based on the PHMSA integrity management requirements for gas distribution pipeline systems (DIMP), 49 CFR Part 192, Subpart P. Each driver, its associated 2023 TY baseline frequency, and key sub-drivers are discussed below. A complete list of sub-drivers is provided in supporting workpapers.[10]

10 Source documents will be provided with the workpapers on July 17, 2020.

D1 – Equipment Failure: Issues such as age or obsolescence may lead to equipment failures. Equipment obsolescence is defined as the state where equipment may be difficult to maintain, the vendor no longer supports the product, spare parts are no longer available, or equipment parts become incompatible. Equipment related events accounted for 19,117 (65 percent) of the 29,590 expected annual number of events.

D2 – Corrosion: External and Internal Corrosion are corrosion key sub-drivers affecting metallic assets. Corrosion can, over time, reduce the wall thickness of the pipe resulting in the release of gas. Corrosion events accounted for 2,791 (9 percent) of the 29,590 expected annual number of events.

D3 – Incorrect Operations: Incorrect operations include human error and incorrect procedures. This may lead to safety hazards when procedures are not followed or when improperly trained or untrained personnel perform work on the distribution system (e.g., failure to follow standards and procedures for installing new plastic pipe can result in construction defects). Incorrect operations accounted for 2,977 (10 percent) of the 29,590 expected annual number of events.

D4 – Excavation Damage: Any excavation impact that results in the need to repair or replace an underground facility due to a weakening or the partial or complete destruction of the facility including, but not limited to, the protective coating, lateral support, CP or the housing for the line device or facility (e.g., third-party dig-ins). Excavation damage accounted for 1,694 (6 percent) of the 29,590 expected annual number of events.

D5 – Material, Weld, or Joint Failure: Any material, weld, or joint that does not perform its intended function or design in accordance with PG&E or industry standards. Material failure or pipe weld accounted for 1,332 (5 percent) of the 29,590 expected annual number of events.

D6 – Other: Other concerns that could threaten the integrity of the pipeline (e.g., a gas leak which is repaired by replacing the pipeline or service without exposing the leak source and the cause of the leak was undetermined). Other concerns accounted for 1,098 (4 percent) of the 29,590 expected annual number of events.

D7 – Natural Force Damage: This risk driver may be caused by a wide range of factors including seismic activity, flooding, earth movement, lightning, and root damage. Natural force damage accounted for 264 (1 percent) of the 29,590 expected annual number of events.

D8 – Other Outside Force Damage: Damage to the distribution facilities caused by external forces that act on the pipeline such as a vehicle impact on a riser. Other outside force damage accounted for 187 (0.6 percent) of the 29,590 expected annual number of events.

Cross bores represent a high risk to public and employee safety as they can result in a gas leak into the sewer system if damaged, such as during sewer cleaning operations. Cross bores accounted for 1 of the 29,950 (<1 percent) average annual number of events. Cross bore is both a sub-driver of the incorrect operations driver and a driver of the cross bore tranche. In order to more clearly see the impact cross bores have on the overall LOC on Gas Distribution Main or Service risk event, cross bore is displayed on the bow tie as a driver, even though it is not a primary driver of this risk.

For a LOC on mains, services, and risers, PG&E used 10-year leak data collected from its RiskFinder database to estimate the frequency of all drivers and sub-drivers. PG&E relied on a 10-year data set because the data provided a good representation of PG&E's current gas distribution system and was sufficient for representing leak sub-driver frequencies. With this data, independent frequencies were developed for mains (steel and plastic), services (steel and plastic), and risers (all types).

6. Cross-Cutting Factor

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the LOC on Gas Distribution Main or Service risk event are shown in Table 8-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 8-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	X	
2	Emergency Preparedness and Response		X
3	Physical Attack	X	
4	Records and Information Management	X	X
5	Seismic	X	
6	SQWF	X	

PG&E is continuing to evaluate the impact that Cyber Attack and Information Technology (IT) Asset Failure has on RAMP risks and expects to present Cyber Attack and IT Asset Failures as cross-cutting factors relative to this RAMP risk in the 2023 GRC.

7. Consequences

The risk model measures the risk associated with a LOC on a gas distribution pipeline main, service, riser, or due to a cross bore. A LOC can result in public, employee, and contractor safety events, a reduction in gas reliability, and/or financial losses. Non-LOC consequences associated with the distribution network are not considered within the scope of this model and are included in Safety, Health, Enterprise Corrective Action Program (ECAP), and Department of Transportation (DOT),[11] SHED's Contractor, Employee, or Third-Party Safety Incident Risks. Additionally, the risk associated with customer-connected equipment is considered its own risk[12] and not included within the scope of this model.

PG&E modeled the risk of a LOC on a main, service, riser, and cross bore with independent frequency, outcome, and consequence distributions as described below.

The two outcomes of a gas distribution LOC event are defined in this model as "major" and "minor" where a major event is equivalent to a PHMSA significant incident, and a minor event is equivalent to a non-PHMSA

11 Safety, Health, ECAP, and DOT (collectively, SHED).

12 See Chapter 19, Other Safety Risks.

significant incident. Per PHMSA, significant incidents are those including: (1) fatality or injury requiring in-patient hospitalization; and/or (2) $50,000 or more in total costs. Gas distribution incidents caused by an adjacent fire or explosion that impacts the pipeline system are excluded. The consequences for the distribution mains, services, and risers tranches and the cross bore tranche are distinct and explained below.

Along with tranches, this model also considers the severity of consequences associated with each driver. Drivers were divided into "severity groups" of High, Medium, and Low, depending on the expected injury and fatality rate associated with each driver. Each severity group has a unique set of consequences defined by an Industry derived severity factor.

For distribution mains, riser, and services the probability of a major outcome was derived for mains, services, and risers by dividing the number of PG&E PHMSA significant incidents by the total population of distribution leaks over the same time period.

A major LOC incident on a main, service, or riser can have safety, reliability, and/or financial consequences. A minor LOC can have only reliability and/or financial consequences.

Ultimately, the risk score was calculated using PG&E and industry weighted:

- Safety rates – Considering asset material type;
- Driver cause – Defined as high, medium, and low severity;
- Location of the asset – High and low population density; and,
- Type of event – Classified as either major or minor.

This resulted in a total of 10 tranches with 60 different risk groupings.

The major and minor risk event outcomes and associated consequences are described below.

a. Consequences for Outcome 1 – Major Event

<u>Safety Consequence</u>

The magnitude of the safety consequences associated with a gas distribution LOC is influenced by several factors. This model takes into account asset type, population density, and driver severity.

For asset type, this model considers the consequences associated with a LOC on a main, a service, and a riser independently. Injury and fatality rates per risk event were derived from PHMSA significant incidents. PG&E does not have sufficient PHMSA significant data to model all the tranches and factors. Therefore, PG&E calculated a safety incident rate using only PG&E data and another safety incident rate using only industry data and used both incident rates, weighted by 50 percent, in the model. The combination of weighted PG&E and industry safety incident rates is more representative than using either data set alone.

The risk has been tranched to account for areas of high population (greater than or equal to 9,000 people per square mile) and low population (less than 9,000 people per square mile). PG&E's exposure of mains (metal and plastic), risers (metal and plastic), and services (all) were grouped into these two population density groups using GD-GIS and 2010 census block data. To develop population consequence factors, PG&E used the reported address of each PHMSA incident and 2010 census block data to map each industry incident to a specific population density. Population factors were derived by normalizing the industry injury and fatality incident rates for mains, services, and risers in low and high population density areas to the overall aggregated industry injury and fatality rate. In areas of high population density, the injury and fatality rate was 1.9 times the industry average rate. In areas of low population density, the injury and fatality rate was 0.9 times the industry average rate. These factors were applied at the tranche level to the weighted asset rates discussed above.

PHMSA data was used to derive a driver "severity factor" for each driver. Injury and fatality rates vary depending on the cause or driver of the incident. Grouping drivers with similar injury and fatality rates together and normalizing to the industry mean resulted in three distinct severity factors of low (0.75 times the average), medium (0.98 times the average), and high (1.70 times the average). These factors were applied per driver to the weighted asset rates.

Reliability Consequence

PG&E used historic outage data (2015-2019) to represent the number of customers impacted by a major LOC event. To estimate the number of customers impacted, PG&E included reliability incidents where a PG&E LOC resulted in an injury or fatality or exceeded $50,000 in damages. Reliability consequences were derived for mains, services, and risers. In future iterations of the model, PG&E will consider expanding the dataset to 10 years to align with the leak data timeframe.

Financial Consequence

PG&E used PHMSA industry financial data (2004-2019) to estimate the financial consequences associated a significant LOC on a main, service, and riser for low and high population densities. Due to limited PG&E data, PG&E weighted the significant PG&E PHMSA reported financial data and non-PG&E industry financial data equally. All historical costs were adjusted for inflation and converted to 2019 dollars.

b. Consequences for Outcome 2 – Minor Risk Event

Reliability Consequence

PG&E used historic outage data (2015-2019) to represent the number of customers impacted by a minor LOC event. To estimate the number of customers impacted, PG&E included all incidents except where a PG&E LOC resulted in an injury or fatality or exceeded $50,000 in damages. To estimate the probability of a minor LOC, PG&E divided the number of leaks that caused an outage by the total number of recorded leaks within the same time period.

Financial Consequence

Using 2020 GRC unit costs, PG&E estimated the cost for repairing a leak associated with a minor LOC for mains, services, and risers.

c. Consequences for Cross Bore Tranches

Similar to the main, service and riser tranches, PG&E divided the cross bore risk into two different tranches, based on population density (San Francisco and Non-San Francisco) and into two outcomes (Major and Minor). To date, PG&E has observed 32 LOC events due to cross bores from 1999-2019; however, none of these have been a “major” LOC event. To estimate the probability of a major event, PG&E made the assumption that the next cross bore event will be a “major” LOC;

and therefore, estimated the probability of a major LOC of 1 out of 33 events (approximately 3 percent), and a minor LOC of 32 out of 33 events (97 percent).[13]

d. Consequences for Cross Bore Risk Event

Major Risk Event – Safety Consequence

PG&E has not observed a major LOC due to a cross bore. PHMSA industry data was used to estimate the safety consequences associated with a cross bore. PG&E reviewed the narrative of each PHMSA significant incident and included incident data where either: (1) a cross bore was confirmed to be the cause of the incident; or, (2) the incident was caused by a gas migration through a sewer. A safety rate was derived from this subset of PHMSA data and supplemented with SME input. The population density factor was applied to this safety rate to estimate the incident safety rate in San Francisco (high population density) and Non-San Francisco (low population density).

Major Risk Event – Reliability Consequence

PG&E estimated the reliability consequences of a major cross bore event to be similar in magnitude to a major LOC on a service asset. As such, PG&E aligned the major cross bore reliability consequences to be equal to that of a major LOC on a service.

Major Risk Event – Financial Consequence

Using the subset of PHMSA data described above in "Outcome 1: Major, Consequence – Safety," PG&E used PHMSA industry data to estimate the financial consequences associated a LOC on a main, service, or riser for low and high population densities.

Minor Risk Event – Reliability Consequence

PG&E estimated the reliability consequences of a minor cross bore event to be similar in magnitude to a minor LOC on a service asset. As such, PG&E aligned the minor cross bore reliability consequences to be equal to that of a minor LOC on a service.

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13 The method PG&E uses to estimate the probability of a major event was recommended by the SED in its review of PG&E's 2017 RAMP Report. nI.17-11-003, SED's Risk and Safety Aspects of RAMP Report of PG&E (Mar. 30, 2018), p. 53.

Minor Risk Event – Financial Consequence

PG&E estimated the financial costs associated with a minor LOC by using the estimated PG&E costs associated with a cross bore repair.

Table 8-4 shows the consequences of the risk event. Model attributes are discussed in Chapter 3, "Risk Modeling and Risk Spend Efficiency."

TABLE 8-4
RISK EVENT CONSEQUENCES

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
					Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial
Major - Seismic	44	0.003%	38.3%	0.9	0.7	323	2.0	42.4	0.6	1.3	0.572	278	1.7	36.4	0.5	1.2
Major - Severity Low	13	0.004%	16.2%	1.2	0.2	602	0.8	11.4	1.2	0.5	0.236	739	1.0	14.0	1.5	0.6
Major - Severity High	30	0.002%	15.9%	0.5	0.5	662	0.8	28.3	1.2	0.5	0.249	350	0.4	14.9	0.6	0.3
Minor - Severity Low	0	80%	12.4%	23,636	-	0	0.0	-	0.0	0.0	-	1,399	22.8	-	0.9	11.4
Major - Severity Medium	21	0.001%	6.2%	0.3	0.3	514	1.1	18.9	1.1	0.7	0.094	153	0.3	5.6	0.3	0.2
Minor - Severity High	0	11%	5.5%	3,242	-	0	0.0	-	0.0	0.0	-	746	9.9	-	0.5	5.0
Minor - Severity Medium	0	9%	3.8%	2,623	-	0	0.0	-	0.0	0.0	-	538	6.9	-	0.4	3.4
Major - Crossbore	51	0.0001%	1.4%	0.03	0.9	5	1.5	49.7	0.0	0.8	0.024	0	0.0	1.4	0.0	0.0
Minor - Seismic	0	0.3%	0.3%	85	-	4	0.0	-	0.0	0.0	-	325	0.2	-	0.2	0.1
Minor - Crossbore	0	0.003%	0.0%	1	-	1	0.0	-	0.0	0.0	-	1	0.0	-	0.0	0.0
Aggregated	**0**	100%	100%	29,590	0.0	0	0.0	0	0	0	1.176	4,529	43.3	72	5	22

C. Controls and Mitigations

Tables 8-5 and 8-6 list all the controls and mitigations PG&E included in its 2017 RAMP, 2020 GRC and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods. A description of the cross-cutting risks and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in described in Chapter 20.

TABLE 8-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP	2020 GRC 2020-2022 Controls[a]	2020 RAMP 2020-2022 RAMP	2020 RAMP 2023-2026 RAMP
1	C1 – Corrective Maintenance	X	X	X	X
2	C2 – Corrosion Control	X	X	X	X
3	C3 – DIMP Leak Survey	X	X	X	X
4	C4 – Leak Management Pilot Control – See Section D.2	X	X	X	X
5	C5 – Locate and Mark	X	X	X	X
6	C6 – Pipeline Replacement Program[b]	X	X	X	X
7	C7 – Preventative Maintenance	X	X	X	X
8	C8 – Public Awareness Program	X	X	X	X
9	C9 - Quality Assurance/Quality Management	X	X	X	X
10	C10 – Training	X	X	X	X
11	C11 – Cross Bore Prevention Program[c]	X	X	X	X
12	C12 (M1) – DIMP Program[d]			X	X

(a) Includes controls associated with: Asset Family – Distribution Mains and Services (Exhibit (PG&E-3), Chapter 4); Gas Distribution Operations and Maintenance (Exhibit (PG&E-3), Chapter 6); Corrosion Control (Exhibit (PG&E-3), Chapter 7); Leak Management (Exhibit (PG&E-3), Chapter 8); and, Gas Operations Technology and Other Distribution Support (Exhibit (PG&E-3), Chapter 11.

(b) Formerly classified as single control C6 in the 2017 RAMP. Two of the three components of this program (Gas Pipeline Replacement Program (GPRP) – Maintenance Activity Type (MAT) 14A and Plastic Pipe Replacement Program – 14D) have been reclassified and split into two separate mitigation programs. The Reliability Pipe Replacement Program (MAT 50A) will remain as a control.

(c) Formerly Control C1 for the Release of Gas with Ignition on Distribution Facilities – Cross Bore risk event in the 2017 RAMP.

(d) Formerly classified as mitigation M1 (DIMP Emergent Work) in the 2017 RAMP.

TABLE 8-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations[a]	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1 – DIMP Emergent Work	X	X	Becomes Control in 2020	
2	M2 – New Valve Installations[b]	X	X	X	X
3	M3 – Enhanced CP Survey and Unprotected Main Evaluation	X	X	X	
4	M4 – Electrically-Connected Isolated Steel Service (ECISS) Program	X	X	X	X
5	M5 (Formerly C12) – Pipeline Replacement Program (Steel)			X	X
6	M6 (Formerly C12) – Pipeline Replacement Program (Plastic)			X	X
7	M7– Cross Bore Legacy Inspection Program[c]	X	X	X	X
8	M8 – Fitting Mitigation Program				X
9	M9 – Mechanical Fitting Replacement Program		X	X	

(a) Includes controls associated with: Asset Family – Distribution Mains and Services (Exhibit (PG&E-3), Chapter 4); Gas Distribution Operations and Maintenance (Exhibit (PG&E-3), Chapter 6); Corrosion Control (Exhibit (PG&E-3), Chapter 7); Leak Management (Exhibit (PG&E-3), Chapter 8); and, Gas Operations Technology and Other Distribution Support (Exhibit (PG&E-3), Chapter 11.

(b) Includes only the new emergency shutdown zone valve component of the Valve Program (MAT 50E). Non-operational and leaking valves are considered corrective maintenance and mapped to C1 – Corrective Maintenance.

(c) Formerly mitigation M1 for the Release of Gas with Ignition on Distribution Facilities – Cross Bore risk event in the 2017 RAMP.

Note: In the 2017 RAMP, the mitigations were numbered sequentially (M1, M2, M3, etc.) and then a letter was appended to the mitigation number to indicate the period during which certain work associated with that mitigation would occur. For example, M1A described the 2016 work, M1B described the 2017-2019 work, and M1C described the 2020-2022 work. In this table and the following sections PG&E refers to the mitigation number without the letter (year) designation as the description of the work did not change, only the volume of work.

1. 2019 Controls and Mitigations

a. Controls

C1 – Corrective Maintenance: Corrective Maintenance includes work required to repair or replace damaged or failed gas facilities. In many cases, the need for such restoration is identified during preventative maintenance activities. Corrective maintenance for distribution mains and services is broken down into the following areas: leak repair, dig-in repair, and CP restoration. This control addresses all drivers for this risk.

C2 – Corrosion Control: In this chapter the Corrosion Control Program specifically addresses natural gas distribution assets that may be at risk for corrosion threats. For the purposes of this chapter, this control is focused on the CP Program, which is a method of protecting against external corrosion. This control addresses the corrosion driver. More specifically it focuses on external corrosion.

C3 – DIMP Leak Surveys: The DIMP Leak Survey Program is a targeted risk mitigation program that goes beyond the regulatory-required leak survey.[14] Survey areas are identified through the annual DIMP risk assessment cycle. Some gas pipelines are identified for monitoring to determine if additional mitigation such as repair or replacement are needed. This control addresses the following drivers: corrosion and material or weld.

C4 – Leak Management: Pipeline safety regulations require PG&E to conduct periodic leak surveys on its distribution system for the presence of gas leaks. The frequency is determined by code. Identified leaks are graded as: Grade 1 (immediate repair required); Grade 2 (repair to be completed within 15 months); and, Grade 3 (monitor and resurvey annually or no later than 15 months per PG&E standard). This control addresses the corrosion and material or weld drivers.

C5 – Locate and Mark: Locate and mark activities provide the physical location for PG&E's underground gas and electric distribution assets for PG&E crews and contractors and third parties who plan to dig near

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[14] See, 49 CFR § 192.1007(d).

those assets, with the majority of the ticket and locate activities required for gas distribution assets. The driver addressed by this control is excavation damage.

C6 – Pipeline Replacement Program: There are three programs within the overall Pipeline Replacement Program:

- The GPRP focuses on pre-1941 steel pipeline. The objective of this program is to reduce the risk to public safety associated with the highest risk steel pipe.
- The Plastic Replacement Program focuses on plastic materials of pre-1985 vintage that have a susceptibility to slow crack growth when exposed to stress risers such as tree roots, differential settlement or rock impingement.
- The Reliability Main Replacement Program focuses on the replacement of gas facilities to improve safety, reliability and maintain compliance with pipeline regulations. This program covers pipe that does not qualify for replacement under the GPRP or Plastic Pipe Replacement Program.

The pipeline replacement programs address the following drivers: corrosion, material or weld, equipment related and other outside force.

C7 – Preventative Maintenance: Preventative Maintenance includes work required to comply with pipeline safety regulations that require PG&E to conduct periodic or routine maintenance on its gas distribution system.[15] This work includes any non-leak related maintenance on mains and services such as repairing pipe supports for above ground main, lowering shallow mains and services and restoring the cover over them. Miscellaneous maintenance also includes distribution pipeline patrolling.[16] The equipment related driver is addressed by this control.

C8 – Public Awareness Program: As required by 49 CFR § 192.616, each pipeline operator must develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API) Recommended Practice

[15] See, 49 CFR § 192.613.

[16] See, 49 CFR § 192.721.

(RP) 1162. API RP 1162 defines requirements for public awareness programs including: the message delivered to each audience, the frequency of message, and the methods for delivering the message and requirements for analyzing and gauging the effectiveness of their public education efforts. The Public Awareness team reviews the program annually to determine the effectiveness of the program. As part of the review, continuous improvement activities are developed for implementation. This control addresses the excavation damage driver.

C9 – Quality Assurance/Quality Management: The purpose of the Quality Management Program is to develop and execute programs that assist with the quality of Gas Operations key risk mitigating and/or compliance processes for the safety and reliability of the gas distribution system. This includes periodically reviewing the work performed by field personnel to determine process adherence as well as the effectiveness and adequacy of the procedures used and training provided. The equipment related and incorrect operations drivers are addressed with this control.

C10 – Training: The Gas Training Curriculum Development Program creates new, and enables significant revisions to, existing training materials ensuring that the Gas Operations workforce is, and remains, competent, safe, and qualified. The development of training curriculum materials helps mitigate operational risks, not only through engineering controls, but also through optimal human performance. This control addresses equipment related and incorrect operations drivers.

C11 (Formerly C1, Release of Gas with Ignition on Distribution Facilities – Cross Bore risk) – Cross Bore Prevention Program: PG&E developed a Cross Bore Prevention Program as a control to eliminate the creation of new cross bores within the system and to address the incorrect operations driver. Utility Procedure TD-4632P-01 Cross Bore Prevention and Mitigation is in place to provide the steps (i.e., inspect, identify, report and address) required for all gas construction work for PG&E, in an effort to prevent any new cross bores.

b. Mitigations

M1 – DIMP Emergent:[17] For 2017-2019, the proposed mitigation was the Curb Valve Replacement Program, a proactive replacement program targeting curb valves with a history of repeated leaks in San Francisco. PG&E expected to replace valves associated with approximately seven miles of pipeline per year. While there was a focus on curb valve replacements, DIMP continued to investigate other issues as part of the overall DIMP Emergent Work Program[18] to determine the risk to the distribution system and to the public.

For 2017-2019, PG&E expected to replace valves associated with approximately seven miles of pipeline per year or 21 total miles. PG&E replaced 735, 841, and 168 valves respectively which translate to 7.4, 8.4, and 1.7 miles of pipe (based on a 100 curb valves/mile of main conversion factor used initially for this mitigation) for a total of 17.4 miles. Curb valve replacements are demand-driven work. Between 2017 and 2019, PG&E found fewer curb valves that needed to be replaced than it forecast.

M2 – New Valve Installations: Through the Valve Program, valves are replaced when leaking or when they can no longer be operated. New valves are primarily installed to improve PG&E's ability to isolate the gas system through Emergency Shutdown Zones. In the 2017 RAMP, PG&E indicated that it expected to install 275 new valves per year for a total of 825 new emergency shutdown zone valves to reduce the size of its zones. The model exposure input in equivalent miles was approximated at 4,308 miles. PG&E installed 722 new emergency shutdown zone valves between 2017 and 2019.The reason for lower than expected installed units is because where possible, PG&E

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17 The 2017 RAMP Mitigation M1B will become Control C12 in 2021 and the control will be re-named "DIMP Program" to more accurately describe the work conducted in this control.

18 This program consists of unanticipated work resulting from investigation into risk drivers and operational events. The Curb Valve Replacement also covered in this program, is the only component which was identified as a mitigation activity in 2017 RAMP. With this program nearing completion, the DIMP Emergent Work is converted to a control activity.

recommissioned existing main valves in re-designing emergency shutdown zones.[19]

M3 – Enhanced CP Survey: This program minimizes the risk of corrosion by ensuring that the location of all steel pipe has been identified, cathodically-protected, and is being monitored appropriately. This program involves performing a field survey of steel pipe and casings and identifying remediation work.[20] In 2017 RAMP, PG&E expected to complete the original scope of approximately 20,000 miles of steel main within five years. This is a one-time project that is expected to be completed in 2021, as planned.

M4 – Electrically-Connected Isolated Steel Service Program: This program was created to identify isolated steel service risers which are electrically-connected by locating wire requiring annual monitoring. Through the ECISS Program, isolated steel service risers are identified and added to CP areas to be monitored annually. The program scope included approximately 350,000 risers identified for field inspections. TPG&E is expected to complete that scope by the end of 2023.

M7 (Formerly M1, Release of Gas with Ignition on Distribution Facilities – Cross Bore risk) – Cross Bore Program: PG&E developed the Cross Bore Program to inspect, identify, and remediate cross bores on the gas distribution system that were installed using trenchless technology. This program uses video equipment to inspect sewer mains and laterals for potential cross bore situations and then repairs any identified cross bores that result from the inspections. The population of cross bores is expected to decrease as more inspections are completed. Any cross bores found are repaired, thereby reducing the risk of LOC and gas migration into a structure and ignition.

In 2017 RAMP, PG&E indicated that it expected to perform 135,000 cross-bore inspections. PG&E's imputed units of work based

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[19] PG&E installed 969 valves of the 952 funded units. The shortfall in installation of new emergency shutdown zone valves in the Valve Program was made up by an increase in count of valves requiring replacement due to leaks or operational issues.

[20] The Enhanced CP Survey is limited to the survey and field investigations (MAT DGD). The identified corrective work can occur through various MATs.

on the 2017 GRC Decision were 123,307[21] inspections. PG&E completed 124,628 inspections, exceeding the imputed amount.

D. 2020-2022 Controls and Mitigation Plan

1. Changes to Controls

Listed below are new RAMP controls and existing controls that will change between 2020 and 2022 from the 2019 controls described above.

PG&E identified 11 controls in the 2017 RAMP. In the 2020 RAMP, PG&E will continue to implement 10 of the 11 controls (C1, C2, C3, C4, C5, C7, C8, C9, C10 and C11). The scope of work for these 10 controls is as described in the 2017 RAMP and in Section C.1.a, above.

One control, C6 – Pipeline Replacement Program, becomes an new mitigation in 2020 (M5 – Pipeline Replacement, Steel, and M6 – Pipeline Replacement, Plastic).

PG&E is also adding one new control, C12 – DIMP Program. This program became a control in 2020. It was mitigation M1 in the 2017 RAMP. The scope of work for this control is as described in the 2017 RAMP and in Section C.1.b, above.

2. Pilot Control

Starting in 2020, PG&E identified one Gas Operations control for which it is calculating an RSE score—the pilot control. Gas Operations selected Leak Management as the pilot control.

PG&E conducts leak surveys of its gas distribution system on a 3-year cycle (the entire system is surveyed every three years). Once a leak is verified and graded, PG&E schedules repair or replacement activities to remediate the leak. The leak survey is conducted using both the traditional survey performed by operator-qualified leak surveyor technicians and the mobile survey using the Picarro Leak survey technology. These surveys cover gas distribution pipeline systems, including services, mains and other gas assets. The RSE for Leak Management is 0.72, which has the highest RSE for the distribution programs.

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21 A.18-12-009, Hearing Exhibit (HE-) 12: Exhibit (PG&E-3), WP 4-134, line 9.

PG&E reviewed the historical leak find rates attributable to Leak Survey to estimate the effectiveness of the Leak Management Programs at reducing system risk. PG&E assumed that without a Leak Management Program, a subset of leaks would remain unknown to PG&E and have a higher probability of interacting with an employee, contractor, or third party. In the absence of the Leak Management Program, the overall risk score increases from its current baseline score.

The forecast costs, RSE and risk reduction scores for the pilot control are shown in the tables below.

TABLE 8-7
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Ctrl. No.	Control Name	MAT	2020	2021	2022	Total
1	C4	Leak Management	DEA	$15,812	$16,132	$16,355	$48,299
2	C4	Leak Management	DEF	15,207	10,722	10,563	36,493
3	C4	Leak Management	FIG	19,776	20,270	20,777	60,822
4	C4	Leak Management	FIH	5,719	5,862	6,008	17,589
5	C4	Leak Management	FIP	13,951	14,300	14,657	42,908
6		Total		$70,465	$67,285	$68,360	$206,111

Note: See WP 8-1

TABLE 8-8
FORECAST COSTS, RSE AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Ctrl. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	C4	Leak Management	DEA	$16,895	$17,372	$17,612	$18,283	$70,162		
2	C4	Leak Management	DEF	10,690	11,547	11,375	11,568	45,180		
3	C4	Leak Management	FIG	21,296	21,829	22,374	23,045	88,544		
4	C4	Leak Management	FIH	6,158	6,312	6,470	6,664	25,605		
5	C4	Leak Management	FIP	15,024	15,399	15,784	16,258	62,465		
6		Total		$70,063	$72,459	$73,617	$75,818	$291,957	0.72	153.6

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

Note: See WP 8-1.

3. Changes to Mitigations

PG&E identified five mitigations in its 2017 RAMP. PG&E will continue to implement mitigations M2, M3, M4 and M7 and the planned units of work are listed in Table 8-9 below.

One mitigation, M1 (DIMP Emergent Work (Curb Valve Replacements) becomes a control in 2020.

Two of the three components of 2017 control (C6) in the 2017 RAMP (GPRP – MAT 14A, and Plastic Pipe Replacement Program – MAT 14D) have been reclassified and split into two separate mitigation programs: (1) M5, Pipeline Replacement (Steel); and, (2) M6, Pipeline Replacement (Plastic). The reason for reclassification is because the two risk driven and targeted vintage pipeline replacement programs have a finite scope which reduce the probability of pipeline failure from PG&E's vintage pipe. PG&E's GPRP focuses on high risk, pre-1941 steel pipe and the Plastic Pipe Replacement Program focuses on pre-1985 Aldyl-A and similar plastic pipe. The Reliability Pipe Replacement Program (MAT 50A) will remain as a control. The planned volume of work is listed in Table 8-9 below.

PG&E is proposing one new mitigation starting in 2020:

M9 – Mechanical Fitting Replacement Program: This is a new program which targets removal of mechanical fittings with known failures. The focus is removal of compression style mechanical fittings with risk of corrosion and leak.

TABLE 8-9
PLANNED MITIGATIONS 2020-2022

Line No.	Mitigation Name and Number	Rate Case Units[(a)]	2020 RAMP Planned Units of Work 2020	2021	2022	Total
1	M2 – New Valve Installations	Valves	100	100	100	300
2	M3 – Enhanced CP Survey and Unprotected Main Evaluation	Non-Unitized	NA	NA	–	NA
3	M4 – ECISS Program	Non-Unitized	–	N/A	N/A	N/A
4	M5 – Pipeline Replacement (Steel)	Miles	40	38	38	115
5	M6 – Pipeline Replacement (Plastic)	Miles	111	141	165	417
6	M7 – Cross Bore Program[(b)]	Inspections	15,000	45,000	50,200	110,200
7	M8 – Fitting Mitigation Program	Fitting	–	–	–	–
8	M9 – Mechanical Fitting Replacement Program	Non-Unitized	N/A	N/A	N/A	N/A

(a) The units of work are presented in "rate case" units – the units referred to in PG&E's gas distribution and/or transmission rate cases. In certain cases, the units of work are represented differently in the RAMP model because the model requires that units of work are standardized. For example, in the GRC PG&E reports feet of distribution main pipeline replaced; whereas, in the RAMP model, PG&E inputs miles of distribution main replaced.

(b) PG&E expects to perform a combination of unable-to-access (UTA) and non-UTA inspections. The number of inspections will be determined based on availability of and access to inspection sites.

The forecast costs for the mitigation work planned for the 2020-2022 period are shown in Tables 8-10 and 8-11 below.

TABLE 8-10
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M3	Enhanced CP Survey and Unprotected Main Evaluation	DGD	$5,468	$6,431	–	$11,899
2	M4	ECISS Program	DGE	3,582	3,961	4,060	11,602
3	M7	Cross Bore Legacy Inspection Program	JQK	31,187	29,535	30,831	91,553
4	M8	Fitting Mitigation Program	JQD	–	–	–	–
5	M9	Mechanical Fitting Replacement Program	JQG	1,000	996	1,021	3,016
6		Total		$41,237	$40,923	$35,911	$118,071

Note: See WP 8-1.

TABLE 8-11
FORECAST COSTS
2020-2022 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M2	New Valve Installations	50E	$6,743	$6,940	$7,113	$20,795
2	M5	Pipeline Replacement Program (Steel)	14A	114,830	138,424	140,968	394,222
3	M6	Pipeline Replacement Program (Plastic)	14D	304,721	404,132	484,361	1,193,213
4		Total		$426,293	$549,495	$632,442	$1,608,230

Note: See WP 8-1

E. 2023-2026 Proposed Mitigation Plan

PG&E will continue mitigations M2, and M4 through M7 in the 2023-2026 period. The proposed volume of work for each mitigation is shown in Table 8-12 below. Mitigations M3, Enhanced CP Survey and Unprotected Main Evaluation, and Mitigation M9, Mechanical Fitting Program, will be completed in 2021 and 2022, respectively.

PG&E is proposing one new mitigation starting in 2023:

M8 – Fitting Mitigation Program: This program targets mitigating plastic fittings with a high failure rate due to manufacturing defects. PG&E plans to mitigate approximately 2,200 units per year starting in 2023 through a 10-year program.

TABLE 8-12
PLANNED MITIGATIONS 2023-2026

		2020 RAMP Planned Units of Work					
Line No.	Mitigation Name and Number	Rate Case Units	2023	2024	2025	2026	Total
1	M2 – New Valve Installations	Valves	100	100	100	100	400
2	M4 –ECISS Program	Non-Unitized	N/A	N/A	N/A	N/A	–
3	M5 – Pipeline Replacement (Steel)	Miles	47	49	47	50	193
4	M6 – Pipeline Replacement (Plastic)	Miles	172	180	188	196	736
5	M7 – Cross Bore Program	Inspections	45,000	45,000	45,000	45,000	180,000
6	M8 –Fitting Mitigation Program	Fitting	2,183	2,183	2,183	2,183	8,732

The forecast costs, RSE, and risk reduction scores for the mitigation work planned for the 2023-2026 period are shown in Tables 8-13 and 8-14 below.

TABLE 8-13
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[(a),(b)]	Risk Reduction
1	M3	Enhanced CP Survey and Unprotected Main Evaluation	DGD	–	–	–	–	–	–	–
2	M4	ECISS Program	DGE	$4,161	–	–	–	$4,161	<0.001	<0.001
3	M7	Cross Bore Legacy Inspection Program	JQK	31,050	31,815	32,580	33,435	128,880	0.04	3.7
4	M8	Fitting Mitigation Program[(a)]	JQD	14,402	14,762	15,131	15,585	59,881	0.05	2.3
5	M9	Mechanical Fitting Replacement Program	JQG	–	–	–	–	–	–	–
6		Total		$49,613	$46,577	$47,711	$49,020	$192,922	–	–

(a) Costs and RSE are applicable only in M8 – Fitting Mitigation Program, and not the entire MAT JQD forecast. In the 2023 GRC, this cost will be represented in a different MAT.

(b) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 8-1

TABLE 8-14
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M2	New Valve Installations	50E	$7,291	$7,473	$7,660	$7,890	$30,314	0.095	2.1
2	M5	Pipeline Replacement Program (Steel)	14A	181,245	192,043	190,413	208,006	771,707	0.018	10.1
3	M6	Pipeline Replacement Program (Plastic)	14D	517,776	555,372	595,226	639,921	2,308,295	0.021	35.8
4		Total		$706,312	$754,888	$793,298	$855,817	$3,110,315		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 8-1

The results of the risk model are shown in Tables 8-13 and 8-14 above. The Plastic Replacement Program has the highest total Risk Reduction. PG&E is proposing significant spending on its Plastic Pipeline Replacement Program between 2023 and 2026. In the 2020 GRC, PG&E, the Office of the Safety Advocate (OSA) and the Coalition of California Utility Employees (CUE) all filed testimony supporting PG&E's plastic pipeline replacement at a greater rate than PG&E proposed in its 2020 GRC opening testimony.[22] This spending plan continues the annual spending levels agreed to in the proposed 2020 GRC settlement for this work.[23]

Similarly, PG&E is also proposing significant spending on its Steel Pipeline Replacement program between 2023-2026 which has the second highest risk reduction. This proposal also aligns with PG&E's goal to limit asset age to around 100 years. While these two programs have lower RSE scores than other programs, PG&E believes it is important to continue replacing high-risk vintage assets. In evaluating its risk model results, PG&E recognized the opportunity to introduce additional tranching to differentiate between new and vintage assets, and to align with the program replacement criteria. PG&E is currently reviewing this change and may incorporate it into the 2023 GRC.

The risk model results show that New Valve Installations has the highest RSE value. The purpose of this program is to reduce the size of emergency shutdown zones and improve PG&E's ability to isolate the gas system. The risk model results show the ECISS Program has the lowest RSE of all mitigation programs. Despite its low RSE score, PG&E believes that it is important to complete this program. The ECISS Program was created to identify isolated steel service risers which are electrically-connected by locating wire. These locations are required to be monitored annually rather than as a separately protected isolated steel, which are monitored on a 10-year cycle. This project is scheduled to be completed by the end of 2023.

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22 A.18-12-009, HE-61: Exhibit (CUE-01), p. 11, lines 7-8; and, HE-275: Exhibit (OSA-01), p. 4-9, lines 4-7.

23 Joint Motion for Approval of the Settlement Agreement, A.18-12-009, (Dec. 20, 2019), p. 17, including fn. 71.

PG&E considers managing cross bores to be among the highest priority safety, integrity and reliability work in the gas distribution system,[24] and as such, is planning to continue mitigating this risk through its Cross Bore Sewer Inspection Program. While the bow tie analysis (Section B.2. above) shows that cross bore is not a significant driver of the LOC on Gas Distribution Main or Service risk event, the program is a unique mitigation activity that eliminates risk with every cross bore inspection performed. Additionally, PG&E's Cross Bore Prevention Program also help eliminate the creation of new cross bores within the system. PG&E is proposing to spend approximately 4 percent of its total 2023-2026 mitigation spending on addressing this important safety risk.

Table 8-2 above shows that the highest risk by asset type is steel pipeline, plastic services, risers in low density locations and non-San Francisco cross bores.

Steel Pipeline: PG&E is addressing steel pipeline replacement in the M5-Pipeline Replacement (Steel) program. PG&E has been replacing steel pipe through its GPRP (M5-Pipeline Replacement (Steel)) since 1985. Currently, the goal of the replacement program is to achieve an asset age limited to less than 100 years. Pipe replacement priority are based on age, leak history, seismic impact, CP, proximity to the public and operational factors so that the highest priority pipe will be replaced first.

Plastic Services: PG&E replaces plastic services through its vintage pipe replacement and reliability programs.

Risers in Low Population Density Locations: PG&E replaces risers through its vintage pipe replacement and reliability programs. PG&E also initiated the ECISS Program (M4) in 2016 to identify and monitor isolated steel service risers in compliance with 49 CFR 192, Subpart I. PG&E anticipates that it will have identified all isolated steel service risers and complete the program in 2023.

Non-SF Cross Bores: PG&E is planning to perform approximately 180,000 cross-bore inspections (M7 Cross Bore Program) between 2023 and 2026, all of which will be outside of San Francisco.

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[24] A.18-12-009, HE-10: Exhibit (PG&E-3), p. 2-39, lines 4-5.

PG&E will revisit the RAMP model results for this risk and its proposed work plan before it files its 2023 GRC. PG&E will look for opportunities to improve its risk model, revise the tranches, and potentially modify the mix of work for reducing risk, addressing regulatory requirements and maintaining the long-term health of the gas distribution system.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: Use of Fire Retardants to Prevent Ignition and Fire Spread around Plastic Spans

PG&E evaluated the use of commercially-available fire retardants around cased plastic spans to prevent ignition and fire spread. This proposal is derived from an Electric Operations pilot program for using pre-emptive fire retardant to better protect above ground assets in the vicinity or path of a wildfire.

The exposure of the gas system to wildfire is limited to above ground assets because in past wildfire events, below ground gas assets have suffered limited damage. The scope of this pre-emptive application includes approximately 3.9 miles of above-ground cased distribution plastic spans in in High Fire Threat Districts. The scope of work includes ground clearing and application of fire retardant to around the distribution plastic spans. The analysis assumes that the benefit of this mitigation is one year, and that PG&E would apply the fire retardant annually before start of the fire season.

PG&E is not pursuing this alternative mitigation at this time given the low RSE and calculated risk reduction. Gas Operations will evaluate the results of the Electric Operations pilot program to help determine if implementing this mitigation for Gas Operations is reasonable.

TABLE 8-15
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Use of Fire Retardants to Prevent Ignition and Fire Spread around Plastic Spans	$63	$65	$66	$68	$262	<0.001	<0.001
2		Total	$63	$65	$66	$68	$262		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 8-1.

2. Alternative Plan 2: Electrification

To support PG&E's and California's decarbonization objectives and air quality standards, PG&E has considered electrification as an alternative to its vintage main pipeline replacement programs. The program would include qualified pipes in the GPRP (MAT 14A) and Plastic Pipe Replacement Programs (MAT 14D). In this alternative, gas mains and services planned for replacement in these two programs would be decommissioned and services converted to all-electric service.

PG&E developed a cost estimate for deactivating pipelines and retrofitting homes based on readily available cost data. For this analysis, PG&E assumed that pipeline deactivation does not impact gas system hydraulics and there is no additional asset investment to continue serving existing gas customers. The cost forecast also did not account for any electric infrastructure upgrades and/or reinforcements, which may be needed for the additional loads. PG&E also assumed that the electrification alternative is 100 percent effective at reducing all gas distribution mains and services risk drivers. Due to model limitations, the potential risk to the electric system was not considered in the risk model.

Implementing this alternative involves higher costs compared to just pipe replacements. Additionally, it requires laws that would mandate all customers to agree to the conversion. PG&E is not pursuing this alternative to its full extent due to customer affordability impacts and sentiments around mandating fuel source options, as well as regulatory and feasibility limitations. While PG&E is choosing not to implement this program at this time, PG&E will continue to evaluate the feasibility of converting individual projects to electric service on an individual project basis.

TABLE 8-16
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A2	Electrification Steel	$223,291	$253,693	$240,931	$290,425	$1,008,341	0.02	11.4
2		Total	$223,291	$253,693	$240,931	$290,425	$1,008,341		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
Note: See WP 8-1.

TABLE 8-17
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A3[b]	Electrification Plastic	$834,960	$876,287	$913,116	$930,114	$3,554,476	0.02	39.4
2		Total	$834,960	$876,287	$913,116	$930,114	$3,554,476		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
(b) For modeling purposes, the Electrification Plastic is numbered A3. Alternative 2 includes both Electrification Steel and Electrification Plastic.
Note: See WP 8-1.

Table 8-18 compares the proposed and alternative mitigation plans.

TABLE 8-18
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)[(b)]	RSE
1	Proposed	M2, M4, M5, M6, M7, M8	$192,922	$3,110,315	54	$2,420,883	0.022
2	Alternative 1	Proposed + A1	$193,184	$3,110,315	54	$2,421,075	0.022
3	Alternative 2	M2, M4, M7, M8 + A2/A3	$192,922	$4,593,131	59	$3,512,415	0.017
4	Inherent	Control 4	$291,957		154	$214,586	0.716

(a) Plan Components refers to the Mitigations presented in Tables 8-5 and 8-6.

(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

Note: See WP 8-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

RISK ASSESSMENT AND MITIGATION PHASE RISK MITIGATION PLAN:

LARGE OVERPRESSURE EVENT DOWNSTREAM OF GAS MEASUREMENT AND CONTROL FACILITY

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A. Executive Summary

Large Overpressure (OP) Event Downstream of Gas Measurement and Control (M&C) Facility refers to the failure of a gas M&C facility to perform its pressure control function resulting in a large overpressure event downstream that can lead to a significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the ability to deliver natural gas to customers. The drivers for this risk event are: Equipment Related and Incorrect Operations. The cross-cutting factors Skilled and Qualified Workforce, Records and Information Management, Emergency Preparedness and Response, Information Technology Asset Failure and Cyber Attack also apply to this risk event.

PG&E's exposure to this risk consists of more than 4,600 transmission and distribution regulating stations in its gas service area. The risk model indicates that this risk event can be expected to occur approximately 5.6 times each year.[1] The Equipment Related driver accounts for 66 percent of the risk events and the Incorrect Operations driver accounts for 34 percent. Cross-cutting factors are considered a sub-driver to Incorrect Operations and account for 4 percent of the overall risk events. Although 94 percent of the risk event outcomes are "benign" (in that they do not lead to any loss of containment), the remaining 6 percent of events that do involve loss of containment account for 99 percent of the risk consequences. The mitigations PG&E will implement from 2020 to 2026 are intended to address all risk drivers.

PG&E has identified 6 tranches of facilities for this risk. Each tranche represents a group of M&C stations that have a relatively homogenous risk

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1 5.6 is the expected number of risk events per year for 2023-2026 in the absence of 2023-2026 proposed mitigations.

profile in terms of likelihood and consequence of the risk event. The top two tranches that account for almost 60 percent of the overall 2023 Test Year (TY) baseline risk score include Transmission Simple Stations and Transmission Complex Stations.

Large OP Event Downstream of Gas M&C Facility has the lowest 2023 TY baseline safety score (5) and the second lowest 2023 TY baseline total risk score (13) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 16, improves by almost 30 percent when the planned and proposed mitigations are applied: the 2023 TY baseline risk score is 13 and the 2026 post-mitigation risk score is 11.

PG&E is proposing a series of controls and mitigations to address the Large OP Event Downstream of Gas M&C Facility risk. The Gas Distribution Station Overpressure Protection (OPP) Enhancements Program and the Gas Transmission (GT) Station OPP Enhancements Program are the two programs with the highest risk spend efficiency (RSE) scores.[2]

TABLE 9-1
RISK OVERVIEW

Risk name	Large OP Event Downstream of Gas M&C Facility
In scope	Large OP Events[(a)]
Out of scope	Small OP Events[(b)]
Data quantification sources[(c)]	PG&E OP Event Data 2012-2019 Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data 2010-2019.

(a) An OP event occurs when gas pressure exceeds the MAOP of the pipeline as determined by California Public Utilities Commission/Department of Transportation requirements. PG&E uses the below criteria to classify OP events as large OP events:

Transmission: Pressure > 110% MAOP (or MAOP + 25 pounds per square inch gauge (psig) for pipelines operating over 250 psig);

- High Pressure Distribution (12 psig ≤ MAOP < 60 psig): Pressure > MAOP + 6 psig;
- High Pressure Distribution (1 psig ≤ MAOP < 12 psig): Pressure > 150% MAOP;
- Low Pressure Distribution: Pressure > 16 inches water-column.

(b) OP events that exceed MAOP but do not exceed the thresholds described in footnote (a).

(c) Source documents will be provided with the workpapers on July 17, 2020.

2 The information herein is subject to those limitations described in Chapter 2, Section D.

1. Risk Overview

PG&E recently changed the name of this risk. At the February 4, 2020 RAMP Workshop (Workshop #3) this risk was called Large Gas Overpressurization Downstream. This risk is now called Large Overpressure Event Downstream of Gas Measurement and Control Facility.

PG&E's natural gas system consists of approximately 6,680 miles of transmission pipeline and 43,200 miles of distribution pipeline. Together, the transmission and distribution systems provide natural gas to more than 4.3 million residential, commercial, and industrial customers.

PG&E relies upon over 4,600 M&C facilities to monitor, measure and control gas pressure and flow within its transmission and distribution systems. These regulating stations protect downstream assets from system pressure excursions.

An OP event occurs when the gas pressure in a pipeline exceeds the pipeline's maximum allowable operating pressure (MAOP). Current designs of gas transmission and distribution regulating stations include a regulating device to control gas pressure and one (primary) OPP device that is intended to operate should the regulating device fail. OP events can occur when both the regulating device and the primary OPP device fail to perform their pressure control function such that the pressure downstream of the facility rises above the MAOP.

The degree to which the MAOP is exceeded determines whether an OP event should be classified as a "large" OP event.

2. Risk Definition

This risk is defined as the failure of a gas M&C facility to perform its pressure control function resulting in a large OP event downstream 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.

B. Risk Assessment

1. Background and Evolution

In the 2017 RAMP, PG&E presented two risks related to the gas M&C facilities.

- M&C Failure – Release of Gas with Ignition Downstream (Chapter 3); and
- M&C Failure – Release of Gas with Ignition at M&C Facility (Chapter 4).

In the 2020 RAMP, the Large OP Event Downstream of Gas M&C Facility presented in this chapter (Chapter 9) covers the same risk that was addressed in Chapter 3 in the 2017 RAMP.

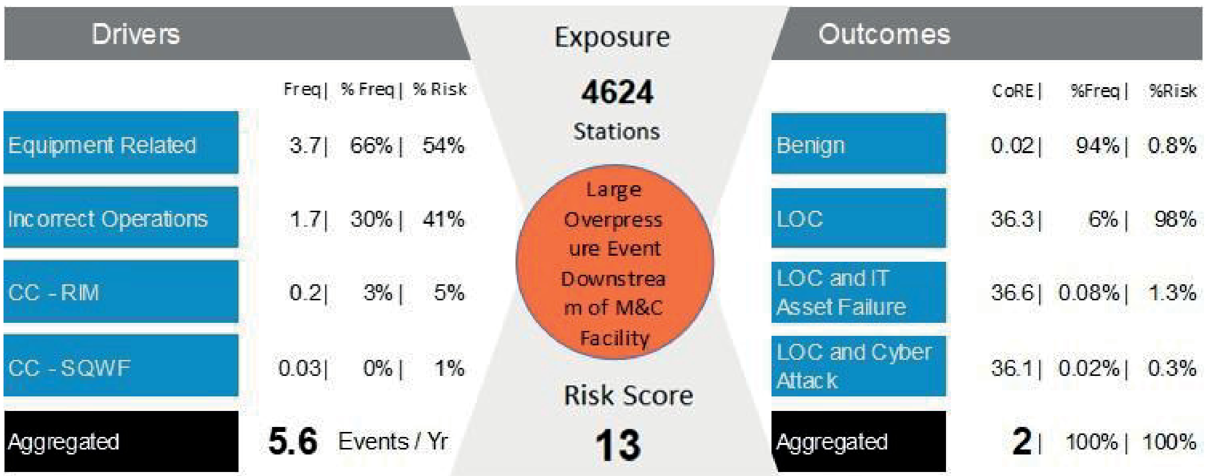
The M&C Failure – Release of Gas with Ignition at M&C Facility covered by Chapter 4 in the 2017 RAMP is not a RAMP risk evaluated in this report. PG&E describes this risk in the Other Safety (Chapter 19, Section K) in the 2020 RAMP. The Chapter 19, Section K risk also includes the risk presented in Chapter 6 in the 2017 RAMP, namely C&P Failure – Release of Gas with Ignition at Manned Processing Facility.

In the 2017 RAMP, the M&C Failure – Release of Gas with Ignition Downstream risk was defined as failure of pressure regulation at an M&C facility leading to a failure downstream resulting in loss of containment with ignition. In the 2020 RAMP, the Large OP Event Downstream of Gas M&C Facility risk presented in this chapter is substantially similar to that presented in the 2017 RAMP in that both risks involve a large OP event at an M&C station resulting in downstream impacts. The difference between the two risks is due to PG&E's expansion of its view of this risk since 2017. The risk presented in the 2017 RAMP only considered the single outcome of a large OP event leading to loss of containment with ignition. The risk presented in the 2020 RAMP considers two outcomes: large OP events that do not lead to any loss of containment ("benign" large OP events) and those that do lead to loss of containment (with or without ignition).

While the most significant consequences are associated with large OP events that lead to loss of containment with ignition, there are still consequences associated with large OP events that result in loss of containment without ignition, as well as with "benign" large OP events. For example, even in the case of a "benign" large OP event, PG&E reports the event to regulatory agencies and takes specific actions to confirm the safety of the facilities involved including verification of records, physical inspection, leak testing, and in some cases component replacement. These activities result in financial consequences. PG&E is proposing mitigations to reduce risks associated with all large OP events, not only large OP events that lead to loss of containment with ignition. Therefore, the outcomes covered by the 2020 RAMP risk have been expanded compared to the 2017 RAMP risk.

2. Risk Bow Tie

FIGURE 9-1
RISK BOW TIE



a. Difference from 2017 Risk Bow Tie

The M&C Failure – Release of Gas with Ignition Downstream (Chapter 3) risk in the 2017 RAMP is comparable to the Large OP Event Downstream of Gas M&C Facility risk in the 2020 RAMP. The drivers in both the 2017 and 2020 bow ties are the same (Equipment Related and Incorrect Operations), though in 2017 the drivers were further divided by High Pressure, Low Pressure and Transmission. This division in drivers in the 2017 RAMP served the same purpose as the inclusion of tranches in the 2020 RAMP. The exposures for the 2017 and 2020 RAMP risks are both based on PG&E data.

The key difference between the two bow ties is that the risk presented in the 2017 RAMP only considered the single outcome of a large OP event leading to loss of containment with ignition whereas the 2020 RAMP risk considers two outcomes: large OP events that do not lead to any loss of containment (benign large OP events) and those that do lead to loss of containment (with or without ignition). The 2020

RAMP risk includes both outcomes because there are consequences associated with each; PG&E's proposed mitigations address both outcomes. By revising the risk event definition, the average annual frequency changes from one event every 15 years to approximately eight events each year.

3. Exposure to Risk

PG&E's natural gas transmission and distribution systems present inherent safety and reliability risks including the risk of large OP events. PG&E measured the risk exposure as the number of stations owned and operated by PG&E. The total exposure used in the model is 4,624.[3] M&C transmission and distribution regulating stations. The risk associated with a large OP event downstream of an M&C facility varies across the transmission and distribution systems since there is considerable variability with respect to the regulating stations in terms of the pressure regulation equipment they contain and the characteristics of the pipeline assets that are located downstream.

4. Tranches

PG&E has identified 6 tranches of facilities for this risk. Each tranche below represents a group of M&C stations that have a relatively homogenous risk profile in terms of likelihood and consequence of the risk event.[4] By grouping stations into distinct tranches, specific risk likelihood and consequence profiles can be assigned to each. The tranches are described below.

Transmission Complex Stations: These stations have complex controls and operation including either a Programmable Logic Circuit or Remote

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3 Station counts consistent with the 2019 revision of the Measurement & Control Asset Management Plan.

4 At Workshop #3, PG&E presented seven tranches. Since that time, PG&E has combined two of those tranches, namely Distribution Farm Taps and Distribution High Pressure Regulator Stations, into a single tranche, Distribution District Regulator Stations (HPR-Type) and Farm Taps. These stations rely on the same type of equipment to control pressure and can therefore be considered as having a similar likelihood of experiencing large OP events. If this risk event were to occur involving a District Regulator Station (HPR-Type) station, a larger number of customers might be impacted, but assuming the same consequences for all stations in the tranche is a conservative approach for the Farm Taps.

Terminal Unit (RTU) to provide control and data transmission. This tranche also includes PG&E's three gas terminals that function as hubs in the gas transmission system to route gas from the backbone transmission lines to local transmission lines.

Transmission Simple Stations: These pilot-operated stations have simple control and operation. Stations within this category may include instrumentation and RTUs, provided they are for monitoring and data transmission purposes only.

Transmission Large Volume Customer Regulator (LVCR) Sets: Large volume customers are those served by a PG&E facility that is capable of delivering 40,000 standard cubic feet per hour (scfh) or more. LVCR Sets are those that have separate regulating stations (i.e., primary regulation) upstream of the typical regulation that occurs at meter set assemblies.

Distribution District Regulator Stations (Non-HPR-Type): These pilot-operated stations serve two or more service lines and typically serve hundreds to thousands of customers. These stations normally receive gas from the high-pressure transmission pipeline system.

Distribution District Regulator Stations (HPR-Type) and Farm Taps: These district regulator stations (HPR-type) are spring-operated. A farm tap is a service line that is connected directly from a transmission line or gathering line to serve customers other than a large-volume customer.

Distribution Low-Pressure District Regulator Stations: Low-pressure district regulator stations regulate gas pressure into "low-pressure distribution systems" with operating pressures below 1 psig.

The number of stations in each tranche, the percent of the exposure each represents, and the percent of risk associated with each tranche is provided in Table 9-2 below.

TABLE 9-2
LARGE OP EVENT RISK EXPOSURE

Line No.	Tranche	Count of Stations[a]	Percent Exposure	Safety Risk Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent of Risk[b]
1	Transmission Complex Stations	131	3%	0.29	4.46	0.03	4.79	36%
2	Transmission Simple Stations	252	5%	0.19	2.88	0.02	3.08	23%
3	Transmission LVCR Sets	98	2%	0.55	0.00	0.04	0.59	4%
4	Distribution District Regulator Stations (Non-HPR-Type)	1,330	29%	1.46	0.16	0.10	1.72	13%
5	Distribution District Regulator Stations (HPR-Type) and Farm Taps	2,608	56%	1.11	0.10	0.07	1.28	10%
6	Distribution Low-Pressure District Regulator Stations	205	4%	1.58	0.04	0.16	1.78	13%
7	Total	4,624	100%	5.18	7.64	0.42	13.24	100%

Notes:
(a) Count of Stations consistent with 2019 Measurement & Control Asset Management Plan.
(b) Risk is calculated based on frequency and consequence. The Percent of Risk is the contribution from each tranche to the overall risk.

5. Drivers and Associated Frequency

a. Risk Drivers

ASME standard B31.8S[5] specifies 21 threats to pipeline integrity that are grouped into nine categories of related failure types. PG&E has identified nine threat categories as risk drivers[6] for the Loss of Containment – Gas Transmission Pipeline (Chapter 7). For the Loss of Containment – Distribution Main or Service (Chapter 8), the risk drivers are based on the threats specified in 49 CFR section 192, Subpart P.

PG&E relies on ASME B31.8S to identify the threats that drive the Large OP Event Downstream of Gas M&C Facility risk. The causes of PG&E's large OP events are attributed primarily to two of the nine ASME B31.8S threat categories, namely Equipment Related and Incorrect Operations. These are the two risk drivers for this risk event. Incorrect Operations refers to large OP events caused by human performance, and all other large OP events are considered Equipment Related. These drivers and their associated 2023 TY baseline frequencies are discussed below.

D1 – Equipment Related: Equipment-related failures can occur due to equipment age, obsolescence, inadequate maintenance, the presence of contaminants such as liquids or debris, or design issues. These failures can lead to OP excursions (which may produce failure of downstream assets) or underpressure excursions (which may result in customer outages). Equipment-related failures accounted for 45 (70 percent) of the 64 large OP events that PG&E experienced from 2012-2019. This results in equipment-related failures accounting for 3.7 (66 percent) of the 5.6 events expected for 2023 when adjusted for the impact of 2020 – 2022 mitigations.

D2 – Incorrect Operations: Incorrect operations are associated with human performance such as errors in design (e.g., sensing line

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5 The American Society of Mechanical Engineers (ASME), ASME B31.8S – 2018, "Managing System Integrity of Gas Pipelines," ASME B31.8S – 2018.

6 The Loss of Containment – Transmission Pipeline risk drivers exclude the Equipment-Related driver that is covered by this risk, Large Overpressure Event Downstream of an M&C Facility.

location), equipment that was installed incorrectly, incorrect regulator set points, or work performed by improperly or inadequately trained personnel. A failure related to incorrect operations can lead to OP excursions or underpressure excursions. Incorrect operations accounted for 19 (30 percent) of the 64 large OP events that PG&E experienced from 2012-2019. This results in the Incorrect Operations driver accounting for 1.7 (30 percent) of the 5.6 events expected for 2023 when adjusted for the impact of 2020 – 2022 mitigations.

b. Risk Driver Frequencies

To determine the likelihood with which PG&E may experience a large OP event in each of the tranches, PG&E analyzed its OP Event Data from 2012 to 2019 to classify large OP events by station type (i.e., tranche) and risk driver. For this risk event, there are a total of six tranches and two risk drivers, resulting in 12 different risk event frequencies that are provided as inputs to the model.[7]

c. Outcome Frequencies

This risk considers two outcomes: large OP events that do not lead to any loss of containment ("benign" large OP events) and those that do lead to loss of containment (with or without ignition). Therefore, the model requires inputs that represent the proportions of large OP events that can be considered as leading and not leading to loss of containment. Whether a large OP event results in a loss of containment downstream depends on the pressure experienced by the downstream pipeline and the characteristics of that pipeline (i.e., steel or plastic). Both the pressure that might be experienced by the downstream pipeline and the characteristics of that pipeline are captured by the designation of the station tranche as transmission or distribution.

As stated above in Section 4, the exposure associated with this risk consists of three transmission station tranches and three distribution station tranches. PG&E analyzed its OP Event Data between 2012 and 2019 to determine how many large OP events on its transmission stations led to losses of containment (2 out of 36 events, or 5.6 percent),

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7 Source documents will be provided with the workpapers on July 17, 2020.

and how many large OP events on its distribution stations led to losses of containment (2 out of 28 events, or 7.1 percent). The proportion of large OP events at transmission stations that lead to the loss of containment outcome is considered to be 5.6 percent, with the benign outcome occurring for the remaining 94.4 percent of events. Similarly, the proportion of large OP events at distribution stations that lead to the loss of containment outcome is considered to be 7.1 percent, with the benign outcome occurring for the remaining 92.9 percent of events.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Large Overpressure Event Downstream of an M&C Facility risk are shown in Table 9-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing are described in Chapter 20.

TABLE 9-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Cyber Attack		X
2	Emergency Preparedness and Response		X
3	Information Technology Asset Failure		X
4	Records and Information Management	X	X
5	Skilled and Qualified Workforce	X	

The two cross-cutting factors that may influence the likelihood of this risk event are Records and Information Management and Skilled and Qualified Workforce. Each of these cross-cutting factors can be considered as representing a subset of the events associated with the Incorrect Operations driver.

Although the Cyber Attack and Information Technology Asset Failure cross-cutting factors are independent of the large OP risk event, it is not impossible for a Cyber Attack or Information Technology Asset Failure to occur simultaneously with a large OP event. If this were to be the case, the consequences associated with the large OP event would be expected to increase.

When analyzing this risk, PG&E considered the cross-cutting factor Climate Change even though it is not listed in the table above. Climate Change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves. During this RAMP period, PG&E will conduct a Climate Vulnerability Assessment (CVA) to further assess how its assets, operations, and employees are vulnerable to the projected impacts of climate change. PG&E intends to use findings from the CVA as well as developments in climate science and internal data to continue to advance the quantification of all event-based risks, including RAMP risks, over this RAMP period.

7. Consequences

As discussed in Section 5.c, there are two potential outcomes associated with this risk event, namely benign large OP events and OP events with loss of containment.

- A benign large OP event is expected to occur 94 percent of the time and accounts for less than 1 percent of the 2023 TY baseline risk score;
- An OP event with loss of containment event is expected to occur 6 percent of the time and accounts for 99 percent of the 2023 TY baseline risk.

a. Consequences for Outcome 1 – Benign Large OP Events

Even though most large OP events that PG&E has experienced have not resulted in any loss of containment, there are still consequences associated with such events. When a "benign" event occurs, PG&E reports the event to regulatory agencies and takes specific actions to confirm the safety of the facilities involved, including verification of records, physical inspection, leak testing, and, in some cases, component replacement. Actions also include immediate reduction of operating pressure until the confirmation steps are completed. These activities result in financial consequences associated with this outcome.

b. Consequences for Outcome 2 – OP Events with Loss of Containment

PG&E has experienced four loss of containment incidents from a large OP event during the time frame used for modeling data (2012-2019).[8] Due to these limited incidents, data regarding outcomes associated with this risk have been obtained from PHMSA reportable incident[9] data from 2010 to 2019, for both transmission and distribution. PG&E relied upon these data to determine safety and financial consequences that may be associated with the loss of containment outcome for this risk event. These data were used for the entire loss of containment outcome since the consequences associated with the loss of containment events that PG&E has experienced are not representative of consequences that could be realized for this outcome (i.e., utilizing PG&E data would underestimate the risk compared to consequences that have been observed by other operators).

While safety and financial consequences were obtained from PHMSA data, the reliability consequences associated with this risk were obtained from PG&E data. The reliability loss of containment consequences in this risk are aligned with the reliability loss of containment consequences from the Gas Transmission Pipeline and Distribution Mains and Services models.

Table 9-4 below shows the consequences of the risk event. Model attributes are discussed in Chapter 3, Risk Modeling and Risk Spend Efficiency.

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8 PG&E experienced an OP event in Alameda in 1994, which enlarged some pilot lights and resulted in several houses catching fire. Recently, a similar event occurred in Lawrence, Massachusetts. See, Application (A.) 18-12-009, Exhibit (PG&E-3), p. 9-16, lines 10-16, including footnote (fn.) 12.

9 An "Incident" is as defined as an event that involves a release of gas and that results in one or more of the following consequences: death or personal injury necessitating in-patient hospitalization; estimated property damage of $50,000 or more (in 1984 dollars); and/or, unintentional estimated gas loss of three million cubic feet or more. 49 CFR § 191.3.

TABLE 9-4
RISK MODEL CONSEQUENCE SUMMARY

	CoRE | %Freq | %Risk	Freq	Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
			Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial
Benign	0 | 94% | 0.8%	5.3	-	-	0.0	-	-	0.0	-	-	0.2	-	-	0.1
LOC	36.3 | 6% | 97.6%	0.36	0.22	5,802	1.1	14.3	21.1	0.9	0.077	2,063	0.4	5.1	7.5	0.3
LOC and IT Asset Failure	36.6 | 0.08% | 1.3%	0.0	0.22	5,809	1.1	14.3	21.3	1.0	0.001	27	0.0	0.07	0.10	0.005
LOC and Cyber Attack	36.1 | 0.02% | 0.3%	0.001	0.22	5,757	1.1	14.4	20.8	0.9	0.0003	7	0.0	0.02	0.03	0.001
Aggregated	**2 |** 100% **|** 100%	5.6	0.01	373	0.1	1	1	0.1	0.078	2,097	0.6	5	8	0.4

C. Controls and Mitigations

Tables 9-5 and 9-6 list the controls and mitigations PG&E included in its 2017 RAMP, 2019 GT&S Rate Case, 2020 General Rate Case (GRC), and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view of controls and mitigations that are: on-going; no longer in place; and, changes to controls and mitigations.

In the following sections PG&E describes the controls and mitigations in place in 2019, how the controls and mitigations have changed since the 2017 RAMP, and the significant changes expected for the controls and mitigations during the 2020-2022 and 2023-2026 periods.

TABLE 9-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP	2019 GT&S/2020 GR 2019-2022 Controls(a)	2020 RAMP 2020-2022 Controls	2020 RAMP 2023-2026 Controls
1	C1 – Corrective Maintenance	X	X	X	X
2	C2 – Gas Quality Assessment	X	X	X	Will become part of C4
3	C3 – Preventive Maintenance	X	X	X	X
4	C4 – Regulator Station Component Replacements and Routine Work (formerly Regulator Station Component Replacement)	X	X	X	X
5	C5 – Regulator Station Rebuilds (formerly Regulator Station Replacement)	X	X	X	X
6	C6 – Other Operations and Maintenance			X	X
7	C7 – Foundational Activities Programs		X	X	X

(a) The controls PG&E proposed in the 2017 RAMP were incorporated by reference in the 2019 GT&S Rate Case. See, A.17-11-009, PG&E Prepared Testimony, p. 4 34, fn. 14.

TABLE 9-6
MITIGATIONS SUMMARY[a]

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2019 GT&S/2020 GRC 2019-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1 – Critical Documents Program	X	X	X	
2	M2 – HPR Replacement	X	X	X	X
3	M3 – Supervisory Control and Data Acquisition (SCADA) Visibility	X	X	X	X
4	M4 – Station OPP Enhancements[b]	X	X	X	X

Notes:

(a) In the 2017 RAMP, the mitigations were numbered sequentially (M1, M2, M3, etc.) and then a letter was appended to the mitigation number to indicate the period during which certain work associated with that mitigation would occur. For example, M1A described the 2016 work, M1B described the 2017-2019 work, and M1C described the 2020-2022 work. In this table and the following sections, PG&E refers to the mitigation number without the letter (year) designation, as the description of the work did not change, only the volume of work.

(b) Only the Transmission program was included in the 2017 RAMP. The Distribution program was in development at the time of the 2017 RAMP.

1. 2017-2019 Controls and Mitigations

a. Controls

C1 – Corrective Maintenance: Corrective Maintenance includes work required to repair failed, damaged or inoperative gas station facilities. In many cases, the need for such restoration is identified during preventive maintenance inspections. This control addresses the Equipment Related driver.

C2 – Gas Quality Assessment: The purpose of this control is to address gas quality issues such as particulates and liquids so that station equipment operates correctly, materials do not degrade due to corrosion, and gas entering the PG&E system meets gas quality requirements. This control addresses the Equipment Related driver.

C3 – Preventive Maintenance: Preventive Maintenance includes inspection and maintenance of station equipment to ensure it remains in working order. Preventive maintenance also includes work that may be required to comply with pipeline safety regulations. This control addresses the Equipment Related driver.

C4 – Regulator Station Component Replacements and Routine Work: This control includes replacement of equipment within a regulator station that has exceeded its useful life or is experiencing performance problems. This control ensures the station equipment and components are operating properly and it reduces the risk of failure by managing equipment obsolescence. This control addresses the Equipment Related driver.

C5 – Regulator Station Rebuilds: This program includes the complete or partial rebuilds of transmission and distribution stations (above or below ground) to replace old and obsolete equipment and piping, to upgrade configurations to meet current design standards and system operating needs, and to address any issues with station operation and maintenance. Rebuilding can also involve relocating stations as appropriate to improve employee safety. This control addresses the Equipment Related and Incorrect Operations drivers.

C6 – Other Operations and Maintenance: This control consists of activities required to control the supply and flow of gas in the transmission and distribution systems that are not otherwise considered preventive or corrective maintenance. The activities of this control address the Equipment Related and Incorrect Operations drivers.

C7 – Foundational Activities Programs: This control includes foundational activities required to drive improvements in Facilities Integrity Management. Examples of activities include: benchmarking activities to identify industry best practices; pilot programs (such as pressure vessel inspections and seismic reviews); and, development of station-specific risk analysis capabilities.

b. Mitigations

M1 – Critical Documents Program: This program consists of revising and/or developing new critical drawings and documents for transmission stations. These drawings and documents will better assist operating and maintenance personnel in understanding and troubleshooting systems and equipment. This mitigation ensures that the drawings and documents used to operate and maintain the facility are commensurate with the complexity of the facility. This mitigation addresses the Incorrect Operations driver.

The Critical Documents Program was proposed as a mitigation in the 2017 RAMP. This is a non-unitized program. To incorporate this mitigation into the 2017 RAMP model, PG&E developed representative units of work (i.e., number of stations) for the years 2017, 2018 and 2019.[10] The Critical Documents program was also forecast as a non-unitized program in the 2019 GT&S Rate Case, with a targeted program completion date in 2021. The program is on track to complete all site visits by end of 2021, with the close out of some projects extending into 2022.

M2 – HPR Replacement: This program is intended to replace distribution system HPR stations that have exceeded their useful life or

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[10] See, I.17-11-003, WP 3-3, fn. 1, for a description of how PG&E developed its units of work estimates.

are experiencing performance problems. This mitigation ensures the equipment and components are operating properly and reduces the risk of a failure by addressing aging and obsolete equipment. This mitigation also reduces the likelihood of incorrect operations due to the ease of operations on newly replaced HPRs. This mitigation addresses the Incorrect Operations and Equipment related drivers.

The HPR Replacement Program was proposed as a mitigation in the 2017 RAMP and was also forecasted in the 2020 GRC. In PG&E's 2017 RAMP, it forecasted HPR replacements at 375 stations in 2017, 405 stations in 2018, and 440 stations in 2019, for a total of 1,220 stations. PG&E addressed 1,047 HPRs between 2017-2019 and is on track to complete the program by the end of next GRC period. By that time, PG&E anticipates this program will become a control.

M3 – SCADA Visibility: To monitor and operate the gas system and mitigate potentially abnormal conditions, Gas Control Center (GCC) personnel must be able to view pressure and flow data from key locations within the gas system. Regulator stations that have SCADA visibility typically have pressure transducers installed at multiple points within the station, both upstream and downstream of regulation. SCADA devices may also be installed elsewhere on the system, for low-point monitoring as well as overpressure monitoring. SCADA devices provide required visibility to GCC personnel. If the devices detect conditions that are out of the normal range, they send an alarm to the GCC, and operators can investigate and take necessary measures.

The SCADA Visibility program includes installing different types of SCADA devices on the gas system: gas transmission SCADA devices on long segments of backbone and other major pipeline (MAT 76M); electronic recorder-transmitter (ERX) devices on the gas distribution system that record pressure and transmit recorded data (MAT 4AF); and, gas distribution RTU Pressure Monitoring Devices (MAT 4AM) that feature multiple sensing capabilities and the ability to relay significant amounts of data in real time. This mitigation addresses the Equipment Related and Incorrect Operations drivers.

PG&E planned to complete SCADA installations at 530 distribution locations (237 in 2017, 144 in 2018 and 149 in 2019) and 24 transmission stations (3 in 2017, 13 in 2018, and 8 in 2019). PG&E completed work at 548 distribution locations and 16 transmission locations. The program is on pace to be fully implemented by 2025.

M4 – Station OPP Enhancements:[11] This program is intended to prevent large OP events at transmission and distribution regulator stations. PG&E has performed investigations on its large OP events to determine causes and to define actions that can prevent recurrence. These investigations have identified some common causes for a number of these events, including common failure modes in pilot-operated regulator stations and systems that have intermittent flow. PG&E has also conducted benchmarking surveys, reviewed industry best practices, and evaluated potential options through the execution of pilot studies. Based on these actions, PG&E is pursuing the strategy of initially installing secondary OPP (e.g., slam-shuts) at pilot-operated regulator stations and performing rebuilds of the large volume customer primary regulator sets. This mitigation addresses the Equipment Related and Incorrect Operations driver.

PG&E only included the Station OPP Enhancements Program for transmission stations in the 2017 RAMP. The Station OPP Enhancements Program for distribution stations was proposed initially in the 2020 GRC.

The Station OPP Enhancements Program was a non-unitized program in the 2019 GT&S Rate Case but for the purposes of incorporating this mitigation into the 2017 RAMP risk model, PG&E developed representative units of work. PG&E completed 18 LVCR rebuilds from 2018-2019. Between 2020 and 2022 PG&E will also focus on rebuilding and retrofitting the remaining LVCRs and other pilot operated transmission stations.

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[11] The Station OPP Enhancements mitigation includes both capital and expense cost components.

D. 2020-2022 Mitigation Plan

1. Changes to Controls

PG&E is making the following changes to its control programs:

C4 – The name of this control is changing to Regulator Station Component Replacements and Routine Work (formerly Regulator Station Component Replacement). The new name more accurately reflects the work in this control.

C5 – The name of this control is changing to Regulator Station Rebuilds (formerly Regulator Station Replacements). The new name more accurately reflects the work in this control.

C6 – Other Operations and Maintenance: This control consists of activities required to control the supply and flow of gas in the transmission and distribution systems that are not otherwise considered preventive or corrective maintenance.

2. Changes to Mitigations

PG&E will continue to implement the four mitigations proposed in the 2017 RAMP. PG&E is not proposing any new mitigations. The Critical Documents Program will be completed in 2022 but all other mitigations will continue into 2023-2026. The volume of work that PG&E plans to complete in 2020-2022 is shown in Table 9-7 below.

TABLE 9-7
PLANNED MITIGATIONS 2020-2022

		Planned Units of Work				
Line No.	Mitigation Name and Number	Rate Case Units[a]	2020	2021	2022	Total
1	M1 – Critical Documents Program (LU1)	Non-unitized	N/A	N/A	N/A	N/A
2	M2 – HPR Replacement (2K)	HPR	340	340	340	1,020
3	M3 – SCADA Visibility (76M)	Non-unitized	N/A	N/A	N/A	N/A
4	M3 – SCADA Visibility (4AF)	Locations	28	28	10	66
5	M3 – SCADA Visibility (4AM)	Locations	124	124	124	372
6	M4 – Station OPP Enhancements (76G)	Non-unitized	N/A	N/A	N/A	N/A
7	M4 – Station OPP Enhancements (50N)	Stations	200	200	200	600

Notes:

(a) Units of work are presented for programs that are unitized in PG&E's gas transmission and distribution rate cases.

Tables 9-8 and 9-9 below show the forecast costs, the RSEs and the risk reduction scores for the mitigation work planned during the 2020-2022 period.

TABLE 9-8
FORECAST COSTS[(a)]
EXPENSE ($000) 2020-2022

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M1	Critical Documents Program	LU1	$7,623	$8,268	$7,998	$23,890
2	M4	Station OPP Enhancements	FHQ, JTX	4,464	4,834	4,954	14,252
3		Total		$12,088	$13,101	$12,953	$38,142

(a) See WP 9-1.

TABLE 9-9
FORECAST COSTS[(a)]
CAPITAL ($000) 2020-2022

Line No.	Mit. No.	Mitigation Name	MAT	2020	2021	2022	Total
1	M2	HPR Replacement	2K#, 2KA, 2KB, 2KC	$55,201	$57,800	$59,245	$172,246
2	M3	SCADA Visibility	4AF, 4AM, 76M	32,990	34,160	34,646	101,796
3	M4	Station OPP Enhancements	50N, 76G	34,823	28,160	21,484	84,467
4		Total		$123,014	$120,120	$115,375	$358,509

(a) See WP 9-1.

E. 2023 – 2026 Proposed Plan

1. Changes to Controls

PG&E is making the following change to its control programs:

C2 – Gas Quality Assessment: This control will not be a separate control starting in 2023 but it will instead become part of Control C4.

2. Mitigation Plan

PG&E is not proposing any new mitigations in 2023-2026. The volume of work PG&E plans to complete in 2023-2026 is shown in Table 9-10 below.

TABLE 9-10
PLANNED MITIGATIONS 2023-2026

Line No.	Mitigation Name and Number	Rate Case Units[(a)]	Planned Units of Work				
			2023	2024	2025	2026	Total
1	M2 – HPR Replacement (2K)	HPR	100	100	100	100	400
2	M3 – SCADA Visibility (76M)	Non-unitized	N/A	N/A	N/A	N/A	N/A
3	M3 – SCADA Visibility (4AF)	Locations	10	10	10	10	40
4	M3 – SCADA Visibility (4AM)	Locations	101	101	100	0	302
5	M4 – Station OPP Enhancements (76G)	Non-unitized	N/A	N/A	N/A	N/A	N/A
6	M4 – Station OPP Enhancements (50N)[(b)]	Stations	200	150	150	0	500

Notes:

(a) Units of work are presented for programs that are unitized in PG&E's gas transmission and distribution rate cases.

(b) The Station OPP Enhancements Program as presented in the 2020 GRC addressed only high-pressure regulator stations; the 2023-2026 program as proposed in the 2020 RAMP also includes only units and dollars associated with high-pressure regulator stations. PG&E is currently evaluating mitigations for low-pressure stations, and additional dollars and units will be proposed in the 2023 GRC.

Tables 9-11 and 9-12 below show the forecast costs, the RSEs and the risk reduction scores for the mitigation work planned during the 2023-2026 period.

TABLE 9-11
FORECAST COSTS, RSE AND RISK REDUCTION[b]
EXPENSE ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1	Critical Documents Program	LU1	–	–	–	–	–	–	–
2	M4	Station OPP Enhancements	FHQ, JTX	$5,078	$5,205	$5,335	$5,469	$21,087	(a)	(a)
3		Total		$5,078	$5,205	$5,335	$5,469	$21,087	–	–

Note:
(a) See Table 9-12.
(b) See WP 9-1.

TABLE 9-12
FORECAST COSTS, RSE AND RISK REDUCTION[b]
CAPITAL ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M2	HPR Replacement	2K#, 2KA, 2KB, 2KC	$17,861	$18,307	$18,765	$19,234	$74,167	0.029	1.6
2	M3	SCADA Visibility	4AF, 4AM, 76M	29,714	30,458	30,955	4,345	95,471	0.025	1.9
3	M4	Station OPP Enhancements	50N, 76G	23,281	19,744	19,922	8,405	71,352	0.197	14.9
4		Total		$70,855	$68,509	$69,642	$31,984	$240,990	–	–

Note:
(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
(b) See WP 9-1.

The risk model results in Tables 9-11 and 9-12 above show that the SCADA Visibility (4AM) Program has the lowest RSE score of the proposed mitigations for this risk. PG&E installs SCADA devices in key locations within the gas system including regulator stations due to the regulator station's importance in operating the gas system. SCADA devices allow the Gas Control Center (GCC) personnel to monitor and operate the gas system and to mitigate potentially abnormal conditions, such as overpressure alarms and valve position indicators. PG&E started installing SCADA devices on its system in 2015 and plans to complete installation of SCADA devices on the gas system by 2025. This program is an enabler for many other programs that allow PG&E to have insight into real-time operations and response protocols. Even though the RSE for this program is lower than other mitigation programs, PG&E believes it is important to complete the SCADA visibility program in order to provide visibility and control of the entire gas system.

The HPR Replacement Program has the second lowest RSE score of the proposed mitigations for this risk. In this instance PG&E believes that continuing to replace HPRs is reasonable given the history of performance issues with this type of equipment. In February 2011, PG&E reported that most of the leaks on the transmission system were on the HPR facilities.[12] Subsequently, PG&E began a program to rebuild or replace HPR-type facilities in order to address equipment deterioration, obsolescence and legacy designs. PG&E developed its HPR program to address gas leaks and facility conditions associated with High Pressure Regulator facilities that are experiencing performance problems. As of January 1, 2018, PG&E estimated that there were approximately 2,700 HPRs that still needed to be replaced or rebuilt. Based on the pace of work proposed in the 2020 GRC, PG&E estimates that it can complete the HPR program during the 2023 GRC period.[13]

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12 PG&E's report, Accelerated Gas Transmission System Aerial and Ground Leak Survey Trends, was submitted to Paul Clanon, CPUC Executive Director, on February 1, 2011.

13 A.18-12-009, Exhibit (PG&E-3), WP 5-13 and WP 5-14.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

Of the four mitigation programs proposed for this risk, the Station OPP Enhancements Program for distribution stations is the program for which the consideration of alternatives is the most appropriate. It is the newest program amongst the mitigations for this risk, and it is also a mitigation that is specific to the Large OP Event Downstream of M&C Facility risk, whereas other mitigation programs can be considered to mitigate other risks presented in Other Safety Risks or not included in the 2020 RAMP.

1. Alternative Plan 1: Rebuild and Retrofit Single-Run Stations

The development of the Station OPP Enhancements Program was informed in part through the review of benchmarking surveys and evaluation of potential options through the execution of pilot studies. Based on these actions, PG&E arrived at the strategy to install secondary OPP (e.g., slam-shuts) at pilot-operated distribution regulator stations. These stations are represented by the Distribution District Regulator Stations (Non-HPR-Type) tranche.

The current goal for the Station OPP Enhancements Program is to have retrofitted all pilot-operated (i.e., Non-HPR-Type) distribution stations with secondary overpressure protection by the end of 2025. PG&E will install slam-shut devices at the majority of these stations. There are, however, some stations where it may not be appropriate to install such devices because of potential negative impacts on reliability. These stations include those that meet all of the following criteria: they are considered critical from a reliability or customer perspective, they feed over 5,000 customers, and they are single-run stations. These critical, single-run stations that serve many customers would currently require separate projects to be initiated to investigate viable secondary overpressure protection options because of potential reliability impacts associated with slam-shut devices at these stations. An alternative to the installation of slam-shut devices is to rebuild all single-run distribution pilot-operated regulator stations to be dual-run stations as required by current regulator station design standards. Dual-run pilot-operated stations built to current regulator design standards would include secondary overpressure protection devices that are acceptable for a dual-run station.

Alternative Plan 1 to the Station OPP Enhancements Program for distribution stations consists of rebuilding the approximately 640 single-run stations as dual-run stations and retrofitting the remainder (460 stations) with slam-shut devices. This alternative assumes that rebuilds for the single-run stations would begin in 2023 after the retrofits of the dual-run stations have been completed. A realistic pace of 30 single-run stations rebuilt per year from 2023-2026 is part of Alternative Plan 1. Station rebuilds already occur within the scope of controls for this risk; the station rebuilds that are included in Alternative Plan 1 would be incremental to the existing station rebuilds in C5 – Regulator Station Rebuilds. Because PG&E has demonstrated that it can execute on the pace of the incremental station rebuilds of 30 per year, the scope and pace of this alternative are considered realistic.

PG&E did not choose this alternative because based on the proposed pace of this work, PG&E would not meet its goal for the Station OPP Enhancements Program - have all distribution pilot-operated stations addressed by the end of the next rate case period (2027). At the end of 2026, there would still be 520 single-run stations that require rebuild.

TABLE 9-15
FORECAST COSTS, RSE AND RISK REDUCTION[c]
EXPENSE ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE(a)	Risk Reduction
1	A1	Rebuild or Retrofit DREG Stations	$3,405	$3,490	$3,578	$3,667	$14,140	(b)	(b)
2		Total	$3,405	$3,490	$3,578	$3,667	$14,140		

Note:

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See Table 9-16.

(c) See WP 9-1.

TABLE 9-16
FORECAST COSTS, RSE AND RISK REDUCTION[b]
CAPITAL ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Rebuild or Retrofit DREG Stations	$44,674	$44,674	$44,674	$44,674	$178,694	0.02	1.9
2		Total	$44,674	$44,674	$44,674	$44,674	$178,694		

Note:

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See WP 9-1.

2. Alternative Plan 2: Rebuild and Retrofit Subset of Single-Run Stations

Alternative 2 is similar to Alternative 1 in that it includes station rebuilds for the single-run stations. However, under Alternative 2, the Station OPP Enhancements Program would meet its goal of addressing all distribution pilot-operated regulator station by the end of the next rate case period. This would be accomplished by reducing the number of single-run station rebuilds and addressing the remainder with retrofits. This alternative has a lower RSE than the proposed plan.

TABLE 9-17
FORECAST COSTS, RSE AND RISK REDUCTION[c]
EXPENSE ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE(a)	Risk Reduction
1	A2	Rebuild or Retrofit Certain DREG Stations	$3,405	$3,490	$3,578	$3,667	$14,140	[b]	[b]
		Total	$3,405	$3,490	$3,578	$3,667	$14,140		

Note:

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See Table 9-18.

(c) See, WP 9-1.

TABLE 9-18
FORECAST COSTS, RSE AND RISK REDUCTION[b]
CAPITAL ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A2	Rebuild or Retrofit Certain DREG Stations	$55,087	$53,823	$54,051	$44,674	$207,634	0.04	6.4
2		Total	$55,087	$53,823	$54,051	$44,674	$207,634		

Note:

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See, WP 9-1.

Table 9-19 compares the proposed and alternative mitigation plans.

TABLE 9-19
MITIGATION PLAN ALTERNATIVES ANALYSIS[d]
($000)

Line No.	Risk Mitigation Plan	Plan Components[a]	Total Expense (2023-2026)[b]	Total Capital (2023-2026)	Risk Reduction (NPV)	Total Spend (NPV)[c]	RSE
1	Proposed	M1, M2, M3, M4	$21,087	$240,990	17.5	$198,051	0.09
2	Alternative 1	M1, M2, M3, M4 (Transmission) + A1	$6,974	$381,650	13.0	$290,161	0.04
3	Alternative 2	M1, M2, M3, M4 (Transmission) + A2	$21,087	$410,590	17.3	$322,640	0.05

(a) Plan Components refers to the Mitigations presented in Table 9-6.

(b) The total spend (NPV) and RSE includes certain costs that were incurred before 2023 because the spend reduces risk during the 2023-2026 period.

(c) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

(d) See, WP 9-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 10

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: WILDFIRE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 10
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: WILDFIRE

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RISK MITIGATION PLAN: WILDFIRE

A. Executive Summary

Over the past few years, California has experienced an unprecedented number of catastrophic wildfires due to climate change. Many of these fires have occurred in Pacific Gas and Electric Company's (PG&E) service territory in Northern California, over half of which lies in High Fire Threat District (HFTD) areas as identified by the California Public Utilities Commission (CPUC or Commission).[1] PG&E recognizes the urgent need to address this challenge and protect the safety of the customers and communities we serve.

The Wildfire risk is defined as PG&E assets or activities that may initiate a fire that is not easily contained and endangers the public, private property, sensitive lands, or the environment. The drivers for this risk event are equipment failure, vegetation, third party, animal, unknown or other, and seismic scenario. Wildfire has the highest safety score of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks.

Wildfire has the highest 2023 test year (TY) baseline safety score (9,865) and the highest 2023 TY baseline total risk score (24,343) of PG&E's 12 RAMP risks. The 2020 baseline risk score (26,072) improves by 28 percent from 2020 to 2026 (i.e., risk is reduced) when PG&E's planned and proposed mitigations are applied: the 2023 TY baseline risk score is 24,343 and the 2026 post-mitigation risk score is 18,871.[2]

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1 The HFTD Map, adopted by the Commission in January 2018, designates three types of fire threat area: Tier 3 ("extreme risk"), Tier 2 ("elevated risk"), and a much smaller Zone 1 (made up of areas on the California Department of Forestry and Fire Protection (CAL FIRE)/U.S. Forest Service High Hazard Zones map that are not subsumed with the Tier 2 and Tier 3 HFTD areas). See Decision (D.) 17-12-024, p. 158, Ordering Paragraph 12, and Appendix D. The 2017 RAMP used an earlier fire threat map because the Commission had not yet finalized the HFTD Map.

2 PG&E's model assumes that baseline risk will increase in 2023-2026, relative to 2020-2022, due to climate factors increasing the number of Red Flag Warning (RFW) days and areas in the future. See Section B.6 below for further discussion.

Exposure to the Wildfire risk is modeled based on the approximately 99,000 overhead primary circuit miles in PG&E's electric distribution and transmission system. The risk includes approximately 443 risk events (ignitions)[3] each year. The equipment failure driver accounts for the highest number of risk events (38 percent); the vegetation driver accounts for the second highest number of risk events systemwide (26 percent). About 32 percent of risk events take place in HFTD areas; these risk events accounted for 99 percent of the overall risk. 88 percent of the consequences of Wildfire risk events are due to the small number of ignitions that result in catastrophic fires (defined as fires that burn 100 or more structures and result in a serious injury or fatality). The mitigations PG&E will implement from 2020-2026 are designed to address these key risk drivers and consequences.

PG&E identified eight tranches for the Wildfire risk that reflect similar risk profiles within each tranche. The tranches are based on ignitions in HFTD areas versus non-HFTD areas, and further breaking those ignitions down into those associated with distribution, transmission, and substation facilities. The distribution system in HFTD areas is further broken down into areas where PG&E has already performed system hardening work, areas where PG&E plans to perform system hardening work, and areas where PG&E does not currently plan to perform system hardening work. The highest tranche-level risk is associated with HFTD – Distribution (To Be Hardened) which accounts for 7 percent of system mileage and 45 percent of the risk.

PG&E is proposing a broad suite of controls and mitigations to address the key wildfire risk drivers. Recent improvements to controls include an enhanced inspection process and a new program to assess pole loading in HFTD areas. PG&E's proposed mitigations include four broad strategies for understanding and responding to Wildfire risk.

1) Reduce risk through several asset management programs, including a long-term program to harden the distribution system in HFTD areas to lower ignition risk and improve fire resilience.

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3 443 ignitions is PG&E's forecast for 2023 ignitions, based on historical ignitions, plus several adjustments, which are described in Section B.5 below.

2) Reduce risk from the vegetation driver by significantly expanding vegetation management activities in HFTD areas beyond compliance requirements.

3) Target the highest risk wildfire conditions (days with high fire threat and high wind in HFTD areas) through the Public Safety Power Shutoff (PSPS) Program.[4] PG&E recognizes that PSPS, while very effective at mitigating ignitions associated with PG&E assets, is also extremely disruptive for customers and is making significant investments to reduce the impact of future PSPS events on customers.

4) Enhance situational awareness with improvements in meteorology, high definition cameras for fire monitoring, field weather stations and satellite monitoring for better weather tracking and forecasting, and sensors in HFTD areas.

The PSPS and System Hardening mitigation programs have the highest Risk Spend Efficiency (RSE) scores and the highest total risk reduction scores.[5] The RSE score for PSPS includes the cost of programs that PG&E is undertaking to reduce the impact of PSPS on customers by reducing the PSPS footprint and shortening restoration times.

PG&E's programs to address Wildfire risk will continue to evolve as its understanding of the wildfire threat improves, and as PG&E incorporates lessons learned from its ongoing efforts, as well as information from customers, communities, and government entities about how to improve the programs' effectiveness and impact. These programs, and PG&E's risk modeling efforts, are dynamic; in response to new information, PG&E may adjust the scope of the programs presented here and/or introduce new programs as part of its funding request in the 2023 General Rate Case (GRC).

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[4] The mitigations described here are much more extensive than the mitigations proposed in the 2017 RAMP, which was filed before the impacts of the catastrophic wildfires in PG&E's service territory in 2017 and 2018 had been assessed. PG&E's analysis of its Wildfire risk in the wake of those fires, and almost all the programs described here, have been previously discussed in PG&E's 2020 GRC testimony. (See e.g., Application (A.) 18-12-009, Exhibit (PG&E-4), Chapter 2A (Wildfire Risk Policy and Overview)) and/or in PG&E's 2020 Wildfire Mitigation Plan (WMP) Report. See Rulemaking (R.18-10-007).

[5] The information herein is subject to those limitations described in Chapter 2, Section D.

TABLE 10-1
RISK OVERVIEW

Line No.	Risk Name	Wildfire
1	In Scope	PG&E assets or activities that may initiate a fire that is not easily contained, endangers the public, private property, sensitive lands or environment.
2	Out of Scope	Fire ignitions and associated impacts not related to PG&E electric system assets.
3	Data Quantification Sources	CPUC-reportable ignitions, CAL FIRE, National Weather Service (NWS), other PG&E data (Outage data, Geographic Information System (GIS) data, PG&E System Earthquake Risk Assessment model, Integrated Logging Information Systems, Transmission Operation Tracking and Logging).

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

Changes in weather, vegetation growth, and tree mortality patterns brought on by climate change, coupled with increased development in formerly wildland areas have led to increased consequences related to wildfire ignitions in recent years. As discussed in PG&E's 2020 GRC testimony on the Wildfire risk, 15 of the 20 most destructive wildfires in California's history have occurred since 2000, including 10 since 2015.[6] PG&E's overhead electrical transmission and distribution assets are potential sources of wildfire ignition. PG&E faces significant wildfire challenges because of the size and geography of its service area. PG&E serves approximately 5.5 million electric customers across a service territory of approximately 70,000 square miles, more than half of which is included in HFTD areas.[7] PG&E's system has approximately 81,000 miles of distribution primary overhead circuits (more than 25,000 of which are in HFTD areas) and approximately 18,000 miles of transmission overhead circuits (more than 5,000 of which are in HFTD areas).

6 A.18-12-009, Exhibit (PG&E-4), p. 2A-3, Figure 2A-1.

7 Order Instituting Rulemaking 18-10-007 (Oct. 25, 2018), 2020 WMP Report, R.18-10-007, (Feb. 7, 2020), Executive Summary, Section B, and GIS verification in June 2020.

Over the last five years (2015-2019), there have been an average of 440 ignitions per year[8] associated with PG&E's facilities, the vast majority of which have been small, and did not result in damage to structures. The leading causes of these ignitions have been equipment failure, vegetation contact with overhead lines, animal contact, and third-party contacts (such as vehicles running into utility poles).

2. Risk Definition

The Wildfire risk is defined as PG&E assets or activities that may initiate a fire that is not easily contained, endangers the public, private property, sensitive lands or environment.

B. Risk Assessment

1. Background and Evolution

Managing wildfire risk is, and has been, a high priority for PG&E. Wildfire risk has been designated a top enterprise and safety risk since 2006, and the Wildfire risk was included in the 2017 RAMP. As discussed in the 2017 RAMP Report, PG&E's total expenditure for 2016 for all wildfire risk-related activities was approximately $750 million.[9] In the wake of the catastrophic wildfires in PG&E's service territory in 2017 and 2018, and an increasing awareness that the conditions that lead to wildfires are increasing throughout the state, PG&E's Electric Operations line of business conducted a thorough re-examination of its Wildfire risk, which led to the significantly expanded mitigation plan proposed in the 2020 GRC. PG&E continues to update its analysis of Wildfire risk and reports to the CPUC on its risk management efforts in several different venues, including RAMP reports, GRC proceedings, and annual WMP.

In the 2017 RAMP, PG&E described 12 controls for the Wildfire risk, including vegetation management in high fire-threat areas and a variety of other expenditures and infrastructure replacement programs, including the

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8 440 is the historical average number of ignitions per year for 2015-2019. For modeling baseline risk, PG&E has made several adjustments to this historical average as described in Section B.5 below.

9 PG&E's RAMP Report, Investigation 17-11-003 (Nov. 30, 2017), p. 11-2, and p. 11-15, Table 11-1.

following: patrols and inspections of PG&E's overhead electric facilities; preventive maintenance of equipment and poles; replacement of conductor, overhead equipment, or poles that have failed or are at risk of failing; and installation of protective equipment.[10] These same controls were presented in the 2020 GRC, though in some cases PG&E forecasted increased spending on these controls. For the 2020 RAMP, PG&E proposes a reorganized list of 17 controls. These revised controls generally relate to the same activities as the previous controls but are streamlined and organized to better reflect the organization of PG&E's WMP. For several of the revised controls, PG&E has significantly changed planned expenditure levels. Table 10-6 at the beginning of Section C below maps the evolution of PG&E's controls for the Wildfire risk from the 2017 RAMP to the 2020 GRC to the 2020 RAMP.

In the 2017 RAMP, PG&E proposed six mitigations for the Wildfire risk, consisting of two additional vegetation management activities, two changes to recloser operations in high fire risk areas, and targeted replacement of two types of assets (overhead conductor and non-exempt surge arresters) in high fire risk areas. In the 2020 GRC, PG&E proposed a significantly expanded set of 19 mitigations as part of its new Community Wildfire Safety Program (CWSP). These mitigations included an expanded Enhanced Vegetation Management (EVM) program and a comprehensive System Hardening program in HFTD areas. They also included several programs designed to enhance PG&E's situational awareness (e.g., cameras, weather stations, and meteorological modeling). The 2020 GRC also included PSPS as a mitigation, as well as some programs designed to lessen the impact of PSPS.

PG&E is presenting 10 mitigations in the 2020 RAMP. These mitigations are very similar to the mitigations presented in the 2020 GRC, except that in the 2020 RAMP PG&E has created two mitigations—M6 – PSPS Impact Reduction Initiatives and M7 – Situational Awareness and Forecasting Initiatives—that contain multiple programs that were classified as separate mitigations in the 2020 GRC. Table 10-7 at the beginning of

10 See Section C.2 below for a list of the controls presented in the 2017 RAMP.

Section C below maps the evolution of PG&E's mitigations for the Wildfire risk from the 2017 RAMP to the 2020 GRC to the 2020 RAMP.

PG&E discussed its Wildfire risk reduction activities in its 2019 and 2020 WMPs though these plans use a very different organizational schema from either the RAMP or GRC. On May 7, 2020, the CPUC's Wildfire Safety Division (WSD) provided a Draft Guidance Resolution to all California investor-owned utilities and a Draft Resolution specific to PG&E providing conditional approval of and feedback on the utilities' 2020 WMPs. See Draft Guidance Resolution WSD-002 and Draft Resolution WSD-003 in R.18-10-007. The CPUC ratified the Draft Resolutions on June 11, 2020. Given the June 30 filing deadline for the 2020 RAMP, PG&E will not be able to substantively respond to WSD's feedback in this report. However, PG&E will respond in the WMP proceeding and will also incorporate WSD's feedback into its presentation of the Wildfire risk in the 2023 GRC.

2. Risk Bow Tie

Figures 10-1 and 10-2 below show the Wildfire risk bow ties for (1) PG&E's entire transmission and distribution overhead electric system and (2) the portion of PG&E's system that lies in HFTD areas. PG&E is including the HFTD-specific bow tie to show how Wildfire risk characteristics differ between HFTD and non-HFTD areas. PG&E's tranche analysis, discussed in Section B.4 below, shows that HFTD areas account for 99 percent of the Wildfire risk. All the terms used in the bow ties are defined below.

FIGURE 10-1
RISK BOW TIE, PG&E SYSTEMWIDE

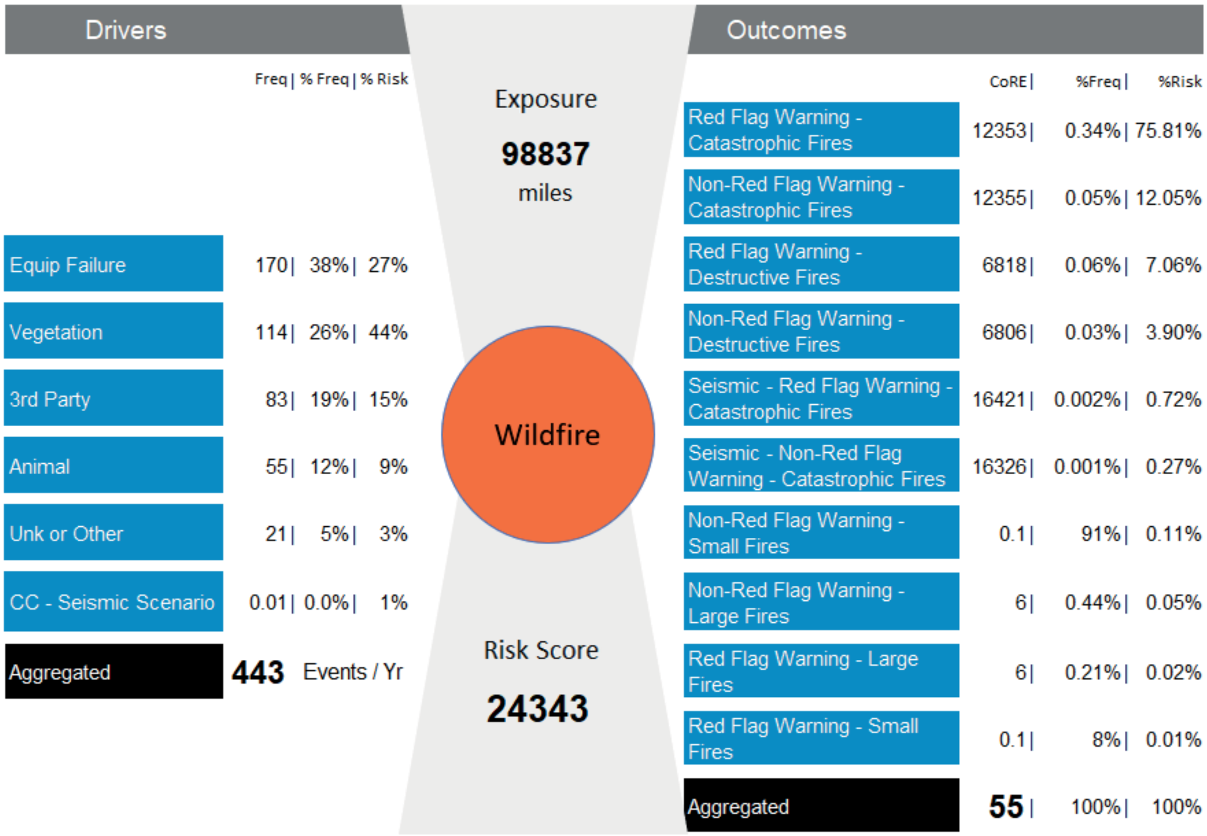
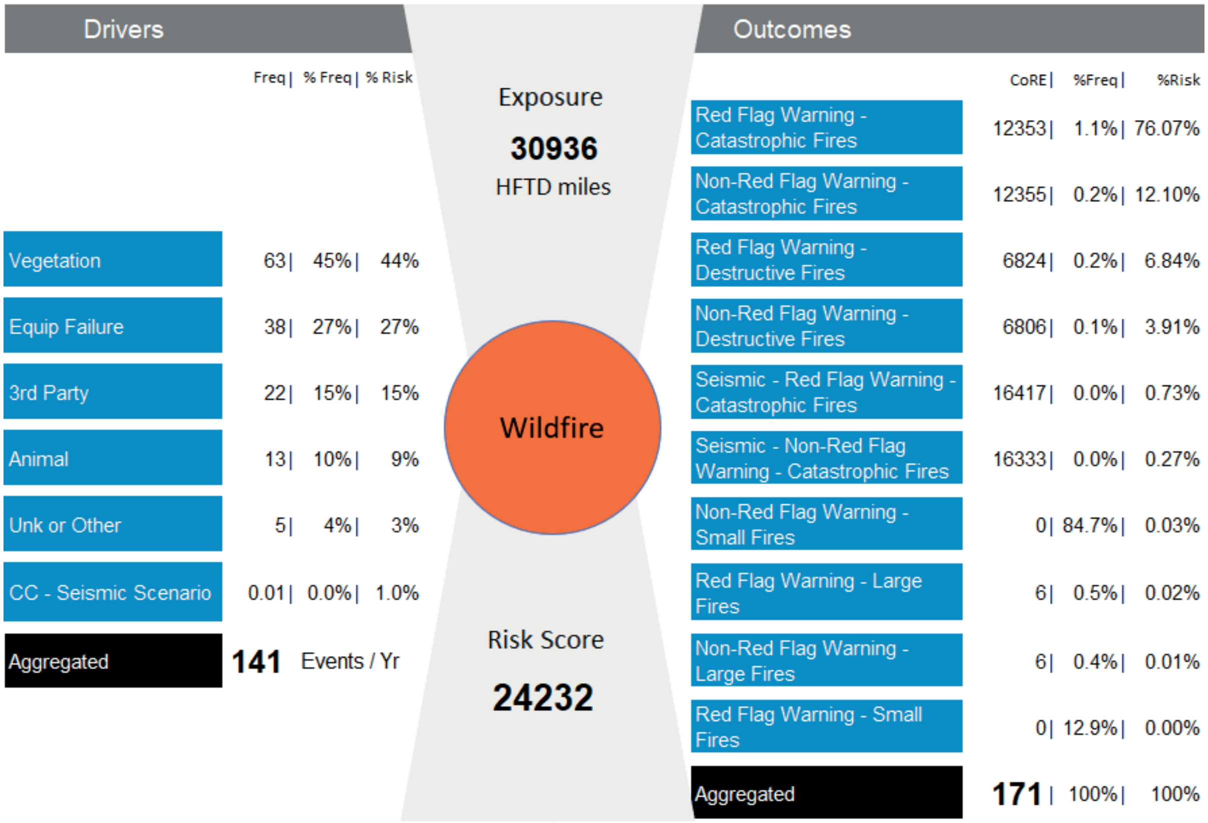


FIGURE 10-2
RISK BOW TIE – HFTD ONLY



Note: Vegetation is the most significant risk driver within HFTD areas.

a. Difference from 2017 Risk Bow Tie

The 2020 RAMP risk bow tie above differs from the bow tie presented in the 2017 RAMP in several important ways. In terms of exposure, the 2020 bow tie considers PG&E's entire overhead transmission and distribution system instead of just the Fire Index Areas (FIA) considered in the 2017 bow tie. See Section B.3, below. The frequencies in the 2017 bow tie were based on 2015-2016 ignitions reported to the CPUC; the frequencies in the 2020 bow tie are based on reportable ignitions data[11] for 2015-2019, including data from seven additional fires that were not included in PG&E's annual report of ignitions to the CPUC because they were under investigation at the time the report was submitted. See Section B.5, below. The 2017 bow tie had several drivers related to equipment failure; the 2020 bow tie has

11 Guidelines based on D.14-02-015.

one equipment failure driver but continues to capture the different types of equipment failure as sub-drivers. The 2020 bow tie also includes a Seismic Scenario driver that was not present in the 2017 bow tie. See Section B.5, below. In the 2017 bow tie, PG&E considered consequences based on categories of overall impact (e.g., Safety, Reliability, Financial). The 2020 bow tie considers consequences with more granularity based on eight individual tranches in terms of the frequency and risk impact attributable to ten different combinations of fire size and weather conditions, including fires associated with a potential seismic event, all in combination for an aggregated risk score.

3. Exposure to Risk

PG&E has approximately 81,000 distribution overhead circuit miles and approximately 18,000 transmission overhead circuit miles in its service territory. All these circuit miles are included in the current Wildfire operational risk model as required by the enabling legislation for the WMP.[12] Prior to the WMP, PG&E's operational risk model only included circuit miles in areas designated by the Commission as high fire risk; the 2017 RAMP measured Wildfire risk exposure measured based on FIA and the 2020 GRC modeled risk exposure based on HFTD areas. In the current model, PG&E accounts for the different risk profiles of HFTD and non-HFTD areas through the tranching process, as discussed below.

4. Tranches

To better understand the causes and consequences of ignitions depending on type of facility and location, PG&E is looking separately at ignitions in HFTD and non-HFTD areas, and further breaking those ignitions down into those associated with distribution, transmission, and substation

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[12] Public Utilities Code Section 8386(c) (11) (the WMP shall include a list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceeding and RAMP filings).

facilities.[13] In response to feedback from intervenors requesting that PG&E's tranches reflect whether assets have been upgraded (i.e., whether system hardening has been performed), PG&E has further divided distribution circuits in HFTD areas into separate tranches for: (1) areas that have already been hardened; (2) areas that have not yet been hardened that PG&E plans to harden; and (3) other HFTD distribution miles. This results in eight proposed tranches that reflect similar risk profiles within each tranche:

HFTD Areas – Distribution (Hardened): Distribution lines in HFTD areas that have already been hardened as of the end of 2019 (171 circuit miles or <1 percent of system mileage).

HFTD Areas – Distribution (To Be Hardened): Distribution lines in HFTD areas that will ultimately be in the scope of the System Hardening Program as currently planned, but have not yet been hardened as of the end of 2019 (6,929 circuit miles or 7 percent of system mileage).

HFTD Areas – Distribution (Remainder): Distribution lines in HFTD areas that are outside the current scope of the System Hardening Program (18,310 circuit miles or 19 percent of system mileage).

HFTD Areas – Transmission: Transmission lines in HFTD areas (5,525 circuit miles or 6 percent of system mileage).

HFTD Areas – Substation: 203 of PG&E's 942 substations (includes switching stations and other facilities) are located in HFTD areas (and assigned one circuit mile of lines for modeling purposes).

Non-HFTD Areas – Distribution: Distribution lines in non-HFTD areas (55,300 circuit miles or 56 percent of system mileage).

Non-HFTD Areas – Transmission: Transmission lines in non-HFTD areas (12,600 circuit miles or 13 percent of system mileage).

Non-HFTD Areas – Substation: 739 of PG&E's 942 substations (includes switching stations and other facilities) are located in non-HFTD areas (and assigned one circuit mile of lines for modeling purposes).

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13 In the 2017 RAMP, PG&E's model was based only on ignitions that occurred in FIAs, and did not differentiate between ignitions caused by distribution, transmission, and substation assets. FIAs were superseded by HFTD areas in the Commission's most recent update of its fire threat map in 2018. PG&E incorporates the new HFTD boundaries in its tranching analysis and in its targeting of mitigations.

Table 10-2 below shows the tranche-level results of the risk analysis.

TABLE 10-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Line No.	Tranche	Percent Exposure	Safety Risk Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent Risk
1	HFTD Areas – Distribution (Hardened)	0.17%	58.64	0.78	85.82	145.25	0.60%
2	HFTD Areas – Distribution (To Be Hardened)	7.01%	4,536.68	61.32	6,460.20	11,058.20	45.43%
3	HFTD Areas – Distribution (Remainder)	18.53%	4,607.80	66.19	6,768.48	11,442.46	47.00%
4	HFTD Areas – Transmission	5.59%	636.08	8.92	938.86	1,583.85	6.51%
5	HFTD Areas – Substation	0.00%	–	–	–	–	–
6	Non-HFTD Areas – Distribution	55.95%	25.34	8.83	75.06	109.23	0.45%
7	Non-HFTD Areas – Transmission	12.75%	0.91	0.35	2.87	4.14	0.02%
8	Non-HFTD Areas – Substation	0.00%	0.02	0.01	0.05	0.07	0.00%
9	Total	100%	9,865.47	146.40	14,331.34	24,343.20	100%

Note: Amount of System Hardening is as of December 31, 2019.

5. Drivers and Associated Frequency

Historically, there were 2,202 fire ignitions associated with PG&E facilities that occurred in PG&E's service territory during the 5-year period 2015-2019, 691 of which were in HFTD areas.[14] This number includes 2,195 ignitions reported in annual fire incident reports to the CPUC, plus seven additional ignitions associated with known historical fires which were not included in annual fire incident reports because their causes were still under investigation at the time the reports were submitted, but which have subsequently been determined to be associated with PG&E equipment.

In order to better represent the driver frequency looking forward, PG&E made adjustments to this historical ignition count for risk modeling purposes.

To forecast 2020 baseline number of ignitions, PG&E made three adjustments:

1) Added 56 ignitions to account for its estimate of ignitions avoided in 2019 due to PSPS;[15]
2) Added 3 ignitions to account for its estimate of possible ignitions due to a Seismic Scenario; and[16]
3) Subtracted 6 ignitions to account for its estimate of the reduction in ignition frequency due to 2019 mitigation programs.[17]

These adjustments result in a net 53 additional ignitions. Adding these 53 ignitions to 2,202 historical ignitions results in adjusted five-year total of 2,255 ignitions, or 451 ignitions per year.

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14 A fire ignition is defined, based on the CPUC's reportable fire ignition definition in D.14-02-015, as an ignition resulting a fire that traveled more than one meter from the ignition point and burnt something other than PG&E facilities. PG&E's current Wildfire risk model uses all reportable ignitions systemwide; previous versions of the model were limited to high fire risk areas (FIAs in the 2017 RAMP and HFTD areas in the 2020 GRC).

15 The methodology for estimating ignitions avoided in 2019 due to PSPS is discussed in the modeling workpapers which will be provided on July 17, 2020. The 56 ignitions were proportionally distributed against all drivers so as not to change driver percentages.

16 The calculations underlying this estimate will be included in workpapers on July 17, 2020.

17 *Id*.

To forecast 2023 TY baseline number of ignitions, PG&E subtracted an additional eight ignitions from the 2020 forecast baseline number of ignitions per year to reflect its estimate of the annual reduction in ignitions, due to the implementation of PG&E's 2020-2022 mitigation programs.[18]

These ignitions were categorized into 6 top level risk drivers and 35 sub-drivers. Each driver and its associated 2023 TY baseline number of ignitions are discussed below,[19] and a complete list of sub-drivers is shown in the workpapers.

D1 – Equipment Failure: This driver is defined as events where failure of a PG&E asset such as a conductor, arrester, insulator, breaker, transformer, etc., caused a reportable ignition. Overall, the Equipment Failure risk driver accounts for 170 (38 percent) of the 443 expected annual number of ignitions systemwide and 38 (27 percent) of the 141 expected annual number of ignitions in HFTD areas. Conductor and splice/clamp/connector failures account for slightly more than half of the equipment failure incidents in the Wildfire model.

D2 – Vegetation: This driver is defined as events where trees, tree limbs, and other vegetation came in contact with a PG&E asset, resulting in a reportable ignition. Overall, the Vegetation risk driver accounts for 114 (26 percent) of the 443 expected annual number of ignitions systemwide, and 63 (45 percent) of the 141 expected annual number of ignitions in HFTD areas.

D3 – Third-Party Contact: This driver is defined as events where member(s) of the public or an object under their control came in contact with

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18 The calculations underlying this estimate will be included in workpapers on July 17, 2020.

19 In a February 19, 2020 letter to PG&E providing feedback on information that PG&E provided in workshops held on January 13, 2020 and February 4, 2020, The Utility Reform Network (TURN) recommended that PG&E include "wind speed, or some specification of weather conditions" as a driver. Since weather conditions do not create ignitions by themselves, PG&E does not consider them a driver. However, PG&E considered weather by separating the likelihood of failure that leads to outcomes by RFW and non-RFW weather conditions (as explained in Section B.7, below). In this way, PG&E can track how adverse weather conditions can lead to different ignition risk profiles. In addition, PG&E incorporated long term projections of climate change by increasing the likelihood of RFW conditions over time in line with the California Fourth Climate Assessment, highlighting the growth in wildfire risk due to changing weather and climate conditions.

a PG&E asset, resulting in a reportable ignition. Examples of third-party contact include a vehicle hitting a distribution or transmission pole or a Mylar balloon hitting equipment or conductor. The Third-Party Contact risk driver accounts for 83 (19 percent) of the 443 expected annual number of ignitions systemwide and 22 (15 percent) of the 141 expected annual number of ignitions in HFTD areas.

D4 – Animal: This driver is defined as events where animals such as birds or squirrels came in contact with a PG&E asset, resulting in a reportable ignition. The Animal risk driver accounts for 55 (12 percent) of the 443 expected annual number of ignitions systemwide and 13 (10 percent) of the 141 expected annual number of ignitions in HFTD areas.

D5 – Unknown or Other: Events associated with PG&E assets, which led a reportable ignition, where evidence of the root cause of the ignition was not available. The Unknown or Other risk driver accounts for 21 (5 percent) of the 443 expected annual number of ignitions systemwide and 5 (4 percent) of the 141 expected annual number of ignitions in HFTD areas.

D6 – Seismic Scenario (Cross-Cutting): Failure events caused by seismic activity. This risk is described further in Chapter 20 of this report. The Seismic risk driver is estimated to account for 0.01 (<1 percent) of the 443 expected annual number of ignitions.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is related to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Wildfire risk are shown in Table 10-3 below. The cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 10-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change		X
2	Emergency Preparedness and Response		X
3	Records and Information Management		X
4	Seismic	X	X

Climate change is accounted for in PG&E's Wildfire risk model on the consequence side of the model by correlating projected future changes in PG&E territory burned with the change in frequency of ignitions that occur during RFWs. This modifies the consequences of an ignition consistent with expected climate-driven changes in the underlying factors that determine the spread and intensity of wildfire.[20] The below graph shows that over time there is an increase in the proportion of ignitions that occur during RFWs, as well as an overall increase in Wildfire risk due to climate change.

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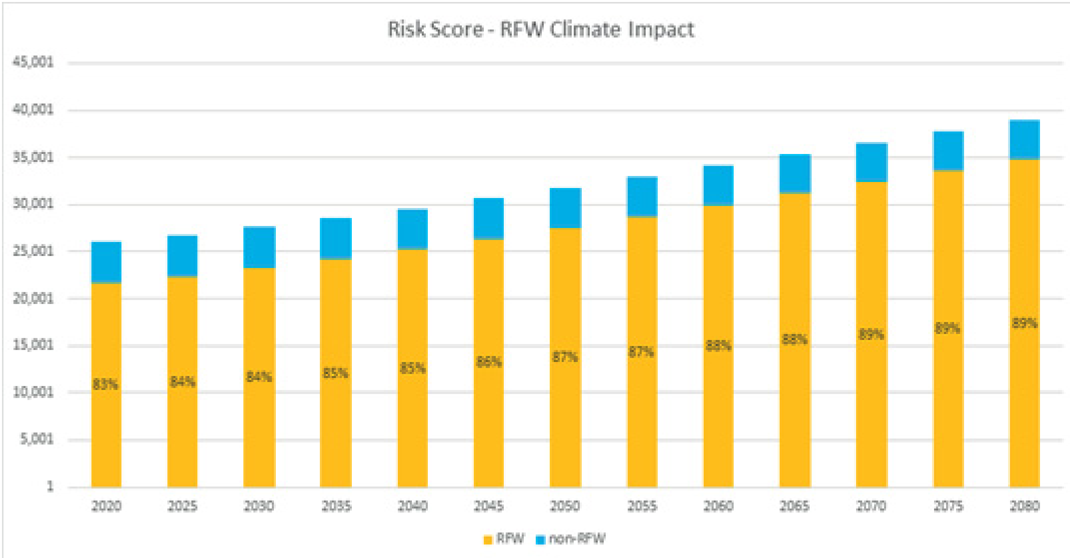
[20] Data for the projected change in future area burned comes from wildfire scenario projections for the California Fourth Climate Assessment, produced by Dr. LeRoy Westerling at the University of California Merced. This uses a statistical model based on historical data on climate, vegetation, population density, and fire history coupled with regionally down-scaled Localized Constructed Analogs climate projections. The data is based on a "business as usual" emissions scenario, Representative Concentration Pathway 8.5.

FIGURE 10-3
RISK SCORE – RFW CLIMATE IMPACT



PG&E is continuing to evaluate the impact that Information Technology (IT) Asset Failure and Cyber Attack have on all its RAMP risks and may present IT Asset Failure and Cyber Attack as cross-cutting factors relative to the Wildfire risk in the 2023 GRC.

7. Consequences

There is a wide range of potential public safety risks resulting from a fire ignition associated with PG&E assets. In the overwhelming majority of cases, fire ignitions do not end up a large wildfire because they are extinguished quickly and/or do not propagate far.[21] However, in some cases, ignitions can result in larger wildfires.

PG&E uses fire incidents from the CAL FIRE database[22] to estimate the safety and financial consequences of wildfire. For each fire incident, the CAL FIRE dataset provides the location, size, number of destroyed/damaged structures, and the number of fatalities/injuries. Reliability consequences are estimated by using distribution customer minutes for outages that were associated with CPUC reportable ignitions and known fires associated with those outages.

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21 More than 95 percent of the reportable ignitions in PG&E's service territory between 2015 and 2019 burned 300 or fewer acres.

22 Based on CAL FIRE Redbook data.

In its discussion of consequences in the 2017 RAMP, PG&E considered all ignitions as a single category. For the 2020 RAMP, PG&E is providing a more granular discussion of ignitions in terms of three variables:

1) The size/destructiveness of the fire that resulted from the ignition. PG&E's categorization of fire size is based on the following definitions:
    a. <u>Catastrophic</u>: A fire that destroys 100 or more structures and results in a serious injury and/or fatality.
    b. <u>Destructive</u>: A fire that destroys 100 or more structures but does not result in a serious injury or fatality.
    c. <u>Large</u>: A fire that burns 300 or more acres but does not meet the definition of a Destructive or Catastrophic fire.
    d. <u>Small</u>: A fire that burns fewer than 300 acres.
2) Whether the ignition took place on a day and in an area in which a RFW was in place or not. RFW is a forecast warning issued by the NWS in the United States to inform the public, firefighters, and land management agencies that conditions are ideal for wildland fire combustion and rapid spread.[23] The potential consequences of ignitions are higher when a RFW is in effect.[24]
3) For catastrophic fires, only, whether the catastrophic fire is associated with a seismic event.

- Table 10-4 shows the frequency and risk consequences associated with these different types of ignitions.

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23 Precise temporal and spatial mapping analysis of RFW conditions is conducted by utilizing RFW GIS shapefiles from: https://mesonet.agron.iastate.edu/request/gis/watchwarn.phtml. (as of June 16, 2020).

In a February 19, 2020 letter to PG&E providing feedback on information that PG&E provided in workshops held on January 13, 2020 and February 4, 2020, TURN recommended that "for clarity" PG&E use "Fire Weather *Conditions* instead of *Warning*" when classifying outcomes. At the time of the workshop, PG&E used the term "Fire Weather Warning" to refer to elements of the NWS Red Flag Warning. PG&E's use of RFWs to categorize outcomes is appropriate because it is a simple, objective metric from a trusted third-party (NWS) that serves as a reasonable proxy for fire weather conditions.

24 Starting in 2023, PG&E's Wildfire risk model assumes that the probability that an ignition occurs at a location and day that RFW is in effect will increase in 5-year increments based on the Cal-Adapt Wildfire Data.

TABLE 10-4
RISK EVENT CONSEQUENCES

Line No.	Fire Type	RFW	Seismic Event	Frequency	Risk
1	Catastrophic	Yes	No	0.34%	75.81%
2	Catastrophic	No	No	<0.10%	12.05%
3	Catastrophic	Yes	Yes	<0.10%	0.72%
4	Catastrophic	No	Yes	<0.10%	0.27%
5	Destructive	Yes	N/A	<0.10%	7.06%
6	Destructive	No	N/A	<0.10%	3.90%
7	Large	Yes	N/A	0.21%	0.02%
8	Large	No	N/A	0.44%	0.05%
9	Small	Yes	N/A	7.83%	0.01%
10	Small	No	N/A	91.04%	0.11%

This risk analysis shows that 83 percent of the total Wildfire risk is from ignitions on RFW days that lead to catastrophic or destructive fires. This supports PG&E’s decision to invest in the PSPS mitigation, which is targeted at reducing ignitions when these conditions are present. It also supports PG&E’s investment in situational awareness mitigations, such as improvements in meteorology that will improve PG&E’s ability to predict and respond to conditions that have the greatest potential for ignitions to turn into more dangerous fires.

Table 10-5 below shows the consequences from the risk model in detail. Model attributes are described in Chapter 3, “Risk Modeling and Risk Spending Efficiency.”

TABLE 10-5
RISK EVENT CONSEQUENCES

					Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety	Electric Reliability	Financial	Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Safety	Electric Reliability	Financial
Red Flag Warning - Catastrophic Fires	12,353	0.3%	76%	1.5	16	39	2,028	5,617	64	6,672	23	59	3,030	8,393	95	9,968
Non-Red Flag Warning - Catastrophic Fires	12,355	0.1%	12%	0.2	16	38	2,035	5,648	59	6,648	4	9	483	1,341	14	1,578
Red Flag Warning - Destructive Fires	6,818	0.1%	7%	0.3	-	38	2,056	-	56	6,762	-	10	519	-	14	1,705
Non-Red Flag Warning - Destructive Fires	6,806	0.0%	4%	0.1	-	37	2,050	-	59	6,747	-	5	286	-	8	941
Seismic - Red Flag Warning - Catastrophic Fires	16,421	0.0%	0.7%	0.0	20	56	3,037	7,289	104	9,027	0.2	1	33	78	1	97
Seismic - Non-Red Flag Warning - Catastrophic Fires	16,326	0.0%	0.3%	0.0	20	58	2,989	7,377	113	8,836	0.1	0	12	29	0	35
Non-Red Flag Warning - Small Fires	0.1	91.0%	0.1%	403	0	0	0	0	0	0	0	19	1	16	10	1
Non-Red Flag Warning - Large Fires	6	0.4%	0.05%	2.0	0	2	4	2	1	2	0	4	8	5	2	5
Red Flag Warning - Large Fires	6	0.2%	0.02%	0.9	0	2	4	2	1	2	0	2	4	2	1	2
Red Flag Warning - Small Fires	0.07	7.8%	0.01%	35	0	0	0	0	0	0	0	2	0	1	1	0
Aggregated	**55**	100%	100%	443	0	0	10	22	0	32	28	110	4,376	9,865	146	14,331

C. Controls and Mitigations

Tables 10-6 and 10-7 list all the controls and mitigations PG&E included in its 2017 RAMP, 2020 GRC and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

TABLE 10-6
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP (2016 Controls)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
1	C1 (2017) – Overhead Patrols and Inspections	X	X	X	Split into C1-C3	
2	C2 (2017) – Vegetation Management	X	X	X	Split into C4-C6	
3	C3 (2017) – Catastrophic Event Memorandum Account - Vegetation Management	X	X	X	Becomes C7	
4	C4 (2017) – Non-Exempt Equipment Replacement	X	X	X	Becomes M4	
5	C5 (2017) – Overhead Conductor Replacement	X	X	X	Replaced by M2	
6	C6 (2017) – Animal Abatement	X	X	X	Becomes C11	
7	C7 (2017) – Protective Equipment	X	X	X	Included in C14	
8	C8 (2017) – Overhead Equipment Replacement	X	X	X	Split into C8-C10	
9	C9 (2017) – Pole Replacement	X	X	X	Becomes C12	
10	C10 (2017) – Wood Pole Bridging	X	X	X	Incorporated into C12	
11	C11 (2017) – Design Standards	X	X	X	Becomes C16	
12	C12 (2017) – Restoration, Operational Procedures and Timing	X	X	X	Becomes C17	
13	C1 – Patrols and Inspections – Distribution Overhead (was part of C1 (2017))				X	X
14	C2 – Patrols and Inspections – Transmission Overhead (was part of C1 (2017))				X	X
15	C3 – Patrols and Inspections – Substation (was part of C1 (2017))				X	X

TABLE 10-6
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Name and Number	2017 RAMP (2016 Controls)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
16	C4 – Vegetation Management – Distribution Overhead (was part of C2 (2017))				X	X
17	C5 – Vegetation Management – Transmission Overhead (was part of C2 (2017))				X	X
18	C6 – Vegetation Management – Substation (was part of C2 (2017))				X	X
19	C7 – Vegetation Management –CEMA (was C3 (2017))				X	X
20	C8 – Equipment Maintenance and Replacement – Distribution Overhead (was part of C8 (2017))				X	X
21	C9 – Equipment Maintenance and Replacement – Transmission Overhead (was part of C8 (2017)) confirm				X	X
22	C10 – Equipment Maintenance and Replacement – Substation (was part of C8 (2017))				X	X
23	C11 – Animal Abatement (was C6 (2017))				X	X
25	C12 – Pole Programs (was C9 (2017))				X	X
26	C13 – Transmission Structure Maintenance and Replacement				X	X
27	C14 – System Automation and Protection (was C7 2017 and part of M15 2020 GRC))				X	X
28	C15 – Reclose Blocking (was M1 and part of M2 in the 2017 RAMP and M14 in the 2020 GRC)				X	X
29	C16 – Design Standards (was C11 (2017))				X	X
30	C17 – Restoration, Operational Procedures, and Training (was C12 2017)				X	X

TABLE 10-7
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP (2017-2019)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
1	M1 (2017) – Wildfire Reclosing Operation Program (System Control and Data Acquisition (SCADA) Programming)	X	Becomes part of M14 (2020 GRC)			
2	M2 (2017) – Wildfire Reclosing Operation Program (SCADA Capability Upgrades)	X	Becomes part of M15 (2020 GRC)			
3	M3 (2017) – Fuel Reduction and Powerline Corridor Management	X	Becomes part of M16 (2020 GRC)			
4	M4 (2017) Overhang Clearing	X	Becomes part of M16 (2020 GRC)			
5	M5 (2017) Non-Exempt Surge Arrester Replacement	X	X	X	Becomes M3	
6	M7 (2017) – Targeted Conductor Replacement (WF)	X	Becomes part of M12 (2020 GRC)			
7	M10 (2020 GRC) – Resilience Zones		X	X	Becomes part of M6	
8	M11 (2020 GRC) – Light Duty Steel Poles for Transmission Lines		X	X	Becomes part of C13	
9	M12 (2020 GRC) Wildfire System Hardening		X	X	Becomes M2	
10	M13 (2020 GRC) – Public Safety Power Shut Off		X	X	Becomes M5	
11	M14 (2020 GRC) – Reclose Blocking		X	X	Becomes C15	
12	M15 (2020 GRC) – Automation and Protection		X	X	Some of this becomes M6, some becomes M10 and some becomes part of C15	

TABLE 10-7
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP (2017-2019)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
13	M16 (2020 GRC) – EVM		X	X	Becomes M1	
14	M17 (2020 GRC) – Vegetation Increased Line Clearances		X	Becomes part of the Vegetation Management control		
15	M18 (2020 GRC) – Wildfire Safety Operations Center		X	X	Becomes part of M7	
16	M19 (2020 GRC) – Expanded Weather Station Deployment		X	X	Becomes part of M7	
17	M20 (2020 GRC) – Storm Outage Prediction Project (SOPP) Model		X	X	Becomes part of M7	
18	M21 (2020 GRC) – Advanced Fire Model		X	X	Becomes part of M7	
19	M22 (2020 GRC) – Wildfire Cameras		X	X	Becomes part of M7	
20	M23 (2020 GRC) – Satellite Fire Detection System		X	X	Becomes part of M7	
21	M24 (2020 GRC) – Enhanced Wire Down Detection		X	X	Becomes part of M7	
22	M25 (2020 GRC) – Wildfire and Infrastructure Protection Teams		X	X	Becomes M8	
23	M26 (2020 GRC) – Aviation Resources		X	X	Not modeled[a]	
24	M27 (2020 GRC) – Employee Engagement, Training, and Tools		X	X	Becomes part of C16 and C17	
25	M28 (2020 GRC) – CWSP Program Management Office (PMO)		X	X	Becomes M9	

TABLE 10-7
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP (2017-2019)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
26	M1 – EVM (was M16 (2020 GRC))				X	X
27	M2 – System Hardening (was M12 (2020 GRC))				X	X
28	M3 – Non-Exempt Surge Arrester Replacement (was M5 (2017))				X	X
29	M4 – Expulsion Fuse Replacement (was C4 (2017))				X	X
30	M5 – PSPS (was M13 (2020 GRC))				X	X
31	M6 – PSPS Impact Reduction Initiatives (includes 2020 GRC mitigations M10 and M15) (Foundational)				X	X
32	M7 – Situational Awareness and Forecasting Initiatives (includes 2020 GRC mitigations M18, M19, M20, M21, M22, M23 and M24) (Foundational)				X	X
33	M8 – Safety and Infrastructure Protection Teams (SIPT) (was M25 (2020 GRC)) (Foundational)				X	X
34	M9 – CWSP PMO (was M28 (2020 GRC)) (Foundational)				X	X
35	M10 – Additional System Automation and Protection (Foundational)				X	X
36	M11 – Remote Grid (2020-2022)				X	

(a) See footnote 39 below.

1. 2019 Controls and Mitigations

a. Controls

C1 – Patrols and Inspections – Distribution Overhead:[25] PG&E patrols and inspects its electric distribution facilities to identify damaged facilities, compelling abnormal conditions, regulatory conditions, and third-party-caused infractions that may negatively impact safety or reliability, including conditions that could cause a wildfire ignition. The pre-2019 baseline inspection program was designed in accordance with General Order (GO) 165.

In 2019, PG&E performed supplemental inspections, using enhanced inspection criteria and expanded documentation requirements, of all its overhead distribution facilities located in Tier 2 and Tier 3 HFTD areas—more than 690,000 poles and associated assets—as part of its Wildfire Safety Inspection Program (WSIP). PG&E refined inspection procedures and developed enhanced WSIP inspection criteria using a risk-based approach, including using Failure Modes and Effects Analysis or "FMEA" to identify single points of failure of electric system components that could lead to fire ignition. The WSIP supplemental assessment used mobile applications, instead of paper maps, and collected of additional asset condition data and photographs.

Going forward, PG&E will integrate WSIP criteria, tools, and process controls into its routine overhead inspection process for PG&E's entire distribution system. In addition, PG&E will adjust the cadence of inspection in alignment with wildfire risk and other risks. This control has the potential to reduce the Equipment Failure driver.

C2 – Patrols and Inspections – Transmission Overhead: As with its distribution facilities, PG&E patrols and inspects its overhead transmission facilities to identify damaged facilities and other conditions that may pose risks, including the risk of a wildfire ignition.

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25 PG&E identified Patrols and Inspections as a single control in the 2017 RAMP. For the 2020 RAMP, PG&E is dividing the control between overhead distribution, transmission, and substation facilities to facilitate the tracking of the relationship of inspections of different types of facilities to the most prevalent operational risks and fire ignition drivers for those facilities.

Transmission overhead facilities were included in the WSIP process described above; from late 2018 through 2019, PG&E performed supplemental aerial and/or visual inspections of more than 49,000 transmission structures located in or near HFTD areas. Going forward, PG&E will integrate WSIP practices into its routine inspection processes. In addition, facility risk will now inform inspection cadence. This control has the potential to reduce the Equipment Failure driver.

C3 – Inspections – Substation: In accordance with GO 174, PG&E inspects its substations (includes switching stations and other facilities) on a monthly or every other month basis, to identify damaged facilities, compelling abnormal conditions, regulatory conditions, and third-party caused infractions that may negatively impact safety or reliability, including conditions that could cause a wildfire ignition.

In addition to these inspections, substations were included in the WSIP process. In 2019 PG&E performed enhanced visual and infrared inspections of 222 substations (including switching stations and other facilities) located in Tier 2 and 3 HFTD areas. Going forward, PG&E may adjust the cadence of enhanced inspections in alignment with wildfire risk and other risks. This control has the potential to reduce the Equipment Failure driver.

C4 – Vegetation Management – Distribution Overhead: PG&E's Vegetation Management Program was developed in coordination with GO 95, Rule 35 and California Public Resources Code (PRC) Sections 4292 and 4293. The program includes "routine" compliance-based vegetation management, including periodic inspections, clearing of vegetation around lines and around poles with equipment that poses a fire risk, and quality assurance.

In 2018 and 2019, PG&E increased vegetation-to-conductor clearances from 18 inches to 48 inches in HFTD areas as required by the CPUC in D.17-12-024. The initial clearance was discussed as a mitigation (M17 – Vegetation increased Line Clearances) in the 2020 GRC; now that the new clearance is established, its ongoing maintenance becomes part of the control. This control has the potential to reduce the vegetation driver.

C5 – Vegetation Management – Transmission Overhead: This control covers similar routine vegetation management activities to C4, but for the transmission system. The routine transmission program was developed in coordination with GO 95, Rule 35, and PRC Sections 4292 and 4293, as well as North American Electric Reliability Corporation FAC 003-4, a Federal Energy Regulatory Commission-approved standard implemented to mitigate transmission outages and resulting blackouts due to vegetation contact. This control has the potential to reduce the vegetation driver.

C6 – Vegetation Management – Substation: This control covers similar routine vegetation management activities to C4, but for substations. The program includes clearing vegetation inside the perimeter of the substation fence and, in HFTD Tier 2 and Tier 3 areas, creating an additional zone of defensible space outside the substation. This control has the potential to reduce the vegetation driver.

C7 – Vegetation Management – (CEMA): Since 2014, PG&E has undertaken several initiatives to address the risks associated with tree mortality stemming from prolonged drought conditions and bark beetle infestation, which caused California's Governor to declare an ongoing state of emergency in 2015. These initiatives, which are funded through the Catastrophic Emergency Memorandum Account (CEMA), include additional inspections and tree work in areas of PG&E's service territory that are at higher risk for tree mortality or wildfire, including HFTD areas, State Responsibility Areas, and Wildland-Urban Interface.

In 2019, PG&E removed approximately 45,600 dead or dying trees close to PG&E facilities through the CEMA Tree Mortality Program. This control has the potential to reduce the vegetation driver.

C8 – Equipment Preventive Maintenance and Replacement – Distribution Overhead: Proactive identification and repair or replacement of critical overhead distribution equipment, such as cross-arms, transformers, capacitors, reclosers, and switches. Equipment is identified through the Patrol and Inspections—Distribution Overhead (C1) control or through *ad hoc* inspection.

In 2019, PG&E's accelerated and enhanced WSIP inspection process in Tier 2 and Tier 3 HFTD areas identified a substantial amount of repair and replacement work (maintenance tags) to be completed. PG&E has completed the high priority corrective actions identified as necessary and will complete the lower priority work over the next three years. PG&E has developed a prioritization model to manage maintenance tags for distribution assets in HFTD areas; that prioritization reflects a calculated wildfire risk score for each maintenance condition/tag based on four factors: asset failure ignition risk, historical asset ignition frequency, likelihood of fire spread and consequence, and potential effect of an asset failure on egress and first responder access. This control has the potential to reduce the Equipment Failure driver.

C9 – Equipment Maintenance and Replacement – Transmission Overhead: Proactive identification and repair or replacement of critical overhead transmission assets, such as conductors, insulators, hardware, and switches. Equipment condition is assessed through patrols, inspections, and high-definition images to determine if equipment poses a risk of failure or is no longer able to perform required functions.

In 2019, the inspection program was accelerated and significantly improved in Tier 2 and Tier 3 HFTD areas. This enhanced scope and process will continue to be used in 2020 and going forward. A substantial amount of repair and replacement work (maintenance tags) was identified in 2019; that work is being performed based on risk prioritization. Note that transmission towers, poles, and other structures are separately addressed in C13. This control has the potential to reduce the Equipment Failure driver.

C10 – Equipment Maintenance and Replacement – Substation: Proactive identification and repair or replacement of critical substation equipment, such as transformers, circuit breakers, switches, ground grids, insulators, and bus structures. Equipment is assessed through inspections, functional/diagnostic testing, and condition monitoring to determine if it poses a risk of failure, is no longer able to perform required functions, or is not cost effective to maintain. Repair and replacement work is performed based on condition assessment and risk prioritization. This control has the potential to reduce the Equipment Failure driver.

C11 – Animal Abatement: The installation of new equipment or retrofitting of existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles such as jumper covers, perch guards, or perching platforms. It also includes animal abatement work in substations. This control has the potential to reduce the Animal driver.

C12 – Pole Programs: This control includes multiple activities related to distribution poles, including intrusive testing, remediation, and loading assessment. Distribution wood poles are remediated (replacement or reinforcement) when necessary, based on degradation observed.

In addition, in 2019 PG&E initiated a new pole loading assessment proof of concept to enhance the analysis of its existing distribution wood poles. At the same time, PG&E has strengthened the safety factor requirements included in its pole loading model parameters. For example, sizing for new and replacement distribution poles now considers peak historical wind speeds in areas where they exceed GO 95 wind speeds. This control has the potential to reduce the Equipment Failure driver.

C13 – Transmission Structure Maintenance and Replacement: This control covers the maintenance repairs and targeted replacements of PG&E's approximately 150,000 transmission structures (steel towers and transmission wood poles). It also covers the intrusive inspection of transmission wood poles; inspection of other transmission structures is included in C2 – Patrols and Inspections – Transmission. This control has the potential to reduce the Equipment Failure driver.

C14 – System Automation and Protection: The installation of new equipment (e.g., fuses, reclosers, and SCADA installations enabling remote operation) that isolates equipment when abnormal system conditions are detected. This control has the potential to reduce the Equipment Failure driver.

C15 – Reclose Blocking: Reclosing devices such as circuit breakers and line reclosers are used to quickly and safely de-energize lines when a problem is detected and re-energize lines when the problem is cleared. However, the automated reclosing function of these devices has the potential to cause an ignition if the device sends power to test whether a fault is clear, but the fault condition (such as a wire down) still exists. To reduce this ignition risk, beginning in 2018, PG&E disabled the automated reclosing functionality during elevated fire conditions on all reclosing devices located in protection zones that intersect with Tier 2 and Tier 3 HFTD areas. Most of these devices are SCADA-enabled and can be disabled remotely, and the remaining devices are disabled manually. If a device operates, PG&E patrols all circuit segments where reclosing functionality has been disabled before re-energizing the circuit to ensure that the lines and line equipment are not damaged.

In 2019, PG&E installed SCADA capability on additional reclosing devices in HFTD areas to support Reclose Blocking; these incremental installations are part of the M10 Additional Automation and Protection mitigation discussed below. In 2019, PG&E began disabling reclosing functionality on both manually and SCADA-controlled devices in protection zones that intersect with Tier 2 and Tier 3 HFTD areas for the duration of the fire season instead of using a system based on fire index daily ratings. This control has the potential to reduce the Equipment Failure and vegetation drivers.

C16 – Design Standards: This control relates to the general standards for proper application of equipment to ensure safe and reliable operation in high fire-threat areas. For example, Utility Bulletin: TD-9001B-009 Rev2 “Fire Rebuild Design Guidance for System Hardening,” which was first published in October 2018 and continues to evolve, sets forth standards to be used in new construction and system upgrades in HFTD areas. This control has the potential to reduce the Equipment Failure driver.

C17 – Restoration, Operational Procedures and Training: This control relates to work standards for high fire-threat areas. Utility Standard TD-1464S establishes requirements for PG&E employees and contractors to follow when travelling over, performing work on, or operating in any forest, brush, or grass-covered lands. In 2019, the standard was updated to better reflect PRC Sections 4427, 4428, and 4430 and to lay out specific mitigations and restrictions based on the work being performed and the daily fire danger.

PG&E created additional training and monitoring materials to facilitate compliance with the revised standard. Bulletin TD-1464B-001 describes reclosing device operating practices, including procedures used as part of the Reclose Blocking control. Bulletin TD-1464B-002 describes procedures for use in implementing PSPS. This control has the potential to reduce Equipment Failure and vegetation drivers.

b. Mitigations

M1 – Enhanced Vegetation Management: The EVM Program is targeted at overhead distribution lines in Tier 2 and Tier 3 HFTD areas and exceeds the requirements of PG&E's annual Routine Vegetation Management that maintains compliance with CPUC mandated clearances (GO 95, Rule 35).[26] This mitigation will reduce the vegetation driver. The EVM Program is a multi-year effort to perform the following activities throughout the Tier 2 and Tier 3 HFTD areas of PG&E's service territory to reduce the likelihood of vegetation contacts with PG&E electric equipment:

Enhanced Radial Clearances: PG&E is trimming trees and other vegetation to create a 12-foot radial clearance around overhead distribution lines, exceeding the 4-foot minimum radial clearance required by the CPUC.

Overhang Trimming: PG&E is removing overhanging branches and limbs from conductor to sky within 4 feet of either side of electric distribution lines, to reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation-conductor contact.

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26 EVM is a mitigation that impacts two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

Identification and Mitigation of Trees with the Potential to Strike: As part of the EVM Program, PG&E is evaluating all trees tall enough to strike electrical lines or equipment and, based on that assessment, pruning or removing trees that pose a safety risk, including dead and dying trees.[27]

Fuel Reduction: PG&E is reducing vegetative fuel in areas under and adjacent to both distribution and transmission lines to further reducing wildfire risk. This work is evaluated on a case-by-case basis looking at factors such as type and amount of fuel, access, and presence and type of vegetation in the zones around lines.

In 2019, in addition to its routine vegetation management activities, PG&E's EVM Program inspected and further pruned or removed vegetation—as described above—along 2,498 miles (approximately 10 percent) of PG&E's overhead distribution lines in Tier 2 and Tier 3 HFTD areas.

M2 – System Hardening: The System Hardening Program is an ongoing, long-term capital investment program to rebuild portions of PG&E's overhead electric distribution system to reduce fire risk.[28] This mitigation has the potential to reduce the Equipment Failure, Vegetation, Animal, and Other drivers.

Under this program, PG&E plans to upgrade approximately 7,100 circuit miles in Tier 2 and Tier 3 HFTD areas. PG&E design standards for system hardening continue to evolve, but the planned upgrade work generally includes: (1) replacement of bare overhead primary and secondary conductor with covered conductor; (2) replacement of poles where necessary to support new, heavier covered conductor; (3) replacement of existing primary line equipment

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27 Removal of dead and dying trees is currently funded through CEMA, and therefore part of the C7 – CEMA Vegetation Management Control.

28 System Hardening is a mitigation that impacts three RAMP risks—Wildfire, Failure of Distribution Overhead Assets, Third-Party Safety Incident—because it will reduce both ignitions and equipment failure, and reduce the potential for third-party contact with energized conductors. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for all three risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

such as fuses/cutouts and switches with equipment that has been certified by CAL FIRE as low fire risk; and (4) replacement of existing transformers with models that contain fire resistant FR3 insulation fluid rather than mineral oil and that meet recent Department of Energy electrical efficiency standards. PG&E may underground portions of existing overhead circuits in limited circumstances, such as in locations along main egress routes where a rebuilt overhead circuit could still potentially fall and block evacuation routes and access for first responders. PG&E may also remove some circuits or portions of circuits that are no longer needed due to changes in grid configuration and/or customer needs.

PG&E conducted some small system hardening pilot projects in 2018 and began work in earnest in 2019, completing 171 line miles.[29] The first projects to be included in the program were some previously identified conductor replacement projects in Tier 2 and Tier 3 HFTD areas which PG&E re-designed consistent with its new design guidance for system hardening. Subsequently, most projects were prioritized and selected based on a risk-based model. PG&E's prioritization process considered likelihood of ignition (based on number, types and condition of assets and historical outage and ignition data), likelihood of spread (based on weather, topographical and fuel type information), consequence (based on population and structure density near the circuit and potential impacts to natural resources), and egress (based on population density and number and types of roads). In addition, PG&E has identified some projects where WSIP inspections identified a large number of maintenance issues that needed to be addressed on a particular circuit.

M3 – Non-Exempt Surge Arrester Replacement: This program is replacing non-exempt surge arresters with exempt surge arresters, which will reduce the potential for release of electrical arcs, sparks, or

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29 The 171 line miles completed in 2019 includes some system hardening work performed outside the System Hardening Program (Major Work Category (MWC) 08W) including some emergency work and the rebuild of circuits in Butte County damaged in the Camp Fire to PG&E's current design standards for HFTD areas.

hot material during operation.[30] The replacements are being done in conjunction with compliance work to remedy a surge arrester grounding issue. PG&E is replacing non-exempt surge arresters throughout its service territory, but only those replacements being performed in HFTD Tier 2 and Tier 3 areas are considered mitigations to the Wildfire risk. PG&E replaced 4,611 non-exempt surge arresters in 2019. PG&E expects to complete non-exempt surge arrester replacements in HFTD areas by 2021 and complete replacements systemwide by 2023. This mitigation has the potential to reduce the Equipment Failure driver.

M4 – Expulsion Fuse Replacement: Non-exempt distribution line equipment, including non-exempt fuses, has the potential to expel hot or molten material upon normal operation leading to an increased risk of ignition.[31] As part of the CWSP, beginning in 2019, PG&E is targeting replacement of 625 non-exempt fuses per year for seven years on poles located in HFTD Tier 2 and Tier 3 areas that PG&E's Vegetation Management Program considers to be high risk based on terrain conditions. This mitigation has the potential to reduce the Equipment Failure driver.

M5 – PSPS: PG&E's PSPS Program proactively de-energizes select transmission and distribution circuit segments within Tier 2 and Tier 3 HFTD areas when elevated fire danger conditions occur. De-energization is determined necessary to protect public safety when PG&E reasonably believes there is an imminent and significant risk of strong winds impacting PG&E assets, and a significant risk of a catastrophic wildfire should an ignition occur. PSPS is used as a measure of last resort and is only deployed when other measures are

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30 Non-Exempt Surge Arrester Replacement is a mitigation for two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

31 Expulsion Fuse Replacement is a mitigation for two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for both risks and divided by the total cost of the mitigation to calculate the overall RSE for the mitigation.

not adequate alternatives. Before lines de-energized during PSPS can be re-energized, PG&E patrols the segments of lines that experienced the elevated fire danger conditions to ensure that they can be safely returned to service. The cost of these patrols is considered part of the cost of the PSPS mitigation. This mitigation has the potential to reduce the Equipment Failure and vegetation drivers.

PSPS was not included in the 2017 RAMP because PG&E developed its de-energization strategy after the 2017 RAMP Report was filed. PG&E first implemented its PSPS Program in 2018 to de-energize lines that traverse Tier 3 HFTD areas under extreme fire risk conditions. In 2019, PG&E expanded the program scope to include high voltage lines and Tier 2 HFTD areas. Extreme hazard weather conditions were particularly severe during the 2019 fire season, resulting in PG&E conducting nine PSPS events, ranging in impact from approximately 10,000 to approximately 1 million customers.

The 2019 PSPS events taught PG&E some difficult lessons. Although grid de-energization is effective at reducing ignition of utility-caused catastrophic wildfires in high fire risk areas, PSPS events are extraordinarily disruptive for our customers and communities. PG&E has reached out through Listening Sessions for feedback from local county agencies on how these events affect their operations and communities and how PG&E can improve the execution of future events. In addition, as discussed in the next section, PG&E has developed several initiatives to reduce the impact of PSPS events.

M6 – PSPS Impact Reduction Initiatives: A key objective of the PSPS Program is to implement measures to reduce the customer impacts of PSPS events as much as possible while still getting the full fire risk reduction benefits of PSPS. PG&E’s goal in 2020 is to reduce PSPS event impact so that fewer customers are affected than would have been for a comparable weather event in 2019 and to restore power more quickly after a PSPS event (i.e., within 12 daylight hours after high-risk weather clears instead of within 24 daylight hours for 90 percent of affected customers). PG&E will focus its efforts on reducing PSPS impacts on those communities that are forecast to be most frequently affected by PSPS events. PG&E's PSPS Impact Reduction Initiatives include:

Customer and Community Outreach: PG&E is engaging customers and the public who may be directly impacted by a PSPS event through various media to increase awareness of and readiness for PSPS events in general and to provide advance notice of specific PSPS events to all affected customers and communities. PG&E is also committed to providing additional services to Access and Functional Needs and Medical Baseline customers in advance of and during PSPS events through partnerships with local government and community-based organizations, and through additional customer outreach targeted at these populations.

PG&E will also provide website and social media updates during PSPS events and open community resource centers in potentially impacted counties and tribal communities to provide residents a space that is safe, energized and air-conditioned or heated.[32]

Transmission Line Assessments: The PSPS Program has established criteria—based on asset health, historical operating performance, vegetation risks, and fire spread potential—for when overhead transmission line facilities can be excluded from being de-energized in PSPS events. These criteria will be applied beginning in 2020. PG&E is also in the process of developing similar criteria for distribution lines.

Transmission Line Sectionalizing: PG&E has installed SCADA switches on transmission lines to support faster restoration during outage events for the last few years. PG&E will use these transmission switches to further reduce the number of customers impacted by PSPS outages. In 2019, the program added 54 new SCADA transmission switches.

Distribution Line Segmentation: PG&E is adding additional automated sectionalizing devices, reconfiguring devices to facilitate

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32 PG&E's customer outreach and other customer-related programs to mitigate the effects of PSPS are described in greater detail in PG&E's 2020 WMP Report, R.18-10-007, p. 5-288 to p. 5-292 and p. 5-298 to p. 5-306.

pre-PSPS event switching, and adding additional system hardening to further sectionalize distribution facilities to be able to minimize the number of customers whose power will be shut off during PSPS events. PG&E installed 298 additional sectionalizing devices in 2019.

Microgrids/Temporary Generation: PG&E is pursuing resiliency and reliability improvements to mitigate the customer impacts of PSPS using temporary front-of-the-meter microgrid solutions. Microgrids, some of which involve using a pre-installed interconnection hub, temporary generation, and sectionalizing, are tools that PG&E will use to provide islanded power to areas that are safe to energize but would otherwise be de-energized in a PSPS event. These approaches can reduce the number of customers impacted by PSPS events and facilitate safe energization of shared community resources that support the surrounding population. In 2019, PG&E implemented a pilot microgrid site (the Angwin Resilience Zone in Napa County) which became operational in September. PG&E successfully used temporary generation at this site, as well as in three safe-to-energize substations in Calistoga, Grass Valley, and Placerville to safely re-energize thousands of customers during the October and November 2019 PSPS events.

PG&E considers these PSPS impact reduction initiatives to be foundational because they do not directly reduce the risk of Wildfire ignition. However, PG&E's Wildfire risk model does take the effect of these initiatives on the reliability impact of PSPS into account; it assumes the number of customer minutes of service interrupted due to PSPS will be 30 percent less than if the impact reduction initiatives were not in place.[33] Because of this, and in order to more accurately capture the full range of costs associated with the risk reduction obtained

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[33] The assumed 30 percent reduction in customer minutes of service interrupted is based on PG&E's estimate of the reduced scope of future PSPS events due to mitigation efforts compared to 2019. Improved restoration time should also reduce customer minutes of service interrupted but that reduction is difficult to quantify with existing data so its effect was not included in the model.

through PSPS, PG&E is including the cost of these initiatives as part of the calculation of the RSE for PSPS.[34]

M7 – Situational Awareness and Forecasting Initiatives: In the 2020 GRC, PG&E proposed several mitigations related to forecasting and situational awareness, including additional weather stations, cameras, sensors, and advanced modeling of weather and fire conditions. Taken together, these mitigations will help PG&E identify times and areas of high fire risk, which will inform decisions about PSPS timing and scope and provide information that will be valuable for asset management and risk analysis. Another critical situational awareness mitigation is PG&E's Wildfire Safety Operations Center, a physical facility that serves as PG&E's wildfire-related information hub and monitors, assesses, and directs specific wildfire prevention and response efforts throughout PG&E's service area in real time. Although many of these situational awareness and forecasting activities were discussed as separate mitigations in the 2020 GRC, in the 2020 RAMP PG&E is discussing them together as a single mitigation. Since these programs support other mitigations that reduce Wildfire risk, but do not reduce the risk themselves, PG&E considers them foundational.

In 2019, PG&E engaged in key situational awareness and forecasting activities including the following:

Advanced Weather Monitoring and Weather Stations: In 2019, PG&E added more than 400 weather stations to its existing network and installed more than 120 high definition cameras in HFTD areas to allow real time monitoring of weather and fire conditions. Additional weather stations and cameras will be added in coming years. In 2019, PG&E also developed a state-of-the-art satellite fire detection system that uses remote sensing data from five geostationary and polar orbiting spacecraft to detect fires.

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34 Note that PG&E did not include the cost of PSPS impact reduction programs in its RSE calculation for PSPS in its 2020 WMP.

Continuous Monitoring Sensors: In 2019, PG&E enabled single-phase SmartMeters™[35] to send real-time alarms when a partial voltage condition is detected. This enhanced situational awareness can help detect abnormal conditions—such as wires down, phase loss from partial fuse operation, or an open jumper/connector—more quickly to enable faster response. To date, PG&E has deployed partial voltage detection capability to approximately 4.5 million single-phase SmartMeters over its entire service territory, including 350,000 SmartMeters on distribution feeders in Tier 2 and Tier 3 HFTD areas.[36] PG&E is also piloting several other types of technologies such as overhead line sensors, early fault detection, and Distribution Fault Anticipation (DFA) to detect system anomalies on both transmission and distribution lines; these sensors may be deployed more broadly in the future depending on the outcome of the pilots.[37]

Meteorology/Fire and Storm Modeling: PG&E utilizes public and proprietary state-of-the-art weather forecast model data and operates an in-house, high-resolution meteorological modeling system to forecast weather conditions, outage potential, and fire potential. In 2018 and 2019, PG&E made significant improvements to its existing models including: (1) successfully completing one of the largest known high-resolution datasets in the utility industry, with 3 kilometer (km) resolution; (2) developing a new Outage Producing Wind (OPW) model to supplement PG&E's existing SOPP model; and (3) significantly enhancing PG&E's existing Fire Potential Index (FPI) model. The FPI model PG&E deployed in 2019 combines weather (wind, temperature and relative humidity) and vegetative

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35 **SmartMeter** is a PG&E registered trademark. All further references to **SmartMeters** in PG&E's testimony in this proceeding should be assumed to refer to the trademarked name, without continually using the ™ symbol, consistent with legally-acceptable practice.

36 In the 2020 GRC, the SmartMeter Partial Voltage Detection Program, which was known then as Enhanced Wires Down Detection, was discussed as mitigation M24.

37 PG&E sensor initiatives that may reduce Wildfire risk are discussed in detail in its 2020 WMP Report R.18-10-007, p. 5-90 to p. 5-96.

fuels (10-hour dead fuel moisture, live fuel moisture, and fuel type) into an index that represents the probability of large fires to occur. The FPI and OPW models are run on the same 3x3 km resolution dataset as the high-resolution weather model.[38]

M8 – Safety and Infrastructure Protection Teams: SIPTs consist of two-person crews composed of International Brotherhood of Electrical Workers-represented employees who are trained and certified safety infrastructure protection personnel. They provide standby resources for PG&E crews performing work in high fire hazard areas, pretreatment of PG&E assets during an ongoing fire, fire protection to PG&E assets, and emergency medical services. SIPT crews will also collect data and provide field observations about weather and system conditions to help determine the scope and timing of potential PSPS events. Since this program supports other mitigations that reduce Wildfire risk, but does not reduce the risk itself, PG&E considers SIPT foundational.

M9 – Community Wildfire Safety Program, Program Management Office: The CWSP PMO was established in 2018 to oversee and coordinate multiple lines of business' implementation of PG&E's wildfire risk mitigation activities. The CWSP PMO is focused on project and program development and management for wildfire mitigation efforts. The CWSP PMO leads the overall program, monitoring progress, handling resource needs, and directing workstreams. The CWSP PMO supports internal and external engagement efforts, including public affairs and government relations support, local customer outreach support, and communications strategy for the program overall. Since it supports other mitigations that reduce Wildfire risk, but does not reduce the risk itself, PG&E considers the CWSP PMO as foundational.

M10 – Additional System Automation and Protection: The C14 – System Automation and Protection control described above consists of PG&E's continued implementation of its historic system automation protection activities. The M10 mitigation consists of additional system

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[38] In the 2020 GRC, work related to weather, outage and fire modeling was discussed as mitigations M20 (SOPP Model Automation) and M21 (Advanced Fire Modeling).

and protection work. In 2019, this included finishing installation of SCADA capability on reclosing devices in HFTD areas to support remote Reclose Blocking. This mitigation also includes evaluating new system protection technologies that may reduce wildfire risk. These new technologies include:

Distribution Transmission Substation—Fire Action Scheme and Technology (DTS-FAST): The DTS-FAST system is designed to reduce the fire risks associated with energized power lines and associated equipment. DTS-FAST was developed internally at PG&E and aims to use fraction-of-a-second technologies to detect objects approaching energized power lines and respond quickly to shut off power, before object impact. DTS-FAST also monitors and detects failure of equipment associated with transmission and distribution towers/poles and aims to use fraction-of-a-second technologies to quickly shut off power. Lastly, if DTS-FAST can operate as optimally modeled, it may allow some circuits to operate energized during PSPS events. The program is currently in the pilot phase.

Rapid Earth Fault Current Limiter (REFCL): REFCL technology is a technology that may allow PG&E to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults. REFCL works by moving the neutral line to the faulted phase during a fault which significantly reduces the energy available for the fault. PG&E is evaluating the REFCL technology through the Electric Program Investment Charge (EPIC) 3.15 Proactive Wires Down Mitigation demonstration project. PG&E began planning the project in 2019; demonstrations are planned to begin in 2020 on operational assets to test REFCL's capabilities and applications within PG&E's system.

Distribution Fault Anticipation: DFA technology captures primary distribution disturbance current and voltage waveforms and may allow PG&E to identify fault and arcing events more quickly than existing technology, which may reduce Wildfire risk. DFA technology is currently being evaluated on six distribution feeders covering 718 line miles as part of an EPIC project scheduled to be completed in 2020.

PG&E has not yet determined whether and to what extent these new technologies can deliver concrete benefits and has not fully evaluated the cost or feasibility of implementing these technologies at scale. Depending on the results of the preliminary evaluations described above, PG&E may propose broader implementation of these technologies in an upcoming WMP proceeding or the 2023 GRC. At least for now, PG&E considers these programs to be foundational activities.

2. 2017 RAMP Update

In this section PG&E describes how the controls and mitigations for the Wildfire risk presented in the 2017 RAMP have evolved.

a. Controls

PG&E described 12 controls for the Wildfire risk in the 2017 RAMP Report and listed those same 12 controls in the 2020 GRC. Although PG&E has reorganized its list of controls for the 2020 RAMP, in part to reflect the organization of the WMP, virtually all the activities included in the former controls are included in the new controls as well. One exception is the C5 Overhead Conductor Replacement control from the 2017 RAMP. This control replaces deteriorated spans of overhead conductor with new spans. Historically, the new conductor installed as part of this program has been bare wire. Although PG&E continues to use bare wire for overhead conductor replacement in non-HFTD areas, in HFTD areas all conductor replacement is being done with covered conductor in accordance with PG&E's new System Hardening standards. As a result, the C5 Overhead Conductor Replacement control from the 2017 RAMP has been superseded by the M2 System Hardening mitigation.

The mapping of the 2017 RAMP controls to the controls described in the 2020 GRC and the controls PG&E is presenting in the 2020 RAMP is shown in Table 10-6 above.

b. Mitigations

In the 2017 RAMP, PG&E proposed six mitigations to reduce Wildfire risk. PG&E noted in the 2017 RAMP report that it might propose different or additional mitigations as a result of its analysis of the October 2017 Northern California wildfires. In the 2020 GRC, PG&E proposed a different, and significantly expanded, set of 19 wildfire mitigations. PG&E further refined its wildfire mitigations and described additional program changes in its 2020 WMP.

The mapping of the 2017 RAMP mitigations to the mitigations described in the 2020 GRC and the mitigations PG&E is presenting in the 2020 RAMP is shown in Table 10-7 above.[39] The current status of the six mitigations proposed in the 2017 RAMP is described below:[40]

M1 (2017) – Wildfire Reclosing Operations Program (SCADA Programming) and M2 (2017) – Wildfire Reclosing Operations Program (SCADA Capability Upgrades): In the 2017 RAMP, PG&E described a program to disable reclosing functionality on certain equipment located in high fire-threat areas beginning in 2017. PG&E also proposed making SCADA capability upgrades to 100 reclosing devices per year from 2020-2022 to allow reclosing functionality to be disabled and re-enabled remotely.

As described above in connection with the C15 Reclosing Blocking control, PG&E did implement a reclose blocking program similar to the one proposed in the 2017 RAMP. PG&E also accelerated the SCADA upgrades initially proposed for 2020-2022 in the 2017 RAMP; those

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[39] The M26 – Aviation Resources mitigation described in the 2020 GRC is not modeled in the 2020 RAMP. In its 2020 GRC testimony, PG&E explained that it had purchased and was operating four heavy-lift helicopters to support utility infrastructure projects, to provide PG&E guaranteed access to heavy-lift helicopters for PG&E's operations and emergency response to restore service during and after wildfires, and to make three of the four helicopters available to CAL FIRE during the fire-fighting season to potentially aid in fire suppression efforts. PG&E is not modeling the potential fire suppression benefit as a Wildfire mitigation in the 2020 RAMP because the benefit is difficult to quantify and there is uncertainty as to the extent to which the helicopters will be used by CAL FIRE for fire suppression.

[40] The different wildfire mitigations proposed in PG&E's 2017 RAMP and 2020 GRC, and the process through which PG&E refined and expanded its proposed mitigations, are described in PG&E's 2020 GRC testimony regarding the Wildfire risk. A.18-12-009, Exhibit (PG&E-4) p. 2A-12 to p. 2A-40.

upgrades were completed in 2019. That work is included in the 2020 RAMP in the M9 Additional System Automation and Protection mitigation.

M3 (2017) – Fuel Reduction and Powerline Corridor Management and M4 (2017) Overhang Clearing: In the 2017 RAMP, PG&E proposed two types of additional Vegetation Management work beyond what PG&E had done in the past: (1) 24,000 miles of overhead clearing work between 2018 and 2022; and (2) 3,600 miles of fuel reduction and powerline corridor management work between 2018-2022.

Work like the work proposed in these mitigations is part of PG&E's current EVM mitigation (M1). The scope of PG&E's proposed EVM mitigation has been refined and expanded based on PG&E's analysis of ignition drivers after the 2017 Northern California wildfires and based on lessons learned from ongoing EVM work. The current work includes not only overhang clearing, and ad hoc fuel reduction work, but also the creation of enhanced radial clearances and the identification and mitigation of trees with a potential to strike power lines. Due to the expanded scope, and to the fact that program activities have proved to be more difficult and costlier than initially estimated, PG&E's current proposed pace for implementing the EVM mitigation is slower than was estimated for the Overhang Clearing and Fuel Reduction mitigations. PG&E currently estimates that it will complete approximately 8,650 miles of EVM work between 2018 and 2022.

M5 (2017) – Non-Exempt Surge Arrester Replacement: In the 2017 RAMP, PG&E proposed completing approximately 90,000 non-exempt surge arrester replacements between 2017 and 2022. This same program is still in place as a 2020 RAMP mitigation (M3) but, due to some reprioritization of work in 2018 and 2019, PG&E now expects to complete the program in 2023, rather than 2022.

M7 (2017) – Targeted Conductor Replacement (WF): In the 2017 RAMP, PG&E proposed a program to replace overhead conductor in high fire risk areas with covered conductor at a rate of 190 miles per year between 2020 and 2022. In the 2020 GRC, PG&E proposed a Wildfire System Hardening mitigation, which included installation of not only covered conductor, but also poles and other equipment in HFTD areas. That expanded program is the same as the M2 System Hardening mitigation in the 2020 RAMP. PG&E estimates that it will complete 1,060 miles of System Hardening upgrades between 2020 and 2022.

D. 2020-2022 Mitigation Plan

1. Changes to Controls

PG&E plans to continue to implement the controls described above for 2019 in 2020-2023. PG&E will continue to evaluate the programs and incorporate lessons learned and may adjust the scope and cadence of the programs as a result. There will be significant changes to a few existing controls, as described below:

Patrols and Inspections – Transmission and Distribution (C1-C2): For 2020 and beyond, PG&E is incorporating fire-risk considerations identified as part of the WSIP process and baseline compliance guidelines into a checklist-guided paperless approach for facilities inspections. PG&E will perform detailed inspections of overhead distribution and transmission facilities located in HFTD areas on a risk-informed cycle; in 2020 PG&E plans to inspect all its facilities in HFTD Tier 3 and one-third of its facilities in HFTD Tier 2.

PG&E's current plan for non-HFTD facilities is to continue with the historical cadence of detailed inspections once every five years. Future year inspection scope and cadence may be adjusted based on the results of this initial cycle of enhanced inspections and shift toward more risk-informed or condition-dependent cycles linked to PG&E predictive models. However, for forecasting purposes, this filing assumes that PG&E will continue to inspect all facilities in HFTD Tier 3 annually, and facilities in HFTD Tier 2 once every three years. PG&E is also performing Field Safety Reassessments of pending maintenance notifications that will not be completed before the start of the upcoming fire season to verify that previously identified maintenance conditions have not further deteriorated to the point that they require more immediate resolution.

Equipment Maintenance and Replacement – Transmission (C9) and Transmission Structure Maintenance and Replacement (C13): PG&E is currently evaluating whether to expand the scope of the proactive replacement of transmission assets in or near HFTD areas, both to reduce ignitions and to potentially allow some transmission circuits that were de-energized in 2019 PSPS events to remain energized. PG&E may include a funding request for this work in future.

Pole Programs (C12): In 2020, PG&E will begin regular use of the new pole loading infrastructure assessment that it piloted in 2019. PG&E's initial goal is to assess all distribution poles located in Tier 2 and Tier 3 HFTD areas by 2024 (at a rate of approximately 230,000 poles per year) to determine whether existing poles are adequate under PG&E's current loading criteria.

Reclose Blocking (C14): PG&E is not planning significant operational changes to the Reclose Blocking Program for 2020-2022. However, PG&E is continuing to evaluate the circuit segments where reclose blocking is applied and may add or remove segments based on lessons learned and additional analysis.

Restoration, Operational Procedures and Training (C16): In 2020, PG&E will update TD-1464B-02 (PSPS procedures) to include lessons learned from 2019 PSPS events and revised meteorology inputs. PG&E will also begin updating the existing Fire Index based Distribution Circuit Segment Guides and maps to circuit based, supporting more detailed meteorology event boundaries. In later years, PG&E will continue to evaluate and update as necessary to reflect lessons learned.

a. Changes to Mitigations

For the most part, PG&E will continue to implement the 2019 Wildfire risk mitigations described above in the 2020-2022 time period. PG&E will continue to evaluate the programs and incorporate lessons learned and may adjust the scope and cadence of the programs as a result. To the extent PG&E is currently planning significant changes to the mitigations for 2020-2022, those changes are described below:

M1 – Enhanced Vegetation Management: PG&E's EVM Program will perform similar trimming and tree removal work in 2020-2022 to what it did it 2019. However, PG&E plans to perform less EVM work on distribution lines in 2020-2022 than it did in 2019 (approximately 1,800 miles of distribution line per year in 2020-2022 versus 2,498 miles in 2019).

Based on its assessment of routine and EVM work on the system as a whole, beginning in 2020 PG&E plans to shift some EVM resources to expand rights of way and remove incompatible trees around lower voltage transmission lines (similar work is already performed around higher voltage transmission lines as part of PG&E's routine vegetation management). This work will be targeted at both reducing wildfire risk and reducing the footprint of future PSPS events by allowing some transmission lines to remain energized.

PG&E will continue to evaluate the effectiveness of the EVM Program and may further adjust its scope to better mitigate risk.

M2 – System Hardening: PG&E plans to progressively increase the pace of system hardening in the 2020-2022 period with a goal of completing approximately 1,060 circuit miles over that period.

PG&E will continue to evaluate the effectiveness of the System Hardening Program and may further adjust its scope to better mitigate risk.

M3 – Non-Exempt Surge Arrester Replacement: PG&E will continue replacing non-exempt surge arresters in HFTD areas until all those replacements are complete, which PG&E anticipates will occur in 2021.[41]

M6 – PSPS Impact Reduction Initiatives: In 2020 and beyond, PG&E will be building on lessons learned in 2019 to expand and refine its initiatives to reduce the scope and duration of PSPS events. New and/or expanded initiatives include:

Transmission Line Assessments: Before the 2020 fire season, PG&E will be evaluating transmission lines in HFTD areas to

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41 PG&E estimates that non-exempt surge arrester replacement work will continue in non-HFTD areas until 2023. Non-exempt surge arrester replacements in non-HFTD areas are not considered part of the scope of the Wildfire risk mitigation, but are considered a mitigation for the Failure of Distribution Overhead Assets risk.

determine which lines can be removed from future PSPS event scope, including assessing whether additional inspections, repairs and/or increased vegetation management would allow particular lines to meet the exclusion criteria.

Transmission Line Sectionalizing: PG&E plans to install an additional 23 SCADA transmission switches in 2020.

Distribution Line Sectionalizing: PG&E plans to install 592 additional sectionalizing devices in 2020 and 130 more devices in 2021. PG&E will assess the need for additional sectionalizing devices after 2021.

Microgrids/Temporary Generation: Building on the PSPS impact mitigation role that front-of-the-meter microgrids played in 2019, PG&E has filed and sought Commission approval to operationalize additional microgrid capabilities in 2020. In addition to more mid-feeder microgrid projects like the ones piloted in 2019, PG&E is expanding its projects to include substation-sited microgrids energized with temporary generators. PG&E will also continue to evaluate the possibility installing permanent distributed generation at some substation locations, though no such projects are planned for 2020. Substation projects involve the rental of mobile generation resources and some infrastructure work to facilitate connection of those resources. PG&E's target for 2020 is to prepare 63 substations to receive temporary generation. These are largely substations that experienced more than one PSPS event in 2019 and had at least some customers that would have been partially or entirely safe-to-energize in the two largest 2019 PSPS events.[42] Current risk modeling assumes that PG&E will continue to operate

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42 The substations in question were impacted by PSPS events in 2019 because the transmission lines feeding them were not safe to energize due to Wildfire risk. As discussed in the 2020 WMP and its initial testimony in the Microgrid and Resiliency Strategies Rulemaking (R.19-09-009), PG&E initially planned to install permanent generation resources at 20 of these substations before the 2020 fire season. However, after further consideration, PG&E is planning to use temporary generation and serve a larger number of substations.

some substation-sited microgrid projects through 2026, with the ratio of temporary to permanent generation varying over time.

Based on operational lessons learned from the 2019 fire season, PG&E is adjusting some practices and increasing the resources it will deploy to support PSPS restoration in 2020. In particular, PG&E plans to significantly increase the number of helicopters it has available for aerial assessment of lines and to use fixed wing aircraft with cameras and infrared equipment to patrol assets at night to make restoration faster.

M7 – Situational Awareness and Forecasting Initiatives: The 2019 initiatives described above will continue in the 2020-2022, with the following changes:

Advanced Weather Monitoring and Weather Stations: PG&E plans to install additional weather stations in 2020 and 2021, with a goal of having 1,300 weather stations by 2021. PG&E also plans to install additional high-definition cameras in 2020-2022, with a goal of having 600 cameras by 2022.

Continuous Monitoring Sensors: PG&E is working to expand its deployment of partial voltage detection capabilities to 3-phase SmartMeters. PG&E plans deploy this capability to approximately 365,000 three-phase SmartMeters throughout its service territory.

Meteorology/Fire and Storm Modeling: In 2020, PG&E will:

- Equip a Meteorology Operations Center at an existing facility;
- Enhance the PG&E Satellite Fire Detection and Alerting system by incorporating more satellite data;
- Establish a Live Fuel Moisture sampling program with the goal of sampling 25 sites and uploading results to the National Fuel Moisture Database;
- Partner with multiple external experts in numerical and fire weather prediction to develop the next version of its weather and fuel moisture modeling system. The updated version of the model will have enhanced verification, greater data capabilities and higher resolution (modeling 2x2 km areas, rather than the

current 3x3 km). PG&E also plans to reproduce its 30-year historical climatological dataset at a 2x2 km resolution;

- Work with an external expert to improve fire occurrence datasets in the PG&E territory using remote sensing technology for enhanced historical analysis of fire events;
- Partner with external experts to build and deploy new herbaceous and woody live fuel moisture models using remote sensing technology;
- Partner with an academic institution to study fire weather phenomena in the PG&E territory using PG&E's new 30-year 2-km weather climatology;
- Partner with a National Laboratory to study the occurrence of dry, offshore (Diablo) wind events under various climate change scenarios; and
- Work with external partner(s) to develop and deploy a Diablo wind event forecasting system, which could potentially provide additional time for PG&E and communities to prepare for these events.

M8 – SIPT: In the 2020-2022 period, PG&E's SIPT Program will focus on updating and stabilizing current technology solutions and increase staffing levels to support mitigation activities. PG&E will incorporate a safety observation card via SafetyNet and Quality Control Program to ensure updated fire prevention and mitigation measures have been adopted by personnel working on any forest, brush, or grass-covered lands.

PG&E is piloting one new mitigation in 2020.

M11 – Remote Grid: Remote Grid is an effort to use decentralized energy sources to permanently supply energy to certain remote customers instead of using hardened traditional utility infrastructure for electricity delivery. PG&E's service territory contains pockets of isolated small customer loads that are served via long electric distribution feeders; some of these feeders pass through HFTD areas and some have been disconnected due to damage from recent wildfires. PG&E is proposing to remove some of these long feeders and instead serve customers from local, decentralized energy sources. This could reduce fire ignition risk and serve as a cost-effective alternative to system hardening and/or rebuilding fire-damaged infrastructure to meet new HFTD design standards. Outside HFTD areas, Remote Grid could be a cost-effective alternative to maintenance costs associated with long feeder lines in remote areas. This mitigation addresses the Equipment Failure, Vegetation, Third Party, Animal, and Other drivers.

In 2020, PG&E plans to deploy three Remote Grid projects at two sites to validate use cases, design standards, deployment processes and commercial arrangements. One project is located in Briceburg, in HFTD Tier 2, and will remove 1.37 miles of line. This is the only project that is modeled as a Wildfire mitigation. Two projects are located at the Carrizo Plain pilot site, which is outside the HFTD but involves circuit segments with high maintenance costs, and will remove 23.8 miles of line. If the results of the initial projects are favorable, PG&E will determine whether to propose further remote grid projects 2021 and beyond.[43] For modeling purposes, PG&E is assuming that there will be no remote grid work in 2021 or 2022 but is presenting remote grid work as an alternative mitigation for 2023-2026. See Section F below.

The volume of mitigation work PG&E plans to complete in the 2020-2022 period is shown in Table 10-8 below.

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43 PG&E's RAMP analysis incorporates information as of May 2020. Based on the results of the remote grid projects in 2020, PG&E will consider revising the forecast for this mitigation in 2021 and beyond. The revised forecast and corresponding RSE calculations will be included in PG&E's 2021 WMP Report and the 2023 GRC.

TABLE 10-8
PLANNED MITIGATIONS 2020-2022

Line No.	Mitigation Name and Number	2020 RAMP Planned Units of Work				
		Units	2020	2021	2022	Total
1	M1 – EVM	Line miles	1,800	1,800	1,800	5,400
2	M2 – System Hardening	Line miles	241	377	442	1,060
3	M3 – Non-Exempt Surge Arrester Replacement	Poles with Arresters in HFTD areas	16,829	16,249	0	33,078
4	M4 – Expulsion Fuse replacement	Fuses	625	625	625	1,875
5	M5 – PSPS	N/A	–	–	–	–
6	M6 – PSPS Impact Reduction Initiatives	N/A	–	–	–	–
7	M7 – Situational Awareness and Forecasting Initiatives	N/A	–	–	–	–
8	M8 – SIPT	N/A	–	–	–	–
9	M9 – CWSP Project Management Office	N/A	–	–	–	–
10	M10 – Additional System Automation and Protection	N/A	–	–	–	–
11	M11 – Remote Grid	Line miles removed	25	0	0	25

The forecast costs for the work planned from 2020-2022 are shown in Tables 10-9 and 10-10 below.

TABLE 10-9
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS))

Line No.	Mit. No.	Mitigation Name	MWC[(a)]	2020	2021	2022	Total
1	M1	EVM	IG	$494,627	$506,993	$519,668	$1,521,288
2	M5	PSPS	AB, IG	170,699	174,967	179,341	525,007
3	M6	PSPS Impact Reduction Initiatives	IG	225,785	211,198	207,502	644,484
4	M7	Situational Awareness and Forecasting Initiatives	IG	30,229	32,379	31,214	93,822
5	M8	SIPT	IG	23,668	37,057	41,286	102,010
6	M9	CWSP PMO	IG	18,529	19,071	19,625	57,226
7	M10	Additional System Automation and Protection	AT, IG	5,150	130	134	5,414
8		Total		$968,687	$981,795	$998,770	$2,949,252

(a) PG&E is recording costs for certain activities in temporary MWC IG but expects to forecast costs for this work in MWC AB or HN in the 2023 GRC.

Note: See WP 10-1.

TABLE 10-10
FORECAST COSTS
2020-2022 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M2	System Hardening	08W	$366,725	$565,640	$698,360	$1,630,725
2	M3	Non-Exempt Surge Arrester Replacement	2AR	62,448	53,290	–	115,738
3	M4	Expulsion Fuse Replacement	2AP	5,423	5,559	5,698	16,679
4	M6	PSPS Impact Reduction Initiatives	21, 48A, 48D, 49H, 49M, 67D, 94A, 94B	159,701	142,489	123,500	425,690
5	M7	Situational Awareness and Forecasting Initiatives	21A, 49I	13,163	12,371	7,433	32,967
6	M8	SIPT	21A	676	1,152	–	1,828
7	M10	Additional System Automation and Protection	09A, 49T	10,753	17,443	17,772	45,969
8	M11	Remote Grid	49M	4,749	–	–	4,749
9		Total		$623,638	$797,944	$852,763	$2,274,345

Note: See WP 10-1.

E. 2023-2026 Controls and Mitigations

1. Changes to Controls

PG&E plans to continue implementing the 2019-2022 controls described above in 2023-2026. PG&E is not currently planning major changes to these programs for 2023-2026 but will continue to evaluate the programs and incorporate lessons learned and may adjust the scope and cadence of the programs as a result.

2. Changes to Mitigations

The M3 – Non-Exempt Surge Arrester Replacement mitigation is not considered a Wildfire mitigation for the 2023-2026 period because PG&E plans to complete all non-exempt surge arrester replacements in HFTD areas by 2021. PG&E plans to continue to implement the other mitigation programs described above for 2019-2022 in 2023-2026, though M11 – Remote Grid is considered an alternative mitigation for 2023-2026 as discussed in Section F below. PG&E is not currently planning major changes to these programs for 2023-2026, but PG&E will continue to evaluate the programs and incorporate lessons learned and may adjust the scope and cadence of the programs as a result.

The volume of mitigation work PG&E plans to complete in the 2023-2026 period is shown in Table 10-11 below.

TABLE 10-11
PLANNED MITIGATIONS 2023-2026

Line No.	Mitigation Name and Number	Units	2020 RAMP Planned Units of Work 2023	2024	2025	2026	Total
1	M1 – EVM	Line Miles	1,800	1,800	1,800	1,800	7,200
2	M2 – System Hardening	Line Miles	504	540	538	536	2,118
3	M4 – Expulsion Fuse Replacement	Non-Exempt Fuses	625	625	625	625	2,500
4	M5 – PSPS	Non-Unitized	–	–	–	–	–
5	M6 – PSPS Impact Reduction Initiatives	Non-Unitized	–	–	–	–	–
6	M7 – Situational Awareness and Forecasting Initiatives	Non-Unitized	–	–	–	–	–
7	M8 – SIPT	Non-Unitized	–	–	–	–	–
8	M9 – CWSP PMO	Non-Unitized	–	–	–	–	–
9	M10 – Additional System Automation and Protection	Non-Unitized	–	–	–	–	–

Tables 10-12 and 10-13 below shows the planned cost, RSE and risk reduction score for each of the Wildfire risk mitigations PG&E plans to implement in the 2023-26 period. The derivation of RSEs and risk reduction scores is explained in Chapter 3, “Risk Modeling.”

TABLE 10-12
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC[a]	2023	2024	2025	2026	Total	RSE[b]	Risk Reduction
1	M1	EVM	IG	$532,660	$545,976	$559,625	$573,616	$2,211,877	2.6[c]	4,156
2	M5	PSPS	AB, IG	183,825	188,420	193,131	197,959	763,334	13.8[d]	16,284[d]
3	M6	PSPS Impact Reduction Initiatives	IG	185,576	141,277	97,011	98,378	522,243	[d]	[d]
4	M7	Situational Awareness and Forecasting Initiatives	IG	30,884	31,656	32,447	33,258	128,245	[e]	[d]
5	M8	SIPT	IG	42,318	43,376	44,460	45,572	175,726	[e]	[d]
6	M9	CWSP PMO	IG	20,116	20,619	21,134	21,663	83,532	[e]	[e]
7	M10	Additional System Automation and Protection	AT, IG	137	141	144	148	570	[e]	[e]
8		Total		$995,515	$971,465	$947,954	$970,594	$3,885,528		

(a) PG&E is recording costs for certain activities in temporary MWC IG but expects to forecast costs for this work in MWC AB or HN in the 2023 GRC.

(b) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(c) The RSE includes the risk reduction for both the Wildfire risk and the Failure of Electric Distribution Overhead Asset risk. See WP 10-3.

(d) The RSE and Risk Reduction score shown on Line 2 (M5 – PSPS) is for the combined M5 – PSPS and M6 – PSPS Impact Reduction Initiatives mitigations.

(e) Foundational mitigation – PG&E does not calculate RSEs for foundational mitigations.

Note: See WP 10-1.

TABLE 10-13
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M2	System Hardening	08W	$796,320	$850,040	$868,052	$886,390	$3,400,802	7.3[b]	17,893
2	M3	Non-Exempt Surge Arrester Replacement	2AR							
3	M4	Expulsion Fuse Replacement	2AP	5,840	6,136	6,289	6,446	24,711	1.0[b]	18
4	M6	PSPS Impact Reduction Initiatives	21, 48A, 48D, 49H, 49M, 67D, 94A, 94B	76,375	76,917	77,199	77,487	307,979	[c]	[c]
5	M7	Situational Awareness and Forecasting Initiatives	21A, 49I	7,619	7,810	8,005	8,205	31,639	[d]	[d]
6	M8	SIPT	21A	–	–	–	–	–	[d]	[d]
7	M10	Additional System Automation and Protection	09A, 49T	18,216	18,778	19,247	19,728	75,969	[d]	[d]
8	M11	Remote Grid	49M	–	–	–	–	–		
9		Total		$904,371	$959,681	$978,792	$998,257	$3,841,100		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

(b) The RSE includes the risk reduction for both the Wildfire risk, the Failure of Electric Distribution Overhead Asset risk, and the Third-Party Safety Incident risk. See WP 10-3.

(c) See Table 10-3, Line 3 for the RSE and Risk Reduction score for M6.

(d) Foundational activity – PG&E does not calculate RSEs for foundational activities.

Note: See WP 10-1.

More than 90 percent of PG&E's proposed planned Wildfire mitigation spending is for three programs – System Hardening, EVM, and PSPS (including the PSPS impact mitigation initiatives). These three programs each significantly reduce the risk score for Wildfire and have a relatively high RSE, despite their high cost. Each of these programs approaches risk reduction from a different angle, with System Hardening focused primarily on equipment failure, EVM focused on vegetation drivers, and PSPS focused on eliminating the potential for ignitions on higher risk circuits during periods of high fire risk due to weather and wind conditions. PG&E believes that this multi-front approach is the best way to address Wildfire risk in its entirety.

System Hardening accounts for 44 percent of PG&E's planned spending on Wildfire mitigations from 2023-2026 and has an RSE of 7.3.[44] The benefits of System Hardening will grow over time as PG&E upgrades a larger portion of the distribution system in HFTD areas. As discussed in Section F below, PG&E is evaluating two alternative, lower-cost approaches to System Hardening which may be appropriate for some circuits, either outside the current scope of the M2 mitigation or as part of a mix of work where different circuit segments receive different levels of construction upgrades based on local conditions and risk priority. PG&E will continue to evaluate the scope and pace of this program and will continue to refine the prioritization model it is using to decide the order in which it upgrades circuits. Depending on resource availability and lessons learned, PG&E may adjust its forecast in future WMP proceedings and/or the 2023 GRC.

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[44] The 2023-2026 RSE of 7.3 that PG&E has calculated for System Hardening here is higher than the 2020-2022 RSE of 4.12 that PG&E calculated in its 2020 WMP Report. See PG&E's 2020 WMP Report, R.18-10-007, Public Attachments at Atch. 1-48. As part of the 2020 RAMP process, PG&E subject matter experts reviewed assumptions about how effective System Hardening will be at mitigating certain equipment failure-related ignitions. This review led to an upward revision of PG&E's estimate of the overall mitigation effectiveness of System Hardening.

EVM accounts for 29 percent of PG&E's planned spending on Wildfire mitigations from 2023-2026 and has an RSE of 2.6.[45] Although the EVM RSE is not as high as the System Hardening RSE, PG&E believes that EVM is a prudent investment because it is targeted at the vegetation driver, which is the largest source of ignitions in the HFTD areas of PG&E's service territory, and because it can be deployed more quickly and over a wider area than System Hardening. The EVM Program continues to evolve as PG&E evaluates the effectiveness of the various activities that make up the program. As a result, PG&E may adjust the proposed scope and pace of the program in future WMP proceeding and/or the 2023 GRC.

PSPS accounts for 21 percent of planned PG&E spending on Wildfire mitigations from 2023-2026 and has an RSE of 13.8, the highest RSE for any Electric Operations RAMP risk mitigation, even when the cost of PG&E's PSPS Impact Reduction Initiatives is included in the calculation.[46] PSPS effectively mitigates risk by de-energizing circuits in areas and at times when fire risk is especially high, almost completely eliminating the risk of ignition while it is in effect. Although PSPS is effective, PG&E is unlikely to significantly expand its scope because of the significant burden it places on customers. Instead, PG&E is investing in initiatives to reduce the impact of PSPS on customers, including sectionalizing to reduce the PSPS footprint and using temporary generation to energize substations that are safe to energize but are served by transmission lines which run through an area where PSPS is in effect. PG&E will continue to refine its PSPS criteria and

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45 The 2023-2026 RSE of 2.6 that PG&E has calculated for EVM here is significantly higher than the 2020-2022 RSE of 0.15 that PG&E calculated in its 2020 WMP Report. See PG&E's 2020 WMP Report, R.18-10-007, Public Attachments at Atch. 1-67. When calculating the RSE for EVM for the 2020 WMP Report, PG&E assumed that EVM only provided one-year benefits. PG&E has confirmed that clearances established through EVM activities will be maintained by the routine Vegetation Management Program, and will therefore provide a continuing benefit, leading to a substantial increase in the RSE.

46 The 2023-2026 RSE of 13.8 that PG&E has calculated for PSPS here is lower than the 2020-2022 RSE of 26.42 that PG&E calculated in its 2020 WMP Report. See PG&E's 2020 WMP Report, R.18-10-007, Public Attachments at Atch. 1-73. This is because, unlike the WMP Report, in the 2020 RAMP PG&E has included the cost for PSPS Impact Reduction Initiatives in its calculation of the RSE for PSPS. PG&E believes that including these costs in the RSE calculation more accurately represents the costs of obtaining the risk reduction benefits that PSPS provides.

PSPS impact mitigation initiatives and may adjust the scope of the program in further WMP proceedings and/or in the 2023 GRC.

Expulsion Fuse Replacement accounts for less than 1 percent of PG&E's planned spending on Wildfire mitigations from 2023-2026 and has an RSE of 1.0. PG&E considers this relatively modest program to be a prudent investment. Based on the results of this program, PG&E may adjust its scope or pace in future years.

Four additional mitigations, which account for 6 percent of PG&E's planned Wildfire mitigation spending in 2023-2026, do not directly reduce risk but provide support for or enhance the effectiveness of other mitigations. These mitigations are considered foundational activities.

- Situational Awareness and Forecasting Initiatives (2 percent of planned 2023-2026 Wildfire mitigation spending) provide important information about weather and other conditions that contribute to fire risk, and support PG&E's emergency response through the Wildfire Safety Operations Center. These initiatives are prudent because they improve PG&E's ability to anticipate wildfire risk levels, identify the need for and scope of PSPS events, and improve emergency response to reduce the consequences from any fires that do start (whether or not they are associated with PG&E equipment).
- SIPT (2 percent of 2023-2026 planned Wildfire mitigation spending) will support PG&E's wildfire risk reduction efforts by serving as standby resources for PG&E crews working in high fire risk areas, gathering data that can be used in mitigation efforts such as PSPS, protecting PG&E assets in the event of a wildfire, and supporting state, county, and tribal firefighting and emergency response coordination efforts. These trained teams provide real-time field observations that help PG&E make more informed operational decisions.
- The CWSP PMO (1 percent of 2023-2026 planned Wildfire mitigation spending) provides critical coordination and oversight for all of PG&E's Wildfire risk mitigations.
- Additional Automation and Protection (1 percent of 2023-2026 planned Wildfire mitigation spending) is a continuing commitment to new

automation and protection technologies that have the potential to create opportunities for further Wildfire risk reduction in the future.

F. Alternative Analysis

In addition to the mitigations discussed above, PG&E considered four alternative mitigations:

1. Alternative Plan 1: M11a – Remote Grid

As discussed above, in 2020 PG&E is piloting three Remote Grid projects, one of which is in an HFTD area. If the outcome of the pilots is favorable, PG&E proposes to expand the mitigation to additional feeders in 2021-2022 and subsequently 2023-2026.[47] Since PG&E has not determined the scale or future location of additional Remote Grid projects, for modeling purposes PG&E assumed that remote grid work in 2023-2026 will continue at the same level as 2020 and allocated the mileage proportionally across all tranches. The high preliminary RSE for this program suggests that it is a good candidate for implementation on a larger scale, though more information is required from the pilots to validate PG&E's current assumptions. Regardless of its efficacy, the scope of this program is inherently limited because it can only be applied to long feeders that serve a small number of customers.

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[47] PG&E's RAMP analysis incorporates information as of May 2020. Based on the results of the remote grid projects in 2020, PG&E will consider revising the forecast for this mitigation in 2021 and beyond. The revised forecast and corresponding RSE calculations will be included in PG&E's 2021 WMP Report and the 2023 GRC.

TABLE 10-14
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M11a	Remote Grid	$5,110	$5,240	$5,370	$5,510	$21,230	17.6[b]	269
2		Total	$5,110	$5,240	$5,370	$5,510	$21,230		

(a) See mitigation workpapers included in the source document modeling package for information used to calculate the RSE.
(b) The RSE includes the risk reduction for both the Wildfire risk and the Failure of Electric Distribution Overhead Asset risk.
Note: See WP 10-1.

2. Alternative Plan 2: A2 (M12) – Fire Retardant

PG&E is evaluating the use of commercially available long-term chemical fire retardants to pre-treat rights of way, areas around equipment and devices, switchyards, substations, and critical facilities to reduce the potential for ignition and fire spread and potentially limit the need for PSPS. PG&E would apply the fire retardant in HFTD areas after the last rain of the spring and before the fire season starts. This mitigation addresses the Equipment Failure, Vegetation, Third Party, Animal, and Other drivers.

In 2020, PG&E aims to pilot application of fire retardant on 455 miles of distribution lines and 274 miles of transmission lines. However, PG&E's ability to execute this pilot may be limited by various county-level environmental permitting conditions. If the pilot confirms the efficacy, acceptability and feasibility of fire retardant application, PG&E may deploy it on a greater scale in future years. For modeling purposes, PG&E assumes that fire retardant will be applied in 2023-2026 at the same annual levels, and the same ratio of distribution to transmission work, as in the 2020 pilot.

TABLE 10-15
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A2	Fire Retardant	$20,628	$21,144	$21,672	$22,214	$85,658	2.1	135
2		Total	$20,628	$21,144	$21,672	$22,214	$85,658		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 10-1.

3. Alternative Plan 3: A3 – Wildfire-Targeted System Upgrades

In addition to its currently proposed M2 System Hardening mitigation, PG&E is evaluating a broad spectrum of other system modifications to reduce Wildfire risk. These other options range from modest improvements, such as additional animal protection on existing lines, to system hardening packages that are only slightly less extensive than the current M2 specification. These alternatives involve less work and provide less risk reduction than the M2 mitigation, but at a lower cost. Some of the alternative system modifications under consideration may be appropriate substitutes for the M2 mitigation in some areas; they may also be an appropriate means for PG&E to reduce risk in HFTD areas currently outside the scope of the 7,100 miles of system hardening currently planned for the M2 mitigation.

PG&E is modeling two representative packages of system modifications as alternative mitigations for M2 System Hardening. The A3 – Wildfire – Targeted System Upgrades alternative mitigation, discussed in this section, involves significantly less work and a much lower per mile cost than the existing M2 mitigation. The A4 – System Hardening-Hybrid alternative mitigation, discussed in the next section, falls between the A3 alternative mitigation and the existing M2 mitigation. PG&E's consideration of the feasibility and effectiveness of various alternatives to M2 System Hardening is still in the early stages; no pilot or workplan has been developed to operationalize any of these alternatives.

The A3 Wildfire-Targeted System Upgrades alternative is a scenario where PG&E does not replace its existing bare wire with covered conductor. Instead, PG&E will employ several system modifications to reduce the potential for outages that could result in ignitions. The upgrades include: animal protection work (e.g., installation of insulated wire covers, dead-end covers, covered jumpers, and cut-out/bushing covers); work to improve separation between phases of conductor to reduce the likelihood of wire-to-wire contact in high wind (e.g., installation of spreader brackets or reframing of cross-arms); assessment of poles under current pole loading standards; and use of trusses, guys, or pole replacement to bring poles up to current loading standard where necessary. This alternative can also include the installation of additional protective devices to enable the use of DCD (Downed Conductor Detection) and SGF (Sensitive Ground Fault) modes. PG&E believes that this alternative may be especially effective in areas with low vegetation density including HFTD areas that are currently outside the scope of the approximately 7,100 miles currently planned for the M2 mitigation.

As the consideration of the feasibility and effectiveness of this alternative is still in early stages, PG&E is modeling it as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of A3 – Wildfire – Targeted System Upgrades work to bring the total mileage of the two mitigations combined up to 1,000 miles per year.

TABLE 10-16
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE(a)	Risk Reduction
1	A3	Wildfire Targeted System Upgrades	$114,644	$108,981	$112,192	$115,494	$451,311	5.0	1,653
2		Total	$114,644	$108,981	$112,192	$115,494	$451,311		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 10-1.

4. Alternative Plan 4: A4 – System Hardening-Hybrid

The System Hardening-Hybrid alternative is a package of system modifications that falls somewhere between the existing M2 mitigation and the A3 – Wildfire – Targeted System Upgrades alternative. It entails replacing existing bare wire with covered conductor that is lighter (i.e., has a smaller cross-section) than the current M2 specification. This lighter conductor, and pole strengthening technologies such as Extended and Tapered Trusses, would allow PG&E to significantly reduce the number of poles that need to be replaced on System Hardening projects. All poles would be assessed to determine whether they need to be strengthened or replaced. Cross-arms would be replaced to improve separation of phases and the animal protection work described in the A3 – Wildfire – Targeted System Upgrades alternative would be performed. Non-exempt equipment replacement and other low impact work is not included in the scenario being modeled.

As with the Wildfire – Targeted System Upgrades alternative discussed above, because PG&E's consideration of the feasibility and effectiveness of the System Hardening-Hybrid alternative is still in early stages, PG&E is modeling it as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of System Hardening – Hybrid work to bring the total mileage of the two mitigations combined up to 1,000 miles per year.

As modeled, both Wildfire – Targeted System Upgrades and System Hardening-Hybrid have comparable RSEs to the existing M2 System Hardening mitigation with a potential lower cost, but less risk reduction per circuit mile. PG&E believes that it is appropriate to invest in the higher level of absolute risk reduction from M2 System Hardening Program in many cases, especially for the higher risk priority circuits that are the current focus of the System Hardening Program. PG&E will continue to evaluate a range of possible system modifications as substitutes for, or supplements to, M2 System Hardening and may include them as part of its funding request in the 2023 GRC.

TABLE 10-17
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A4	System Hardening [Hybrid]	$544,560	$517,661	$532,910	$548,597	$2,143,728	7.3	11,581
2		Total	$544,560	$517,661	$532,910	$548,597	$2,143,728		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
Note: See WP 10-1.

Table 10-18 compares the proposed and alternative mitigation plans.

TABLE 10-18
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023 2026)	Total Capital (2023 2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)	RSE
1	Proposed	M1, M2, M3, M4, M5, M6	$3,497,455	$3,733,492	38,352	$5,321,905	7.21
2	Alternative 1	Proposed + M11a	$3,497,455	$3,754,727	38,615	$5,337,513	7.23
3	Alternative 2	Proposed + A2	$3,583,112	$3,733,492	38,482	$5,384,866	7.15
4	Alternative 3	Proposed + A3	$3,497,455	$4,184,803	39,937	$5,654,205	7.06
5	Alternative 4	Proposed + A4	$3,497,455	$5,877,220	48,180	$6,900,330	6.98

(a) Plan Components refers to the Mitigations presented in Table 10-6.
(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.
Note: See WP 10-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS

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RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS

A. Executive Summary

The Failure of Electric Distribution Overhead Assets (Failure of DOH Assets) risk is defined as failure of electric distribution overhead assets or lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. The drivers for this risk event are: Distribution Line Equipment Failure; Other; Vegetation; Animal; Natural Hazard; Other Pacific Gas and Electric Company (PG&E) Assets or Processes; and Human Performance. The cross-cutting factors Seismic, Information Technology Asset Failure, Skilled and Qualified Workforce, Climate Change, Records and Information Management, and Emergency Preparedness and Response also impact this risk.

Exposure to this risk is based on the 80,716 circuit miles of primary overhead distribution lines in PG&E's electric system. The risk model estimates approximately 24,834 risk events (outages) each year.[1] The Distribution Line Equipment Failure and Vegetation drivers together account for 56 percent of the risk events. The Other driver accounts for 30 percent of the risk events. The mitigations PG&E will implement from 2020-2026 are designed to address these key risk drivers.

The risk of ignitions associated with asset failures is modeled as part of the Wildfire risk rather than the Failure of DOH Assets risk. See Chapter 10. In terms of other types of consequence, asset failures not coincident with Seismic events or IT Asset Failure account for 98 percent of the risk events and 87 percent of the risk score. Asset failures associated with seismic events account for less than 1 percent of the risk events but 12 percent of the risk score.

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[1] 24,834 is PG&E's forecast for annual number of outages for 2023-26 in the absence of proposed mitigations from 2023-26.

PG&E identified five tranches for this risk event: two tranches for groups of circuits with issues historically identified as carrying an increased risk for asset failure and three tranches based on circuits' reliability performance. The highest tranche-level risk is associated with circuits with poor reliability performance (56 percent of the risk) and circuits with a significant amount of small copper conductor (21 percent of the risk).

Failure of DOH Assets has the ninth highest 2023 test year baseline safety score (18) and the third highest 2023 test year baseline total risk score (526) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 546, improves by 9 percent when the planned and proposed mitigations are applied: the 2023 test year baseline risk score is 526 and the 2026 post-mitigation risk score is 500.

PG&E is proposing a suite of controls and mitigations to address the key risk drivers. The Grasshopper/KPF Switch Replacement program has the highest 2023-2026 Risk Spend Efficiency (RSE) and the 3A and 4C Line Recloser Controller Replacement program has the highest total 2023-2026 risk reduction score of the mitigations primarily focused on Failure of DOH Assets risk.[2]

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[2] The information herein is subject to those limitations described in Chapter 2, Section D.

TABLE 11-1
RISK OVERVIEW

Line No.	Risk Name	Failure of DOH Assets
1	In Scope	Failure of assets associated with PG&E's overhead electrical distribution system that include: poles and support structures; primary and secondary conductor; voltage regulating equipment; protection equipment; switching equipment; transformers; and PG&E-owned streetlights. Outage incidents caused by PG&E ignitions are considered reliability consequences; such incidents are captured in the Wildfire risk.
2	Out of Scope	Consequences of any ignitions associated with the failure of the electrical distribution system assets described above (which are included in the scope of the Wildfire risk) and failure of assets due to the activities of PG&E employees, PG&E contractors, and third parties (which are included in the scope of the Employee Safety Incident, Contractor Safety Incident, Third-Party Incident and Motor Vehicle Incident risks) are not considered.
3	Data Quantification Sources[(a)]	Data associated with the drivers/source of failures and data associated with reliability impact of failures are taken from PG&E's DOH Outage Dataset from January 1, 2015 to December 31, 2019. Data associated with the safety consequences of failures is taken from PG&E's Electric Incident Reports from January 1, 2015 to December 31, 2019. Data associated with the financial impact of failures is taken from PG&E's DOH Restoration Costs Dataset from January 1, 2017 to September 30, 2019.

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

PG&E's Electric Operations line of business manages more than 80,000 circuit miles of primary overhead distribution lines and associated equipment. Failure of these assets can result in outages and can also have significant public safety impacts.

2. Risk Definition

Failure of distribution overhead assets or lack of remote operational functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.

B. Risk Assessment

1. Background and Evolution

Historically, PG&E analyzed the risk of electric overhead distribution system asset failures on an asset type basis, with a separate risk profile for each asset type such as primary conductors, poles, transformers, etc. When the 2017 RAMP was filed, the Electric Operations Risk Register had eight different risks related to overhead distribution assets.[3] Only one of these risks, DOH Conductor – Primary, was included in the 2017 RAMP.[4]

In 2018, Electric Operations combined the risks associated with individual overhead distribution system asset types into a consolidated Failure of DOH Assets risk that includes all asset types. This is part of PG&E's migration towards an event-based risk register. The consolidation supports a holistic analysis of the risk of overhead electric distribution asset failure as it addresses all the drivers that may cause a failure "event."

The Failure of DOH Assets risk in the 2020 RAMP includes the equipment failure-related components of the DOH Conductor – Primary risk from the 2017 RAMP, as well as additional scope related to failures of all the other electric distribution overhead asset types (i.e., poles, voltage regulating equipment, protective equipment, switching equipment, transformers, secondary conductor, and streetlights).

In the 2017 RAMP discussion of the DOH Conductor – Primary risk, PG&E noted that its risk model had "highlighted the need to differentiate between the two events currently included in the Third-Party Safety Incident, and Motor Vehicle Safety Incident risks, i.e., contact with intact conductor and wire down events" because the two events had significantly different causes and consequences. PG&E stated that it would evaluate whether to separate the third-party contact with intact driver from the DOH Conductor – Primary risk.[5] PG&E performed the evaluations and concluded that safety incidents involving conductors caused by PG&E employees, PG&E contractors, and third-parties should be analyzed and managed separately from safety incidents due to equipment failures related to conductor, because the consequences and mitigations are quite different. These

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[3] These eight risks were: (1) Distribution Overhead Conductor – Primary; (2) Distribution Poles; (3) Distribution Overhead Line Equipment – Voltage Regulators, Booster, and Capacitors; (4) Distribution Overhead Line Equipment – Protective; (5) Distribution Overhead Conductor – Secondary; (6) Distribution Overhead Transformers; (7) Distribution Overhead Streetlight Structures; and, (8) Distribution Overhead – General.

[4] 2017 RAMP Report of PG&E, Investigation (I.) 17-11-003 (Nov. 30, 2017) (2017 RAMP Report), Chapter 9.

[5] 2017 RAMP Report, p. 9-28.

employee, contractor, and third-party incidents are now being managed by PG&E's Safety, Health, Enterprise Corrective Action Plan (ECAP), Department of Transportation (DOT) (collectively, SHED) organization in the Third-Party Safety Incident, Employee Safety Incident, Contractor Safety Incident, and Motor Vehicle Safety Incident risks.[6]

The drivers, controls, and mitigations for the DOH Conductor – Primary 2017 RAMP risk are broadly applicable to the other asset types as described in connection with the new Failure of DOH Assets 2020 RAMP risk. There have been some adjustments in drivers and consequences and certain additional controls and mitigations have been considered because of the additional equipment types covered by the new risk.

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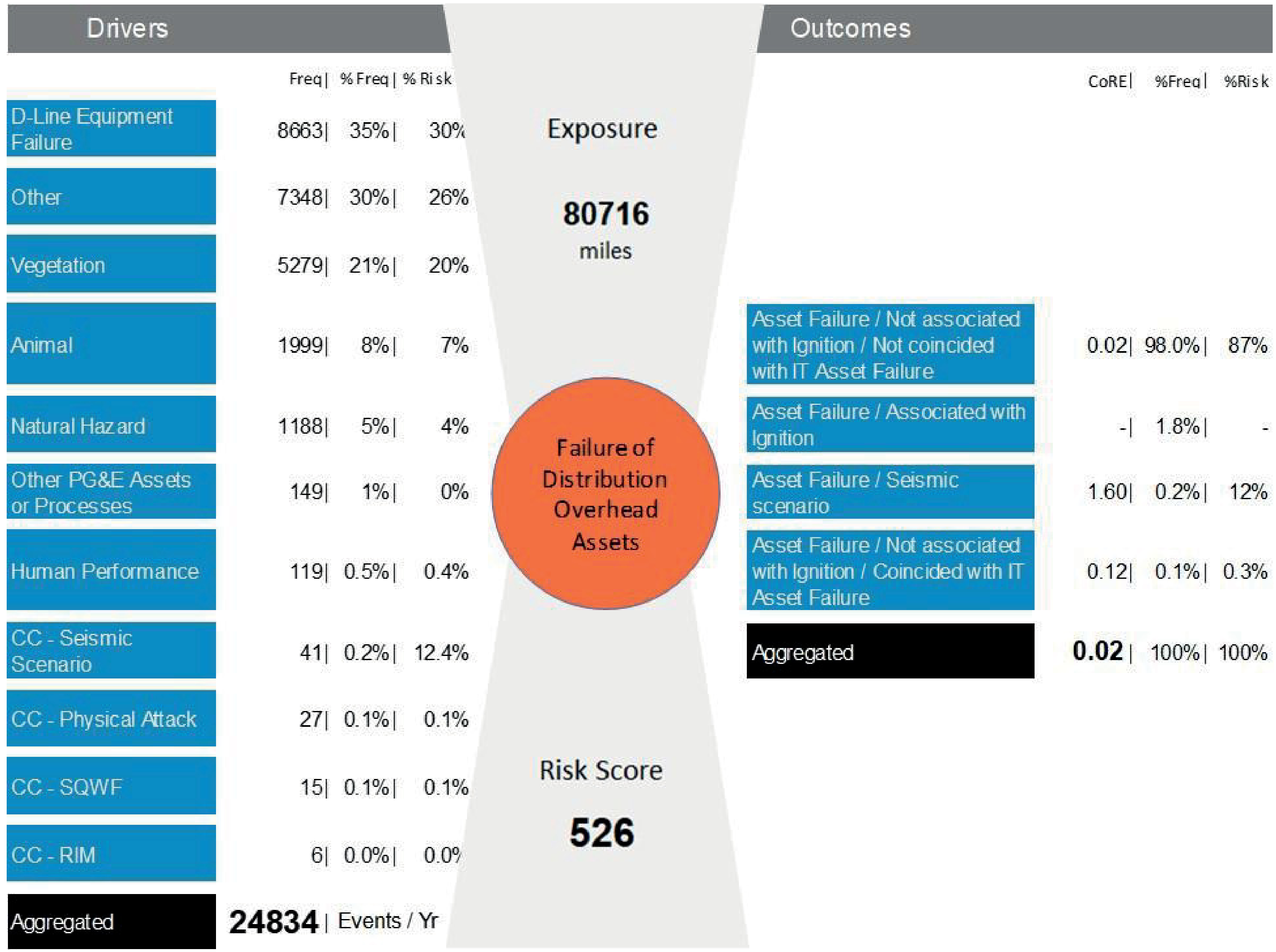
6 The Third-Party Safety Incident, Employee Safety Incident, Contractor Safety Incident, and Motor Vehicle Safety Incident risks are discussed in Chapters 14 through 18 of this report.

2. Risk Bowtie

FIGURE 11-1
RISK BOWTIE



a. Difference from 2017 Risk Bowtie

Failure of DOH Assets was not included as a risk in the 2017 RAMP.

3. Exposure to Risk

PG&E's electric overhead distribution system consists of more than 80,000 circuit miles of primary conductor and associated assets. PG&E models its exposure to the Failure of DOH Assets risk based on the number of circuit miles of primary distribution conductor on its system. PG&E uses outages as a proxy for electric distribution overhead asset failures.

4. Tranches

When PG&E presented its preliminary tranching of the Failure of DOH Assets risk to the California Public Utilities Commission (CPUC or Commission) and intervenors at the February 4, 2020 workshop, PG&E used two tranches: circuits with (1) a less than 50 percent or (2) a greater than 50 percent chance of conductor failure based on historical asset health and other factors. PG&E received feedback that it should consider tranches based on location/environmental characteristics and that it should also attempt to capture failures of other asset types besides conductor as part of its tranching. Based on this feedback, PG&E is now dividing the Failure of DOH Assets risk into five tranches. Two of these five tranches are used to separate out two groups of circuits that PG&E has historically identified as carrying an increased risk for asset failure:

<u>Elevated Wire-downs (Small Copper Conductors)</u>: Small copper conductor (4-CU and 6-CU) contributes to many wire-down incidents and is a focus for PG&E's risk reduction efforts. Some small copper conductor is present on more than 80 percent of PG&E's distribution circuits. To create a reasonable tranche that would differentiate between circuits with a small amount of copper conductor and a more significant amount, PG&E set the threshold for this tranche as any circuit with 7.5 percent or more of its length wired with either 4-CU or 6-CU conductor, or a combination of the two. This tranche includes 22,298 circuit miles or approximately 28 percent of PG&E's overhead distribution system.

Circuits with Aluminum Conductor Steel-Reinforced (ACSR) in Corrosion Zones: These are circuits with ACSR in designated corrosion zones in the Central Coast and Los Padres Divisions. PG&E had previously identified these circuits as having a significantly higher historical failure rate for conductor and connectors than the system average. This tranche includes 4,796 circuit miles or 6 percent of PG&E's overhead distribution system.

After separating out the two tranches described above, PG&E further divided the remaining circuits into three additional tranches based on reliability performance:

Poor Reliability Performance: Circuits within the 66th to 100th percentile of the reliability scores provided in Electric Operations Work Plan 2020. This tranche includes 33,349 circuit miles or approximately 41 percent of PG&E's overhead distribution system.

Moderate Reliability Performance: Circuits within the 33rd to 66th percentile of reliability scores provided in Electric Operations Work Plan 2020. This tranche includes 15,798 circuit miles or approximately 20 percent of PG&E's overhead distribution system.

High Reliability Performance: Circuits within the 0-33rd percentile of reliability scores provided in Electric Operations Work Plan 2020. This tranche includes 4,475 circuit miles or approximately 6 percent of PG&E's overhead distribution system.

Table 11-2 below provides the tranche-level results of the risk analysis.

TABLE 11-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Line No.	Tranche	Percent Exposure	Safety Risk Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent Risk
1	Elevated Wire-Downs (Small Copper Conductor)	28%	4.4	92.8	15.7	112.9	21%
2	Circuits w/ Aluminum Conductor Steel-Reinforced in Corrosion Zones	6%	1.6	48.1	6.0	55.8	11%
3	Poor Reliability Performance	41%	7.9	259.3	29.1	296.3	56%
4	Moderate Reliability Performance	20%	3.0	40.9	10.9	54.8	10%
5	High Reliability Performance	6%	0.6	3.4	2.1	6.1	1%
6	Total	100%	17.6	444.6	63.8	526.0	100%

5. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is related to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Failure of DOH Assets risk are shown in Table 11-3 below. The cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 11-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	X	
2	Emergency Preparedness and Response		X
3	Information Technology Asset Failure		X
4	Physical Attack	X	
5	Records and Information Management	X	X
6	Seismic	X	X
7	Skilled and Qualified Workforce	X	

When analyzing the Failure of DOH Assets risk PG&E considered the cross-cutting factor Climate Change. Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves. Electric distribution overhead assets can be sensitive to natural hazards, including extreme heat events, major rain events, major snow/ice events, extreme wind, lightning, flooding due to extreme precipitation, subsidence, and others. To reflect the impact of changing climate conditions on this risk, PG&E used climate projections to modify the expected frequency of these natural hazard sub-drivers and thereby the frequency of risk occurrence.

PG&E is continuing to evaluate the impact that Cyber Attack has on RAMP risks and expects to present Cyber Attack as a cross-cutting factor relative to additional RAMP risks in the 2023 GRC.

6. Drivers and Associated Frequency

PG&E identified nine drivers and 61 sub-drivers for the Failure of DOH Assets risk. Each driver and its associated 2023 test-year estimated frequency is discussed below. A complete list of sub-drivers is provided in supporting workpapers.[7]

D1 – Distribution Line (D-Line) Equipment Failure: Failure events due to transformer, conductor, connector, cross-arm, and other electric distribution overhead asset failures. The D-Line Equipment Failure driver accounts for 8,663 (35 percent) of the 24,834 annual expected number of outages.

D2 – Other: Failure events without known causes (e.g., patrol found nothing). The Other driver accounts for 7,348 (30 percent) of the 24,834 annual expected number of outages.

D3 – Vegetation: Failure events caused by trees, tree limbs, or other vegetation. Sub-drivers for the Vegetation driver capture whether the incident was due to a tree falling into lines (including whether the tree has visible defects), a branch (including whether the branch was overhanging or not and, if not, what distance it was from the lines), or a grow-in. The Vegetation driver accounts for 5,279 (21 percent) of the 24,834 annual expected number of outages.

D4 – Animal: Failure events caused by animals such as birds or squirrels. The Animal driver accounts for 1,999 (8 percent) of the 24,834 annual expected number of outages.

D5 – Natural Hazard: Failure events caused by natural hazards such as lightning, flood, ice or snow, and heat wave. The Natural Hazard driver accounts for 1,188 (5 percent) of the 24,834 annual expected number of outages.

D6 – Other PG&E Assets or Processes: Failure events caused by PG&E processes (e.g., return circuit normal) or non-overhead assets such as generators, metering equipment, etc. The Other PG&E Assets or Processes driver accounts for 149 (1 percent) of the 24,834 annual expected number of outages.

D7 – Human Performance: Failure events caused by PG&E employees based on improper construction, operating error or other actions. The

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7 A list of sub-drivers will be included in the modeling workpapers that will be provided on July 17, 2020.

Human Performance driver accounts for 119 (less than 1 percent) of the 24,834 annual expected number of outages.

D8 – Seismic Scenario (Cross-Cutting): Failure events caused by seismic activity. This risk is described further in Chapter 20 of this filing. The Seismic Scenario driver accounts for 41 (less than 1 percent) of the 24,834 annual expected number of outages.

D9 – Skilled and Qualified Workforce (Cross-Cutting): Failure events caused by lack of a sufficiently trained workforce. This risk is described further in Chapter 20 of this filing. The Skilled and Qualified Workforce driver accounts for 15 (less than 1 percent) of the 24,834 annual expected number of outages.

7. Consequences

The Failure of DOH Assets bowtie includes four outcomes for an asset failure:

<u>Asset Failures Associated with an Ignition</u>: If an ignition was found to be associated with an outage on the electric distribution overhead system, that outage is tagged as an "asset failure associated with an ignition." Asset failures associated with an ignition account for approximately 2 percent of the frequency associated with the Failure of DOH Assets risk. The consequences of failures associated with ignitions are considered in PG&E's Wildfire risk model, but PG&E is including them in the bowtie here so that it is clear what portion of Failure of DOH Assets incidents contribute to the Wildfire model. For the purposes of the Failure of DOH Assets model, PG&E is setting the risk score of these incidents to zero.

<u>Asset Failures Associated with a Seismic Scenario</u>: Electric distribution overhead asset failures caused by seismic activity account for less than 1 percent of the frequency associated with this risk but 12 percent of the risk score.

<u>Asset Failures Associated with an Information Technology (IT) Asset Failure</u>: These failures are estimated to account for less than 1 percent of both the frequency and the risk score for this risk.

<u>Failure Not Associated with an Ignition, and not Coincident with IT Asset Failure</u>: Outages on the electric distribution overhead system not

associated with an ignition, seismic scenario, or IT asset failure account for 98 percent of the frequency and 87 percent of the risk score for this risk.

Table 11-4 shows the consequences of this risk event. Model attributes are discussed in Chapter 3, Risk Modeling and Risk Spend Efficiency.

TABLE 11-4
RISK EVENT CONSEQUENCES

					Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety	Electric Reliability	Financial	Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Safety	Electric Reliability	Financial
Asset Failure / Not associated with Ignition / Not coincided with IT Asset Failure	0.02	98%	87%	24338	0.00001	0.031	0.005	0.0007	0.016	0.003	0.350	756	127.1	17.5	378.1	63.6
Asset Failure / Associated with Ignition	-	1.8%	-	442	-	-	-	-	-	-	-	-	-	-	-	-
Asset Failure / Seismic scenario	1.6	0.2%	12%	41	0.00001	2.680	0.009	0.0007	1.592	0.004	0.001	110	0.4	0.0	65.1	0.2
Asset Failure / Not associated with Ignition / Coincided with IT Asset Failure	0.1	0.1%	0%	13	0.00001	0.222	0.005	0.0007	0.113	0.003	0.000	3	0.1	0	1	0
Aggregated	**0.02**	100%	100%	24834	0.00001	0.035	0.005	0.0007	0.018	0.003	0.351	869	127.5	18	445	64

C. Controls and Mitigations

PG&E did not include Failure of DOH Assets as a 2017 RAMP risk, but it did include the Distribution Overhead Conductor – Primary (DOCP) risk, most of which is now integrated into the Failure of DOH Assets risk. Tables 11-5 and 11-6 list all the controls and mitigations for the DOCP risk that PG&E included in its 2017 RAMP and 2020 GRC, and maps them to the Failure of DOH Assets controls and mitigations discussed the 2020 RAMP (for 2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections PG&E describes the controls and mitigations for Failure of DOH Assets in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

TABLE 11-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP (2016 Controls)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2020-2023)
1	C1 (2017) – Public Awareness Programs	X	X	X	Becomes part of C2/C3 for Third Party Safety Incident risk	
2	C2 (2017) – Vegetation Management	X	X	X	Becomes C1	
3	C3 (2017) – Catastrophic Event Memorandum Account – Vegetation Management	X	X	X	Becomes C2	
4	C4 (2017) – Overhead Electric Distribution Preventive Maintenance	X	X	X	Becomes C3	
5	C5 (2017) – Overhead Conductor Replacement	X	X	X	Becomes C4	
6	C6 (2017) – Overhead Patrols and Inspections	X	X	X	Becomes C5	
7	C7 (2017) – Overhead Infrared Inspections	X	X	X	Becomes C6	
8	C8 (2017) – Targeted Circuits Program	X	X	X	Becomes C12	
9	C9 (2017) – Supervisory Control and Data Acquisition	X	X	X	Becomes C7	
10	C10 (2017) – Annual Protection Reviews	X	X	X	Becomes C8	
11	C11 (2017) – Electric Distribution Line and Equipment Capacity	X	X	X	Becomes C9	
13	C1 – Vegetation Management (was C2 (2017))				X	X
14	C2 – Vegetation Management - Catastrophic Event Memorandum Account – (was C3 (2017))				X	X
15	C3 – Equipment Preventive Maintenance and Replacement – Distribution Overhead (was C4 (2017))				X	X

TABLE 11-5
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Name and Number	2017 RAMP (2016 Controls)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2020-2023)
16	C4 – Overhead Conductor Replacement (was C5 (2017))				X	X
17	C5 – Patrols and Inspections – Distribution Overhead (was C6 (2017))				X	X
18	C6 – Overhead Infrared Inspections (was C7 (2017))				X	X
19	C7 – Supervisory Control and Data Acquisition (was C9 (2017))				X	X
20	C8 – Annual Protection Reviews (was C10 (2017))				X	X
21	C9 – Electric Distribution Line and Equipment Capacity (was part of C8 (2017))				X	X
22	C10 – Design Standards				X	X
23	C11 – Pole Programs				X	X
24	C12 – Targeted Reliability Program (was C8 (2017))				X	X
25	C13-Enhanced Inspections-Distribution				X	X

TABLE 11-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP (2017-2019)	2020 GRC (2017-2019)	2020 GRC (2020-2022)	2020 RAMP (2020-2022)	2020 RAMP (2023-2026)
1	M3 (2017) – Additional Public Awareness	X	X	X	Becomes part of C2/C3 for Third Party Safety Incident risk	
2	M8 (2017) – Overhang Clearing	X	Becomes part of M8 (2020 GRC)			
3	M8 (2020 GRC) – Enhanced Vegetation Management		X	X	Becomes M1	
4	M1 – Enhanced Vegetation Management				X	X
5	M2 – System Hardening				X	X
6	M3 – Non-Exempt Surge Arrester Replacement				X	X
7	M4 – Expulsion Fuse Replacement				X	X
8	M5 – Additional Asset Data Capture – Outage Information Reporting, Outage Cause, and Failure Analysis				X	X
9	M6 – Grasshopper/KPF Switch Replacement				X	X
10	M7 – Regulated Output (RO) Streetlight Replacement				X	X
11	M8 – Ceramic Post Insulator Replacement				X	X
12	M9 – Improved Distribution Risk Model				X	X
13	M10 – 3A and 4C Line Recloser Controller Replacement				X	X
14	M11 – Remote Grid				X	

1. 2019 Controls and Mitigations

a. Controls

C1 – Vegetation Management – Distribution Overhead: PG&E's Vegetation Management program was developed in coordination with General Order (GO) 95, Rule 35 and California Public Resources Code sections 4292 and 4293. The program includes "routine" compliance-based vegetation management, including periodic inspections, clearing of vegetation around lines and around poles with equipment that poses a fire risk, and quality assurance. In 2018 and 2019, PG&E increased vegetation-to-conductor clearances from 18 inches to 48 inches in High Fire Threat District (HFTD) areas as required by the CPUC in Decision 17-12-024. This control has the potential to reduce the Vegetation driver.

C2 – Vegetation Management – Catastrophic Emergency Memorandum Account (CEMA): Since 2014, PG&E has undertaken several initiatives intended to address the risks associated with tree mortality stemming from prolonged drought conditions and bark beetle infestation, which caused California's Governor to declare an ongoing state of emergency in 2015.[8] These initiatives, which are funded through the Catastrophic Emergency Memorandum Account, include additional inspections and tree work in areas of PG&E's service territory that are at higher risk for tree mortality or wildfire, including HFTD areas, State Responsibility Areas, and Wildland-Urban Interface. This control has the potential to reduce the Vegetation driver.

C3 – Equipment Preventive Maintenance and Replacement – Distribution Overhead: Proactive identification and repair or replacement of critical overhead distribution equipment, such as cross-arms, transformers, capacitors, reclosers and switches. Equipment is identified through the Patrol and Inspections – Distribution Overhead (C5) control or through ad hoc inspection. This control involves both expense and capital work.

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[8] Governor's Proclamation of a State of Emergency, October 30, 2015.

In 2019, PG&E's accelerated and enhanced Wildfire Safety Inspection Program (WSIP) inspection process in Tier 2 and Tier 3 HFTD areas (described below in connection with the Patrol and Inspections – Distribution Overhead (C5) control) identified a substantial amount of repair and replacement work (maintenance tags) to be completed. PG&E has completed the high priority corrective actions identified as necessary during the WSIP inspections and will complete the lower priority work over the next three years, with prioritization based on a risk-based approach. This control has the potential to reduce the D-Line Equipment Failure driver.

C4 – Overhead Conductor Replacement: The overhead conductor replacement program replaces spans of conductor that have failed or are likely to fail, based on historical events and conductor attributes that include number of splices, fault duty, and exposure to harsh environments, such as coastal salt and fog. The program also includes post-wire down event investigations and splice data reviews. Note that this program involves the replacement of bare conductor with upgraded bare conductor in non-HFTD areas. In HFTD areas, when PG&E replaces existing bare conductor, it installs covered conductor as part of the M2 System Hardening mitigation described below. The Overhead Conductor Replacement control has the potential to reduce the D-Line Equipment Failure driver, specifically the Conductor sub-driver.

C5 – Patrols and Inspections – Distribution Overhead: PG&E regularly patrols and inspects its electric distribution overhead facilities to identify damaged assets, compelling abnormal conditions, regulatory conditions, and third-party caused infractions that negatively impact safety or reliability, including conditions that may pose a risk of equipment failure. The pre-2019 baseline inspection program was designed in accordance with regulatory requirements (GO 165).

In 2019, PG&E performed supplemental inspections, using enhanced inspection criteria and expanded documentation requirements, of all its electric distribution overhead facilities located in HFTD Tier 2 and Tier 3 areas as part of its WSIP. This supplemental assessment included the use of mobile applications instead of paper maps and the collection of additional asset condition data and photographs. Going forward, PG&E will integrate WSIP criteria, tools, and process controls into its routine overhead inspection process for PG&E's entire distribution system. In addition, PG&E will adjust the cadence of inspections in alignment with wildfire risk and other risks. As discussed further in Section E.1, below, PG&E is piloting an RSE calculation for the portion of this control that relates to overhead inspections, which is designated as C13 – Enhanced Inspections. This control has the potential to reduce the D-Line Equipment Failure driver.

C6 – Overhead Infrared Inspections: The infrared inspection program targets the physical inspection of overhead conductors using thermographic technology to identify damaged or deteriorated conductors and connectors. Through 2019, infrared inspections included a multi-year, system-wide survey to identify and record the number and location of splices on electric distribution overhead primary conductors for future use in the evaluation of system risk and prioritization of conductor replacement projects. Going forward, infrared inspections will be conducted on circuits on a risk-prioritized basis, with a focus on Tier 2 and Tier 3 HFTD areas. This control has the potential to reduce the D-Line Equipment Failure driver.

C7 – Supervisory Control and Data Acquisition: This program includes the installation, upgrade and replacement of remotely controlled automation and protection equipment in distribution substations and on feeder circuits. This work improves operating efficiency, enables better outage response and diagnosis, improves system protection, and improves employee and public safety by enabling PG&E to automatically and remotely de-energize lines in response to emergencies such as wires down. This control has the potential to reduce the Other driver.

C8 – Annual Protection Reviews: This engineering program primarily covers electric distribution engineering and planning work which supports a variety of asset management activities and is necessary to safely and reliably plan, design, and operate PG&E's electric distribution system. General engineering work includes reviews of distribution system protection equipment and settings to ensure the devices will operate correctly and in a coordinated fashion. This control has the potential to reduce the D-Line Equipment Failure driver.

C9 – Electric Distribution Line and Equipment Capacity: Although the primary purpose of PG&E's capacity program is to mitigate existing or projected overloads and voltage levels, these anomalies can also lead to equipment failure. When overloaded line equipment and conductors fail, service reliability is reduced and public safety concerns (such as wires down) can be created. These effects are mitigated by addressing potential overload conditions before they occur by installing and/or replacing equipment to increase capacity. These projects also sometimes include conductor replacement. This control has the potential to reduce the D-Line Equipment Failure and Other drivers.

C10 – Design Standards: General standards for proper installation, maintenance and operation of equipment to ensure safe and reliable operation. PG&E is continually evolving its design standards to improve efficiency and reduce risk.[9] For example, Utility Bulletin TD-9001B-009 sets forth standards to be used in new construction and system upgrades in HFTD areas. This control has the potential to reduce all drivers.

C11 – Pole Programs: This control includes multiple activities related to distribution poles, including intrusive testing, remediation, and loading assessment. Distribution wood poles are remediated (through replacement or reinforcement) when necessary, based on observed degradation. In addition, in 2019 PG&E initiated a new pole loading assessment proof of concept to enhance the analysis of its existing distribution wood poles. At the same time, PG&E has strengthened the safety factor requirements included in its pole loading model parameters. For example, sizing for new and replacement distribution poles now considers peak historical wind speeds in areas where they

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9 PG&E Utility Bulletin TD-9001B-009, Rev. 2, Fire Rebuild Design Guidance for System Hardening (Nov. 15, 2019). The Bulletin was first published in October 2018 and continues to evolve.

exceed GO 95 wind speeds. This control has the potential to reduce the D-Line Equipment Failure driver.

C12 – Targeted Reliability Program: This control includes targeted work to improve reliability. Typically, the work involves a combination of new fuse and line recloser installations, conductor replacements, installation of fault indicators, reframing of poles to increase phase separation, installation of bird/animal guards, and other maintenance, inspection, and vegetation management work. At the time of the 2017 RAMP, this work was performed as part of PG&E's Targeted Circuits program. PG&E's current program focuses more narrowly on localized reliability issues rather than considering entire circuits. This control has the potential to reduce the D-Line Equipment Failure driver.

b. Mitigations

M1 – Enhanced Vegetation Management (EVM): Since 2018, PG&E has significantly expanded its traditional vegetation management activities around distribution lines in HFTD areas to reduce the likelihood of vegetation contacting lines. Though intended primarily as a mitigation for the Wildfire risk, EVM also has the potential to reduce the Vegetation driver of the Failure of Electric Distribution Overhead Assets risk.[10]

M2 – System Hardening: The System Hardening program is an ongoing, long-term capital investment program to rebuild portions of PG&E's overhead electric distribution system. Over the course of this program, PG&E plans to upgrade approximately 7,100 miles of overhead distribution circuit in HFTD areas. Though intended primarily as a mitigation for the Wildfire risk, System Hardening also reduces the D-Line Equipment Failure, Animal, Natural Hazard, Other, Other PG&E

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10 The EVM mitigation is discussed in greater detail in connection with the Wildfire risk in Chapter 10. EVM is a mitigation that impacts two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

Assets or Processes and Vegetation driver of the Failure of Electric Overhead Assets risk.[11]

M3 – Non-Exempt Surge Arrester Replacement: This program, which is being implemented throughout PG&E's system, will replace non-exempt surge arresters with new exempt surge arresters, and correct abnormal grounding conditions where necessary. The purpose of this mitigation is primarily to reduce fire risk and bring grounding into compliance, but it will also reduce the likelihood of equipment failures associated with surge arresters by replacing old equipment with new equipment.[12] In 2019, PG&E replaced 4,611 non-exempt surge arresters as part of this program. The program is expected to continue through 2023. This mitigation has the potential to reduce the D-Line Equipment Failure driver.

M4 – Expulsion Fuse Replacement: Beginning in 2019, PG&E is targeting replacement of 625 non-exempt fuses per year for seven years on poles located in HFTD areas. Although the primary purpose of this program is to reduce Wildfire risk, it will also reduce the risk of equipment failure associated with the fuses that are replaced.[13]

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11 The System Hardening mitigation is discussed in greater detail in connection with the Wildfire risk in Chapter 10. System Hardening is a mitigation that impacts three RAMP risks—Wildfire, Failure of Distribution Overhead Assets, Third Party Safety Incident—because it will reduce both ignitions and equipment failure, and reduce the potential for third party contact with energized conductors. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for all three risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

12 Non-Exempt Surge Arrester Replacement is a mitigation for two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

13 The Expulsion Fuse mitigation is discussed in greater detail in connection with the Wildfire risk in Chapter 10. The Expulsion Fuse program is a mitigation for two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

This mitigation has the potential to reduce the D-Line Equipment Failure driver.

M5 – Additional Asset Data Capture – Outage Information Reporting, Outage Cause, and Failure Analysis: This mitigation consists of various efforts to improve PG&E's ability to capture information about the location and cause of outages, and about the reasons for equipment failures. It may include facilitating asset data capture on mobile devices in the field or automatically, efforts to improve PG&E's outage database, and changes in standards and procedures to expand the amount of asset failure information gathered by field personnel. These improvements will facilitate PG&E's move towards a more data-driven, risk-based asset management strategy. PG&E considers this to be a foundational activity because it supports other controls and mitigations rather than directly reducing risk. As a result, PG&E is not calculating a risk reduction score or an RSE for this mitigation.

M6 – Grasshopper/KPF Switch Replacement: Grasshopper and KPF switches are obsolete types of overhead distribution line switches which PG&E is eliminating from its system. PG&E's ongoing Grasshopper/KPF Switch Replacement Program proactively replaces obsolete switches installed between 1950 and 1970 to minimize potential safety issues during routine and emergency switching operations and improve reliability. In 2019, PG&E replaced eight switches as part of this program. PG&E estimates that as of the end of 2019 there are 151 additional switches that need to be replaced. This mitigation has the potential to reduce the D-Line Equipment Failure driver.

M7 – Regulated Output (RO) Streetlight Replacement: This is a program to replace a small number of antiquated RO streetlights that PG&E owns and operates in San Francisco. These RO streetlights are prone to failure and difficult to maintain; in some cases, spare parts are no longer manufactured and cannot be obtained. PG&E completed replacement of 22 of 24 RO loops in 2019; there are still 49 additional streetlights that need to be converted to complete work on the remaining

2 RO loops. PG&E is not currently planning to perform any work in this program in 2020-2022 because of the City and County of San Francisco's (CCSF) 5-year paving moratorium, which went into effect in late 2017. Instead, PG&E plans to replace the 49 remaining RO streetlights in 2023 when the 5-year moratorium expires.[14] This mitigation has the potential to reduce the Other PG&E Assets or Processes driver.

M8 – Ceramic Post Insulator Replacement: This program will replace ceramic post insulators manufactured prior to 1972. Manufacturing techniques for ceramic insulators in the 1960s and 1970s were not as advanced as today. PG&E has determined that over time these older insulators may experience failures at lower-than-rated cantilever strength. PG&E linemen have expressed safety concerns regarding these insulators and, depending on failure mode, a failed ceramic post insulator can carry an energized conductor down to the ground creating a potential safety hazard to the public and utility workers. This mitigation program is targeted at replacing the existing population of vintage ceramic insulators with newer post insulators made of composite materials that have a lower risk of breaking. The program will focus on poles that are already being targeted through PG&E's ongoing Non-Exempt Surge Arrester Replacement program. PG&E estimates that it will replace older ceramic post insulators on approximately 4,589 poles in connection with the Non-Exempt Surge Arrester Replacement program. Additional replacements will occur on an ad hoc basis in other ongoing programs when they identify older ceramic post insulators, but these replacements are outside the scope of the mitigation considered here. As of February 2020, PG&E has replaced approximately 820 older ceramic post insulators through the program; the program is scheduled to end in 2023 at the same time the Non-Exempt Surge Arrester Replacement program is completed.

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14 PG&E has approached CCSF about the possibility of making an exception to the paving moratorium for this work. If CCSF agrees, PG&E may complete the remaining replacements prior to 2023.

This program has the potential to mitigate the D-Line Equipment Failure driver.

c. 2017 RAMP Update

With a couple of exceptions, PG&E is presenting the same controls for the Failure of DOH Assets risk in the 2020 RAMP as it did for the DOCP risk in the 2017 RAMP though the numbering and in some cases naming of the controls in slightly different. One DOCP control from the 2017 RAMP, Public Awareness, has not been carried forward to the Failure of DOH Assets risk because that program was designed to reduce third party contact with energized conductors, which is now addressed as part of the Third-Party Safety Incident RAMP risk. PG&E has added two new controls – Design Standards and Pole Programs – which relate to electric distribution overhead assets other than conductor. Also, the scope of asset-based controls such as Equipment Preventive Maintenance and Replacement now extends to all electric distribution overhead line assets, not just conductor.

PG&E proposed two mitigations for DOCP in the 2017 RAMP. One of these, Additional Public Awareness Outreach, is not carried forward to the Failure of DOH Assets risk because, like the Public Awareness control discussed above, it is now in the scope of the Third-Party Safety Incident RAMP risk. The second mitigation, Overhang Clearing, was subsumed in the Enhanced Vegetation Management mitigation presented in the GRC, and that continues to be the case here. PG&E is proposing several asset-based mitigations for Failure of DOH Assets in the 2020 RAMP that post-date the filing of the 2017 RAMP and/or which target electric distribution overhead assets other than conductor and therefore would not have been mitigations for DOCP risk. These mitigations include: System Hardening, Non-Exempt Surge Arrester Replacement, Expulsion Fuse Replacement, Grasshopper/KPF Switch Replacement, RO Streetlight Replacement, Ceramic Post Insulator Replacement, and 3A and 4C Line Recloser Controller Replacement. Two other proposed mitigations—Asset Data Capture and Improved Distribution Risk Model—are new activities that did not exist at the time the 2017 RAMP was filed.

D. 2020-2022 Control and Mitigation Plan

1. Changes to Controls

In general, PG&E will continue to implement the same controls in 2020-2022 as it did in 2019. Significant changes to existing controls are discussed below.

C4 – Overhead Conductor Replacement: PG&E is evaluating a possible increase in its current planned mileage of overhead conductor replacement. This increase could begin as early as 2022. PG&E will discuss any such proposed increase in the 2023 GRC.

C5 – Overhead Patrols and Inspections: For 2020 and beyond, PG&E is incorporating fire-risk considerations identified as part of the WSIP process and baseline compliance guidelines into a checklist-guided paperless approach for facilities inspections. PG&E will perform detailed overhead inspections of overhead electric distribution facilities located in HFTD areas on a risk-informed cycle; in 2020 PG&E plans to inspect all its facilities in HFTD Tier 3 and one-third of its facilities in HFTD Tier 2. PG&E's current plan for non-HFTD facilities is to continue with the historical cadence of detailed inspections once every five years. Future year inspection scope and cadence may be adjusted based on the results of this initial cycle of enhanced inspections and may shift toward more risk-informed or condition-dependent cycles linked to PG&E predictive models. However, for forecasting purposes, this filing assumes that PG&E will continue to inspect all facilities in HFTD Tier 3 annually and facilities in HFTD Tier 2 once every three years. PG&E is also performing Field Safety Reassessments of pending maintenance notifications that will not be completed before the start of the upcoming fire season to verify that previously identified maintenance conditions have not further deteriorated to the point that they require more immediate resolution.

C6 – Infrared Inspections: PG&E completed its systemwide infrared splice inventory in 2019 but will continue infrared inspections of the system on a regular, risk-prioritized cadence focused primarily on HFTD areas.

C11 – Pole Programs: In 2020, PG&E will begin regular use of the new pole loading infrastructure assessment that it piloted in 2019. PG&E's initial goal is to assess all poles located in Tier 2 and Tier 3 HFTD areas by 2024, at a rate of approximately 230,000 poles per year, to determine whether existing poles are adequate under PG&E's current loading criteria.

2. Changes to Mitigations

In general, PG&E plans to implement the same mitigations in 2020-2022 as it did in 2019. Significant changes to the mitigation plan are discussed below:

M1 – Enhanced Vegetation Management: PG&E's EVM program will perform similar pruning and tree removal work in 2020-2022 to what it did it 2019. However, PG&E plans to complete less EVM work on distribution lines in 2020-2022 than it did in 2019 (approximately 1,800 miles of distribution line per year in 2020-2022 versus 2,498 miles in 2019). Based on its assessment of routine and enhanced vegetation management work on the system as a whole, beginning in 2020 PG&E plans to shift some EVM resources to expand rights of way and remove incompatible trees around lower voltage transmission lines (similar work is already performed around higher voltage transmission lines as part of PG&E's routine vegetation management).

M2 – System Hardening: PG&E plans to progressively increase the pace of system hardening in the 2020-2022 period with a goal of completing approximately 1,060 circuit miles in that period.

M6 – Grasshopper/KPF Switch Replacement: PG&E estimates that, as of the beginning of 2020, there are approximately 151 grasshopper and KPF switches that still need to be replaced. Program management anticipates completing the replacement of all 151 remaining switches between 2020 and 2025, including 1 switch in 2020, and 30 switches per year from 2021-2025.

M7 – RO Streetlight Replacement: As discussed above, PG&E is not currently planning to perform any RO Streetlight Replacement work in 2020-2022 because of the City and County of San Francisco (CCSF) paving moratorium that is in effect until 2023. Work will resume in 2023.

PG&E is implementing three new mitigations beginning in the 2020-2022 time period:

M9 – Improved Distribution Risk Model: PG&E is developing an improved distribution risk model that when fully implemented will provide a more risk-based framework for decisions about asset inspection, maintenance, and replacement of all overhead electric distribution assets. Each asset will receive a risk score, in line with the Multi-Attribute Value Function Framework, that considers the probability of failure (based on asset health factors) and the resulting consequences (based on the function and location of the assets). PG&E believes this risk-based approach will address drivers of asset failure more effectively than the traditional, compliance-based approach. PG&E will be continually evolving this improved model through at least 2026. PG&E considers this to be a foundational activity because it supports other controls and mitigations rather than directly reducing risk. As a result, PG&E is not calculating a risk reduction score or an RSE for this mitigation.

M10 – 3A and 4C Line Recloser Controller Replacement: PG&E uses line reclosers across its electric distribution overhead system to manage, locate, and isolate faults and to re-energize circuits in the event of an outage. Some of these line recloser units use older model 3A or 4C controllers, which have limited functionality compared to newer controller models. These functional limitations increase the risk of circuit failure and impact PG&E's ability to isolate faults and re-energize circuits in the event of an outage. Line reclosers are also categorized as protective devices and are programmed to protect customers from safety hazards due to fault conditions including wire-down incidents and sustained outages. There is a high risk of such fault incidents if these devices do not operate as intended. In particular, because the sensor technology in existing 3A controllers is less sophisticated than in newer controllers, a line recloser equipped with a 3A controller may not detect all the faults that a newer controller would, which may lead to a higher incidence of energized wires down. To mitigate this risk, PG&E proposes to replace all 3A and 4C line recloser controllers in its system with newer models.[15]

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15 3A and 4C Line Recloser Controller Replacement is a mitigation for two RAMP risks—Failure of DOH Assets and Third-Party Safety Incident—because it will reduce outages and third-party contact with energized conductor. The primary benefit of the mitigation is to reduce Failure of DOH Assets risk. PG&E calculated the aggregated risk reduction score for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation.

PG&E estimates that there are approximately 810 of these units that will need to be replaced as part of the program.[16] PG&E plans to pilot this program by replacing five 3A units in both 2021 and 2022 and then launch a full-scale program in 2023.

M11 – Remote Grid: Remote Grid is an effort to use decentralized energy sources to permanently supply energy to certain remote customers instead of using hardened traditional utility infrastructure for electricity. PG&E's service territory contains pockets of isolated small customer loads that are served via long electric distribution feeders; some of these feeders pass through HFTD areas and some have been disconnected due to damage from recent wildfires. PG&E is proposing to remove some of these long feeders and instead serve customers from local, decentralized energy sources. This could reduce fire ignition risk, and will also reduce outages. Remote Grid could also be a cost-effective alternative to the high maintenance and restoration costs associated with these long feeder lines in remote areas. This mitigation addresses the D-Line Equipment Failure, Vegetation, Third Party, Animal, Natural Hazard, Human Performance, Other PG&E Assets or Processes and Other drivers.

In 2020, PG&E plans to deploy three Remote Grid projects at two sites to validate use cases, design standards, deployment processes, and commercial arrangements. One project is located in Briceburg, in HFTD Tier 2, and will remove 1.37 miles of line. This project is being modeled as a mitigation to both the Wildfire and Failure of DOH Assets risks.

Two projects are located at the Carrizo Plain pilot site, which is outside the HFTD but involves circuit segments with high maintenance costs, and will remove 23.8 miles of line. If the results of the initial projects are favorable, PG&E will determine whether to propose further remote grid projects in 2021 and beyond. For modeling purposes, PG&E assumes there will be no remote grid work in 2021 or 2022 but is presenting remote grid work as an alternative mitigation for 2023-2026. See Section D.1 below.

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16 PG&E estimates that there are approximately 860 of these controllers on the system, but that approximately 50 will be replaced by other programs.

The volume of mitigation work PG&E plans to complete in the 2020-2022 period is shown in Table 11-7 below.

TABLE 11-7
PLANNED MITIGATIONS 2020-2022

Line No.	Mitigation Name and Number	Units	2020 RAMP Planned Units of Work 2020	2021	2022	Total
1	M1 – Enhanced Vegetation Management	Miles	1,800	1,800	1,800	5,400
2	M2 – System Hardening	Miles	241	377	442	1,060
3	M3 – Non-Exempt Surge Arrester Replacement	Poles with surge arresters	2,511	3,091	19,340	24,942
4	M4 – Expulsion Fuse Replacement	Fuses	625	625	625	1,875
5	M5 – Additional Asset Data Capture	N/A	–	–	–	
6	M6 – Grasshopper/ KPF Switch Replacement	Switches	1	30	30	61
7	M7 – RO Streetlight Replacement	Streetlight	0	0	0	0
8	M8 – Ceramic Post Insulator Replacement	Poles with insulators	1,410	1,048	1,048	3,506
9	M9 – Improved Distribution Risk Model	N/A	–	–	–	
10	M10 – 3A and 4C Line Recloser Controller Replacements	Controller	0	5	5	10
11	M10 – Remote Grid	Miles Removed	25	0	0	25

The estimated costs for the work planned in 2020-2022 are shown in Tables 11-8 and 11-9 below.

TABLE 11-8
FORECAST COSTS[b]
EXPENSE ($000) 2020-2022

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M5	Additional Asset Data Capture	AB	$4,200	$1,230	$1,261	$6,691
2	M9	Improved Distribution Risk Model	AB	2,900	1,435	1,471	5,806
3		Total		$7,100	$2,665	$2,732	$12,497

(a) Mitigation M1 (Enhanced Vegetation Management) is not shown in this table because the costs for this work are aligned to the Wildfire risk (Chapter 10).

(b) See WP 11-1.

TABLE 11-9
FORECAST COSTS[b]
CAPITAL ($000) 2020-2022

Line No.	Mit. No.[a]	Mitigation Name	MWC	2020	2021	2022	Total
1	M3	Non-Exempt Surge Arrester Replacement	2AR	$8,132	$14,359	$62,632	$85,123
2	M6	Grasshopper and KPF Switch Replacement	08S	30	1,135	1,165	2,330
3	M7	Regulated Output Streetlight Replacement	2AG	–	–	–	–
4	M8	Ceramic Post Insulator Replacement	2AQ	3,440	2,620	2,686	8,746
5	M10	3A and 4C Line Recloser Replacement	49B	–	513	525	1,038
6		Total		$11,602	$18,627	$67,008	$97,237

(a) Mitigation M2 (System Hardening) is not shown in this table because the costs for this work are aligned to the Wildfire risk (Chapter 10).

(b) See, WP 11-1.

E. 2023-2026 Proposed Control and Mitigation Plan

1. Changes to Controls and RSE for Piloted Control

In general, PG&E plans to continue the same level of work for controls in 2023-2026 as it has planned for the 2020-2022 period.

PG&E committed to piloting the calculation of a risk reduction score and RSE for one Electric Operations RAMP risk control in the 2020 RAMP. Electric Operations is piloting the C13 – Enhanced Inspection control for the Failure of DOH Assets risk. The Enhanced Inspection control consists of the inspection portion of the C5 – Overhead Patrols and Inspections control and includes the changes in inspection scope and cadence that began with the WSIP in 2019. For modeling purposes, PG&E assumes, based on its 2020 work plan, that will inspect circuits in Tier 3 HFTD areas every year and circuits in Tier 2 HFTD areas every three years. However, PG&E continues to assess the effectiveness of the increased cadence of the program and may shift its strategy as more data is made available. Enhanced Inspections, which has a preliminary RSE of 0.37 for the Failure of DOH Assets risk[17], will reduce the D-Line Equipment Failure risk driver and provide PG&E with a better understanding of its asset conditions and maintenance practices. The table below shows the forecast program spending and preliminary RSE for the Enhanced Inspections control.

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[17] Enhanced Inspections will also reduce Wildfire risk, but PG&E has not calculated a Wildfire-related risk reduction score at this time. PG&E will calculate risk reduction related to the Wildfire risk for enhanced inspections in the 2023 GRC, either separately or as part of larger inspections control.

TABLE 11-10
FORECAST COSTS, RSE AND RISK REDUCTION[b]
EXPENSE 2023-2026
($000)

Line No.	Ctrl No.	Control Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	C13	Enhanced Inspections-Distribution	BFB	$164,367	$168,475	$172,688	$177,005	$682,535	0.37	187.5
2		Total		$164,367	$168,475	$172,688	$177,005	$682,535		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) See, WP 11-1.

2. Changes to Mitigations

In general, PG&E plans to implement the same mitigations in 2023-2026 as it did in the 2020-2022. Significant changes to the mitigation plan are discussed below:

M2 – System Hardening: PG&E plans to continue to increase the pace of system hardening with a goal of completing approximately 2,118 circuit miles in the 2023-2026 period.

M3 – Non-Exempt Surge Arrester Replacement: PG&E expects to complete all replacements in the program by 2023.

M5 – Grasshopper/KPF Switch Replacement: Based on PG&E's current work plan, PG&E expects to replace 30 switches per year from 2023-2025, at which point the all replacements will be completed.

M7 – RO Streetlight Replacement: PG&E is planning to resume work in this program and complete all replacements in 2023.

M10 – 3A and 4C Line Recloser Controller Replacement: PG&E plans to incorporate lessons learned from the pilot replacements in 2021 and 2022 to launch a full-scale replacement program in 2023. PG&E is targeting replacement of all remaining 3A and 4C controllers over a 10-year period beginning in 2023, replacing approximately 81 units per year.

The volume of mitigation work PG&E plans to complete in the 2023-2026 period is shown in Table 11-11 below.

TABLE 11-11
PLANNED MITIGATIONS 2023-2026

Line No.	Mitigation Name and Number	Units	2020 RAMP Planned Units of Work				
			2023	2024	2025	2026	Total
1	M1 – Enhanced Vegetation Management	Miles	1,800	1,800	1,800	1,800	7,200
2	M2 – System Hardening	Miles	504	540	538	536	2,118
3	M3 – Non-Exempt Surge Arrester Replacement	Poles with surge arresters	15,890	0	0	0	15,890
4	M4 – Expulsion Fuse Replacement	Fuses	625	625	625	625	2,500
5	M5 – Additional Asset Data Capture	N/A	–	–	–	–	–
6	M6 – Grasshopper/ KPF Switch Replacement	Switches	30	30	30	0	90
7	M7 – RO Streetlight Replacement	Streetlight	49	0	0	0	49
8	M8 – Ceramic Post Insulator Replacement	Poles with insulators	499	0	0	0	499
9	M9 – Improved Distribution Risk Model	N/A	–	–	–	–	–
10	M10 – 3A and 4C Line Recloser Replacement	Controller	81	81	81	81	324

3. Mitigation Risk Spend Efficiencies

Tables 11-12 and 11-13 below show the planned cost, RSE and risk reduction score for each of the Failure of DOH Assets risk mitigations PG&E plans to implement in the 2023-26 period.

TABLE 11-12
FORECAST COSTS, RSE AND RISK REDUCTION[e]
EXPENSE ($000) 2023-2026

Line No.	Mit No.	Mitigation Name	MWC	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1	Enhanced Vegetation Management	HN[b]						[c]	16.5
2	M5	Additional Asset Data Capture	AB	$1,292	$1,325	$1,358	$1,392	$5,366	[d]	[d]
3	M9	Improved Distribution Risk Model	AB	1,508	1,545	1,584	1,624	6,261	[d]	[d]
4		Total		$2,800	$2,870	$2,942	$3,015	$11,627		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

(b) PG&E is recording costs for this work in temporary MWC IG# but expects to forecast costs for this work in the 2023 GRC in MWC HN.

(c) The costs and RSE or this mitigation are aligned to the Wildfire risk (Chapter 10).

(d) Foundational mitigation. PG&E does not calculate an RSE or risk reduction score for foundational mitigations.

(e) WP 11-1.

TABLE 11-13
FORECAST COSTS, RSE AND RISK REDUCTION[d]
CAPITAL ($000) 2023-2026

Line No.	Mit No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M2	System Hardening	08W						(b)	122.0
2	M3	Non-Exempt Surge Arrester Replacement	2AR	$47,686	–	–	–	$47,686	0.02	0.8
3	M4	Expulsion Fuse Replacement	2AP						(b)	0.4
4	M6	Grasshopper and KPF Switch Replacement	08S	1,195	1,224	1,255	–	3,674	3.69	10.3
5	M7	Regulated Output Streetlight Replacement	2AG	5,277	–	–	–	5,277	<0.01	<0.01
6	M8	Ceramic Post Insulator Replacement	2AQ	1,310	–	–	–	1,310	0.72	0.8
7	M10	3A and 4C Line Recloser Replacement	49B	8,723	8,941	9,164	9,394	36,222	1.54[c]	37.0
8		Total		$64,192	$10,165	$10,419	$9,394	$94,169		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
(b) The costs and RSE of this mitigation are aligned to the Wildfire risk (Chapter 10).
(c) The RSE includes the risk reduction for both the Failure of Electric Distribution Overhead Assets risk and the Third-Party Safety Incident risk.
(d) See, WP 11-1.

More than 95 percent of PG&E's 2023-2026 spending on mitigations that reduce the Failure of DOH Assets risk is for three mitigations, EVM, System Hardening, and Expulsion Fuse Replacement, that are primarily targeted at reducing PG&E's Wildfire risk, but also have the secondary effect of reducing the number of outages due to equipment failure in the areas where they are implemented. The cost of those programs and their RSEs, which aggregate risk reduction of the Wildfire and Failure of DOH Assets risk, are discussed in Chapter 10. The RSEs for EVM, System Hardening, and Expulsion Fuse Replacement (2.6, 7.2, and 1.0, respectively) are all relatively high and demonstrate that PG&E's investment in those mitigations is reasonable.

Non-Exempt Surge Arrester Replacement accounts for 45 percent of 2023-2026 spending on mitigations that are primarily focused on the Failure of DOH Assets risk. The program, which will be completed in 2023, has a relatively low 2023-2026 RSE of 0.02, but PG&E believes the grounding portion of the work is mandatory in order to bring surge arrester installation into compliance with GO 95 and that the simultaneous replacement of surge arresters is prudent asset management.

3A and 4C Line Recloser Controller Replacements accounts for 34 percent of 2023-2026 spending on mitigations that are primarily for the Failure of DOH Assets risk and has a 2023-2026 RSE of 1.39. Grasshopper/KPF Switch Replacements accounts for 3 percent of 2023-2026 spending on mitigations that are primarily for the Failure of DOH Asset risks and has a 2023-2026 RSE of 3.69. Ceramic Post Insulator Replacement, accounting for 1 percent of 2023-2026 spending on mitigations that are primarily for the Failure of DOH Assets risk, has a 2023-2026 RSE of 0.72. These mitigations have relatively high RSE scores and address public and employee safety concerns, as well as potentially reducing outages.

The RO Streetlight Replacement program accounts for 5 percent of 2023-2026 spending on mitigations that are primarily for the Failure of DOH Assets risk; it has a 2023-2026 RSE of less than 0.01. PG&E believes it likely that its current model significantly understates the risk reduction value (and RSE) of the program because it does not differentiate between "normal" streetlight outages on non-RO systems, and streetlight outages on RO systems. Outages on RO systems are more complicated to resolve, as one failure can lead to multiple failures in unison, and RO system outages may last for extended periods of time due to the lack of availability of spare parts. In any event, PG&E believes this investment is prudent from an asset management perspective to eliminate the last few antiquated PG&E-owned RO streetlights from its system.

The two foundational activities for the Failure of DOH Assets risk, Additional Asset Data Capture and Improved Distribution Risk Model, account for 5 percent and 6 percent, respectively, of 2023-2026 spending on mitigations that are primarily for the Failure of DOH Assets risk. PG&E believes it is prudent to invest in these mitigations because they will improve PG&E's ability to capture information about the location and cause of outages and the reasons for equipment failures. This information will help PG&E improve its more risk-based framework for decisions about asset inspection, maintenance, and replacement for all overhead distribution assets.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E.2 above, PG&E also considered alternative mitigations. The mitigations described in Section E.2 above constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations, along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: M11a – Remote Grid

As discussed above, in 2020 PG&E is piloting three Remote Grid projects, one of which is in an HFTD area. If the outcome of the pilots is favorable, PG&E proposes to expand the program to additional feeders as a mitigation for 2023-2026. Since PG&E has not determined the scale or future location of additional Remote Grid projects, for modeling purposes PG&E assumed that remote grid work in 2023-2026 will continue at the same level as 2020 and allocated the mileage proportionally across all tranches.

TABLE 11-14
FORECAST COSTS, RSE AND RISK REDUCTION[c]
CAPITAL ($000) 2023-2026

Line No.	Mit. No.	Mitigation Name	RSE[a]	Risk Reduction
1	M11a	Remote Grid	[b]	5.1

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
(b) The costs and RSE of this mitigation are aligned to the Wildfire risk (Chapter 10).
(c) See WP 11-1.

2. Alternative Plan 2: A2 (M12) – Targeted Transformer Replacement to Mitigate Overloading

Due to rising temperatures in California related to global warming, PG&E expects increasing demand for air conditioning from its customers. Increased demand is likely to overload certain elements of the overhead electric distribution system—this mitigation focuses on addressing the risk of overloaded transformers. Over the next 10 to 20 years, PG&E estimates that up to 1 percent of the approximately 750,000 overhead transformers in its electric distribution system could become susceptible to failure from overloading due to increases in demand. PG&E is currently evaluating a program to proactively identify and upgrade its most vulnerable overhead distribution transformers with higher capacity units to minimize risk of overloading. Electric Program Investment Charge programs 3.13 and 3.20 are currently funding research to collect statistical data on transformer loading to help identify at-risk transformers, using remote sensing and SmartMeter™ devices. The program is in the early stages of development, and PG&E has not identified a scope or prepared risk reduction or cost estimates. As a result, PG&E has not calculated an RSE. PG&E will continue to develop this program and may present it as a mitigation in the 2023 GRC.

3. Alternative Plan 3: A3 – Wildfire – Targeted System Upgrades

In addition to its currently proposed M2 System Hardening mitigation, PG&E is evaluating a broad spectrum of other system modifications to reduce Wildfire risk. These other options range from modest improvements, such as additional animal protection on existing lines, to system hardening packages that are only slightly less extensive than the current M2 specification. These alternatives involve less work and provide less risk reduction that the M2 mitigation, but at a lower cost. PG&E believes that the alternative system modifications under consideration may be appropriate substitutes for the M2 mitigation in some areas, and may also be an appropriate means for PG&E to achieve risk reduction in HFTD areas currently outside the scope of the approximately 7,100 miles currently planned for the M2 mitigation.

To show the risk reduction potential of the wide range of options under consideration, PG&E is modeling two representative packages of system modifications as alternative mitigations for M2 System Hardening. The A3 – Wildfire – Targeted System Upgrades alternative mitigation (discussed in this section) involves significantly less work and a much lower per mile cost than the existing M2 mitigation. The A4 – System Hardening-Hybrid alternative mitigation (discussed in the next section) falls between the A3 alternative mitigation and the existing M2 mitigation. PG&E's consideration of the feasibility and effectiveness of various alternatives to M2 System Hardening is still in the early stages; no pilot or workplan has been developed for implementation of any of these alternatives.

The A3 Wildfire – Targeted System Upgrades alternative is a scenario whereby PG&E does not replace its existing bare wire with covered conductor. Instead, PG&E will employ several system modifications to reduce the potential for outages that could result in ignitions. The upgrades include: animal protection work (i.e., installation of insulated wire covers, dead-end covers, covered jumpers, and cut-out/bushing covers); work to improve separation between phases of conductor to reduce the likelihood of wire-to-wire contact in high wind (i.e., installation of spreader brackets or reframing of cross-arms); assessment of poles under current pole loading standards; and, use of trusses, guys or pole replacement to bring deficient poles up to standard. This alternative can also include the installation of additional protective devices to enable the use of DCD (Downed Conductor Detection) and SGF (Sensitive Ground Fault) modes. PG&E believes that this alternative may be especially effective in areas with low vegetation density (including HFTD areas) that are currently outside the scope of the approximately 7,100 miles currently planned for the M2 mitigation.

PG&E is modeling this alternative as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of A3 – Wildfire – Targeted System Upgrades work, to bring the total mileage of system hardening performed up to 1,000 miles per year from 2021-2026. That would result in a Wildfire – Targeted System Upgrades target of 623 miles in 2021, 558 miles in 2022, 496 miles in 2023, 460 miles in 2024, 462 miles in 2025, and 464 miles in 2026.

TABLE 11-15
FORECAST COSTS, RSE AND RISK REDUCTION
CAPITAL 2023-2026
($000)

Line No.	Mit. No.	Mitigation Name	RSE	Risk Reduction
1	A3	Wildfire-Targeted System Upgrades	[(a)]	19.6

(a) The costs and RSE for this mitigation are aligned to the Wildfire risk (Chapter 10).

4. Alternative Plan 4: A4 – System Hardening-Hybrid

The System Hardening-Hybrid alternative is a package of system modifications that falls somewhere between the existing M2 mitigation and the A3 – Wildfire-Targeted System Upgrades alternative. It entails replacing existing bare wire with covered conductor that is lighter (i.e., has a smaller cross-section) than the current M2 specification. This lighter conductor, and pole strengthening technologies such as Extended and Tapered (ET) Trusses, would allow PG&E to significantly reduce the number of poles it needs to replace on System Hardening projects. All poles would be assessed to determine whether they need to be strengthened or replaced. Cross-arms would be replaced to improve separation of phases, and animal protection work (as described in the A3 – Wildfire-Targeted System Upgrades alternative) would be performed. Non-exempt equipment replacement and other low impact work is not included in the scenario being modeled.

As with the Wildfire–Targeted System Upgrades alternative, PG&E is modeling the System Hardening–Hybrid alternative as part of a mitigation plan that would include the currently forecast amount of M2 System Hardening work, plus sufficient additional mileage of System Hardening – Hybrid work, to bring the total mileage of system hardening performed up to 1,000 miles per year from 2021-2026. That would result in a System Hardening - Hybrid target of 623 miles in 2021, 558 miles in 2022, 496 miles in 2023, 460 miles in 2024, 462 miles in 2025, and 464 miles in 2026.

As modeled, both Wildfire – Targeted System Upgrades and System Hardening-Hybrid have comparable RSEs to the existing M2 System Hardening mitigation, with a lower cost but less risk reduction per circuit mile. PG&E believes that it is appropriate to invest in the higher level of absolute risk reduction from M2 System Hardening program in many cases, especially for the higher-risk priority circuits that are the current focus of the System Hardening program. PG&E is continuing to evaluate a range of possible system modifications as substitutes for, or supplements to, M2 System Hardening, and may include them as part of its funding request in the 2023 GRC.

TABLE 11-16
FORECAST COSTS, RSE AND RISK REDUCTION
CAPITAL 2023-2026
($000)

Line No.	Mit. No.	Mitigation Name	RSE	Risk Reduction
1	A3	System Hardening-Hybrid	[(a)]	72.5

(a) The costs and RSE for this mitigation are aligned to the Wildfire risk (Chapter 10).

Table 11-17 compares the proposed and alternative mitigation plans:

TABLE 11-17
MITIGATION PLAN ALTERNATIVES ANALYSIS[c]
($000)

Line No.	Risk Mitigation Plan	Plan Components[a]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[b]	Total Spend (NPV)	RSE
1	Proposed	M1, M2, M3, M4, M6, M7, M8, M10	–	$94,169	188	$73,597	2.55
2	Alternative 1	Proposed + M11a	–	$94,169	193	$73,597	2.62
3	Alternative 2	Proposed + A3	–	$94,169	207	$73,597	2.81
4	Alternative 3	Proposed + A4	–	$94,169	258	$73,597	3.50
5	Inherent	Control 13	$682,535	–	209	$501,683	0.37

(a) Plan Components refers to the Mitigations presented in Tables 11-5 and 11-6.

(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

(c) See, WP 11-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 12

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: FAILURE OF ELECTRIC DISTRIBUTION NETWORK ASSETS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 12
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: FAILURE OF ELECTRIC DISTRIBUTION NETWORK ASSETS

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CHAPTER 12
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: FAILURE OF ELECTRIC DISTRIBUTION NETWORK ASSETS

A. Executive Summary

The Failure of Electric Distribution Network Assets[1] risk is defined as the failure of distribution network assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. The drivers for this risk event are underground network equipment failure, human performance, and natural hazards. The cross-cutting factors, seismic, physical attack, skilled and qualified workforce, and records and information management also impact this risk.

Exposure to this risk is based on the 188 circuit miles of networked circuits. The risk model estimates approximately 10 risk events each year.[2] Equipment failure, human performance, and the seismic scenario cross-cutting scenario together account for 99 percent of the risk events. Two sub-drivers, primary cable failure and primary splice failure, account for 77 percent of the equipment failure risk, which is 66 percent of the risk. Catastrophic asset failures (defined as failures that result in a vault explosion, manhole cover displacement, and/or a fire) unrelated to a seismic scenario account for 96 percent of the risk and 18 percent of the risk events; asset failures associated with a seismic scenario account for 1 percent of risk and 1 percent of the risk events.[3] The mitigations Pacific Gas and Electric Company (PG&E) will implement from 2020-2026 are designed to address these key risk drivers.

PG&E identified three tranches for this risk event based on differences in the network asset replacement strategy: circuits with a high failure rate that are a current priority for replacement; circuits where older network cable has already

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1 The risk name can also be referred to as Failure of Distribution Underground Network Assets.

2 10 is PG&E's forecast for the number of the risk events per year for 2023-2026 in the absence of proposed mitigations from 2023-2026.

3 The percentages are based on 2023 test year (TY) baseline frequency and risk scores.

been replaced; and all other circuits: The highest tranche-level risk, 89 percent, is associated with those circuits prioritized for replacement.

Failure of Electric Distribution Network Assets has the eleventh highest 2023 TY baseline safety score (6) and the lowest 2023 TY baseline total risk score (7) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 15, is reduced by 61 percent when the planned mitigations are applied: the 2023 TY baseline risk score is 7 and the 2026 post-mitigation risk score is 6.

PG&E is presenting a suite of controls and mitigations to address the key risk drivers. The CMD-Type Network Protector Replacement and Incremental Primary Network Cable Replacement mitigation programs have the highest risk spend efficiency (RSE) scores and the highest total risk reduction scores among 2023-2026 mitigations for this risk.[4]

TABLE 12-1
RISK OVERVIEW

Line No.	Risk Name	Failure of Electric Distribution Network Assets
1	In Scope	Failure of assets associated with urban underground electrical distribution networks (in downtown San Francisco and Oakland) including Network transformers, Network protectors and Network cables, primary and secondary.
2	Out of Scope	Failure of assets associated with underground transmission cables or the non-network aspects of the underground distribution system.
3	Data Quantification Sources[(a)]	Events: PG&E records of network equipment failures from February 2008 through December 2019. Outcomes: Safety Outcomes are estimated based on Subject Matter Expert (SME) judgment (methodology discussed in Section B.7 below); Reliability and non-Safety-related Financial consequences are based on Distribution Underground Outage Restoration Costs from January 1, 2017 through September 2019.

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

PG&E maintains networked distribution systems in downtown San Francisco and downtown Oakland to provide reliable service to key electric

4 The information herein is subject to those limitations described in Chapter 2, Section D.

customers. In a networked system, customers can receive power from one of several sources, so that an outage on one of those sources will not result in an outage for the customer. Overall, PG&E's networked distribution systems consist of 188 circuit miles of cable in 12 network groups, ten in San Francisco and two in Oakland. In addition to cable, associated facilities include network transformers, protectors, and relays, monitoring equipment including Supervisory Control and Data Acquisition (SCADA), and the underground vaults where most network equipment is located.

Because PG&E's networked distribution facilities are located in dense urban areas, the consequences of asset failure may be different than for other aspects of the electric distribution system. Because of this, and because of the different asset mix relative to other aspects of the distribution system, PG&E considers the risk of failure of network assets separately from the failure of other distribution assets.

Failure of Electric Distribution Network Assets was not included in the 2017 RAMP. The 2017 RAMP noted that there was a risk on the Electric Operations (EO) risk register called "Network Components (in Urban/High Density Areas)." This risk was equivalent to Failure of Electric Distribution Network Assets risk, but did not have a high enough risk score to be included as a 2017 RAMP risk. However, as discussed further in Section B.7 below, at the end of 2019 PG&E changed its methodology for estimating the safety consequences of the Failure of Distribution Network Assets risk. As a result, its risk score went up, causing it to score high enough to be included as a risk in the 2020 RAMP.

2. Risk Definition

The failure of distribution network assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.

B. Risk Assessment

1. Background and Evolution

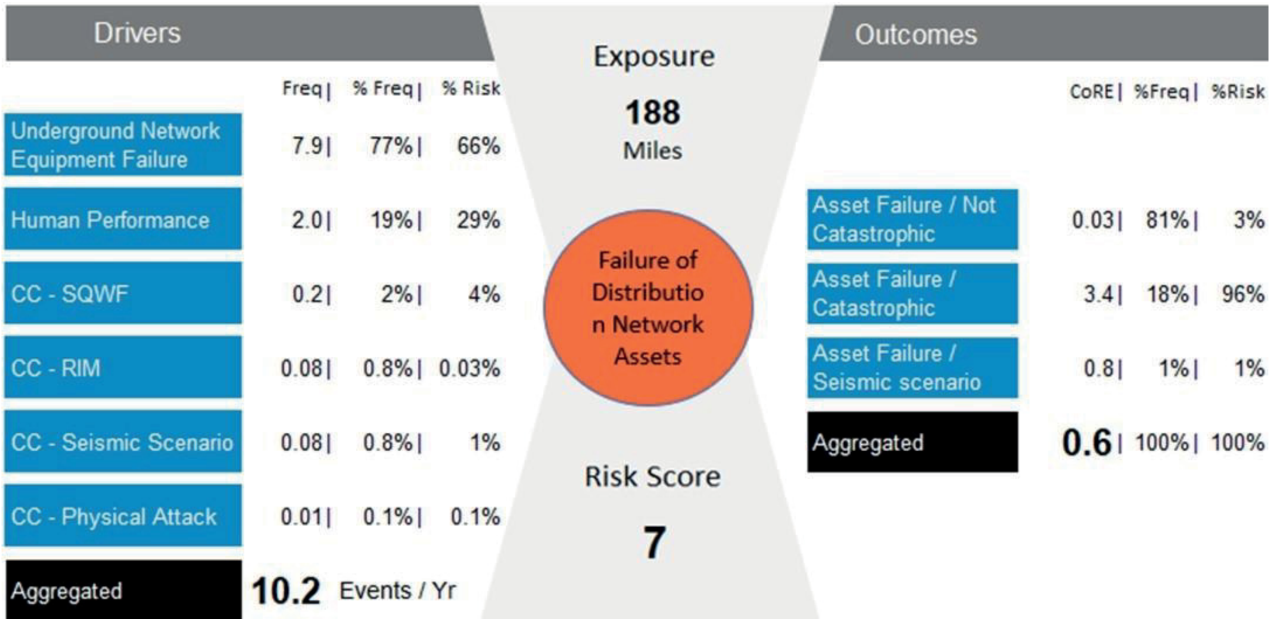
As described above, the Failure of Electric Distribution Network Assets risk has been on the EO risk register since 2014 but was not included in the 2017 RAMP because it had a relatively low risk score. However, due to a change in PG&E's assessment of the potential safety consequences of a failure incident, the safety risk score for the Failure of Electric Distribution Network Assets risk has increased and PG&E is including it in the 2020 RAMP.

Network assets such as network cable, network transformers and other network transformer components can fail in the course of regular operation, as the result of human error, or due to natural hazards such as earthquakes. Catastrophic failures of network assets can cause fires, manhole displacements, and/or vault explosions with significant public safety consequences; all network asset failures potentially affect customer reliability.

PG&E established its current Network Asset Management Plan in 2008. PG&E has put in place a number of programs to mitigate both the risk and consequences of network asset failure including condition-based monitoring and/or testing of cable and network components, regular maintenance and replacement of cable and network components, installation and maintenance of a SCADA system, and a targeted program to install venting manhole covers on underground vaults, including network vaults, to reduce the consequences of a vault explosion.

2. Risk Bow Tie

FIGURE 12-1
RISK BOW TIE



3. Exposure to Risk

PG&E maintains approximately 188 circuit miles of networked circuits. The Failure of Electric Distribution Network Assets risk exposure includes all network cable, network transformers, and other associated equipment such as network protectors and relays.

4. Tranches

PG&E identified three tranches for the Failure of Electric Distribution Network Assets risk based on differences in the network asset replacement strategy for:

- Circuits with a high failure rate (prioritized for replacement based on failures and cable testing[5]): These circuits make up 132 (70 percent) of the 188 circuit miles of PG&E's network distribution system and are associated with 89 percent of network asset failure risk.

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5 Cable testing involves an electrical process for applying voltage signals to cable to assess the integrity of the cable's insulation (and concentric neutral when applicable).

- Reconductored circuits (circuits whose older vintage network cables have been replaced as of end of year 2019): These circuits make up 33 (18 percent) of the 188 circuit miles of PG&E's network distribution system and are associated with 1 percent of network asset failure risk.
- All other circuits (circuits with newer vintage ethylene propylene rubber (EPR) type cable): These circuits make up 23 (12 percent) of the 188 circuit miles of PG&E's network distribution system and are associated with 9 percent of network asset failure risk.

Table 12-2 below shows the risk analysis results at the tranche level.

TABLE 12-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Line No.	Tranche	Percent Exposure	Safety Risk Score	Reliability Risk Score	Financial Risk Score	Total Risk Score	Percent Risk
1	Circuits with a High Failure Rate	70%	5.70	0.16	0.02	5.88	89%
2	Reconductored Circuits	18%	0.00	0.08	0.01	0.09	1%
3	All Other Circuits	12%	0.59	0.02	0.00	0.61	9%
4	Total	100%	6.29	0.26	0.03	6.58	100%

5. Drivers and Associated Frequency

PG&E identified seven drivers (four of which are cross-cutting factors) and 24 sub-drivers of the Failure of Electric Distribution Network Assets risk. Each driver and its associated 2023 TY estimated frequency is discussed below. A complete list of sub-drivers is provided in supporting workpapers.[6]

D1 – Underground Network Equipment Failure: Failure events due to primary cable, primary splice, secondary cable failure, or other components of the network. These events account for 7.9 (77 percent) of the 10.2 expected annual number of network asset failures.

D2 – Human Performance: Failure events caused by PG&E employees based on improper construction, operating error, or other actions. These events account for 2.0 (19 percent) of the 10.2 expected annual number of network asset failures.

6 Sub-drivers are listed in the modeling workpapers which will be provided on July 17, 2020.

D3 – Seismic Scenario (Cross-Cutting): Failure events caused by seismic activity. This risk is described further in Chapter 20 of this report. These events account for 0.08 (<1 percent) of the 10.2 expected annual number of network asset failures.

D4 – Skilled and Qualified Workforce (Cross-Cutting): Failure events caused by lack of a sufficiently trained workforce. This risk is described further in Chapter 20 of this report. These events account for 0.2 (2 percent) of the 10.2 expected annual number of network asset failures.

D5 – Records and Information Management (Cross-Cutting): Failure events caused by not implementing fully an effective records and information management program and controlling data quality. This risk is described further in Chapter 20 of this report. These events account for less than 0.08 (<1 percent) of the 10.2 expected annual number of network asset failures.

D6 – Physical Attack (Cross-Cutting): Failure events caused by physical attack on PG&E assets. This risk is described further in Chapter 20 of this report. These events account for less than 0.01 (<1 percent) of the 10.2 expected annual number of network asset failures.

D7 – Natural Hazards: Failure events caused by a natural hazard event such as flood, rain, etc., (but excluding earthquakes, which are the basis for the seismic cross-cutting factor). These events did not account for any network asset failures in the period PG&E used as the historical basis for its modeling, but they do have a potential to cause network asset failures.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Failure of Electric Distribution Network Assets risk are shown in Table 12-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 12-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	X	
2	Emergency Preparedness and Response		X
3	Physical Attack	X	
4	Records and Information Management	X	X
5	Seismic	X	X
6	Skilled and Qualified Workforce	X	

PG&E is continuing to evaluate the impact that Cyber Attack and Information Technology (IT) Asset Failure have on RAMP risks and may present them as cross-cutting factors relative to the Failure of Electric Distribution Network Assets risk in the 2023 General Rate Case (GRC).

7. Consequences

Historically, PG&E estimated the safety consequences (potential injuries and/or fatalities) of the Failure of Electric Distribution Network Assets risk based on historical data from PG&E's Electric Incident Reports. However, PG&E has concluded that this approach likely understates the potential for high safety consequence incidents of network asset failure (which have been very infrequent, but have occurred on PG&E's system). Therefore, EO decided to incorporate SME judgment regarding potential safety consequences of a network asset failure in its modeling. Specifically, EO updated the model to include SME judgment that a failure of an electric distribution network asset will result in a serious injury incident once every 10 years and a fatality incident once every 15 years.

PG&E separately analyzed the consequences of: (1) asset failures associated with a seismic scenario; (2) asset failures associated with catastrophic outcomes (defined as failures that resulted in a vault explosion, manhole cover displacement, and/or a fire) other than those caused by a seismic scenario; and (3) asset failures not associated with catastrophic outcomes or with a seismic scenario.

- Asset failures related to a seismic scenario account for 1 percent of the frequency associated with this risk and 1 percent of the risk score.

- Catastrophic asset failures not associated with a seismic scenario account for 18 percent of the frequency, but 96 percent of the risk score.
- Non-catastrophic asset failures not associated with a seismic scenario account for 81 percent of the frequency, but 3 percent of the risk score.

Table 12-4 below shows the consequences of this risk event. Model attributes are described in Chapter 3, “Risk Modeling and Risk Spend Efficiency.”

TABLE 12-4
RISK EVENT CONSEQUENCES

					Natural Units Per Event			CoRE			Natural Units per Year			Attribute Risk Score		
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety	Electric Reliability	Financial	Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Safety	Electric Reliability	Financial
Asset Failure / Not Catastrophic	0.0	81%	3%	8.3	-	0.05	0.006	-	0.0	0.0	-	0	0.05	-	0.2	0.02
Asset Failure / Catastrophic	3.4	18%	96%	1.8	0.06	0.04	0.005	3.4	0.0	0.0	0.10	0	0.01	6	0.0	0.00
Asset Failure / Seismic scenario	0.8	1%	1%	0.1	0.01	0.45	0.012	0.5	0.2	0.0	0.00	0	0.0	0	0.0	0.0
Aggregated	**0.6**	100%	100%	10.2	0.01	0.05	0.006	0.6	0.0	0.0	0.11	1	0.1	6	0	0.0

C. Controls and Mitigations

Because the Failure of Electric Distribution Network Assets risk was not included in the 2017 RAMP, PG&E has not previously presented a list of controls and mitigations for this risk. In the following sections, PG&E describes the baseline controls and mitigations in place in 2019, and then discusses any new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

1. 2019 Controls and Mitigations

a. Controls

PG&E had the following controls in place for the Failure of Electric Distribution Network Assets risk as of 2019:

C1 – Network Cable Replacement and Switch Installations: This control consists of the systematic replacement of network cable assets and installation of switches in downtown San Francisco and Oakland networks. Many of the existing network primary and secondary cables date from the 1920s to the 1960s and are nearing the end of their useful life. The network systems replacement program is an on-going program that started in 2011. The program work includes replacing primary and secondary cables, modifying network transformers to accept the new primary cables, and installing switches. PG&E is installing switches at the same time cables are replaced to meet operational requirements by providing a switching location outside the substation to establish feeder clearance points. Switch installation also improves work efficiency and emergency response times by eliminating the need to involve substation personnel for clearing and grounding at the station for feeder clearance work that needs to be performed outside the substation. This control has the potential to reduce the Underground Network Equipment Failure driver.

C2 – Network Maintenance and Corrective Work: Maintenance work associated with PG&E's Network Asset Management Plan includes inspection and oil sampling of all major oil-filled network components of transformers, inspection and testing of network protectors, maintenance and routine replacement of the network SCADA system, and electric corrective notification work in network vaults. This control has the potential to reduce the Underground Network Equipment Failure driver.

C3 – Network Component (Transformer, Protector) Replacements Condition Based: PG&E routinely monitors the condition of its network transformers and network protectors by means of inspection, insulating oil analysis, testing, and on-line sensor monitoring. PG&E replaces network components identified as needing replacement due to their condition with new, safer and more reliable technologies. Replacement transformers are either explosion-resistant or dry-type and use a single-tank design to minimize the risk of catastrophic failure. Network protectors are replaced at the same time as transformers since they have a similar life span. This control has the potential to reduce the Underground Network Equipment Failure driver.

C4 – Asset Information Improvements/Asset Data Comparison and Updates: This control consists of various initiatives to validate and improve the quality of data in PG&E's IT systems concerning electric distribution network assets. These initiatives include automating some data entry processes that are currently manual to ensure accuracy and data synchronization, updating IT applications based on construction change sketches, and correcting data based on discrepancy reports for assets and attributes in PG&E databases. PG&E has also initiated an Electric Program Investment Charge project to expand the capabilities of its condition-based maintenance alarm system to use more data sources. This control has the potential to reduce the Underground Network Equipment Failure driver.

C5 – Network Health Report (Units Offline): This is a report used to spot check the number of units offline to use as an indicator of the operational health of the network to highlight any prolonged clearances and increased reliability risks. This control has the potential to reduce the Underground Network Equipment Failure driver.

C6 – Standards, Processes, and Training: This Includes Workmanship Skills and Training, Standards, Bulletins, Guidelines, Utility Procedures, and Personnel Training & Qualifications. This control has the potential to reduce the Skilled and Qualified Workforce cross-cutting factor.

b. Mitigations

PG&E had the following mitigations in place for the Failure of Electric Distribution Network Assets risk in 2019:

M1 – Network Component Replacements – Targeted Replacement of Oil-Filled Transformers in High-Rise Buildings: PG&E is currently engaged in a targeted program to replace older, oil-filled transformers located in high-rise buildings with dry-type units to improve reliability and minimize fire risk in the event of a transformer failure. PG&E replaced nine transformers in 2019 as part of the program and plans to complete oil-filled high-rise replacements in 2022.[7] This mitigation has the potential to reduce the Underground Network Equipment Failure driver.

M2 – Venting Manhole Cover Replacements: This is an ongoing program to replace existing solid and grated manhole covers on vaults with hinged venting manhole covers designed to stay in place in the event of a vault explosion. A venting cover that stays in place during a vault explosion reduces the potential for exposure to hot gasses from the vault, eliminates the risk of a projectile manhole cover, and reduces the force of the explosion. This program began in 2010 and has been focused on covers to vaults located in High Pedestrian Zones (HPZ) in San Francisco and Oakland, which includes many network vaults. PG&E has completed approximately 90 percent of the necessary replacements in HPZs in San Francisco; most of the remaining HPZ locations have non-standard vaults/covers, which have a higher cost and tend to require more permitting. In 2019, PG&E replaced 540 manhole covers as part of this program. PG&E expects to complete replacement of manhole covers on network vaults by 2022, but replacements will continue on vaults that are not part of the network

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7 In its 2020 GRC, PG&E forecast that oil-filled, high rise replacements would be completed by 2021. In response to a request from the Office of the Safety Advocate, PG&E agreed that it would notify the California Public Utilities Commission of any changes to that schedule and provide a new timeline for completing the project. PG&E now forecasts that it will complete all replacements in 2022 and will provide an update on the program in the 2023 GRC.

system after that. This mitigation has the potential to reduce the consequences of a network equipment failure by reducing the likelihood and negative effects of an underground vault explosion.

M3 – Installation of SCADA Equipment for Safety Monitoring: This is a targeted program to upgrade PG&E's original 1980s vintage SCADA monitoring equipment on its 12 network groups. The upgraded system provides additional equipment condition information, which allows PG&E to identify equipment conditions that can be addressed before in-service failure occurs. It also allows PG&E to operate some equipment in network vaults remotely, instead of having to send crews to the vault to operate the equipment manually. The new features enhance the safety, reliability, and efficiency of the network systems. PG&E began its targeted SCADA upgrades in 2009 and currently forecasts that they will be completed by 2028. In 2019, PG&E completed work on one network group and began work on another. PG&E considers SCADA upgrades to be a foundational activity because they support other controls and mitigations rather than directly reducing risk. As a result, PG&E is not assigning a risk score or calculating an RSE for this mitigation.

D. 2020-2022 Control and Mitigation Plan

1. Changes to Controls

In general, PG&E plans to continue to implementing the same controls in the 2020-2022 period that it did it 2019. PG&E will continue to review its controls to incorporate new developments and lessons learned.

The M1 – Network Component Replacements – Targeted Replacement of Oil-Filled Transformers in High-Rise Buildings mitigation is expected to be completed in 2022. Maintenance of these new transformers will become part of the C2 – Network Maintenance and Corrective Work control going forward.

2. Changes to Mitigations

PG&E plans to continue to implement the same mitigations in the 2020-2022 period that it did in 2019. As discussed below, two of these mitigation programs are scheduled for completion in 2022

M1 – Network Component Replacements – Targeted Replacement of Oil-Filled Transformers in High-Rise Buildings: PG&E plans to complete the remaining 14 replacements in this program by 2022. The current target is to replace six transformers in 2020, six more transformers in 2021, and the final two transformers in 2022.

M2 – Venting Manhole Cover Replacements: PG&E plans to complete its planned replacement of manhole covers on network vaults by 2022, with an estimated 200 replacements in 2020, 341 replacements in 2021, and 241 replacements in 2022.

M3 – Installation of SCADA Equipment for Safety Monitoring: PG&E plans to continue replacing SCADA equipment on the network at a rate of approximately one network group per year.

The volume of mitigation work PG&E plans to complete in the 2020-2022 period is shown in Table 12-5 below.

TABLE 12-5
PLANNED MITIGATIONS 2020-2022

		2020 RAMP Planned Units of Work				
Line No.	Mitigation Name and Number	Units	2020	2021	2022	Total
1	M1 – Network Component Replacements – High-Rise Oil-Filled Transformers	Transformers	6	6	2	14
2	M2 – Venting Manhole Cover Replacements	Covers	200	341	241	782
3	M3 – Installation of SCADA Equipment for Safety Monitoring	Groups	1	1	1	3

The forecast costs for the work PG&E plans to complete, RSEs and risk reduction scores for the work PG&E plans to complete in the 2020-2022 period is shown in Table 12-6 below.

TABLE 12-6
FORECAST COSTS
2020-2022 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	Maintenance Activity Type (MAT)	2020	2021	2022	Total
1	M1	Network Component Replacements – Targeted Replacement of Oil-Filled Transformers in High-Rise Buildings	2CC	$3,467	$3,553	$1,634	$8,654
2	M2	Venting Manhole Cover Replacements	2CD	2,597	5,533	4,307	12,437
3	M3	Installation of SCADA Equipment for Safety Monitoring	2CE	8,467	8,873	9,110	26,449
4	M4	Incremental Primary Network Cable Replacements	56N	–	–	–	–
5	M5	Network Component Replacements – Targeted Replacement of Dry-Type Transformers in High-Rise Buildings	2CC	–	–	–	–
6	M6	Network Component Replacements – Targeted Replacement of CMD-Type Network Protectors	2CC	–	–	–	–
7		Total		$14,531	$17,959	$15,051	$47,541

Note See WP 12-1.

E. 2023-2026 Control and Mitigation Plan

1. Changes to Controls

In general, PG&E plans to continue implementing the same controls in the 2023-2026 period that it did it in the 2020-2022 period. PG&E will continue to review its controls to incorporate new developments and lessons learned.

2. Changes to Mitigations

PG&E expects to complete replacements in the M1 – Network Component Replacements – High-Rise Oil-Filled Transformers mitigation and the network-related portion of the M2 – Venting Manhole Cover Replacements mitigation by the end of 2022.

PG&E is proposing three new mitigations for 2023-2026:

M4 – Incremental Primary Network Cable Replacements: Since 2011, PG&E has been proactively replacing older Paper Insulated Lead Covered (PILC) cable in its electric distribution network with EPR cable. Newer EPR cables are significantly less likely to fail than older PILC cables and industry studies also suggest that EPR cables have higher tolerance to overload conditions. Beginning in 2023, PG&E is proposing to increase the number of circuit miles of network cable replaced in this existing program (described in the C1 control above) by 25 percent, which would result in replacement of approximately three additional miles of network cable per year from 2023-2026. This mitigation has the potential to reduce the Underground Network Equipment Failure driver.

M5 – Network Component Replacements – Targeted Replacement of Dry-Type Transformers in High-Rise Buildings: PG&E plans to complete its replacement of oil-filled network transformers in high-rise buildings in 2022. In 2023-2026 period, PG&E is planning to replace some older dry-type transformers also located in high-rise buildings. PG&E has identified 22 of these older dry-type transformers, mostly installed in the 1980s, located in four high-rise buildings (three in San Francisco and one in Oakland). These units are at the end of their useful lives and some of them have rust and other corrosion. PG&E estimates that replacing these 22 transformers will take three years and cost approximately $10 million, with nine replacements per year planned for 2023 and 2024 and four replacements planned for 2025. This mitigation has the potential to reduce the Underground Network Equipment Failure driver.

M6 – Network Component Replacements – Targeted Replacement of CMD-Type Network Protectors: PG&E has approximately 1,390 network protectors in its electric distribution network system. There are four different kinds of network protectors in service currently: GE, CM22, CM52, and CMD. Based on service records, PG&E has concluded that CMD network protectors are more difficult to repair and replace as they are of an older style and have obsolete components. This program aims to replace all CMD units in the PG&E network with more reliable network protector models. PG&E estimates there are 229 CMD network protectors on its electric distribution network system. PG&E is proposing an 8-year program to replace these units beginning in 2023 at a rate of approximately 30 units per year.[8] This mitigation has the potential to reduce the Underground Network Equipment Failure driver.

The volume of mitigation work PG&E plans to complete in the 2023-2026 period is shown in Table 12-7 below.

TABLE 12-7
2023-2026 PLANNED MITIGATIONS

Line No.	Mitigation Name and Number	Units	2020 RAMP Planned Units of Work 2023	2024	2025	2026	Total
1	M3 – Installation of SCADA Equipment for Safety Monitoring (Installation)	Groups	1	1	1	1	4
2	M4 – Incremental Primary Network Cable Replacements (MAT 56N)	Circuit Miles	2.86	2.86	2.86	2.86	11.44
3	M5 – Network Component Replacements – High-Rise Dry-Type Transformers	Transformers	9	9	4	0	22
4	M6 – Network Component Replacements – Targeted Network Protector Replacement	Network Protectors	30	30	30	30	120

3. Mitigation Risk Spend Efficiencies

Table 12-8 below shows the planned cost, RSE and risk reduction score for each of the Failure of Electric Distribution Network Assets risk mitigations PG&E plans to implement in the 2023-26 period.

8 PG&E assumes 225 units will be replaced in the program and four units will be replaced through other programs.

TABLE 12-8
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MAT	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1	Network Component Replacements – Targeted Replacement of Oil-Filled Transformers in High-Rise Buildings	2CC	–	–	–	–	–	–	–
2	M2	Venting Manhole Cover Replacements	2CD	–	–	–	–	–	–	–
3	M3	Installation of SCADA Equipment for Safety Monitoring	2CE	$9,337	$9,571	$9,810	$10,055	$38,774	[b]	[b]
4	M4	Incremental Primary Network Cable Replacements	56N	6,510	6,673	6,840	7,011	27,033	0.07	1.44
5	M5	Network Component Replacements - Targeted Replacement of Dry-Type Transformers in High-Rise Buildings	2CC	4,077	4,615	2,301	–	10,992	<0.01	<0.01
6	M6	Network Component Replacements - Targeted Replacement of CMD-Type Network Protectors	2CC	1,615	1,656	1,697	1,740	6,708	0.37	1.85
7		Total		$21,540	$22,514	$20,648	$18,806	$83,507		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE
(b) Foundational mitigation. No RSE or risk reduction calculated
Note See WP 12-1.

Approximately 45 percent of PG&E's planned Failure of Electric Distribution Network Assets mitigation spending for the 2023-2026 period is for installation of upgraded network SCADA equipment to replace SCADA installed in the 1980s which is at the end of its useful life and has less capability than modern SCADA equipment. PG&E began these replacements in 2009 and plans to complete all replacements by 2028. PG&E considers this a foundational activity (and has not calculated a risk score or RSE) because it does not directly reduce risk, but instead provides information about the network system, including equipment condition, that can be used to reduce risk. PG&E believes that this investment is prudent because it replaces assets at the end of their useful life with assets that have more extensive capabilities, and because the visibility and remote operation capacity that modern SCADA provides will improve the safety, reliability, and efficiency of PG&E's electric distribution network system.

Two other mitigations – incremental primary network cable replacement (0.07 RSE) and targeted network protector replacement (0.37 RSE) are asset management programs that achieve their risk reductions by replacing older equipment that is prone to failure with newer equipment. As this risk focuses on work in highly-urban areas that have a wide distribution of safety consequences, the mitigation programs are considered investments that minimize large safety impacts.

The M5 mitigation – replacement of older dry-type transformers in high-rise buildings – received a low RSE (less than 0.01). PG&E believes that its current model understates the risk reduction of this program because the model assigns the same safety and reliability consequences to all potential failures of network transformers. But, for several reasons, the consequences of a failure of any of the 22 dry-type, high rise transformers that are the focus of this program would be much more severe than failure of a "typical" network transformer. First, these transformers serve buildings with critical facilities such as large data centers and transportation infrastructure. Second, while most network transformers are interchangeable and PG&E has an inventory of spares, the dry-type transformers that are the focus of this program are custom built and require substantial lead time. Third, as a general matter, replacing high rise transformers requires substantial lead time because it usually involves a crane and extensive permitting. PG&E believes that it is important to proactively replace these units before they fail to avoid the possibility of a long period of transformer downtime.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E also considered alternative mitigations. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: A1 – Install Completely Submersible SCADA Enclosures

One risk to PG&E's electric distribution network system is that rising tide levels associated with global warming will lead to more flooding of underground vaults containing network equipment. PG&E considered the possibility of installing completely submersible SCADA enclosures to prevent SCADA system components in vaults in San Francisco and Oakland from failing due to saltwater intrusion.

Approximately 40 manholes were already upgraded with submersible SCADA enclosures in or around 2005, leaving 750 additional locations that still need an upgrade. The currently available submersible enclosure is large and heavy and cannot be installed in some vaults because of space constraints; PG&E estimates that there are 710 locations where an installation would be feasible.

PG&E is still in the process of modeling the risk associated with SCADA system component failure since these types of failures do not directly result in loss of power (as would be the case for a transformer failure), but rather the ability to monitor the system real-time, which may result in higher risk of asset failure due to changes in operating conditions. As a result, PG&E has not calculated an RSE for this program. PG&E will continue to evaluate the potential for risk reduction from installation of submersible SCADA enclosures and may present it as a mitigation program in the 2023 GRC.

TABLE 12-9
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE	Risk Reduction
1	A1	Install Completely Submersible SCADA Enclosures	$8,594	$8,808	$9,029	$9,254	$35,685	(a)	(a)
2		Total	$8,594	$8,808	$9,029	$9,254	$35,685		

(a) PG&E is not calculating an RSE or risk reduction score for this program.
Note: See WP 12-1.

2. Alternative Plan 2: M5a – Reduce Proposed Rate of Dry-Type Transformer Replacement

PG&E is proposing the M5 mitigation to replace 22 dry-type network transformers in four high-rise buildings in San Francisco and Oakland over the course of three years. PG&E also considered an alternative mitigation that would have replaced those same transformers, but over a 6-year period (2023-2028) instead of a 3-year period (2023-25). The 6-year program was estimated to be marginally more expensive due to a larger cost escalation impact over the course of the program, resulting in a slightly lower RSE score. Although not currently modeled, PG&E also determined based on past experience with high rise projects that a 6-year program would likely have additional expenses and logistical complexity associated with lengthier labor contracts and installation permits. Ultimately, PG&E concluded that a 3-year program is feasible and that completing the work in three rather than six years is preferable because it will reduce risk more quickly.

TABLE 12-10
FORECAST COSTS, RSE AND RISK REDUCTION
CAPITAL 2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	M5a	Reduce Proposed Rate of Dry-Type Transformer Replacement	$1,977	$2,152	$1,597	$1,672	$7,398	<0.001	0.002
2		Total	$1,977	$2,152	$1,597	$1,672	$7,398		

(a) See MW included in the source document modeling package for information used to calculate the RSE.
Note See WP 12-1.

3. Alternative Plan 3: A3 – Replace Network Transformers Based on Age, Instead of Condition

As part of its regular asset maintenance programs, PG&E monitors the health of the transformers in its electric distribution network system through regular testing (e.g., Dissolved Gas Analysis for oil-filled transformers). This condition-based assessment allows PG&E to make maintenance decisions based on operating conditions (voltage, temperature etc.), which are more significant drivers of transformer operating life than years in service. This alternative mitigation considers the impact of changing from a condition-based replacement program to an age-based asset replacement program for these network transformers.

Switching to an age-based approach would eliminate inspections of transformers below a certain age threshold but would not address the risk of premature failures of “younger” transformers which would have been identified and mitigated as part of a condition-based approach. The incremental risk of these premature failures was estimated as the weighted average of the number of transformers under the age-based replacement threshold and the average failure rate associated with transformers of a given age. On average, PG&E replaces approximately 12 transformers annually under the condition-based replacement program. PG&E assumes the same replacement rate in the age-based replacement scenario, so PG&E would replace 12 transformers annually between 2023-2026, but prioritize units based on age instead of condition. This would reduce inspection costs by approximately $2.4 million (the amount spent annually on oil-filled transformer testing) but increase the overall risk of transformer failure by approximately 9.3 percent. PG&E does not consider this trade-off acceptable.

The table below shows the proposed spending and RSE associated with each of PG&E's proposed alternative mitigations for the electric distribution network system.

TABLE 12-11
FORECAST COSTS, RSE AND RISK REDUCTION[c]
2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total(a)	RSE[b]	Risk Reduction
1	A3	Replace Network Transformers Based on Age Instead of Condition	$(2,675)	$(2,742)	$(2,810)	$(2,881)	$(11,108)	<0.001	<0.001
2		Total	$(2,675)	$(2,742)	$(2,810)	$(2,881)	$(11,108)		

(a) Implementing this alternative mitigation would reduce inspection costs for oil-filled transformer testing.
(b) See MW included in the source document modeling package for information used to calculate the RSE.
Note See WP 12-1.

Table 12-12 compares the proposed and alternative mitigation plans.

TABLE 12-12
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[a]	Total Expense (2023-2026)	Total Capital (2023-2026)[c]	Risk Reduction (NPV)[b]	Total Spend (NPV)	RSE
1	Proposed	M4, M5, M6	–	$152,057	11	$112,145	0.097
2	Alternative 1	Proposed + A1	–	$152,057	11	$112,145	0.097
3	Alternative 2	M4, M6 + M5a	–	$148,462	11	$109,173	0.100
4	Alternative 3	Proposed + A3	–	$140,949	11	$103,981	0.105

(a) Plan Components refers to the Mitigations described in Sections C, D and E.

(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

(c) Plan components include the risk reduction benefits and costs of C1-Network Cable Replacement and Switch Installations.

Note See WP 12-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 13

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN:

LARGE UNCONTROLLED WATER RELEASE

PACIFIC GAS AND ELECTRIC COMPANY
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RISK ASSESSMENT AND MITIGATION PHASE
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A. Executive Summary

The Large Uncontrolled Water Release risk represents the potential for a large release of water from one of Pacific Gas and Electric Company's (PG&E or the Company) significant or high hazard dams adversely impacting the public, Company, or federal lands. The drivers for this risk event are flood, seismic, internal erosion, and physical attack. The cross-cutting factors Information Technology (IT) Asset Failure, Cyber Attack, Physical Attack, Records and Information Management, and Emergency Preparedness and Response also impact the risk event. Climate is incorporated into the flood driver through the conservative calculations used.

Exposure to this risk is derived from the 61 PG&E dams classified as high or significant hazards by Federal Energy Regulatory Commission (FERC).[1] The risk model includes approximately 0.015 risk events each year (one event every 67 years). The flood driver accounts for 86 percent of the risk events, seismic accounts for 10 percent, internal erosion accounts for 4 percent, and Physical attack accounts for 0.1 percent of the risk events. PG&E's planned mitigations for 2020-2026 are designed to address these key risk drivers.

Each of PG&E's 61 high and significant hazard dams is its own tranche. While many dams share similar characteristics, each dam is unique, and PG&E evaluates potential risks for each individual dam. Spaulding No. 2, Spaulding No. 3, and Belden Forebay account for 64 percent of the tranche-level risk due to downstream consequences.

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1 The FERC hazard potential classification is a system that categorizes dams according to the degree of adverse incremental consequences of a failure or mis-operation of a dam. The hazard potential classification does not reflect in any way on the current condition of the dam (e.g., safety, structural integrity, floor routing capacity). See Federal Emergency Management Agency (FEMA), Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams, April 2004, p. 2.

Large Uncontrolled Water Release has the eighth highest 2023 test year (TY) safety score (41) and ninth highest 2023 TY total risk score (70) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. PG&E proposes a series of controls and mitigations to address the Large Uncontrolled Water Release risk. The 2020 baseline risk score of 73.0 is expected to improve by 24 percent when the planned mitigations are completed, with a projected 2023 TY baseline risk score of 69.8 and 2026 post-mitigation risk score of 55.9. The Spillway Remediation and Internal Erosion Mitigation programs have the highest Risk Spend Efficiency (RSE) scores and the highest total risk reduction scores.[2]

TABLE 13-1
RISK OVERVIEW

Line No.	Risk Name	Large Uncontrolled Water Release
1	In Scope	High and significant hazard dams per the FERC classification
2	Out of Scope	Low hazard dams, canals, waterways, powerhouses, and other hydroelectric assets
3	Data Quantification Sources[(a)]	Exposure: FERC classifications Flood: Probable Maximum Flood (PMF), Potential Failure Model Analysis (PFMA) Seismic: FERC 2000-year design criterion Internal Erosion: Site specific analyses Financial: Average property values, quantity of structures destroyed, qualitative infrastructure factors, dam restoration costs, power replacement costs Safety: Inundation maps, Emergency Action Plans (EAP), FEMA flood studies

(a) Source documents will be provided with workpapers on July 17, 2020.

1. Risk Overview

PG&E's water storage and conveyance systems consist of dams, reservoirs, tunnels, canals, flumes, siphons, and penstocks which enable PG&E to store and transport water from runoff and aquifer flows for flexible generation at PG&E's hydro powerhouses. Additionally, the conveyance

2 The information presented herein is subject to the limitations described in Chapter 2, Section D.

and storage systems are operated to provide water storage and delivery for water conservation, fish and wildlife habitat protection and enhancement, domestic water usage, recreational water requirements, and agricultural water needs.

Collectively, the system consists of approximately: 96 reservoirs, 73 diversions, 169 dams, 168 miles of canals, 43 miles of flumes, 132 miles of tunnels, 57 miles of pipe (penstocks, siphons, and low head pipes), four miles of natural waterways, and 140,000 acres of fee-owned land.

PG&E's Power Generation organization is responsible for managing its hydro portfolio. Within Power Generation, the Dam Safety Program (DSP) is managed by Power Generation's Engineering Department, which is responsible for ensuring the long-term safe and reliable operation of PG&E's dams. PG&E's dams are regulated by both the FERC and the California Department of Water Resource's Division of Safety of Dams (DSOD). PG&E's DSP is aligned with FERC's Owner's DSP guidelines. Due to the potentially catastrophic impact of a dam failure, this risk is overseen by the Safety and Nuclear Oversight committee of PG&E's Board of Directors. PG&E has also established a Dam Safety Advisory Board made up of industry experts who critically evaluate the performance of the DSP. Furthermore, PG&E's recent organizational optimization included expanding the scope of the Nuclear Quality Verification organization to provide support to the entire Generation Organization. PG&E also maintains active membership and involvement with industry groups like the National Hydropower Association and The Centre for Energy Advancement through Technological Innovation. Further, PG&E internally applies lessons learned from events in the industry such as the 2017 Oroville dam spillway incident and the ongoing investigations on the Edenville and Sanford dam failures in Michigan.

In addition to planning and implementing actions to maintain dam safety, the DSP implements programs that educate the public about dam and waterway safety hazards; install hazard warning signs through the hydro system; and maintain prevention, preparedness, education, and outreach activities.

Power Generation strives to continuously improve its processes, deliver high quality work, and meet and exceed compliance requirements with standards and procedures through its Dam Safety and Asset Management programs. One critical element of the Dam Safety and Asset Management programs is quantification of asset risk. PG&E's Dam Safety team is enhancing its risk tools through implementation of the Vulnerability Index. The Vulnerability Index was developed by the British Columbia Hydro and Power Authority (BC Hydro). The Vulnerability Index, currently in the early stages of development for PG&E, is an innovative risk-informed tool for evaluating dam health, safety, and criticality, was used to support this RAMP Report. Further, as asset risks are identified, PG&E mitigates and controls the risks through: operational changes and restrictions; increased or modified maintenance; monitoring and surveillance; and repair, refurbishment, or replacement projects.

FERC and DSOD inspect PG&E's dams every 1-3 years depending on the hazard classification. PG&E complies with federal regulations that require an independent qualified dam safety consultant to perform an inspection of its high and significant hazard dams every 5 years.[3] The independent consultant inspection is a comprehensive review of the physical condition of the dam, dam operations, instrumentation, and confirmation of the dam design relative to design-basis floods, seismic events, and static conditions. The inspection also includes a PFMA that postulates ways a dam could fail and provides guidance about monitoring the dams for signs of potential failures. PG&E receives reports following the FERC, DSOD, and independent safety consultant inspections that may include recommended actions to maintain or improve dam safety. PG&E prioritizes and addresses the identified issues.

2. Risk Definition

Given the inherent risk of owning and operating hydro assets, there is a potential for a large uncontrolled water release adversely impacting the public, the Company, or state and federal lands.

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[3] 18 Code of Federal Regulations (CFR) Part 12D.

B. Risk Assessment

1. Background and Evolution

PG&E's 2017 RAMP included a Hydro-System Safety – Dams risk[4] that is similar to the Large Uncontrolled Water Release included in this 2020 RAMP.

The 2020 RAMP includes 61 dams, significantly more than the 20 highest consequence dams included in the 2017 RAMP. The 20 dams included in the 2017 RAMP were identified by PG&E's dam safety experts based on an assessment of the dams that would have the highest consequences from catastrophic failure. The 61 dams included in the 2020 RAMP are all High and Significant Hazard dams, by FERC classification, owned and operated by PG&E.

In the 2017 RAMP, PG&E identified three dam failure drivers: seismic, flood, and seepage. A fourth driver, Physical Security, has been added to the 2020 RAMP risk. In the 2020 RAMP, the "seepage" driver is renamed "internal erosion." The frequency of events occurring due to seismic, flood, or internal erosion events is similar in 2020 as it was presented in 2017 with the flood driver being responsible for approximately 86 percent of the potential event occurrences.[5] PG&E is currently performing probabilistic risk assessment studies in order to add the mis-operation driver to the RAMP model, but the current planned completion is end of year 2021, so the driver will not be available in the 2020 RAMP.

PG&E's 2017 RAMP analyses were based on assessments informed by PG&E data, industry data, and Subject Matter Experts (SME). In 2020, PG&E's analysis of its Large Uncontrolled Water Release risk is additionally informed by PMF studies, FERC data, site-specific analyses, inundation zone maps, and FEMA flood studies, as well as PG&E's response to the incident at Oroville Dam which resulted in many of the mitigations proposed in this report.

Since the portfolio risk is represented by a sum of the risk of each individual dam failure, and PG&E added 41 dams to this RAMP, the

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4 PG&E's RAMP Report, Investigation 17-11-003 (Nov. 30, 2017), Chapter 13.

5 PG&E's 2017 RAMP Report, p. 13-4 to p. 13-6.

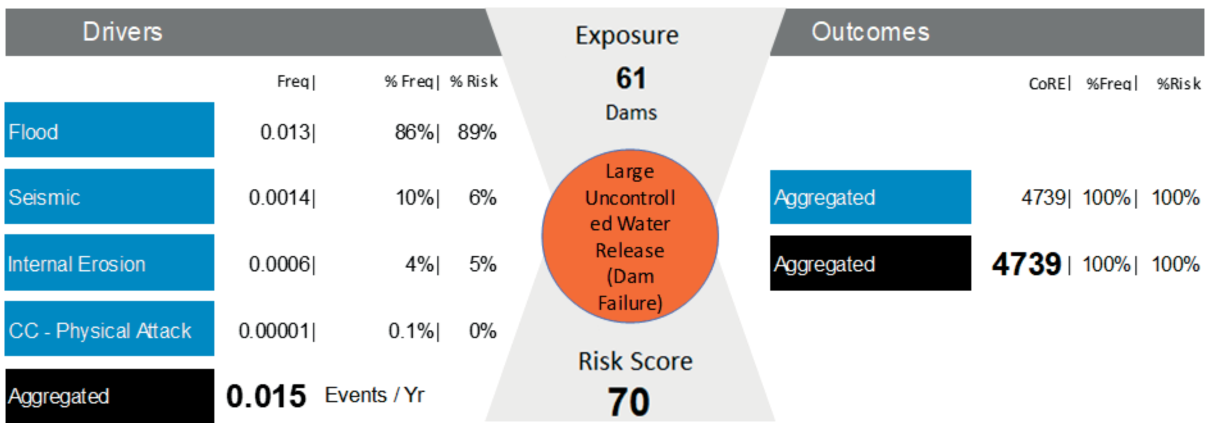
aggregated frequency of failure for the portfolio of dams increased compared to the 2017 RAMP, though the risk for each individual dam from the 2017 RAMP is relatively unchanged.

2017 RAMP = 1 failure of high consequence dam per 140 years

2020 RAMP = 1 large uncontrolled water release per 68 years

2. Risk Bow Tie

FIGURE 13-1
RISK BOW TIE



a. Difference from 2017 Risk Bow Tie

PG&E's use of the bow tie has evolved to better show the conceptual information that informs the results of the risk modeling. Each driver has an initiating event frequency as shown on the left side of the bow tie. As shown in the source documents referenced in WP 13-3, each dam is given a catastrophic failure likelihood for each driver expressed as a percent; combining the driver frequency by the failure likelihood results in the catastrophic failure frequency. The catastrophic failure likelihood considers characteristics of the dam. As an example, if the dam is known to have additional spillway freeboard over the flow required for the PMF, then the catastrophic failure likelihood would be used to decrease the probability of catastrophic failure of the dam as it would be expected to withstand the initiating event. Alternatively, if a dam has a known deficiency that would impact its capability to withstand the initiating event, the catastrophic failure likelihood would be used to increase the probability of catastrophic failure. For example, if a dam had no additional freeboard over the PMF and a known condition affecting its capability to pass water through the spillway, the catastrophic failure likelihood would be over 100 percent.

3. Exposure to Risk

The assets in scope for PG&E's 2020 RAMP risk Large Uncontrolled Water Release are the 61 PG&E dams[6] classified as high or significant hazard dams per FERC. Expanding the list of dams to the entire portfolio of high and significant hazard dams greatly improves PG&E's ability to compare and rank each dam's risk. Further, it reduces uncertainty as dams with similar consequences and features can be compared to ensure outcomes are commensurate.

FERC defines a significant hazard potential as:

> …those dams where failure or mis-operation results in no probable loss of human life but can cause economic loss, environmental damage, disruption of lifeline facilities, or can impact other concerns. Significant hazard potential classification dams are often located in predominantly rural or agricultural areas but could be located in areas with population and significant infrastructure.[7]

FERC defines a high hazard potential as, "…those where failure or mis-operation will probably cause loss of human life."[8]

The DSOD classifies the downstream hazard potential of all state jurisdictional dams based on a sunny-day loading condition. Significant hazard potential is defined as:

> [N]o probable loss of human life but can cause economic loss, environmental damage, impacts to critical facilities, or other significant impacts.

High hazard potential is defined as, "[e]xpected to cause loss of at least one human life." Extreme high hazard potential is defined as:

> [E]xpected to cause loss of at least one human life and one of the following: [r]esult in an inundation of at least 1000 persons or more, or [r]esult in the inundation of facilities or infrastructure, the inundation of

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6 The 61 dams in scope are listed in supporting workpapers. See WP 13-3.

7 FEMA, Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams, April 2004, p. 5.

8 FEMA, Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams, April 2004, p. 6.

which poses a significant threat to public safety as determined by the department on a case-by-case basis.[9]

DSOD's extremely high and high hazard classifications are effectively subdivisions of the high hazard classification used by FERC.

The DSP implements measures to manage and reduce the risks of owning and operating PG&E's dams. In addition to well-established regulatory driven deterministic approaches for evaluating the safety of dams, PG&E has undertaken many initiatives to better understand and quantify drivers, dam health, and potential outcomes to a catastrophic dam failure. Data sources used in the 2020 RAMP model include information collected during:

- Routine observations by trained Hydro operations and maintenance (O&M) personnel;
- Regular inspections by qualified engineers in PG&E's DSP;
- Regular inspections by the FERC and DSOD;
- 5-year Independent Consultant Safety Inspections in accordance with 18 CFR Part 12D;
- Environmental assessments of each site; and
- Engineering evaluations of dam stability, seismicity, spillway design capacity, and other design and operational issues as conditions and engineering guidelines evolve.

4. Tranches

PG&E identified 61 tranches for the Large Uncontrolled Water Release risk. Each of PG&E's 61 high and significant hazard dams is its own tranche. While many dams share similar characteristics, each dam is unique, and PG&E evaluates potential risks for each individual dam. In a few instances, a dam failure may result in flows that could fail a downstream dam, known as a cascading dam failure, in which case the failure of the upstream dam includes the impact of failure of the downstream dam. Including in these instances, each dam is modeled independently and the model features dam-specific driver and consequence data. The aggregated bow tie combines the modeled results of all the dam failures, though dam

9 California Code of Regulations, § 335.4, Section (a).

failures are independent events with the exception of cascading failures. A list of the 61 dams, its FERC and DSOD classifications, dam type and location is included in supporting workpapers.[10]

Table 13-2 shows the tranche-level results of the risk analysis for the top 10 tranches based on total risk score.

TABLE 13-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Line No.	Tranche	Percent Exposure	Safety Risk Score	Financial Risk Score	Total Risk Score	Percent of Total Risk
1	Spaulding No. 2	1.6%	7.05	15.43	22.48	32%
2	Spaulding No. 3	1.6%	3.51	7.68	11.19	16%
3	Belden Forebay	1.6%	10.92	0.20	11.12	16%
4	Fordyce	1.6%	1.21	2.35	3.56	5%
5	Spaulding No. 1	1.6%	1.16	1.66	2.82	4%
6	Salt Springs	1.6%	2.32	0.32	2.63	4%
7	McCloud	1.6%	2.45	0.12	2.57	4%
8	Bucks Lake (Storage)	1.6%	1.55	0.03	1.58	2%
9	Pit 5 Open Conduit	1.6%	1.38	0.01	1.40	2%
10	Pit 3	1.6%	0.93	0.04	0.97	1%
11	All Remaining Dams	84%	8.98	0.53	9.51	14%
12	Total	100%	41.46	28.37	69.82	100%

5. Drivers and Associated Frequency

PG&E identified four drivers and two sub-drivers for the Large Uncontrolled Water Release risk. Each driver and its associated 2023 TY baseline frequency is discussed below.

D1 – Flood: Flooding typically occurs as a result of heavy rain or snowmelt, or a combination of rain on snow. Equipment failure or sudden releases from upstream water control structures can also lead to flooding. Weather-related flooding events typically are easier to predict in the short term and are managed through the use of reservoir storage, releases through spillways and outlets, and coordinating high flow events with upstream and downstream dam operators. The risk model uses historic flow data that PG&E maintains for each dam to develop index-level flood frequency data combined with the deterministic Probable Maximum Precipitation/Probable Maximum Flood (PMP/PMF) analyses and rated

[10] See WP 13-3.

spillway capacity to estimate the frequency of a flood that would exceed each dam's capacity to safely pass a flood event. Climate change data is inherently included in this driver as the PMP/PMF calculations consider trends in recent and historical precipitation and flood data. The analyses resulted in a cumulative likelihood of a catastrophic dam failure for all 61 high and significant hazard dams as of one possible event in 77 years. Flood accounted for 0.013 (86 percent) of the 0.015 expected annual number of events.

D2 – Seismic: Due to the nature of seismic events, the precise size, location, and timing of earthquakes cannot be predicted. PG&E is in the process of moving towards quantification of the seismic risk. In this report, different methods are used for calculation of the seismic risk for concrete and embankment dams.

In calculating seismic risk for concrete dams, the seismic risk model (developed outside of the RAMP's operational risk model and used as input to the RAMP operational risk model) is based on an underlying assumption that, on average, the deterministic ground motions currently used to evaluate PG&E's dams conservatively equate to approximately a 2000-year seismic event recurrence interval. Based on the residual stability of the structure evaluated for that deterministic event, a subjective catastrophic failure factor was applied to determine the likelihood of a seismic induced failure. Dam structures with higher residual stability received a higher subjective factor; whereas, structures just meeting or near guidelines were given a factor of 1.0 or no change from the 2000-year base event frequency.

In calculating the seismic risk for embankment dams, the seismic risk model uses the entire seismic hazard curve, which defines the probability of exceeding a specific ground motion level. For a given ground motion loading level, the response of the embankment dam is modeled by a simplified numerical model that computes the expected deformation. This deformation is then related to a probability of failure using fragility curves based on the relative deformation of the dam or the residual freeboard. Annual failure rates are then computed by considering the probability of failure over the entire range of loading levels. Additionally, uncertainty in analysis (ground motion, dam response, analytical model, and fragility) are considered.

The aggregate evaluation of the portfolio of 61 dams resulted in an average likelihood that one seismic event with the potential to cause dam failure could occur every 714 years. Seismic events accounted for 0.0014 (10 percent) of the 0.015 expected annual number of events.

D3 – Internal Erosion (formerly Seepage): All dams experience seepage, which is water migration through the dam and can occur through pore spaces, cracks, and joints in the dam structure, foundation, and abutments. Seepage is a normal occurrence and typically presents little or no risk to the integrity of the dam. However, seepage that is not properly managed or controlled can lead to internal erosion potentially resulting in progressive, catastrophic dam failure. For the earthfill dams, the estimated frequency of such failures is based on the Association of State Dam Safety Officials (ASDSO) Dam Safety Incidents Database filtered for recent failures resulting from internal or foundation/abutment erosion.[11] For the rockfill dams, the failure probability was determined by extrapolating the results of a Probabilistic Risk Assessment performed for Fordyce Dam. In general, the rockfill dams are less likely to fail due to internal erosion than earthfill dams. Concrete dams rarely, if ever, fail due to excessive internal erosion and, as a result, these dams do not contribute to the frequency of this driver. Climate change data impacting this driver is not included in the model. Cyclical or rapid environmental temperature changes can worsen the condition of concrete and other protective features of dams, but data to support trending of such temperature changes was not available. The aggregate evaluation of the portfolio of 61 dams resulted in an average likelihood that one internal erosion initiating event with the potential to cause dam failure could occur every 1,667 years. Internal erosion events

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11 The ASDSO Dam Safety Incident Database (damsafety.org/incidents) provides basic information on dam safety incidents and lists the incident driver among other information. Review of the database showed a significant increase in the number of events reported starting in 2008 with 2018 being the last complete year in the dataset at the time of the analysis. For the 11 years of data, failures were filtered for those resulting from internal or foundation/abutment erosion to develop an annual failure rate for this driver.

accounted for 0.0006 (4 percent) of the 0.015 expected annual number of events.

D4 – Physical Attack: PG&E implements the hydropower security program in compliance with FERC guidance.[12] Controls and mitigations PG&E has in place or plans to enact are sensitive in nature and are not discussed or credited in this report. After assessing the quantification data for frequency, there are no instances of a dam failure driven by Physical Attack in the United States. Combining data from the Department of Homeland Security[13] and a recent study by the United States Society of Dams[14] with the assumption that the next dam attacked would result in dam failure gives an event frequency of once per 4.4 million years. Physical Attack events accounted for 0.00001 (0.1 percent) of the 0.015 expected annual number of events.

a. Sub-Drivers

SD1 – Information Technology Asset Failure: An IT asset failure coincident with conditions that cause a risk event (Flood, Seismic, Internal Erosion, Physical Attack) will increase the likelihood that a catastrophic outcome will occur. Critical System Availability goals are 99.9 percent and IT has mapped 39 asset categories to the dam failure risk. This results in an estimated frequency of IT asset failure to be one in 26 years.

SD2 – Cyber Attack: A cyber attack coincident with conditions that cause a risk event (Flood, Seismic, Internal Erosion, Physical Attack) will increase the likelihood that a catastrophic outcome will occur. A sunny-day cyber attack has the potential to put recreators

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[12] FERC: Division of Dam Safety and Inspections FERC Security Program for Hydropower Projects, Revision 3A. March 30, 2016. https://www.ferc.gov/industries/hydropower/safety/guidelines/security/security.pdf. (as of June 17, 2020).

[13] Worldwide Attacks Against Dams: A Historical Threat Resource for Owners and Operators. 2012. https://damfailures.org/wp-content/uploads/2019/04/Worldwide-Attacks-Against-Dams.pdf. (as of June 17, 2020).

[14] Next Generation of Dam Safety and Security Frameworks: A Big Picture. Fall 2019. https://www.ussdams.org/wp-content/uploads/2019/10/Fall-2019-for-web.pdf. (as of June 17, 2020)

downstream of a dam at risk, however this risk event is excluded from this risk as the outcome would be significantly lower than the catastrophic dam failure modeled by this risk. Power Generation has controls in place to prevent this event; beyond controls in the IT systems, instruments measuring component status and flow would alert operators to components out of alignment. Further, at some watersheds, physical device controls are in place during recreation preventing incidental movement and some components also cannot be operated remotely. For either event, the frequency of a cyber attack event is estimated to be one in 280 years.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Large Uncontrolled Water Release risk are shown in Table 13-3 below and described above in Section B.5. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 13-3
CROSS-CUTTING FACTORS SUMMARY

Line No.	Cross-Cutting Risk	Impacts Likelihood	Impacts Consequence
1	Climate Resilience	X[(a)]	–
2	Cyber Attack	X	
3	Emergency Preparedness and Response	–	X
4	IT Asset Failure	X	
5	Physical Attack	X	–
6	Records and Information Management	–	X
7	Seismic	X[(b)]	–

(a) Climate impacts are inherently captured in the PMF studies.
(b) Seismic events are included as an inherent driver.

7. Consequences

In developing consequence inputs, PG&E relied on PG&E inundation maps included in the EAP to analyze the consequences of the Large Uncontrolled Water Release risk. The inundations maps provide areas of expected impact in the event of a dam failure based on FERC and DSOD guidelines. The data used to evaluate this risk was supported by PG&E SME judgement. The PG&E SMEs used up to date dam-specific inspections, technical documents, and industry data to estimate driver, mitigation, and consequence model data.

Safety: Fatality severity distribution was derived by applying the results of the Dekay-McClelland empirical method[15] with the variables of Population at Risk (PAR), force of water (Fd), and warning time (Wt) developed for each dam. PAR was determined by counting the number of structures within the inundation zone from the flood maps for each dam and estimating one person per structure: Fd is a binary value of "0" or "1" that was defined as "1" when a structure was less than 30 minutes from the expected time of inundation after dam failure; and Wt is measured in hours and assumed to be equivalent to the front of the inundation wave arrival time derived from the inundation maps for each high consequence dam. The result of each dam-specific calculation is used to create a distribution sample for the fatality severity input to the RAMP model for the quantity of fatalities occurring in the event of dam failure. To estimate the number of injuries that could result from a catastrophic failure at each dam, as the Dekay-McClelland empirical method does not have a value for injury, PG&E applied a ratio of 1.87 injuries per fatality based on the National Oceanic and Atmospheric Administration flood data for California. Based on these safety consequence inputs and the likelihood of the risk event at each dam, the model results show a portfolio average annualized safety consequence of 0.13 equivalent fatalities expected per year.

Reliability: The impact to the electric grid resulting from a catastrophic dam failure is expected to be negligible because in most cases, the generation can be replaced quickly, and the homes of customers directly impacted by the inundation would be uninhabitable. Thus, the impact of the loss of generation from powerhouses in the inundation zones is included in

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15 Dekay, Michael L., and McClelland, Gary H., "Predicting Loss of Life in Cases of Dam Failure and Flash Floods" 1993.

the Financial consequence as it does not fit the units provided in the Multi-Attribute Value Function attributes for reliability.

Environmental: Impact to the environment due to a catastrophic dam failure is included with the Financial consequence. Factors considered for determining the environmental costs included the cost of clean-up and remediation, which would vary based on the amount of water released, soil displacement, and the duration of clean-up.

Financial: PG&E relied on average home prices, number of structures damaged, infrastructure factors, expected dam restoration costs, and loss of generation estimates to determine financial impacts. Specifically, PG&E counted the number of structures inundated and estimated that 50 percent of the expected average property value would be the cost necessary to repair the damage. Dam restoration cost was estimated using dam size and type and reservoir size as variables with an escalation factor applied. Lastly, an infrastructure factor was applied to the property damage to consider the cost of damages to roads, powerlines, and other infrastructure. To capture the reliability impacts of dam failure, power replacement costs from each powerhouse in the inundation zone of each dam is also included in the financial impact. The aggregated model results provide a baseline financial impact of dam failure at $8.0 million per year.

Consequences of this risk event are shown in Table 13-4 below. Model attributes are described in Chapter 3, “Risk Modeling and Risk Spend Efficiency.”

TABLE 13-4
RISK EVENT CONSEQUENCES

	CoRE | %Freq | %Risk	Freq	Natural Units Per Event		CoRE		Natural Units per Year		Attribute Risk Score	
			Safety	Financial	Safety	Financial	Safety	Financial	Safety	Financial
			EF/event	$M/event			EF/yr	$M/yr		
Aggregated	4,739 | 100% | 100%	0.0	8.8	544.9	2,814	1,925	0.13	8.0	41	28.4
Aggregated	**4,739** | 100% | 100%	0.0	8.8	544.9	2,814	1,925	0.13	8.0	41	28.4

C. Controls and Mitigations

Tables 13-5 and 13-6 list all the controls and mitigations PG&E included in its 2017 RAMP, 2020 General Rate Case (GRC), and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place or completed, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and significant changes to mitigations or controls during the 2020-2022 and 2023-2026 periods.

TABLE 13-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP Controls	2020-2022 GRC Controls	2020-2022 RAMP Controls	2023-2026 RAMP Controls
1	C1 – Hydro Operations Maintenance	X	X	Incorporated in C5	
2	C2 – Facility Safety Inspections	X	X	Incorporated in C5	
3	C3 – FERC and DSOD Inspections	X	X	Incorporated in C5	
4	C4 – Part 12D Inspections and Follow-Up	X	X	Incorporated in C5	
5	C5 – DSP	X	X	X	X

TABLE 13-6
MITIGATIONS SUMMARY

Line No.	Mitigation and Number	2017 RAMP Mitigations	2020-2022 GRC 2017-2020 Mitigations	2020-2022 RAMP Mitigations	2023-2026 RAMP Mitigations
1	M1 – Internal Erosion Mitigations	X	X	X	X
2	M1a – Lake Fordyce Dam	X	X	X	X
3	M1b – Main Strawberry Dam	X	X	X	X
4	M1c – Relief Dam	X	X		
5	M1d – Courtright Dam	X	X		
6	M2 – Spillway Remediations			X	X
7	M2a – Scott Dam	X	X	X	
8	M2b – Belden Dam	X	X	X	X
9	M2c – Salt Springs Dam	X	X	X	
10	M3 – Seismic Retrofit	X	X	X	X
11	M3a – Crane Valley Intake Tower	X	X	X	
12	M4 – Low-Level Outlet (LLO) Refurbishments	X	X	X	X
13	M4a – Pit 1 Forebay	X	X	X	
14	M4b – Relief Dam	X	X		
15	M4c – Spaulding Dam	X	X		
16	M4d – Lake Almanor	X	X	X	
17	M5 – Internal Erosion Mitigations	X	X	X	X

1. 2017-2019 Controls

The five 2017-2019 controls address overall dam safety, including the three RAMP risk drivers, flood, seepage (internal erosion), and seismic. The five 2017-2019 controls were previously separate elements of the DSP and have been combined into the single DSP control for the years 2020 and beyond.

C1 – Hydro O&M: Trained O&M personnel routinely observe dams. These personnel are stationed in the watersheds where the PG&E dams are located. During regular visits to the dams, the O&M personnel perform visual observations of the dams, collect monitoring data, and report any changed or unusual conditions that could potentially impact dam safety or PG&E's ability to operate the facility's spillways and outlet structures.

C2 – Facility Safety Inspections: Facility safety engineers perform inspections of PG&E's dams at an interval between annually to triennially, depending on the size and hazard classifications of each dam. These inspections identify any unusual conditions that may affect dam safety and develop responses to those conditions to ensure safe and reliable operation. The dam safety engineers also review monitoring data for each high and significant hazard dam whenever readings are above threshold levels or as part of the Dam Safety Surveillance and Monitoring Plan/Report that is prepared annually. PG&E's Chief Dam Safety Engineer (CDSE) supervises the work performed by the facilities safety engineers. PG&E uses consultants who have expertise in dam safety to perform evaluations and studies that support the facility's safety inspections and follow-up activities when issues arise to augment its internal inspection efforts.

C3 – FERC and DSOD Inspections: FERC and DSOD engineers inspect PG&E's dams at an interval of annually to triennially, depending on the dams' DSOD and FERC hazard classifications. These agencies provide inspection reports that include observations, recommendations, and requirements to address issues that are identified. PG&E addresses issues documented in these inspections and communicates with the regulators to fulfill requirements and expectations.

C4 – Part 12 D Inspections and Follow-Up: 18 CFR Part 12D requires an independent consultant to perform a safety inspection every five years. This inspection is a comprehensive review of the physical condition of the dam, dam operations, and confirmation of the dam design relative to design-basis floods, seismic events, and static conditions. This process also includes a PFMA that takes a comprehensive look at ways a dam could fail and guides monitoring observations to focus on signs of the potential failure modes in addition to the overall observations. PG&E has implemented the Part 12D inspections as required and maintains and tracks completion of recommendations from those inspections.

C5 –DSP: PG&E's CDSE is responsible for implementing the DSP. The DSP includes measures to reduce the risks of owning and operating a dam. FERC establishes guidelines for the DSP. PG&E's DSP exceeds FERC guidelines for an Owner's DSP by employing an independent panel of experts, the Dam Safety Advisory Board, to audit the DSP and to advise on dam safety issues. For complex dam safety issues, a Board of Consultants may be convened to opine and advise on issues and help guide PG&E's actions to address those issues.

2. 2017-2019 Mitigations

M1 – Seepage Mitigation Projects: Multiple seepage mitigation projects began in 2017-2019. Seepage mitigation projects addressed the internal erosion risk driver.

M1a – Fordyce Dam: The major seepage mitigation project commenced on Fordyce dam in 2016 will continue through 2023. This mitigation will address seepage through the upstream toe of this rockfill concrete face dam by installation of a geomembrane liner. The major capital investment work began in 2018 with another significant increase in spend in 2020-2023 as the foundational project work completes and the geomembrane installation begins.

M1b – Main Strawberry Dam: Repeated freeze and thaw on the Main Strawberry Dam face have degraded the concrete face and exposed reinforcing steel through excessive spalling. Spalling is addressed by removing and replacing damaged sections of spalled concrete. This multi-year project began in January 2017 and is expected to continue through 2024. The capital cost projections are flat as the work for each year is standard concrete restoration work and often repeated throughout the industry.

M1c – Relief Dam: Relief Dam is in a similar condition to Main Strawberry Dam due to freeze-thaw cycles. The project was delayed in 2017 and an alternative analysis is ongoing.

M1d – Courtright Dam: Cracks and spalling of various concrete joints were present in the Courtright Dam face as a result of compression caused by dam settlement. The project was further evaluated and determined to not be necessary.

M2 – Spillway Remediation and Improvement Projects: PG&E continues to engage with regulators and the industry in the combined response to the incident at Oroville Dam. The projects below were included in PG&E's 2017-2019 plans and did not include a response to Oroville Dam as investigations were still ongoing. Spillway remediation and improvement projects address the flood risk driver.

M2a – Scott Dam: Projects were planned at Scott Dam to remediate spillways. The remediations were recommended in the 18 CFR Part 12 Independent Consultant Inspection report. In response to the recommendations, PG&E made structural modifications and is in the process of designing, procuring, and installing one mobile self-contained radial gate hoist. This project is scheduled to complete by the end of 2020.

M2b – Belden Dam: PG&E found cracking along the base of a wall panel on the Belden Spillway during unrelated excavation work. Subsequent analysis found that the crack was likely caused by overstress as a result of oversaturated soil surrounding the spillway chute wall causing the wall to deflect inwards from the original constructed position. Two potential plans to address the problem were evaluated: (1) construct a cantilevered reinforced concrete retaining wall extending away from the chute; or (2) construct a reinforced concrete retaining wall with an anchor block element and vertical post-tensioned corrosion protected anchors. PG&E further evaluated these conditions in 2018 to determine which method would best address the spillway base cracking. As a result of this evaluation, PG&E determined the spillway had insufficient capacity based on the current PMF. PG&E has hired a consultant to further advance the PMF analyses and determine the final design needed for the spillway. This mitigation is included in the updated 2023-2026 quantified spillway mitigations.

M2c – Salt Springs Dam: By November 2019, PG&E replaced the seals on all 13 radial gates at Salt Springs were replaced and repainted the gates. This mitigation has been completed.

M3 – Seismic Retrofit: The seismic retrofit planned for the Crane Valley Project intake tower will begin in 2022. The seismic retrofit mitigations address the seismic risk driver.

M3a – Crane Valley Intake Tower: The intake tower at Crane Valley services both the powerhouse and the LLO. It was identified during the

2014 Independent Consultant Safety Inspection at the Crane Valley Project that the intake tower had not been evaluated using current seismic analysis methods. PG&E performed an updated analysis and determined that the intake tower is vulnerable to a brittle shear failure at either the construction joint near elevation 3,321 feet or at elevation 3,333 feet above the location where the diagonal struts connect to the main tower. PG&E's DSP engineers determined that designs provided by the original vendor in 2019 were unacceptable. A new vendor has been selected, but this has resulted in delays to implementing the project. This mitigation is now planned to be included by 2022 and is included in this RAMP Report.

M4 – LLO Refurbishments: Pit 1 LLO and radial gate retrofit, initiated as part of a FERC recommendation, Relief Dam LLO bevel gear replacements, and dredging in Spaulding Dam were planned to ensure reliable operation of the LLOs at these three dams. LLO refurbishments address the seismic and internal erosion risk drivers.

M4a – Pit 1 Forebay: During the work originally scheduled for completion by 2019, it was determined the valve needed a new actuator to ensure reliable operation. In order to procure and install a new actuator, this project was extended through 2020 and is included in this RAMP Report.

M4b – Relief Dam: Replacement of the bevel gears described in the previous section was completed by the end of 2017.

M4c – Spaulding Dam: After completing some dredging at Spaulding Dam in 2016 and 2017, additional dredging was determined to not be necessary.

M4d – Lake Almanor: As PG&E identified in its 2020 GRC testimony, additional work was determined to be necessary to complete this mitigation.[16] The project is still on track to complete in 2021 and is included in this RAMP Report.

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[16] Application 18-12-009, Exhibit (PG&E-5), p. 2-13, Lines 16-26.

3. 2017 RAMP Update

In the 2017 RAMP, PG&E proposed five controls including Control C5, DSP. PG&E will continue to implement the DSP and the work previously conducted as part of controls C1, C2, C3, and C4 will be incorporated into C5 in 2020 and beyond.

In the 2017 RAMP, PG&E proposed four types of mitigations with individual projects assigned to each type.

M1 – Seepage Mitigations: PG&E proposed four seepage mitigation projects.

M1a – Fordyce Dam: Design and preconstruction efforts for the installation of a geomembrane liner were underway as of 2019.

M1b – Main Strawberry Dam: The work to remove damaged sections of spalled concrete proceeded as planned during the 2017-2019 period.

M1c – Relief Dam: The work to remove damaged sections of spalled concrete was delayed and an alternative analysis is being performed.

M1d – Courtright Dam: PG&E evaluated the plan to address cracks and remove and replace spalled concrete sections. The project was cancelled based on the results of the evaluation.

M2 –Spillway Mitigations: PG&E proposed three spillway mitigation projects.

M2a – Scott Dam: Modification of the radial gates proceeded as planned. Structural modifications have been implemented and PG&E will install a mobile self-contained radial gate hoist by the end of 2020.

M2b – Belden Dam: PG&E has repaired joints, performed inflow design flood analysis and patched concrete. PG&E continues to evaluate the design of the spillway and plans to complete this project by 2024. This mitigation is included in the updated 2023-2026 quantified spillway mitigations.

M2c – Salt Springs Dam: PG&E completed replacement of 13 radial gates between 2017 and 2019. The project was expedited and is complete.

M3 – Seismic Mitigations: PG&E proposed one seismic mitigation project, the Crane Valley Intake Tower Seismic Retrofit. In 2019, the selected vendor delivered a design that PG&E's DSP engineers deemed unacceptable. PG&E selected a replacement vendor for this project, which has delayed the completion of the project until 2020.

M4 – LLO Refurbishments: PG&E proposed four LLO refurbishment projects.

M4a – Pit 1 Forebay: PG&E completed painting the gate and replacing seals. PG&E identified the need for a new actuator and the project completion date was extended through 2020.

M4b – Relief Dam: The project to replace bevel gears proceeded as planned and was completed in 2017.

M4c – Spaulding Dam: Project deemed unnecessary after initial dredging in 2016 and 2017 and planned further dredging was cancelled.

M4d – Lake Almanor: The project to replace the LLO gates was rescoped in 2018 and is now projected to be complete in 2021.

D. 2020-2022 Controls and Mitigation Plan

1. Controls

PG&E will continue to implement the DSP and the work previously conducted as part of controls C1, C2, C3, and C4 will be incorporated into C5. The scope of the DSP is unchanged from 2017 and defined as:

C5 – Dam Safety Program: The primary responsibility of PG&E's DSP is continual long-term safe and reliable operation of PG&E owned dams, which is achieved by:

– Implementing inspections and programs to protect the public and the Company's assets through overall management of dam safety risks, including: O&M inspections; annual Dam Safety Inspections; annual FERC and DSOD inspections, 5-year Independent Consultant Inspections; public safety programs; EAP programs; and operations reviews programs.

– Maintaining a well-trained and resourced organization with a primary focus on public and employee safety as well as compliance with FERC and DSOD requirements;

– Clear communication of policies and expectations regarding dam safety and regulatory compliance to all DSP team members, O&M personnel,

- and other stakeholders focused on maintaining and reducing the inherent risk in operating a dam;
- Defined protocols for communicating and reporting dam safety issues to aid in ensuring public safety and allowing the regulators to stay informed of PG&E's hydro assets; and
- Defining the responsibilities and authority of the CDSE to be accountable for achieving dam safety with support from PG&E's senior leadership.

2. Mitigations

PG&E is proposing four types of mitigations for the 2020-2022 period: Spillway Remediations; Seismic Retrofits; Internal Erosion Mitigations; and LLO Refurbishments. A list of projects by mitigation is included in supporting workpapers.[17]

M1 – Internal Erosion Mitigations: Excessive internal erosion through concrete face rockfill dams and earthfill dams can lead to a potential piping of finer grained materials through a dam with graded materials. For rockfill dams, this erosion is more likely with "dirty" rockfill dams (those with a larger quantity of finer grained materials between the rocks) and typically develops from cracking and deterioration of the concrete face or other anomalies in the seepage barrier that form due to dam settlement and allow water to pass through the dam. When this seepage becomes excessive, it can cause migration of finer materials creating voids that can eventually lead to a failure of the dam. Internal erosion mitigations address the driver through three primary methods—repairing or sealing cracks and joints in the upstream face, restoring spalled concrete and grouting, or less commonly, providing a new liner or water barrier partially or fully covering the upstream face. Repairing and sealing cracks and joints and restoring spalled concrete are the primary methods common both in the industry and to PG&E as proven methods effective at reducing internal erosion.

Installing a geomembrane liner is a longer-term resolution whereas the joint repairs and concrete patching typically deteriorate over a few years and require continual maintenance and re-application. However, a potential

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17 See WP 13-4.

major cost impact of installing geomembrane liners could result from additional work to install a cutoff at the toe of the dam to alleviate differential hydraulic pressure in the dam created by installing the liner. Excessive hydraulic pressure differential could exacerbate internal erosion. PG&E measures the effectiveness of the mitigation and need for additional maintenance or re-application through visual inspection of flow through the downstream toe of each dam and downstream flow instrumentation. PG&E is planning five internal erosion mitigation projects. The complete list of internal erosion mitigation projects is provided in the supporting workpapers.

M2 – Spillway Remediations: This mitigation category ensures spillways and necessary components in the spillway are available to control flow, particularly during high reservoir level or other high-water flow events including the flood risk driver. PG&E has categorized 43 projects as spillway remediations between 2020 and 2022. The complete list of spillway remediation projects is included in supporting workpapers.[18]

M3 – Seismic Retrofits: This mitigation category is for projects that ensure the robustness of dams and reliability of components of dams after postulated major seismic events. The Crane Valley Dam intake tower project was included in the 2017 RAMP but the scheduled end date has been extended from 2020-2022. The scope of work for this mitigation has not changed. As the Crane Valley Dam intake tower project ensures reliability of an LLO during a postulated seismic event, the modeling has been updated to mitigate both the seismic and internal erosion drivers. Further PG&E has identified radial gates requiring seismic retrofits; these projects mitigate the flood driver as they ensure the reliability of radial gates which are used to control flow during floods that may occur coincident with or shortly after a seismic event. PG&E will conduct six seismic retrofit projects. The complete list of seismic retrofit projects is included in supporting workpapers.

M4 – LLO Refurbishments: Although LLOs will not directly mitigate the three major drivers, maintaining reliable operation of these features is critical to safely relieving the water loading on a dam during or after a seismic or

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18 WP 13-4.

internal seepage event to potentially prevent a more catastrophic failure. PG&E has categorized eight LLO Refurbishments between 2020 and 2023. The complete list of LLO refurbishment projects is included in supporting workpapers.

Tables 13-7 and 13-8 below shows the estimated costs for the mitigation work planned from 2020-2022.

TABLE 13-7
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M1	Internal Erosion Mitigations	AXR	$1,050	$829	–	$1,879
2	M2	Spillway Remediations	AXR	5,714	6,286	2,345	14,345
3	M4	LLO Refurbishments	AXR	50	–	–	50
4		Total		$6,814	$7,115	$2,345	$16,274

Note: See WP 13-1.

TABLE 13-8
FORECAST COSTS
2020-2022
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M1	Internal Erosion Mitigations	2LR, 2NR	$4,174	$16,903	$17,628	$38,705
2	M2	Spillway Remediations	2LR, 2NR	4,033	19,802	42,059	65,893
3	M3	Seismic Retrofits	2LR	12,780	3,707	10,507	26,995
4	M4	LLO Refurbishments	2LR, 2NR	9,818	4,063	6,279	20,160
5		Total		$30,805	$44,474	$76,474	$151,753

Note: See WP 13-1.

E. 2023-2026 Proposed Mitigation Plan

PG&E is proposing four types of mitigations for the 2023-2026 period: internal erosion mitigations, spillway remediations, seismic retrofits, and LLO refurbishments. A list of projects by mitigation is included in supporting workpapers.[19]

M1 – Internal Erosion Mitigations: PG&E does not currently anticipate starting any internal erosion projects between 2023 and 2026. PG&E will continue to inspect the dams and continuously evaluate and prioritize the need for additional mitigations during this time period. Of the five internal erosion projects in the 2020-2022 time period, two will continue into the 2023-2026 time period.

M2 – Spillway Remediations: PG&E does not anticipate starting any spillway remediation projects between 2023 and 2026. PG&E will continue to inspect the dams and continuously evaluate and prioritize the need for additional mitigations during this time period. Of the 43 projects in the 2020-2022 time period, 22 will continue into the 2023-2026 time period.

M3 – Seismic Retrofits: PG&E anticipates starting one seismic retrofit in the 2023-2026 time period. PG&E will continue to inspect the dams and continuously evaluate and prioritize the need for additional mitigations during this time period. Three of the six projects in the 2020-2022 time period will continue into the 2023-2026 time period.

M4 – LLO Refurbishments: PG&E does not anticipate starting any LLO refurbishments in the 2023-2026 time period. PG&E will continue to inspect the dams and continuously evaluate and prioritize the need for additional mitigations during this time period. Three of the eight projects in the 2020-2022 time period will continue into the 2023-2026 time period.

Tables 13-9 (expense) and 13-10 (capital) below show the forecast costs for the mitigation work planned from 2023-2026. The RSE and risk reduction scores for each mitigation are shown in Table 13-10.

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19 See WP 13-4.

TABLE 13-9
FORECAST COSTS
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026
1	M1	Internal Erosion Mitigations	AXR	–	–	–	–
2	M2	Spillway Remediations	AXR	$350	–	–	–
3	M4	LLO Refurbishments	AXR		–	–	–
4		Total		$350	–	–	–

Note: See WP 13-1.

TABLE 13-10
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1	Internal Erosion Mitigations	2LR, 2NR	$20,662	$1,900	–	–	$22,562	0.37	6.7
2	M2	Spillway Remediations	2LR, 2NR	78,850	107,700	40,000	40,000	266,550	0.69	139.0
3	M3	Seismic Retrofits	2LR	19,700	7,300	7,000	5,500	39,500	0.01	0.4
4	M4	LLO Refurbishments	2LR, 2NR	1,202	–	–	–	1,202	0.14	0.14
5		Total		$120,413	$116,900	$47,000	$45,500	$329,813		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
Note: See WP 13-1.

Table 13-10 shows that the Spillway Remediation program has both the greatest risk reduction and highest RSE. Commensurate with these modeling results PG&E is proposing to spend approximately 80 percent of its forecast costs on this high value program.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: Internal Erosion Mitigation, Geomembrane Liners

In response to a suggestion from the Public Advocates Office at the California Public Utilities Commission regarding PG&E's 2017 RAMP, PG&E considered the alternative of installing geomembrane liners on all high and significant hazard dams that currently have projects planned to reduce internal erosion, but those projects do not include installing a geomembrane liner. This mitigation would require geomembrane liners to be installed for Strawberry and Spaulding No. 1. This proposed alternative would be performed instead of the proposed Internal Erosion Mitigation Plan.

This alternative represents a significant increase in spend over the next several years. Because the model does not currently have a degradation curve that would better represent the lifespan of the geomembrane liner (approximately 50 years) versus the lifespan of the original projects (approximately 3-5 years), mitigation effectiveness is given with the standard discounted rate over the 50-year impact. However, a significant risk reduction is still seen in the decrease in initiating event frequency of internal erosion due to the benefits of the geomembrane liners.

TABLE 13-11
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Internal Erosion Mitigation, Geomembrane Liner	$50,963	$32,201	$30,701	$30,701	$144,565	0.06	6.6
2		Total	$50,963	$32,201	$30,701	$30,701	$144,565		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note: See WP 13-1.

2. Alternative Plan 2: Geosciences Engineering and Risk Research Plan

Alternative 2 – Geosciences Engineering and Risk Research Plan: PG&E Geosciences developed a proposal to better quantify the seismic hazards and risk to PG&E Hydro assets through applied research. This proposal should be considered supplemental to the proposed mitigation plan. The program consists of three subject areas: Seismic Source Characterization (SSC), Ground Motion Characterization (GMC), and Engineering and Risk. The SSC area focuses on identifying and characterizing seismic sources. The GMC area focuses on improving our ability to model earthquake ground motions and uncertainty. The Engineering and Risk area focuses on collecting data and developing and implementing methodologies that improve our ability to quantify seismic risk. In order to organize the research program, 5-year windows of research activities are planned and each year's activities would be reviewed by external panels.

Notably, since this is a research project, the forecasted risk reduction cannot be quantified. Completing this study would improve the accuracy of our model and our understanding of the possible seismic impacts to PG&E's hydro assets. This would allow for better prioritization of work and mitigation of existing, but currently unknown hazards and risks and does have the potential to decrease spend through more accurate project designs. The expected cost of the plan is $200,000 per year for 5 years

TABLE 13-12
FORECAST COSTS
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total
1	A2	Geosciences Engineering and Risk Research Plan	$200	$200	$200	$200	$800
2		Total	$200	$200	$200	$200	$800

Note: See WP 13-1.

3. Alternative Plan 3: PMF Studies

Alternative 2 – PMF Studies: PG&E has piloted an updated methodology for PMP analysis and is currently working with regulators to ensure acceptability of the analysis. It would require 21 additional studies to update all of PG&E's high and significant hazard dams. This alternative should be considered as supplemental to the proposed mitigation plan.

Notably, since this is a research project, the forecasted risk reduction cannot be quantified. Completing this study would improve the accuracy of our model and our understanding of the possible flood impacts to PG&E's hydro assets. This would also allow for better prioritization of work and mitigation of existing but currently unknown hazards and risks. There is further potential this will reduce the cost of future mitigations through more accurate spillway capacity designs. This alternative is expected to cost $6,500,000 over three years to complete the study.

TABLE 13-13
FORECAST COSTS
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total
1	A3	PMF Studies	$2,200	$2,200	$2,100	–	$6,500
2		Total	$2,200	$2,200	$2,100	–	$6,500

Note: See WP 13-1.

Table 13-14 compares the proposed and alternative mitigation plans.

TABLE 13-14
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[)(b)]	Total Spend (NPV)	RSE
1	Proposed	M1, M2, M3, M4	$350	$329,813	146.21	$250,656	0.58
2	Alternative 1	M2, M3, M4 + A1	$350	$451,816	146.09	$340,481	0.43
3	Alternative 2	Proposed + A2	$350	$329,813	146.21	$250,656	0.58
4	Alternative 3	Proposed +A3	$350	$329,813	146.21	$250,656	0.58

(a) Plan Components refers to the Mitigations presented in Table 13-6.
(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.
Note: See WP 13-1.

GAS AND ELECTRIC COMPANY

CHAPTER 14

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: REAL ESTATE AND FACILITIES FAILURE

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 14
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: REAL ESTATE AND FACILITIES FAILURE

A. Executive Summary

The Real Estate Facilities and Failure Risk is the risk of an event which causes a building, facility or property within Pacific Gas and Electric Company's (PG&E or the Company) service area to be deemed unsafe, or inaccessible for operation or occupancy, such that PG&E is unable to use the building or property to support operational needs. Key risk drivers include a seismic, flood, landslide, building fire, or physical security event.

The scope of this risk includes all PG&E-owned or leased buildings and facilities. All other non-facility-related PG&E assets, such as electric and gas transmission and distribution systems, dams, and substations are covered under other risks.

Exposure to this risk is based on a tranche-level analysis of 50 representative buildings from the subset of facilities managed by Corporate Real Estate Strategy and Services (CRESS) that included high-, mid-, and low-rise office buildings, service centers, conference centers, and critical facilities in predominately high seismic areas of the state. The risk model analysis indicates that the expected number of events per year is approximately eight for this risk. 62 percent of the risk events are seismic events while physical security, flood, landslide, and building fire account for 38 percent of the risk events. Seismic risk also makes up more than 99 percent of the total risk impact score and physical security, flood, landslide, and building fire events comprise the remaining portion of the risk score. Based on this analysis, PG&E's planned mitigations primarily address seismic risk events.

71 percent of the tranche-level risk is related to two high-rise, highly-populated buildings located in a relatively high seismic zone (San Francisco General Office (SFGO) Complex). 12 percent of the tranche-level risk is related to five mid-rise buildings, and the remaining

17 percent is based on the sample of single story or low-rise buildings found in service centers, office complexes, and other facilities.[1]

Real Estate Facilities and Failure Risk has the seventh highest 2023 test year (TY) baseline safety score (69) and sixth highest 2023 TY baseline total risk score (97) of PG&E's top 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score, 103, improves by 16 percent when the planned mitigations are applied: the 2023 TY baseline risk score is 97 and the 2026 post-mitigation risk score is 87.[2]

Between 2020 and 2022, PG&E will conduct foundational activities, such as surveying buildings that meet a certain criterion. This criterion will include parameters, such as age (to determine contemporaneous codes that were applied to design and construction), location (to determine local seismic activity), height or stories (to determine potential building performance), and/or population density (to weigh potential safety risks) that will inform the multi-year seismic mitigation programs. The buildings or structures will be reviewed against a seismic performance criterion to determine if the structures should be renovated or replaced either by redevelopment or relocation (relocation is particularly related to leased facilities). PG&E will begin renovation or replacing targeted facilities identified during the foundational survey starting in 2023 or sooner depending on the implementation of CRESS' Service Center Investment Program currently outlined in the 2020 General Rate Case (GRC) request or within PG&E's proposed regionalization plans.[3]

PG&E completed its RAMP analyses at the end of May 2020. In June 2020, PG&E announced Company headquarters will move from San Francisco to Oakland beginning in 2022. This upcoming move is not reflected in the risk analysis presented herein, but will be incorporated into the 2023 GRC.

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[1] See WP 14-3.

[2] During the February 4, 2020 RAMP Workshop a California Public Utilities Commission (CPUC) staff member asked PG&E if the risk score for the Real Estate and Facilities failure risk is based on past events or if it is based on United States Geological Survey (USGS) data sources. PG&E's risk model considers the probability of seismic events based on rates of peak ground acceleration exceedance. The USGS Hazard Analysis used in PG&E's model does not rely solely on historical events, but rather, uses data collected from both past seismic events, models of ground motion and the potential recurrence of those events.

[3] The information herein is subject to those limitations described in Chapter 2, Section D.

TABLE 14-1
RISK OVERVIEW

Line No.	Risk Name	Real Estate and Facilities Failure
1	In Scope	Building, facilities or property owned or leased by PG&E
2	Out of Scope	Other non-facility related PG&E assets, such as electric and gas transmission and distribution assets, power generation assets, substations.
3	Data Quantification Sources[(a)]	<u>Seismic Data</u> – Recent studies of three sites in October 2019; initial modeling data of 15 sites as of November 2019. Analysis includes seismic hazard developed by USGS and building damage vulnerability by risk assessment software SP3 developed by the consulting firm "Haselton Baker Risk Group (HB Risk)" using simplified Federal Emergency Management Agency (FEMA) procedure P-58 methodology. Used available building specific information. The initial study was used as surrogate for further expansion to a sample of 50. <u>Flood Data</u> – Current and historical FEMA Flood Zone Data, PG&E Geographic Information System Analytics Department. <u>Landslide Data</u> – Data from PG&E Meteorology Department. <u>Physical Attack Data</u> – Crimes-Against-Persons Index aggregated property crime evaluation Federal Bureau of Investigation crime data. <u>Fire Data</u> – National Fire Protection Association, National Fire Incident Reporting System, Commercial Building Energy Consumption Survey.

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

PG&E owns more than 3,000 buildings throughout its 72,000 square mile service area. PG&E continually manages the exposure of these facilities to unplanned natural disasters, such as fires, floods, landslides, and seismic events, and other risks, such as trespass, theft, and physical attacks on PG&E property.

CRESS manages a subset of PG&E facilities that is primarily comprised of "occupied spaces." These facilities include office buildings, service centers (including operations buildings, shops, warehouses, equipment yards, and vehicle maintenance garages), data centers and other facilities that house critical operating infrastructure, contact or call centers, and Customer Service Offices (CSO) where customers conduct in-person transactions with PG&E representatives. CRESS does not manage structures or facilities, whether occupied or only housing equipment, that are part of PG&E's electric, gas, and/or information technology infrastructure.

For example, certain substations have buildings that were previously used for substation maintenance or circuit switching. These other buildings are not managed by CRESS but instead managed by other lines of business, such as PG&E's Electric Distribution Operations teams.

2. Risk Definition

The Real Estate Facilities and Failure Risk is an event which causes a building, facility or property within PG&E's territory to be deemed unsafe, or inaccessible for operation or occupancy, such that PG&E is unable to use the building or property to support operational needs.

B. Risk Assessment

1. Background and Evolution

The Real Estate and Facilities Failure risk was added to PG&E's Enterprise Risk Register in 2019 and is a new risk in the 2020 RAMP. Previously this risk was disaggregated into two separate risks: the Seismic Vulnerability Risk and the Fire Life Safety Risk. For the 2020 RAMP, the Real Estate and Facilities Failure Risk incorporates these two risks into one risk which also includes additional risk drivers, such as flood, landslide and physical attack, which results in a higher overall risk score than the previous disaggregated seismic and fire risks.

2. Risk Bow Tie

FIGURE 14-1
RISK BOW TIE

3. Exposure to Risk

Exposure to this risk is based on an analysis of a representative sample of 50 facilities managed by CRESS and includes low-, mid-, and high-rise facilities. Most of the facilities are in higher seismic areas, primarily the San Francisco Bay Area, and/or facilities that are higher in employee density. The list also includes facilities that house crucial core computer or customer support operations, such as data centers, grid and gas control centers, emergency operations centers, telecom hubs, and customer contact centers. The risk model is based on approximately eight risk events occurring each year.

As discussed in more detail below, seismic event(s) account for the majority of the Real Estate and Facilities Failure risk. PG&E's facilities are in various seismic zones throughout its service territory including relatively high seismic zones in the coastal regions, most significantly the greater San Francisco Bay Area, and others located in relatively low seismic zones, such as the San Joaquin Valley and Sierra Nevada Foothills. Each PG&E facility is required to meet the seismic ordinances, codes, and/or standards promulgated by the local jurisdiction or Agency Having Jurisdiction (AHJ) at the time the facilities were first permitted and constructed, or when certain levels of renovation trigger compliance with then-current building codes. While all PG&E buildings were built to contemporaneous codes and standards, some are believed to be at risk of failure during a certain design earthquake greater than the design earthquake in the building code when the building was constructed. This is mainly due to the evolution and/or maturity of seismic knowledge, mapping of faults, and experience with building performance during recent significant seismic events.

4. Tranches

The Real Estate and Facilities Failure risk model includes a representative sample of 50 facilities, each of which is its own tranche. The 50 individual facilities are grouped into 4 groups of facilities that share similar characteristics.

- Group 1 – The SFGO Complex: High rise facilities in San Francisco making up PG&E's Headquarters (PG&E's only high-rise structures);
- Group 2 – Mid to High Risk Facilities Other than SFGO: Mid-rise (greater than four stories) office buildings, e.g., San Jose, San Ramon, and Concord.
- Group 3 – Low-Rise Structures: Structures typically found at service centers, office complexes, or conference centers.
- Group 4 – Critical Facilities: Critical facilities house core computer or customer support operations, such as data centers, grid and gas control centers, emergency operations centers, telecom hubs, and customer contact centers.

Table 14-2 below shows the results of the tranche-level analysis.

TABLE 14-2
RISK EXPOSURE AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Percent Exposure	Safety Risk Score	Financial Risk Score	Total Risk Score	Percent Risk Score
1	High-Rise – 2 Buildings	4%	48.19	20.37	68.56	71%
2	Mid-Rise – 5 Buildings	10%	8.28	3.34	11.62	12%
3	Low-Rise/Single-Story – 43 Buildings	86%	12.84	3.57	16.41	17%
4	Total	100%	69.31	27.28	96.59	100%

5. Drivers and Associated Frequency

PG&E identified five drivers for the Real Estate and Facilities Failure risk. Each driver and its associated 2023 TY baseline frequency are discussed below.

Seismic: This driver includes seismic events in PG&E's service territory and accounts for five (62 percent) of the eight expected number of the risk events per year. There are four sub-drivers identified for this risk aligned to the Seismic driver: Seismic Minor; Seismic Moderate; Seismic Strong; and Seismic Severe.

Physical Attack: Physical attack includes attacks against PG&E buildings or facilities, such as a bomb threat, active shooter, or other crimes against PG&E's facilities. This driver also includes theft, property vandalism, trespass, and adjacent non-lawful assembly near PG&E's facilities. This driver accounts for two (27 percent) of the eight expected number of the risk events per year. Although the frequency of risk events from the Physical Attack driver is the second highest among the drivers, the Physical Attack driver has a low impact on financial consequences due to experience with resultant losses (materials theft and/or fence damage).

Building Fire: This driver includes fire-related incidents in PG&E's buildings or facilities and accounts for fewer than one incident (11 percent) of the eight expected number of the risk events per year. The Fire Risk driver is projected to have little effect on financial outcomes because the risk impact is primarily on non-structural elements, e.g., smoke damage, water damage due to sprinklers.

Flood: Includes flood-related incidents in PG&E's buildings or facilities. This driver accounts for fewer than one incident (1 percent) of the eight expected number of the risk events per year. Flood is projected to have little effect on financial outcomes because the risk impact is primarily on non-structural elements, e.g., flooding only in parking areas.

Landslide: Includes landslide related incidents impacting PG&E's buildings or facilities. This driver accounts for fewer than one incident (1 percent) of the eight expected number of the risk events per year. Landslide is projected to have little effect on financial outcomes because PG&E's

facilities are primarily built on flat land and not adjacent to steep terrain, slopes or mountainous areas.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Real Estate and Facilities Failure risk are shown in Table 14-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 14-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood (Driver)	Impacts Consequence
1	Seismic	X	X
2	Physical Attack	X	
3	Records and Information Management		X
4	Emergency Preparedness and Response		X

Seismic driver accounts for more than 99 percent of the total risk score and results in consequence of risk events more severe than other risk drivers.

7. Consequences

The consequence impacts for the Real Estate and Facilities Failure risk are related to safety and finance:

<u>Safety</u>: Safety consequences in the risk model are driven primarily by a seismic event resulting in employee injuries and/or fatalities as a result of structural and/or non-structural damage to PG&E's facilities. Injuries and fatalities are influenced by the number of seated employees for those buildings in the risk model. Fire, flood, and landslide events did not result in potential injuries and/or employee fatalities in the risk model because the consequences of these events were generally non-structural in nature associated with minor damage to the building or grounds. Physical attacks against PG&E facilities are rare. If they occur, they primarily consisted of incidents of property theft.

Financial: Financial consequences in the risk model are driven by the cost to rebuild a structure after a seismic event. Building costs are based on typical PG&E and/or industry costs to rebuild on a cost per square foot of building space.

– Fire, flood, and landslide events did not result in significant financial costs because consequences of these events were generally non-structural in nature associated with minor damage to the building or grounds.

– Financial consequences resulting from physical attack were also low as the nature of actual physical attack resulted in incidents of property theft. The severity of a seismic event is the largest driver of safety and financial consequences. The severity of a seismic event is divided into four possible outcomes based on the measure of peak ground acceleration (greater than 0.05 g)—a measure of how hard the earth shakes at a given geographic point. Events causing ground shaking less than 0.05 g were judged to have insignificant impact based on historical experience and as such were not considered consequential.[4]

Each of the four possible outcomes described above results in varying probabilities of building failure for the individual buildings or tranches in the risk model.

- Minor (0.05g-0.20g) – Accounts for 50 percent of the risk event occurrences and 22 percent of the risk.
- Moderate (0.21g-0.40g) – Accounts for 8 percent of the risk event occurrences and 28 percent of the risk.
- Strong (0.41g-0.60g) – Accounts for 2 percent of the risk event occurrences and 24 percent of the risk.
- Severe (>0.60g) – Accounts for 1 percent the risk event occurrences and 25 percent of the risk.

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4 During the February 4, 2020 RAMP Workshop, a CPUC staff member asked PG&E for a translation of seismic outcomes that were expressed as the ground shaking intensity (measured in units of gravity "g") into Richter magnitude scale units. The potential earthquake magnitudes considered for modeling this risk range from small (~M5) to large (M7+). However, the location of the earthquake has a significant impact on the shaking levels (measured in units of gravity "g") that will be experienced at various facilities, i.e., buildings close to the fault shake harder than buildings further away.

Table 14-4 shows the consequences of the risk analysis. Model attributes are discussed in Chapter 3, “Risk Modeling and Risk Spend Efficiency.”

TABLE 14-4
RISK EVENT CONSEQUENCES

					Natural Units Per Event		CoRE		Natural Units per Year		Attribute Risk Score	
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Financial $M/event	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety	Financial
Seismic Moderate	40	8%	28%	0.7	0.3	8.3	26	14	0.19	5.7	18	9
Seismic Severe	200	1%	25%	0.1	0.8	29.8	157	43	0.10	3.6	19	5
Seismic Strong	135	2%	24%	0.2	0.6	18.7	105	31	0.10	3.2	18	5
Seismic Minor	5	50%	22%	4.1	0.1	1.5	3	2	0.28	6.0	14	7
Minor Damage	0.1	38%	0.2%	3.1	-	0.1	-	0.1	-	0.4	-	0.2
Aggregated	**12**	100%	100%	8.2	0.1	2.3	8	3	0.66	18.9	69	27

C. Controls and Mitigations

Tables 14-5 and 14-6 list all the controls and mitigations PG&E included in 2020 GRC, as well as those planned in the 2020 RAMP (2020-2022, the design and analyze phase) and 2023-2026 (the mitigation implementation phase). The tables provide a view as to controls and mitigations that are on-going, those that are no longer in place, and new mitigations.

The Real Estate and Facilities Failure risk was not included in the 2017 RAMP. However, PG&E did identify mitigations and controls in the 2020 GRC shown in the tables below.

TABLE 14-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP	2020-2022 GRC 2017-2020 Controls	2020-2022 RAMP	2023-2026 RAMP
1	C1 – Regional Optimization[(a)]		X	X	X
2	C2 – Service Center Optimization[(b)]		X	X	X
3	C3 – CSO Optimization		X	X	X
4	C4 – Facilities Management Preventive Maintenance Program		X	X	X
5	C5 – Site Design Structural and Engineering Reviews[(c)]		X	X	X
6	C6 – Segregation of Assets[(c)]		X	X	X
7	C7 – Facility Inspection Program		X	X	X
8	C8 – Security System Hardening		X	X	X

(a) C1 –Regional Optimization is currently paused.
(b) C2 –Service Center Optimization is currently paused. PG&E discusses this control in Sections C.1 and D.1 below.
(c) This control is included in PG&E's 2020 GRC, though not always specifically identified as such.

TABLE 14-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1 – Seismically Risk Rank Facilities Using Tiered System			Foundational Mitigation[(a)]	
2	M2 – Identify Seismic Risk Reduction for Multistory Buildings			Foundational Mitigation	
3	M3 – Develop an Updated Seismic Standard			Foundational Mitigation	
4	M4 – Additional Fire Inspections of Older Facilities			Foundational Mitigation	
5	M5 – Refresh/Review of Key Sites Potentially Impacted by Flood/Landslide/Physical Attack			Foundational Mitigation	
6	M6 – Renovate or Relocate Facilities Other than SFGO		X		X

(a) PG&E defines foundational mitigations as activities that support risk reduction but do not reduce risk themselves. Because these activities do not directly reduce risk, PG&E does not provide a risk score or risk spend efficiency score (RSE) for them.

Between 2020 and 2022, PG&E will complete several foundational activities that will inform the CRESS multi-year seismic mitigation programs.

1. 2019 Control Work

In 2019, CRESS continued to implement its Facilities Management Preventive Maintenance Program, Facility Inspection Program, and to invest in Security System Hardening as controls, e.g., additional security gates and updated fencing. The Regional Optimization control is currently paused due to affordability measures but may be reintroduced as the Company implements its regionalization strategy.

Service Center Optimization (Control C2) incorporates two distinct efforts: (1) service center investment; and (2) Service Center Optimization. service center investment focuses on renovations, maintenance, compliance issues and upgrades, often to resolve site safety concerns. Service Center Optimization focuses on optimizing Service Center operations. Service Center Optimization is currently paused as PG&E evaluates its regionalization strategy.

As part of on-going portfolio management, PG&E continues to make service center investments that may result in indirect improvements that reduce risk, e.g., renovation or replacement of older facilities with newer facilities. Site Design Structural and Engineering Reviews are implemented as a normal course of renovating or standing up new facilities and those costs are embedded within PG&E's Portfolio Budget. Segregation of Assets, such as main and backup electric grid control or distribution control centers have been implemented in previous years and not accounted for in 2019 costs.

D. 2020-2022 Controls and Mitigation Plan

Real Estate and Facilities Failure was not a 2017 RAMP risk. While PG&E did not specifically identify programs as RAMP controls or mitigations in its 2020 GRC, CRESS actively develops and implements programs to mitigate facilities risk, enhance safety, and/or maintain compliance. The controls and mitigations described below were included in PG&E's 2020 GRC, though not always specifically identified as such, and have been in place prior to 2019 with the exception of the Regional Office and Service Center Optimization Programs which started in 1995 but were paused in December 2018. The programs will most likely restart in 2021 as part of PG&E's proposed regionalization plan.

1. 2020-2022 Controls

C1 – Regional Office Optimization: PG&E will consolidate offices, group similar job functions, exit leased facilities and replace them with owned facilities, and/or optimize under-utilized buildings to reduce operational costs to drive affordability. When consolidating offices or exiting facilities, PG&E will consider where opportunities for seismic, flood, landslide, fire, physical attack, and/or climate change risk reductions exist. CRESS is assisting with development of a regional office optimization strategy to support realignment of Company operations to a regional structure. This strategy will also consider additional or alternate workplaces to support ongoing wildfire mitigation efforts. As part of these efforts, PG&E will prioritize renovation of, or relocation from, buildings/workplace that present risks mentioned above. This control impacts seismic, flood, landslide, fire, and physical attack drivers.

C2 – **Service Center Optimization**: Service Center Optimization addresses service centers, yards, and operational facilities throughout PG&E's service area that are core to customer support and emergency response and restoration efforts. These facilities house field operations, equipment, vehicles, and materials. Facility hardening efforts to reduce risks at these centers include updating perimeter security and fencing to current PG&E standards, upgrading site drainage capabilities and storm water runoff infrastructure, and replacing non-permitted temporary or legacy structures with current code compliant structures. This control impacts seismic, flood, landslide, fire, and physical attack drivers.

C3 – CSO Optimization: The CSO Optimization Plan addresses all CSOs throughout PG&E's service territory. These offices are staffed by PG&E employees who provide face-to-face service to customers and process bill payments and other non-payment transactions. The CSO Optimization plan will enable a better customer experience and drive operational efficiencies and affordability by closing or re-locating underutilized CSOs to locations with larger foot traffic for easier customer access.[5] The CSO Optimization Plan also considers potential seismic and physical security risks at CSO facilities. This control impacts seismic, flood, landslide, fire, and physical attack drivers.

C4 – Facilities Management Preventive Maintenance Program: PG&E's Facilities Management Preventive Maintenance Program includes preventive maintenance services for the entire CRESS-managed portfolio including specific activities in support of maintaining fire and life safety systems and components. This includes facility inspections conducted by PG&E building mechanics, third parties, alliance partners, and external regulators to confirm that PG&E equipment is properly maintained and complies with all fire and life safety laws and regulations. Preventive Maintenance programs include inspections of fire alarms, protection and detection systems, and validating all required maintenance and updates. This control primarily impacts fire and physical attack drivers.

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5 Issues related to PG&E's Customer Service Centers are addressed in PG&E's 2020 GRC proposed settlement.

C5 – Site Design Structural and Engineering Reviews: All new and retrofitted PG&E facilities must be built to current local codes and ordinances related to site and/or building design criteria promulgated by AHJs. Additionally, architectural and engineering design review is conducted as part of the local permit process with sign-off from local AHJs prior to permits being issued for occupancy. This control impacts seismic, flood, landslide, and fire drivers.

C6 – Segregation of Assets: PG&E's critical assets, such as main and backup electric grid control or distribution control centers, gas control and dispatch centers, data centers, and customer call centers are placed in different areas or regions ensuring a local disaster does not affect all facets of critical operations. This control primarily impacts the seismic or flood driver.

C7 – Facility Inspection Program: The Facility Inspection program focuses on monthly visual inspections for all CRESS-managed buildings and sites by CRESS facilities services personnel. Inspections include reviews of safety house-keeping items including personal appliances in facilities, daisy-chaining of extension cords which could start a fire, and non-structural seismic issues, such as racking and vertical storage issues to reduce risks during a seismic event. This control impacts seismic, fire, and physical attack drivers.

C8 – Security System Hardening: CRESS works with PG&E's Corporate Security Department to identify areas for security system hardening, such as installing higher fencing, automatic gates, and/or enhanced perimeter surveillance devices. This control impacts the physical attack driver.

2. 2020-2022 Foundational Mitigations

Between 2020 and 2022, PG&E will complete several foundational mitigations that will inform the CRESS multi-year seismic mitigation programs.

M1 – Seismically Risk Rank Facilities Using Tiered System: The CRESS Seismic Program will risk rank PG&E facilities using a tiered system commensurate to the risk significance. The risk ranking will start with facilities in the greater Bay Area and then be expanded to the entire PG&E

service area based on ranking and selection criteria. The risk ranking will consist of:

– An initial effort to identify safety concerns based on key parameters, such as location, type of building, occupancy levels, age of buildings, previous retrofits, within certain seismic zones, structural and non-structural vulnerabilities; and
– Additional efforts to provide improved risk estimates.

M2 – Identify Seismic Risk Reduction for Multi-Story Buildings: Multistory buildings (>four stories) are a dominant contributor to the seismic driver of the Real Estate and Facilities Failure Risk. The focus of this foundational activity is to improve the risk estimates and identify potential risk reduction plans for these buildings.

M3 – Develop an Updated Seismic Standard: PG&E buildings were built to contemporaneous codes and standards. However, more recent seismic experiences indicate that some could be at risk of failure when experiencing an earthquake greater than the design earthquake at the time of construction. All buildings will be assessed to determine the necessary performance level and reviewed for seismic performance and potential damage. CRESS' updated seismic standard will define the minimum criteria by facility type and will focus first on high risk/high population density buildings managed by CRESS. The standard will require:

– Mission Critical Facilities perform to the Fully Operational level (no consequential damage, continuous service);
– Business Critical Facilities perform to the Operational level (most operations and functions can resume immediately);
– Occupied buildings perform to the Life Safety level (structure damage may occur but will not compromise safe exit from the building); and
– Non-occupied structures perform to the Collapse Prevention level (structural damage may be severe, but collapse is prevented though non-structural elements may fail);

Continued validation is required to appropriately classify buildings and understand their seismic risk as business needs may be expanded, buildings and systems age and may experience degradation, and/or seismic modeling maturity may suggest increased resiliency.

M4 – Additional Fire Inspections of Older Facilities: Approximately 75 percent of the Company's service centers are more than 45 years old and certain buildings or systems may be nearing end of useful lifespan. Many do not comply with current fire codes related to fire sprinklers or fire dampening. This foundational activity involves conducting additional fire life safety inspections for older facilities. As PG&E renovates or replaces them, these facilities will be brought up to the current standards and code requirements that ultimately enhance the ability to detect and extinguish a workplace fire. In the meantime, CRESS has augmented its visual inspections to mitigate this risk.

M5 – Refresh/Review of Key Sites Potentially Impacted by Flood/Landslide/Physical Attack: CRESS will review certain sites that could be impacted by floods and/or landslides including non-PG&E sites adjacent to PG&E facilities. This review will also focus on areas that may have changes in flood plains and/or experience from recent storm events. Geotechnical and engineering screening may be completed through the review of refreshed flood and liquefaction maps throughout the PG&E service area to look for ground faulting or failure. As PG&E renovates or replaces facilities, these facilities will be brought up to current standards and code requirements. Any site that is identified with an immediate threat will be reviewed for potential renovations to mitigate risks as required. CRESS will continue to work with PG&E's Corporate Security department to address any facilities that may have a higher potential of physical attack determined from recent experience or from Corporate Security's crime incident models.

Table 14-7 below shows the forecast costs for the planned 2020-2022 mitigations.

TABLE 14-7
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC/ MAT	2020	2021	2022	Total
1	M1-M5	Foundational Mitigations	BI	$500	$1,000	$1,000	$2,500
2	Total			$500	$1,000	$1,000	$2,500

Note: See WP 14-1.

E. PG&E 2023-2026 Mitigations

PG&E's 2023-2026 mitigation plan will focus on reducing seismic risk across its building portfolio by renovating or relocating low-, mid-, and high-rise complexes that do not meet minimum performance criteria. Planning, design, and analysis will occur in 2020-2022 (the foundational mitigations described above) with renovation or relocation efforts occurring 2023-2026 and beyond.

PG&E is proposing one mitigation that consists of two concurrent efforts:

M6 – Renovate or Relocate Facilities Other than SFGO:

Effort 1: Renovate or Relocate Low Rise Facilities

PG&E will systematically evaluate and retrofit or relocate all low-rise facilities such as service centers and office buildings that do not meet a minimum seismic performance level to reduce seismic risk. This collection of buildings is the highest number of buildings but with relatively low risk scores, as compared to mid- and high-rise structures. Renovation or relocation of buildings will also be coupled with workplace strategies driven by Company regionalization efforts.

Effort 2: Renovate or Relocate Mid Rise and High-Rise Structures (Other Than SFGO)

PG&E will review midrise and high-rise structures against the minimum seismic performance criteria and renovate or relocate facilities accordingly. This collection of buildings is a relatively low number of buildings but with relatively high-risk scores, as compared to low-rise structures. This effort will also be coordinated with Company regionalization efforts.

Tables 14-8 below shows the forecast costs for the planned 2023-2026 mitigations.

TABLE 14-8
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026	Total[a]	RSE[b]	Risk Reduction
1	M6	Renovate or Relocate Facilities Other than SFGO	BI	$1,000	$1,000	$1,000	$1,000	$4,000	–	–
2		Total Expense		$1,000	$1,000	$1,000	$1,000	$4,000	–	–
3	M6	Renovate or Relocate Facilities Other than SFGO	22	$20,000	$20,000	$20,000	$20,000	$80,000	–	–
4		Total Capital		$20,000	$20,000	$20,000	$20,000	$80,000	–	–
5				–	–	–	–	–	0.83	51.14

(a) Renovation and relocation costs represented in this table may be greater depending on the number of facilities targeted.
(b) See Mitigation Effectiveness workpapers included in the source document modeling package for information used to calculate the RSE.
Note: See WP 14-1.

PG&E's risk analysis demonstrates that the combination of the proposed mitigation and Alternative 2 (described below) provides the greatest overall risk reduction (see Table 14-11 below). Alternative 2, Renovate or Relocate the SFGO, has the highest contribution to risk impact, but is expected to have a relatively high cost compared to the proposed mitigation. In early June 2020 PG&E announced plans to relocate the SFGO to Oakland and to sell the current General Office complex.

PG&E believes the proposed mitigation plan is appropriate because facilities that pose the greatest seismic risk to the Company are prioritized for review and corrective actions.

Alternative 1 also has a high risk reduction score. PG&E will continue to evaluate this alternative mitigation—alone and in combination with the proposed mitigation—as it develops and implements its real estate and facilities strategy.

F. Alternative Analysis

In addition to the proposed mitigations described in Section 3 above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: A1 Relocate Facilities for Climate Change (Other Than SFGO)

As part of PG&E's overall strategy to relocate facilities and employees, PG&E will consider relocating buildings located in areas of potential sea level rise, and/or employ local or site-specific mitigation efforts to avoid flood impacts to those facilities. PG&E has certain facilities that are located in areas of potential rising sea level and tides (e.g., cities along the Pacific Coast—Eureka, Pismo Beach, Santa Cruz, and Point Arena) and others adjacent to the San Francisco Bay (e.g., Oakland, San Carlos, Fremont, and Richmond). PG&E is undertaking a multi-year Climate Vulnerability Assessment that will consider the extent to which sea-level rise may impact PG&E facilities and when such impacts could occur. Relocation opportunities will also consider regionalization strategies as well as facility optimization.

This alternative was not selected because the risk of flood at PG&E facilities is low and relocation costs are high. This mitigation may be reconsidered depending on the Climate Vulnerability Assessment findings.

TABLE 14-9
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Relocate Facilities for Climate Change (other than SFGO)	$125,000	$125,000	$125,000	$125,000	$500,000	–	–
2		Total	$125,000	$125,000	$125,000	$125,000	$500,000	0.13	47.08

(a) See mitigation effectiveness workpapers included in the source document modeling package for information used to calculate the RSE. Forecasted costs on this table are represented by placeholders and may be adjusted depending on the number of facilities impacted.

Note: See WP 14-1.

2. Alternative Plan 2: A2 Renovate or Relocate the SFGO

PG&E will evaluate options related to renovating or replacing the SFGO complex.[6]

This alternative mitigation has the highest risk reduction impact (71 percent) of any of the mitigations considered. While this alternative has the highest RSE, the estimated cost of this alternative is relatively high, as compared to cost to reduce risks throughout the portfolio. Risk related to the SFGO complex is primarily driven by the perceived performance of the largest building (77 Beale) during an extreme seismic event.

PG&E provided high-level cost estimates for this alternative. These estimates were developed solely for developing an initial RSE and should not be considered actual forecasts for performing this work.

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6 PG&E's RAMP risk analysis was complete by the end of May 2020. In June 2020 PG&E announced plans to relocate the SFGO to Oakland and to sell the current General Office complex.

TABLE 14-10
FORECAST COSTS, RSE AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A2	Renovate or Relocate the SFGO	$187,500	$187,500	$187,500	$187,500	$750,000		
2		Total	$187,500	$187,500	$187,500	$187,500	$750,000	1.17	645.27

(a) See mitigation effectiveness workpapers included in the source document modeling package for information used to calculate the RSE. Forecasted costs on this table are represented by placeholders and may be adjusted depending whether renovation or relocation strategies are implemented.

Note: See WP 14-2.

1 Table 14-11 compares the proposed and alternative mitigation plans.

TABLE 14-11
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)	RSE
1	Proposed	M6	$4,000	$80,000	51	$61,873	0.83
2	Alternative 1	M6+ A1	$4,000	$580,000	92	$430,166	0.21
3	Alternative 2	M6 + A2	$4,000	$830,000	696	$614,312	1.13

(a) Plan Components refers to the Mitigations presented in Table 14-6

(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

Note: See WP 14-2

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 15

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: THIRD-PARTY SAFETY INCIDENT

PACIFIC GAS AND ELECTRIC COMPANY
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A. Executive Summary

Third-Party Safety Incident refers to a Pacific Gas and Electric Company (PG&E or the Utility) recordable third-party injury or fatality that is due to an interaction with or use of a PG&E facility or location, not involving an asset failure. Recordable injuries include those which may result in a serious injury in alignment with the Division of Occupational Safety and Health (DOSH)—better known as “Cal/OSHA”— definition or a fatality. Third party refers to a member of the public who is a non-PG&E employee and is not a PG&E contractor. The drivers for this risk event are car pole/guy; electric contact; others; drowning or other incidents on PG&E managed/owned property; job site; slip/trip/fall; suicide; falling object/vegetation; and motor vehicle incident (non-pole related).

Exposure to this risk is measured within the PG&E system territory and divided into four tranches to facilitate the quantitative risk analysis: third-party interaction with electric operations assets and job sites; third-party interaction with gas operations assets and job sites; third-party interaction with PG&E managed land and water; and third-party interaction with power generation assets. The risk model includes approximately 3,378 risk events each year based on available data which includes Electric Operations incidents only (i.e., car pole/guy and electric contact). The risk outcomes include third-party interaction with reliability impact and third-party interaction. The risk consequences include third-party serious injuries and fatalities. The mitigations PG&E will implement from 2020-2026 are designed to address the risk drivers.

Third-Party Safety Incident has the second highest 2023 baseline test year safety (887) score and second highest 2023 baseline total risk score (944) of PG&E’s 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline risk score is 949, the 2023 baseline test year risk score is 944 and the 2026 post-mitigation risk score is 932.

Public safety within the PG&E service territory is the primary focus of the lines of business (LOB) programs and projects included in this chapter as controls and mitigations.[1]

TABLE 15-1
RISK OVERVIEW

Line No.	Risk Name	Third-Party Safety Incident
1	In Scope	Recordable third-party (public) injuries or fatalities due to interaction with or during the use of a PG&E facility, not involving asset failure.
2	Out of Scope	Third-party recordable injuries or fatalities resulting from the failure of an asset. Third-party gas dig-in recordable injuries or fatalities are included as key drivers for Gas Operations Loss of Containment Risks. Non-preventable motor vehicle incidents involving third-party interaction are included in the Motor Vehicle Safety Incident risk.
3	Data Quantification Sources	PG&E data including third-party initiated incidents logged in the Integrated Logging Information System, Transmission Operation Tracking & Logging tool, Serious Incidents Reports from PG&E's RiskMaster Database and Electric Incident Reports from 2012 through December 2019.[a]

(a) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

To place greater emphasis on third-party safety incidents, which do not involve the failure of a PG&E asset, and in alignment with PG&E's transition to an event-based risk register, with mutually exclusive risks that can be clearly modeled, the Third-Party Safety Incident risk has been added to the PG&E risk register and is included as a separate chapter in the 2020 RAMP Report.

PG&E's 70,000 square mile service territory in northern and central California consists of approximately 106,000 circuit miles of distribution electric lines, 18,000 circuit miles of interconnected transmission lines, 42,000 miles of natural gas distribution pipelines, 6,400 miles of

1 The information herein is subject to those limitations described in Chapter 2, Section D.

transmission pipelines, 67 powerhouses[2] and an extensive collection of facilities that support this infrastructure. With PG&E facilities located throughout northern and central California, third-party interaction with them is inevitable. Third-party interaction with PG&E facilities is addressed by PG&E's operating lines of business: Gas Operations, Electric Operations, and Power Generation, who have developed and have implemented or are continuing to implement programs to address third-party safety incidents unique to their facilities.

Significant third-party safety incidents with impacts to Gas Operations facilities include: Damage at Measurement and Control (M&C) Transmission or Distribution facilities due to vandalism or vehicle incidents; threats from construction and excavation activities; pipe damage through a third-party dig-in (discussed further in the Gas Operations Loss of Containment risks and out of scope for this risk); well failure arising from third-party damage; and meter station vehicular damage. PG&E's Third-Party Safety Incident risk controls and mitigation efforts for Gas Operations include public awareness programs, gas safety education, patrols, physical security, and the replacement, remediation, and retirement of facilities.

Public awareness programs reduce the threat of third-party damage to pipelines through educational outreach regarding safe excavation near pipelines. PG&E's gas safety communication efforts use a variety of media to effectively reach the greatest population possible within PG&E's service territory. These efforts include sending bill inserts, e-mails, brochures or letters to communicate gas safety information, providing targeted agricultural excavation safety messaging, and hosting 811 "Call Before You Dig" workshops. Patrols help to identify third-party threats from construction and excavation activities. Vandalism is mitigated through enhanced physical security efforts. Third-party safety is further enhanced with the retirement of gas gathering facilities, including idle pressurized pipe, and the replacement

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2 Company profile: https://www.pge.com/en_US/about-pge/company-information/profile/profile.page (as of June 17, 2020).

and remediation of exposed and shallow pipe. This work further reduces the likelihood of third-party contact.

Significant third-party safety incidents with impacts to Electric Operations facilities include: wire down events; contact with energized intact conductors; pole failures due to car-pole incidents, and vandalism and third-party sabotage at substations. PG&E's Third-Party Safety Incident risk controls and mitigation efforts for Electric Operations are focused on public awareness programs, education, outreach efforts, and physical security improvements.

Public awareness programs to educate non-PG&E contractors and non-PG&E employees about power line safety and the hazards associated with wire down events and are intended to reduce the number of third-party electrical contacts. Outreach efforts include social media campaigns focused on increasing customer awareness of overhead lines, representation at local fire safe councils and community events and the automated customer notification system. Security improvements can include proactive equipment replacement, security measures and intrusion detection devices.

Significant third-party safety incidents with impacts to Power Generation facilities include: drownings, suicides, and boating incidents related to PG&E-managed or owned hydroelectric facilities (dams, waterways, and canals); interaction with job sites; falling object or vegetation-related incidents. Hydroelectric Program objectives include third-party risk reduction and public safety. Procedures are in place for planning for unusual water releases along with their associated safety warnings. Additional Power Generation compliance programs that support these objectives include Public Safety Plans (PSP) as required by PG&E hydroelectric facility Federal Energy Regulatory Commission (FERC) licenses and FERC required Emergency Action Plans (EAP) for all significant and high hazards dams. The Plans are exercised annually with a seminar and phone drill.

Hydroelectric public awareness programs include hydroelectric safety education, patrols, physical security, and facilities review. Programs such as Time-Sensitive Dams/Sudden Failure Assessments, and Canals and Waterways Safety are also being implemented.

A sunny-day cyber-attack at a dam could potentially put recreators downstream of a dam at risk. This risk event would involve a component failure due to cyber-attack. This event is also discussed in the Large Uncontrolled Water Release (Dam Failure) risk chapter. Power Generation has controls in place to prevent this event beyond controls in the IT systems; instruments measuring component status and flow would alert operators to components out of alignment. Further, at some watersheds, physical device controls are in place during recreation preventing incidental movement and some components also cannot be operated remotely.

Hydroelectric safety communication efforts use a variety of methods to effectively reach the greatest population possible within PG&E's service territory. These efforts include sending bill inserts, e-mails, brochures or letters to communicate hydrogeneration facilities safety information. As an example, in 2019, the Safe Kids Program resulted in reaching out to 66,000 teachers and educating 295,000 students.

2. Risk Definition

The definition of the Third-Party Safety incident risk is a PG&E recordable third-party injury or fatality that is due to an interaction with or during the use of a PG&E facility, not involving asset failure. Recordable injuries include those which may result in a serious injury in alignment with the DOSH definition or a fatality. Third party refers to a member of the public who is a non-PG&E employee or a non-PG&E contractor.

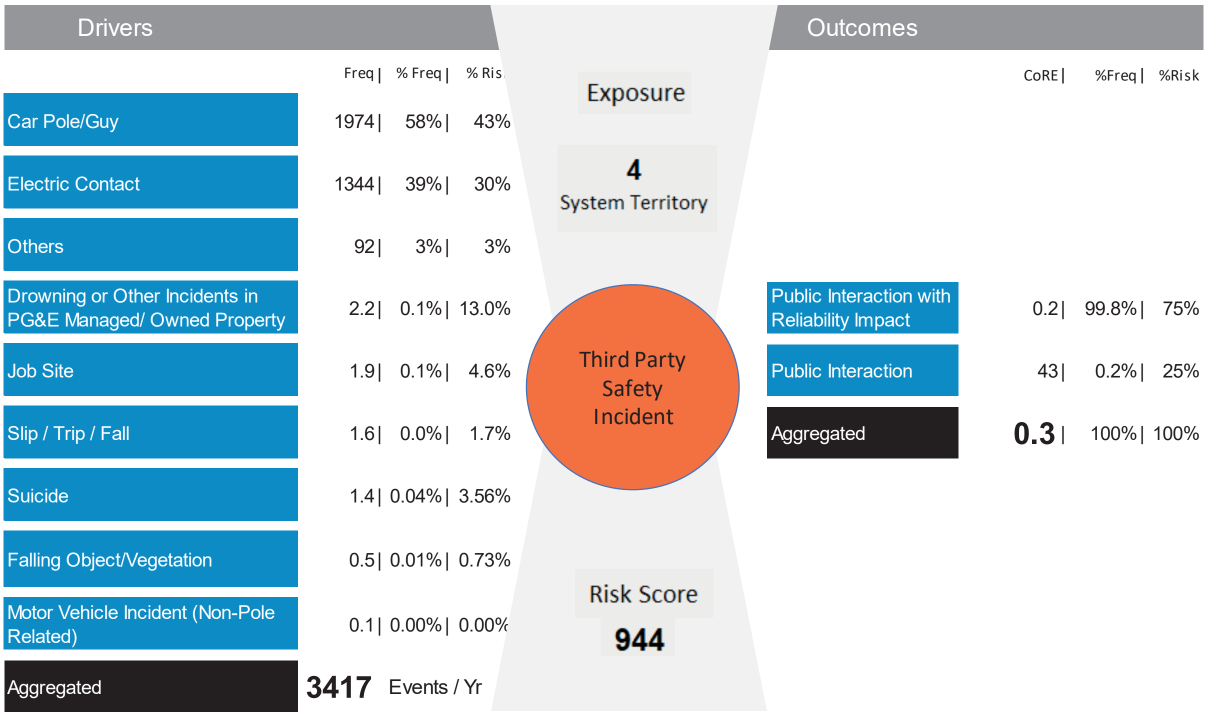
B. Risk Assessment

1. Background and Evolution

The Third-Party Safety Incident risk is a new risk and has been added to the PG&E event-based risk register. It is included in the 2020 RAMP based on its risk score. The Third-Party Safety Incident risk places greater emphasis on third-party safety incidents that do not involve the failure of a PG&E asset and aligns with PG&E's transition to an event-based risk register with mutually exclusive risks that can be clearly modeled.

2. Risk Bow Tie

FIGURE 15-1
RISK BOW TIE – 2023 TEST YEAR



3. Exposure to Risk

To quantify the Third-Party Safety Incident risk exposure, PG&E's RAMP model uses data from the PG&E Serious Incidents Reports, relevant information from PG&E's Riskmaster database and PG&E's Electric Incident Report (EIR). Electric Utilities must report to the CPUC any incident which results in a fatality or personal injury rising to the level of in-patient hospitalization; are the subject of significant public attention or media coverage; or, result in damage to property of the utility or others estimated to exceed $50,000 and are attributable or allegedly attributable to utility-owned facilities. EIR data are also used to analyze reliability consequences. Annually, PG&E Electric Operations experiences approximately 3,400 incidents. Fewer than 1 percent of these result in a third-party serious injury or fatality. Note that Gas Operations reporting for dig-in incidents is out of scope for the risk.

4. Tranches

PG&E identified four tranches for the Third-Party Safety Incident risk.

- Third-party interaction with Electric Operations assets and job sites;
- Third-party interaction with Gas Operations assets and job sites;
- Third-party interaction with PG&E managed land and water; and
- Third-party interaction with Power Generation assets.

Third-party interaction with Electric Operations assets and job sites:

This tranche includes third-party safety incidents by driver and consequences related to serious injuries and fatalities, as well as reliability in Customer Minutes Interrupted, which are used to measure the duration of the customer's loss of power. Incidents that meet one or more of the electric incident reporting requirements are reported to the CPUC in the EIR. These incidents may also meet PG&E's reporting requirements for serious injuries or a fatality and are included in the PG&E Serious Incidents Report.

Third-party interaction with Gas Operations assets and job sites:

This tranche includes third-party safety incidents by driver and consequences related to serious injury and fatality, other than third-party gas dig-ins. Serious injuries and fatalities are included in the PG&E Serious Incidents Report.

Third-party interaction with Power Generation assets and PG&E managed/owned property:

The remaining two tranches include third-party interaction with power generation assets and PG&E managed/owned property. The tranches include third-party safety incidents by driver and consequences related to serious injury and fatality. Serious injuries and fatalities are included in the PG&E Serious Incidents Report.

The percent exposure and percent risk by tranche is shown in Table 15-2 below.

TABLE 15-2
EXPSOURE AND RISK BY TRANCHE

Line No.	Tranche Description	Percent Exposure	Electric Reliability Risk Score	Safety Risk Score	Total Risk Score	Percent Risk
1	Third-Party Interaction with Electric Operations Assets and Job Sites	25%	56	652	708	75%
2	Third-Party Interaction with Gas Operations Assets and Job Sites	25%	–	59	59	6%
3	Third-Party Interaction with Power Generation Assets and Job Sites	25%	–	7	7	1%
4	Third-Party Interaction with PG&E Managed Land and Water	25%	–	170	170	18%
5	Total	100%	56	887	944	100%

5. Drivers and Associated Frequency

PG&E identified nine drivers and five sub-drivers for the Third-Party Safety Incident risk. Each driver and its associated 2023 test year baseline frequency and key sub drivers are discussed below.

D1 – Car Pole/Guy: Refers to third-party vehicular contact with a PG&E pole or guy wire. Car pole/guy events accounted for 1,974 (58 percent) of the 3,417 expected annual number of risk events not involving an asset failure.

D2 – Electrical Contact: Refers to third-party contact with a PG&E electric asset. Electrical contact events accounted for 1,344 (39 percent) of the 3,417 expected annual number of risk events not involving an asset failure.

D3 – Others: Refers to a third-party incident that is not addressed by any of the other Third-Party Safety Incident risk drivers. Other events accounted for 92 (3 percent) of the 3,417 expected annual number of risk events that do not involve asset failure.

D4 – Job Site: Refers to a third-party incident resulting in a recordable injury or fatality that occurs at a PG&E job site. This driver includes three sub-drivers: job site slip, trip, fall-related; job site falling object/vegetation; and job site motor vehicle incident related. There are two annual expected interactions involving a PG&E job site included in the RAMP model dataset. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

D5 – Drowning or Other Incidents at PG&E Owned/Managed Property: Refers to third-party drownings or other water-related incidents resulting in a recordable injury or fatality that occur at a PG&E owned or managed property. This driver includes two sub-drivers: drowning or other incidents in PG&E managed/owned property; and drowning or other incidents in PG&E managed/owned property-hydro spill. There are two annual expected drownings or other incidents in PG&E managed/owned Property interactions included in the RAMP model dataset. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

D6 – Slip/Trip/Fall: Refers to third-party slips, trips or falls resulting in a recordable injury or fatality that are the result of contact with a PG&E asset or that occur at PG&E job site or facility. There are two annual expected slip trip, or fall interactions included in the RAMP model dataset. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

D7 – Suicide: Refers to third-party suicide that occurs on or at a PG&E asset or facility. There is one annual average suicide event associated with interactions included in the RAMP model dataset. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

D8 – Falling Object/Vegetation: Refers to a recordable injury or fatality that is the result of a PG&E asset that falls onto or otherwise contacts a third party, or due to vegetation management activities (e.g., trimming or removal) by PG&E or PG&E contactors and that falls onto or otherwise contacts a third party. There are 0.5 annual expected interactions included in the RAMP model dataset. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

D9 – Motor Vehicle Incident (non-pole related): Refers to third-party vehicular contact with a PG&E asset or facility (non-pole related) resulting in a recordable injury or fatality. There are 0.1 annual expected interactions in this category included in the RAMP model dataset which resulted in two fatalities. The data for this driver is limited to those recorded in the PG&E Serious Incidents Report.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP.

There are no cross-cutting factors that directly impact Third-Party Safety Incident risk.

When analyzing this risk PG&E considered the cross-cutting risk Climate Change. Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves. During this RAMP period PG&E will conduct a Climate Vulnerability Assessment (CVA) to further assess how its assets, operations, and employees are vulnerable to the projected impacts of climate change. PG&E intends to use findings from the CVA as well as developments in climate science and internal data gathering to continue to advance the quantification of all event-based risks, including RAMP risks, overt this RAMP period.

7. Consequences

The basis for measuring the consequences of the Third-Party Safety Incident risk is: Does third-party interaction with a PG&E facility result in a recordable injury or fatality.

The consequences of a third-party Incident risk event occurring are:

- Safety: Third-party Interaction with Injury or Fatality
- Reliability: Third-party Interaction with Reliability Impact.

PG&E relied on the PG&E Serious Incidents Reports and Electric Incidents Reports from 2012 through 2019 to analyze the safety consequences of the Third-Party Safety Incident risk. The PG&E Serious Incidents Report includes serious injuries and fatalities related to third-party events.

PG&E relied on the PG&E Electric Reliability Reports for customer outage data from 2014 through 2019 to analyze the reliability consequences of the Third-Party Safety Incident risk. The reported customer outage data provides the duration of electric outages by circuit.

PG&E did not model financial consequences due to data confidentiality.

The consequences of the risk event are shown in Table 15-3 below. Model attributes are described in Chapter 3, "Risk Modeling and Risk Spend Efficiency."

TABLE 15-3
RISK EVENT CONSEQUENCES

	CoRE | %Freq | %Risk	Freq	Natural Units Per Event		CoRE		Natural Units per Year		Attribute Risk Score	
			Safety EF/event	Electric Reliability MCMI/event	Safety	Electric Reliability	Safety EF/yr	Electric Reliability MCMI/yr	Safety	Electric Reliability
Public Interaction with Reliability Impact	0.2 | 99.8% | 75%	3,412	0.004	0.03	0.2	0.02	12.5	113	652	56
Public Interaction	43 | 0.2% | 25%	5	0.8	-	43	-	4.5	-	236	-
Aggregated	**0.3 |** 100% **|** 100%	3,417	0.00	0.03	0.26	0.02	17.0	113	887	56

C. Controls and Mitigations

Tables 15-4 and 15-5 list all the controls and mitigations PG&E included in its 2017 RAMP (for the most part these are the 2019 baseline controls and mitigations), 2019 Gas Transmission and Storage Rate Case (GT&S), 2020 General Rate Case (GRC) and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

TABLE 15-4
CONTROLS SUMMARY

Line No.	Control Name and Number	Line of Business and Reference to 2020 GRC[a]	2017 RAMP (Ref. to 2017 RAMP)[b]	2020-2022 GRC 2017-2020 Controls	2020-2022 RAMP	2023-2026 RAMP
1	C1 – PG&E Code of Safe Practices (CSP)	Gas Operations (GO), Electric Operations (EO), Power Generation (PGen)				X
2	C2 – Public Awareness Programs	EO (Exhibit (PG&E-4), Ch. 18)		X	X	X
3	C3 – Public Awareness Program (Bill Inserts)	EO (Exhibit (PG&E-4), Ch. 18)		X	X	X
4	C4 – Gas Operations Physical Security Controls	GO				X
5	C5 – Public Awareness Programs	GO (Exhibit (PG&E-3), Ch. 6)		X	X	X
6	C6 – Meter Protection Program	GO (Exhibit (PG&E-3), Ch. 4)		X[c]	X	X
7	C7 – Safe Kids Program – K-8 Safety Education	EO, GO, PGen			X	X
8	C8 – Hydroelectric FERC License PSP	PGen			X	X
9	C9 – Early Warning Systems, Signage and Alarms	PGen			X	X
10	C10 – Streetlight Conversions to LED Technology	EO (Exhibit (PG&E-4), Ch. 6)		X[d]		

TABLE 15-4
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Name and Number	Line of Business and Reference to 2020 GRC[(a)]	2017 RAMP (Ref. to 2017 RAMP)[(b)]	2020-2022 GRC 2017-2020 Controls	2020-2022 RAMP	2023-2026 RAMP
11	C11 – PG&E Electric Design Pole Location Requirements	EO			X	X
12	C12 - Visibility Strips on Electric Distribution Poles and Guy Markers	EO			X	X
13	C13 - Anti-Climbing Guard Assemblies for Steel Towers	EO			X	X
14	C14 – Hydro Facility Unusual Water Releases and Water Safety Warning Standard and accompanying procedure (PG-2727S and PG-2727P-01).	PGen			X	X
15	C15 - PG&E Dam Safety Surveillance and Monitoring Program (PG-2762S)	PGen			X	X

(a) Application (A.) 18-12-009.
(b) Investigation (I.) 17-11-003.
(c) The Meter Protection Program was a mitigation, not control, in the 2020 GRC.
(d) This program is included in the 2020 GRC but not listed as a risk mitigation.

TABLE 15-5
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	Line of Business	2017 RAMP 2017-2019 Mitigations (Ref. to 2017 RAMP)	2019 GT&S 2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1 and M2 – Shallow and Exposed Pipe Replacement and Remediation Programs	GO (2019 GT&S, p. 4-37[a])			X	X, although not included in the RAMP analysis
2	M3 – Time-Sensitive Dams/Sudden Failure Assessments	PGen			X	X, although not included in the RAMP analysis
3	M4 – Canals and Waterways Safety Barriers	PGen			X	X
4	M5 – EAPs for all significant and high hazards dams.	PGen			X	X., although not included in the RAMP analysis
5	M6 – System Hardening	EO			X	X, although not included in the RAMP analysis
6	M7 – 3A and 4C Line Recloser Controller Replacement	EO				X, although not included in the RAMP analysis

(a) A.17-11-009.

1. 2019 Controls

The controls and mitigations proposed in the 2017 RAMP for the Third-Party Safety Incident risk were included as part of the individual lines of business risks. For the purposes of aligning the controls and mitigations from the 2017 RAMP with those PG&E is proposing for the 2020-2026 period, the Third-Party Safety Incident programs included by the lines of business in their risks in 2017 are listed below.

a. Controls

1) Gas Operations Controls

C1 – PG&E Code of Safe Practices (CSP) for all PG&E LOBs, including Electric Operations, Gas Operations, and Power Generation: The CSP includes the requirement that for job sites on or near a roadway, work area protection devices and advance warning signs shall be placed and maintained in accordance with the "California Manual on Uniform Traffic Control Devices for Streets and Highways, January 13, 2012," and/or the California Joint Utility Traffic Control Manual, February 2014 6th Edition. The requirements apply to all employees who oversee or are directly responsible for the protection of the public, PG&E employees and contractors entering a PG&E working area.

C4 – Physical Security: Gas Operations physical security controls protect against third-party interaction with gas facilities and include: security guards at the Compression and Processing and M&C facilities (e.g., McDonald Island, Topock, Los Medanos and Hinkley); facility fencing, security cameras, and vegetation management; security enhancements such as ballistic protection around critical components such as compressor stations and tanks; protection of exposed transmission pipe and valves by adding anti-climbing or concrete barriers; security enhancements related to communication systems such as adding visual and audible alarm annunciations, and upgrading existing security technology to include video analytics.

C5 – Public Awareness Programs: PG&E's Public Awareness Program: PG&E's Public Awareness Program conducts educational outreach activities for professional excavators, local public officials, emergency responders, and the general public who lives and works within PG&E's service territory. The program communicates safe excavation practices, required actions prior to excavating near underground pipelines, availability of pipeline location information, and other gas safety information throughout the year through a variety of methods including bill inserts, e-mails, brochures, mass media advertising, press releases, and participation in community meetings and events. PG&E communicates gas safety information multiple times each year. These efforts are aimed at increasing public awareness about the importance of underground gas facilities and the need to call 811 before an excavation project is started.[3]

C6 – Meter Protection Program (MPP): The purpose of the MPP is to protect meters and risers that are vulnerable to vehicular damage, and to install service valves where existing service valves are inaccessible. Preventing damage from vehicles is required in accordance with Title 49 of the Code of Federal Regulations – Transportation, Section 192.353. Meter protection is accomplished in four ways: inspections to confirm field conditions; installation of bollards; installation of valves; and relocation of meter sets. Alternative meter protection measures such as customer-installed permanent structures are also available.[4]

C7 – Safe Kids Program: The PG&E Safe Kids Program has been in place since 2001 and is also in use with Power Generation Hydroelectric and Electric Operations. The program follows a robust public safety outreach communications strategy including the development and delivery of comprehensive electric, gas, and hydroelectric public safety awareness classroom materials to all

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[3] The Gas Operations Public Awareness Program is included in PG&E's 2020 GRC, A.18-12-009, Exhibit (PG&E-3), p. 6-14 to p. 6-16.

[4] The Gas Operations MPP is described in PG&E's 2020 GRC, A.18-12-009, Exhibit (PG&E-3), p. 4-27.

kindergarten through 8th grade schools throughout the PG&E service territory. The overarching program objective is to Save Lives and Prevent Injuries.

2) **Electric Operations Controls**

C1 – PG&E CSP for all PG&E LOBs, including Electric Operations, Gas Operations, and Power Generation: The CSP includes the requirement that for job sites on or near a roadway, work area protection devices and advance warning signs shall be placed and maintained in accordance with the "California Manual on Uniform Traffic Control Devices for Streets and Highways, January 13, 2012", and/or the California Joint Utility Traffic Control Manual, February 2014 6th Edition. The requirements apply to all employees who oversee or are directly responsible for the protection of the public, PG&E employees and contractors entering a PG&E working area.

C2 – Public Awareness Programs: Public awareness programs educate third-party workers and the public about power line safety and the hazards associated with wire down events. These programs are intended to reduce the number of third-party electrical contacts and as a control, has the potential to reduce exposure to Third-Party drivers and the consequences related to Safety Injuries and Fatalities. The programs consist of outreach efforts describing the hazards associated with working around power lines through various delivery channels. PG&E plans to continue outreach for each of the following programs, though the delivery channels may vary each year:

– Worker Beware Program: Communications targeting third-party contractors within PG&E's service territory. Includes direct mailings of safety material, offers of additional complimentary safety and training materials.

– Logging Safety Program Outreach: Communications targeting the logging industry. Includes delivery channels such as brochures, social media, visor cards, safety posters, and DVDs.

– Third-Party Tree Workers Program: Communications targeting stakeholders with operations within PG&E's service territory.

– Orchard Worker Safety Program: Communications targeting northern California orchards. Includes direct mailings as well as safety training videos.

– Mind-the-Lines Program: Social media campaign focused on increasing customer awareness of overhead lines.

C3 – Public Awareness Program (Bill Inserts): Draft and mail out bill inserts that inform customers of the dangers related to wire down events and the hazards associated with performing activities around intact overhead conductors. The material will be distributed in paper form and electronically within a monthly bill. Continuing to send bill inserts increases the volume of public safety messaging with the goal of making the general public more aware of the hazards associated with wire down events or overhead conductor. This may reduce the number of Third-Party Contact with Intact Conductor and the exposure related to the Third-Party (Wire Down) contact events.

C7 – Safe Kids Program: The PG&E Safe Kids program has been in place since 2001 and is also in use with Power Generation Hydroelectric and Gas Operations. The program follows a robust public safety outreach communications strategy including the development and delivery of comprehensive electric, gas, and hydroelectric public safety awareness classroom materials to all kindergarten through 8th grade schools throughout the PG&E service territory. The overarching program objective is to Save Lives and Prevent Injuries.

C10 - Streetlight Conversions to LED Technology: Electric Operations had conversion of approximately 120,000 of the 140,000 PG&E-owned conventional streetlights in PG&E's service territory to LED technology, which improves public safety by providing brighter and more reliable lighting while reducing energy usage.

C11 – PG&E Electric Design Manual Pole Location Requirements: The PG&E Electric Design Manual includes specifications for locating poles so that all portions of the line are within rights-of-way and easement requirements, clearances from trees and vegetation, and states that all applicable PG&E requirements stipulating proper pole easements and locations must be followed including compliance with CPUC General Order 95. Specifications include key considerations when locating or relocating poles is to avoid car pole incidents. If at all possible, place poles away from high-risk locations and as far as practical from traveled roadways. High-risk locations include, among others: (1) The outside of roadway curves, especially curves immediately downstream from long, straight sections of roadway; (2) End-of-lane "drops" (where a traffic lane suddenly ends); (3) Traffic islands

C12 – Visibility Strips on Electric Distribution Poles and Guy Markers: Emphasis on the presence of electric distribution system poles is a primary consideration when determining whether to mark electric distribution mark poles and guy markers. Reflective visibility strips shall be installed on wood, fiberglass, steel power poles, or guy poles, and guy markers as follows:

a) On poles and guy markers installed on state highways, in accordance with the marking section of the Caltrans Traffic Manual.
b) On poles and guy markers located within 15 feet from the paved surface or 15 feet from the edge of the traveled, unpaved portion of city or county roads (streets) where not protected by curbs.
c) On poles and guy markers within 6 feet of an adjacent driveway, private roadway (street intersection), turnaround, parking lot, or thoroughfare in rural district, capable of being traversed by vehicles where not protected by curbs.

Visibility strips should not be installed where there is no reasonable expectation of traffic. For example: Cross country poles, poles through waterways or wetlands, rear easement poles, poles behind guardrails, or poles on embankments that are well above or below the road.

If existing visibility strips become damaged or otherwise do not serve their intended purpose, they shall be replaced in accordance with PG&E documentation for the Marking, Numbering, and Identification of line structures.

C13 – Anti-Climbing Guard Assemblies for Steel Towers: Guards are placed in the vicinity of transmission tower legs to prevent potentials climbers from getting a hand or foothold. Guards must not be installed above a point on the tower leg that would prevent climbing by Company employees using a 20-foot extension ladder (approximately 16 feet).

3) Power Generation Controls

C1 – PG&E CSP for all PG&E LOBs, including Electric Operations, Gas Operations, and Power Generation: The CSP includes the requirement that for job sites on or near a roadway, work area protection devices and advance warning signs shall be placed and maintained in accordance with the "California Manual on Uniform Traffic Control Devices for Streets and Highways, January 13, 2012", and/or the California Joint Utility Traffic Control Manual, February 2014 6th Edition. The requirements apply to all employees who oversee or are directly responsible for the protection of the public, PG&E employees and contractors entering a PG&E working area.

C7 – Safe Kids Program: The PG&E Safe Kids program has been in place since 2001 and is also in use with Gas Operations and Electric Operations. The program follows a robust public safety outreach communications strategy including the development and delivery of comprehensive electric, gas, and hydroelectric public safety awareness classroom materials to all kindergarten through 8th grade schools throughout the PG&E service territory. The overarching program objective is to Save Lives and Prevent Injuries. For Power Generation, there is additionally focused outreach to schools within zip codes that have our hydrogeneration facilities including powerhouses and canals. The 2019 program has resulted in reaching out to 66,000 teachers and educating 295,000 students.

C8 – Public Safety Plans (PSP): Per PG&E Utility Standard PG-2129S, Power Generation conducts a review of each hydro project's PSP annually. PSPs are a regulatory requirement for each of PG&E's hydro FERC licenses. Each PSP must be updated and filed with FERC at least once every 10 years, more frequently if significant changes occur or upon request by FERC. Over the past five years, PG&E has implemented significant improvements to the PSP format. Currently, 16 of the 25 PSPs have been re-filed in the newer formats. In 2019, the Kerkoff and Mokulumne PSPs were filed. An updated Drum Spaulding PSP will be filed. Over the next five years, the goal is to have all 25 PSPs filed in the newer formats.

C9 – Early Warning System Signage and Alarms: In 2019 Early Warning Technologies (EWT) were identified and recommended for the time-sensitive dams. Examples of EWT's include sirens, automated notification systems and increased signage. PG&E Public Safety is working with the project planning team to launch several projects to implement EWT's for time-sensitive dams. The initial phases of this program are in place with continued improvements in progress.

C14 – Hydro Facility Unusual Water Releases and Water Safety Warning Standard and accompanying procedure (PG-2727S and PG-2727P-01): The documents establish PG&E Hydro facility requirements for planning and making unusual water releases or high flow events and their associated safety warnings.

C15 – PG&E Dam Safety Surveillance and Monitoring Program (PG-2762S): PG-2762S establishes and defines PG&E's Dam Safety Surveillance and Monitoring Program for the continued long-term safe and reliable operation of PG&E's dams. Dam surveillance involves the collection of data by various means, including inspections and instrumentation, whereas monitoring involves the review of the collected data as obtained and over time for any adverse trends.

b. Mitigations

1) Gas Operations Mitigations

M1 and M2 – Shallow and Exposed Pipe:[5] The Shallow and Exposed Pipe Programs were established to address the risks posed by shallow and exposed pipe on both land and locations of water/levee crossings. The purpose of the land-based portion of the Shallow and Exposed Pipe Program is to identify, prioritize, and mitigate locations where pipeline: has insufficient cover; is vulnerable to exposure from third parties; or has become exposed due to natural forces. The depth of pipelines installed by PG&E meet or exceed the minimum depth requirement in effect at the time of initial construction, however, over time, initial depth of cover may become reduced or the pipe may become exposed due to natural forces, such as erosion or stream washouts. This program enhances public safety and improves system reliability by prioritizing pipe for re-burial or replacement through a risk-based engineering analysis that considers the pipeline specifications manufacturing details, as well as operating and maintenance history. The water and levee crossing portion of this program was established to organize and catalog information, maps, drawings, leases, and permits regarding pipeline installations in waterways and levees. PG&E's Water and Levee Crossing Program improves system safety and reliability by identifying and evaluating erosion, third-party damage threats, and other hazards to trenched-in pipeline installations located under waterways, and within levee structures. This program assesses and monitors: 129 jurisdictional waterways; 177 levees; and an estimated 900 non-jurisdictional waterways throughout PG&E's service territory. Additionally, between 2019 and 2021, this program will assess an estimated additional 5,000 pipeline locations which cross intermittent or seasonal

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5 See Chapter 7, "Loss of Containment on Gas Transmission Pipeline," Section C, Mitigation M5 (Shallow Pipe) and Mitigation M6 (Exposed Pipe).

waterways. PG&E replaced 0.5, 1.0, and 0.7 miles of shallow and exposed pipe in 2017, 2018, and 2019, respectively.

2) Electric Operations Mitigations

PG&E identified two Electric Distribution mitigations that will also mitigate third-party safety risk.

M6 – System Hardening: This program is described in Chapter 11, "Failure of Electric Distribution Overhead Assets."

M7 – 3A and 4C Line Recloser Program: This program is described in Chapter 11, "Failure of Electric Distribution Overhead Assets."

3) Power Generation Mitigations

M3 – Public Outreach, Time-Sensitive Dams, Sudden Failure Assessments: In 2019 a sudden failure assessment was performed for PG&E's time-sensitive dams. A sudden failure assessment analyzes the detection, verification, notification and emergency management response time and compares it with the arrival of a flood inundation wave. 33 of PG&E's dams are classified as "time-sensitive." Time-sensitive is defined as: in the event of a dam failure or large uncontrolled release of water; homes, businesses, or recreation facilities could be flooded by a dam inundation before being notified by local emergency management agencies. In 2019 PG&E developed and mailed a general information brochure to more than 7,000 recipients who could be affected by a time-sensitive dam, notifying them that they live near a time-sensitive area and encouraging them to plan for the unlikely event of a sudden dam failure. Each brochure notifies the reader that they live near a Time-Sensitive area and encourages them to plan for the unlikely event of a sudden dam failure. In addition to the mailer, in 2019 EWT's were identified and recommended for the time-sensitive dams. Examples of EWT's include sirens, automated notification systems and increased signage. PG&E Public Safety is working with the project planning team to launch several projects to implement EWT's for time-sensitive dams. In 2020, PG&E has issued a contract to have a consultant perform sudden failure assessments for the remainder of the PG&E EAP dams, to confirm that they are still not time-sensitive. Updated inundation maps are utilized with modern flood modeling and analysis of developments near PG&E dams to determine if changes exist that would make a dam time-sensitive.

M4 – Canals and Waterways Safety: In 2019 Power Generation installed 10,497 linear feet of barrier fencing along PG&E's canal systems. Most of these fencing projects were completed in the Drum system and were identified through a systematic risk ranking assessment. In 2020 PG&E is forecasting 14,000 linear feet of barrier fencing installation. In 2019 PG&E also addressed the positioning and design of canal escape aids. Using industry benchmarking and canal attributes, PG&E determined locations for escape aids, and are installing 139 ladders along the Drum system canals. In 2019, Power Generation created a new brochure and mailed it to approximately 1,100 customers. The brochure provides safety information to property owners with canals that bisect their property. In 2019, a new canal entry emergency response plan was published to guide efficient and timely communications between PG&E personnel and local first responders when responding to emergencies resulting from public entry into PG&E-owned water conveyance systems. Delays in routing these calls to the appropriate hydroelectric generation switching centers can hamper response efforts. This document provides PG&E with a defined communications plan that helps to ensure an expedient response to search and rescue/recovery efforts.

M5 – Emergency Action Plans (EAP): In accordance with State and Federal regulations, PG&E maintains EAPs for all significant and high hazards dams.[6] Per FERC guidelines each EAP must be

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6 FERC defines a significant hazard potential as:

tested annually with a seminar and phone drill. Every five years a tabletop and functional exercise is required. In 2019, five EAP seminars and two tabletop exercises were held. A total of 172 participants joined in these exercises with participants including state and local emergency management agencies, state and federal regulators, localities impacted by dams, and PG&E personnel. Fourteen EAP phone drills were held in 2019 to verify and test PG&E emergency notification flow charts for EAP dams. A total of 272 stakeholders participated in the phone drills.

The following EAP initiatives have been identified for 2020:

- Introduce web-based EAP training for appropriate PG&E staff.
- Establish and implement an Automated Notification System to be used in EAP activation.
- Integrate electronic EAPs and associated files (i.e., inundation maps and shapefiles) into DamWatch for stakeholder access.
- Incorporate a welcome/thanks video from Power Generation leadership into EAP exercises.

D. 2020-2022 Controls and Mitigations

All of the controls listed in Section C.1.a above will continue from 2020-2022.

The Gas Operations and Power Generation mitigations described in Section C.1.b will continue through the 2020-2022 period.

PG&E identified one Electric Operations mitigation – System Hardening – that will also help to reduce the Third-Party Safety Incident risk, specifically the Electrical Contract driver. Electric Operations describes this mitigation in relation to two risks, Failure of Electric Distribution Overhead Assets and

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“those dams where failure or mis-operation results in no probably loss of human life but can cause economic loss, environmental damage, disruption of lifeline facilities, or can impact other concerns. Significant hazard potential classification dams are often located in predominantly rural or agricultural areas but could be located in areas with population and significant infrastructure.: FERC defines a high hazard potential as, “. . . those where failure or mis-operation will probably cause loss of human life.” See, Federal Emergency Management Agency, Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams, April 2004, pp. 5-6.

Wildfire.[7] System Hardening includes several activities designed to reduce wildfire risk, electric outages and equipment line failure. One of the System Hardening activities, replacing uninsulated wire with covered conductor, will also help to reduce Third-Party Safety Incident risk by reducing third-party contacts with electric wires. The System Hardening mitigation is described below.

M6 – System Hardening: PG&E is planning to upgrade approximately 7,000 miles of overhead distribution circuit in High Fire Thread District (HFTD) Tier 2 and Tier 3 areas to reduce the risk of wildfire ignitions associated with overhead equipment. The upgrades will include: replacing existing uninsulated wire with covered conductor; replacing poles as necessary to support the weight of the new covered conductor and/or for fire resilience; replacing non-exempt line equipment with lower fire risk equipment; and replacing transformers with lower fire-risk and higher efficiency models. In addition to reducing the risk of wildfire ignitions, this mitigation will also reduce outages and equipment failures, for example due to vegetation-conductor contact or conductor to conductor contact in high winds.

E. 2023-2026 Proposed Mitigation Plan

PG&E will continue to implement the five mitigations described in Section C.1.b above in the 2023-2026 period. The work planned for M1 and M2, Shallow and Exposed Pipe, is described in Chapter 7, "Loss of Containment on Gas Transmission Pipeline." The controls listed in Section C.1.a above will continue from 2023 to 2026.

The activities for Mitigation 3 (Public Outreach, Time-Sensitive Dams, Sudden Failure Assessments) Mitigation 4 (Canals and Waterways Safety), Mitigation 5 (EAP) and Mitigation 6 (System Hardening) remain as described above.

Mitigation 4 (Canals and Waterways Safety) is directly applicable to reducing injuries associated with interactions with PG&E's facilities that do not involve an asset failure. It has been included in the RAMP 2020 plan.[8]

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7 See Chapter 11, Failure of Electric Distribution Overhead Assets, Section C, Mitigation M3 and Chapter 10, Wildfire, Section C, Mitigation M2.

8 Costs for this mitigation are included in WP 15-1.

PG&E identified an additional Electric Operations mitigation – 3A and 4C Line Recloser Controller Replacement – that will start in 2023 and will also help to reduce the Third-Party Safety Incident risk, specifically the Electrical Contract driver. Electric Operations describes this mitigation in relation to it Failure of Electric Distribution Overhead Assets risk.[9] Replacing older recloser controllers is designed to improve PG&E's ability to isolate faults and re-energize circuits. One of the benefits of replacing the 3A safety hazards due to fault conditions including wire-down incidents. The 3A and 4C Line Recloser Controller Replacement mitigation is described below.

M6 – 3A and 4C Line Recloser Replacement Program: PG&E uses line reclosers across its DOH system to manage, locate/isolate faults and re-energize circuits in the event of an outage. Some of these line recloser units use older model 3A or 4C controllers, which have limited functionality compared to newer controller models. These functional limitations increase the risk of circuit failure and impact PG&E's ability to isolate faults and re-energize circuits in the event of an outage. Line reclosers are also categorized as protective devices, and are programmed to protect customers from safety hazards due to fault conditions including wire-down incidents, sustained outages etc. There is a high risk of such fault incidents if these devices do not operate as intended. To mitigate this risk, PG&E proposes to replace all 3A and 4C line recloser controllers in its system with newer models.

Table 15-6 below shows the risk reduction scores for the proposed mitigations. The costs for the three mitigations are borne by the line of business implementing the mitigation: System Hardening is sponsored by Electric Operations, see Chapter 10, Wildfire; Canals and Waterways Safety Barriers, is sponsored by Power Generation;[10] and 3A and 4C Line Recloser Program is sponsored by Electric Operations, See Chapter 11, Failure of Electric Distribution Overhead Assets. While the costs for these mitigations are

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9 See Chapter 11, "Failure of Electric Distribution Overhead Assets," Section C, Mitigation M10.

10 The forecast expense costs for Mitigation 4 are: $675,000 (2020); $695,250 (2021); $716,108 (2022); $737,501 (2023); $759,718 (2024); $782,510 (2025); and $805,985 (2026). See WP 15-1.

sponsored by other lines of business, the benefits of these mitigations still apply to the Third-Party Safety Incident risk.

TABLE 15-6
RISK REDUCTION

Line No.	Mit. No.	Mitigation Name	RSE[(a)]	Risk Reduction
1	M2	System Hardening	–	103.0
2	M4	Canals and Waterways Safety Barriers (b)	1.7	3.8
3	M10	M10- 3A and 4C Line Replacement	–	4.0

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the Risk Spend Efficiency (RSE).

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: Targeted Third-Party Electric Safety Pilot Program

PG&E will design and conduct a pilot program to target regions or circuits that have a high number of, or high rate of,[11] third-party contact with electric assets incidents. PG&E will analyze its third-party electric asset contact data to identify those regions or circuits where third-party contact with electric assets is most prevalent. It will evaluate the physical locations and types of incidents to determine which of the potential mitigation options are most likely to reduce the third-party electric contact risk in each specific location.

The potential mitigation options include:

11 PG&E will evaluate both locations with the highest number of individual incidents and areas where there are the highest incident rates – the highest number of incidents per circuit mile.

- Eliminate the Hazard – Eliminate the hazard by undergrounding a for portion of the electric power lines.
- Engineering Control – Reduce the likelihood that a third-party vehicle will contact a PG&E pole by relocating power poles, installing crash barriers, and/or another type of pole diversion.
- Public Awareness – Increase public awareness as to the location and potential danger of contacting an electric asset by installing visibility strips, reflective paint, and/or additional signage and conducting marketing campaigns.

Designing and implementing the pilot program will require close coordination with municipalities and landowners where PG&E's assets are located. This will ensure that the mitigations PG&E is proposing meet all municipal requirements and will give PG&E an opportunity to better estimate the number and type of mitigations that reduce the most risk in different situations and are the most cost effective.

PG&E will provide an update about this pilot program in the 2023 GRC.

TABLE 15-7
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	A1	Targeted Third-Party Electric Safety Pilot Program	$250	$256	$263	$269	$1,038	147	112

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

Note See WP 15-1.

2. Alternative Plan 2: Delay Installation of Canals and Waterways Safety Barriers

Alternative 2 considers delaying the installation of canals and waterways safety barriers by two years. PG&E prefers to maintain the planned schedule. It is possible that this mitigation could be delayed due to resource limitations and/or work planning or coordination issues. PG&E did not select this alternative because it would delay important safety work.

TABLE 15-8
RSE AND RISK REDUCTION
2023-2026

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE	Risk Reduction
1	A2	Delay Canals and Waterways Barrier Installation	$738	$760	$783	$806	$3,086	1.7	3.8

Note See WP 15-1.

Table 15-9 compares the proposed and alternative mitigation plans.

TABLE 15-9
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(a)]	Total Spend (NPV)[(b)]	RSE
1	Proposed	M2, M4, M10	–	$3,086	111	$2,267	49
2	Alternative 1	Proposed + A1	$1,038	$3,086	222	$3,030	73
3	Alternative 2	M2, M10 + A2	–	$3,086	111	$2,267	49

(a) Plan Components refers to the Mitigations presented in Table 15-5.
(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.
Note See WP 15-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 16

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: EMPLOYEE SAFETY INCIDENT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 16
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: EMPLOYEE SAFETY INCIDENT

A. Executive Summary

Employee Safety Incident refers to any event resulting in an Occupational Safety and Health Administration (OSHA)-recordable[1] injury or fatality, excluding events resulting from asset failure. The drivers for this risk event are: contact with objects and equipment; exposure to harmful substances or environment; falls, slips or trips; fire and explosion; bodily reaction and exertion; and violence or other injuries by persons or animals. The cross-cutting factors of Skilled and Qualified Workforce, Records and Information Management, Physical Attack, and Climate Change also impact this risk event.

Exposure to this risk is measured as the approximately 22,000 members of Pacific Gas and Electric Company's (PG&E or the Company) workforce. The risk model includes 603 risk events each year. The drivers responsible for the most risk are: overexertion and bodily reaction, representing 18 percent of the risk events and 18 percent of the risk; typing, key-entry or mousing, representing 9 percent of the risk events and 9 percent of the risk; straining in twisting/turning, representing 8 percent of the risk events and 8 percent of the risk. The mitigations PG&E will implement from 2020 to 2026 are designed to address these key risk drivers.

PG&E identified 2 tranches for this risk event: office-based employees and field employees. The types of risk to office-based employees are significantly different than the types of risk faced by field employees. 74 percent of the risk events are associated with the field employees tranche.

Employee Safety Incident has the fifth highest 2023 test year (TY) safety score (86) and the eighth highest 2023 TY total risk score (90) of PG&E's 12 Risk Assessment and Mitigation Phase (RAMP) risks. The 2020 baseline

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1 An OSHA-recordable event is defined as work related injuries or illnesses that must be reported to OSHA and that results in any of the following: medical treatment beyond first aid; loss of consciousness; one or more days away from work following the incident; restricted work or transfer to another job; any significant injury or illness diagnosed by a physician; any work-related fatality.

risk score of 93, improves by 28 percent when the planned mitigations are applied: the 2023 TY risk score is 90 and the 2026 post-test year risk score is 66.

PG&E is proposing a series of controls and mitigations to address Employee Safety Incident risk. The Enterprise Safety Management Systems (ESMS), Vehicle Ergonomics Program and the On-Site Clinics have the highest Risk Spend Efficiency (RSE) scores. The ESMS and On-Site Clinics have the highest total risk reduction scores.[2]

TABLE 16-1
RISK OVERVIEW

Line No.	Risk Name	Employee Safety Incident
1	In Scope	PG&E employee OSHA-recordable injuries and fatalities that are not the result of an asset failure.
2	Out of Scope	PG&E employee OSHA-recordable injuries and fatalities resulting from the failure of an asset.
3	Data Quantification Sources[(a)]	PG&E data including: PG&E Human Resources Report (HR) (2008-2018). PG&E Cal-OSHA-recordable data by claim cause and claim cause category Incident Detail Report (2008-May 2019) PG&E Safety and Environmental Management System (SEMS) Database. PG&E serious employee injuries and fatalities from the Serious Incidents Report including earlier versions (2008-2019)

(a) Source documents will be provided with the July 17, 2020 RAMP update.

1. Risk Overview

PG&E has approximately 22,000 employees who provide natural gas and electric services to approximately 16 million people throughout PG&E's 70,000-square-mile service area.

PG&E's team includes safety and health professionals who focus on preventing employee illness and injuries through: strategic planning, governance, oversight, analytics and reporting functions; expert field safety

2 The information presented herein is subject to the limitations described in Chapter 2, Section D.

support to drive strategy, programs and continuous improvement; workers' compensation case management and expertise helping our workforce stay at work and return to work; serious injury and fatalities prevention, life safety, regulatory compliance and governance, and workforce health programs; Safety Leadership Development (SLD), field observations, and assessing safety program impact; and incident investigations and human factor analyses.

Key programs that PG&E's Safety and Health organization is responsible for include:

- PG&E Occupational Health and Safety Plan (One Plan), which is a comprehensive view for improving employee and contractor safety and health through 2022. The One Plan is divided into Focus Areas for supporting goals and strategies and incorporates best practice safety programs. As such, it is dynamic in nature and is continually refreshed to accommodate changes in the business. As part of 2025 strategy the One Plan will transition to a foundation for performance improvement by increasing leadership presence in the field, clarifying responsibilities and work standards, and adopting lessons learned across the organization.
- Enterprise Safety Management System to manage risk to PG&E employees and contractors. As previously discussed in the 2017 RAMP, planning and preparation for the ESMS took place from 2017 through 2019 with implementation beginning in 2020. The ESMS consists of a series of capabilities (people, process, governance, and technology systems) required to define, plan, implement, and continuously improve workforce safety. The ESMS becomes the way PG&E "delivers the business of safety" and is based on a consistent and comprehensive enterprise safety controls framework reinforced with system assurance. PG&E's commitment is to implement the system by 2022.
- Field safety operations works with the lines of business (LOB) to deliver safety programs to improve safety culture, identify hazards, and reduce incidents and injuries in the field. The goal of field safety is to identify and reduce risk exposures through observations, supporting incident

investigations, training, hazard identification, safety tailboards, program implementation support and emergency response.

- PG&E's Serious Injury or Fatality (SIF) Program focuses on the specific exposures which have led to serious injuries and fatalities. PG&E worked with Behavioral Science Technology, Inc. to analyze employee incident data and identified 22 categories of exposure factors, using criteria from the Herbert William Heinrich Safety Triangle Theory for Industrial Accident Prevention and industry criteria and processes.

  All injuries and reported near hits are evaluated relative to the SIF exposure factors, and the team conducts in-depth Cause Evaluations for all incidents classified as SIF-potential or SIF-actual. The results of these investigations are monitored through the Corrective Action Program (CAP) as PG&E develops corrective actions to reduce the likelihood of recurrence. PG&E also observes field work groups and provides immediate feedback relative to potential safety issues and collects data about SIF exposure factors and risky behaviors.

- Enterprise CAP The Enterprise CAP provides a centralized, standardized governance structure, and process for issue identification and resolution. The CAP process enables employees and contractors the ability to identify and report issues, or ideas, related to gas assets, and processes. The CAP process ensures that issues are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. In 2019, PG&E employees and contractors submitted approximately 40,000 CAP issues company wide. Examples of how CAP improves safety:

  – A PG&E employee recognized that there were potentially counterfeit parts on a forklift PG&E had rented. The counterfeit part is known to fail at 40 percent of the stated capacity and could have resulted in a SIF. Through the CAP process, this issue was documented and reviewed and resulted in a change to PG&E's equipment rental process.

  – A PG&E employee recognized there were brass insulators being used that had a history of failing while employees were conducting work, exposing employees to potential burn-related injuries. Through CAP, a replacement program resulted in replacing 4,400 insulators at more than 100 PG&E substations.

  – While reviewing PG&E's Employee Life Safety Training courses, an employee noted the absence of guidance related to active shooter scenarios and submitted a CAP item, then three PG&E training courses were developed and implemented to provide employees training on responding to an active shooter event.

PG&E has also instituted SLD and Operational Learning. PG&E has accelerated SLD training for crew leaders (crew leaders lead teams of front-line employees doing field operations and maintenance work) so they have the necessary safety skills to create trust, set expectations, remove barriers to safety and identify and mitigate at-risk behaviors. SLD also includes reducing the administrative responsibilities on its front-line leaders to enable them to spend more time in the field. Operational Learning tools help drive continuous improvements in safety. For example, PG&E may bring together skilled facilitators and employees to develop solutions to ongoing safety issues. Operational Learning shifts the focus from blaming an employee when something goes wrong to understanding what happened and how to prevent it from happening again. For instance, through operational learning, PG&E developed and implemented a revised vehicle familiarization/driving training program to reduce preventable motor vehicle incidents resulting from backing into stationary objects after learning from PG&E employees that they were not adequately trained and prepared to operate Company vehicles

2. Risk Definition

Any event resulting in an employee OSHA-recordable injury or fatality, excluding events resulting from asset failure.

B. Risk Assessment

1. Background and Evolution

The Employee Safety risk was included in PG&E's 2017 RAMP.[3] In the 2020 RAMP, the Employee Safety Incident event has changed from the 2017 RAMP. The Employee Safety Incident risk event is now defined as "Employee Safety Incident" instead of the 2017 definition, "failure to identify and mitigate occupational exposures that result in an employee OSHA recordable injury/illness or fatality." The 2017 RAMP risk definition focused on potential occupational exposures, whereas the 2020 RAMP risk event focuses on actual employee safety incidents.

In the 2017 RAMP, PG&E presented two risks related to employee safety: Employee Safety (Chapter 15) and Lack of Fitness for Duty (FFD) Program Awareness (Chapter 17). The two risks are closely aligned, and FFD Program Awareness is no longer a risk on PG&E's Enterprise Risk Register. Previously, the Employee Safety risk was defined as the failure to identify and mitigate occupational exposures that may result in employee injuries or fatalities. The FFD Program Awareness risk was defined as PG&E people leaders (directors, managers, superintendents and supervisors) who fail to identify and act upon observed behaviors that indicate an employee may be unable to work safely, which could result in an employee injury or fatality. The mitigations and controls for both the Employee Safety and FFD Program Awareness risks are now included in this risk. They are discussed in detail below.

In the 2020 General Rate Case (GRC) PG&E explained that the FFD Program Awareness risk will be transitioned to a control for the Employee Safety risk in the future.

The risk drivers in the 2020 RAMP have also evolved. For the 2017 RAMP, as part of the initial quantitative risk analysis effort, PG&E categorized its risk drivers according to the Bureau of Labor Statistics Occupational Injury and Illness Classification Manual using PG&E California Occupational Safety and Health Administration (Cal/OSHA)-reportable data to determine frequencies. The 2020 RAMP analysis builds on the

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3 PG&E's RAMP Report, Investigation 17-11-003 (Nov. 30, 2017), Chapter 15.

categorization and includes Cal/OSHA-recordable injury claim causes and also direct causes where the data are available. Approximately 70 percent of the claim cause data include a direct cause from the supervisor investigation analysis packet.

2. Risk Bow Tie

FIGURE 16-1
RISK BOW TIE – 2023 TEST YEAR

3. Exposure to Risk

The Employee Safety Incident risk exposure is based on an annual average of 22,265 employees—approximately 60 percent are considered office-based (i.e., work in PG&E office locations) and approximately 40 percent work primarily in the field.

PG&E relied on its GN 801 – Employee and Non-Employee Details (Internal) Reports for developing the exposure to risk data. PG&E job classifications were used to estimate the number of office and field employees for the exposure tranches.

4. Tranches

PG&E identified two tranches for the Employee Safety Incident risk based on a review of PG&E-recordable injuries and fatalities data:

- PG&E office-based employees including but not limited to Managers, Engineers and Scientists, Analysts, Planners, Learning and Development, HR, Information Technology (IT), Supply Chain, Finance, and Law professionals, (60 percent of the workforce); and
- PG&E field employees including but not limited to linemen, plant technicians, field analysts, system operators, mechanics, electricians, materials handlers, nuclear security, and troublemen (40 percent of the workforce).

The types of hazards, or risk exposures are different for office-based and field employees. Office-based employees are more susceptible to injuries such as those resulting from typing or key entry, strains, slips, trips, and falls. Field employees are more susceptible to injuries resulting from strains from lifting, pulling or pushing, repetitive use of tools, contact with objects and equipment, falls from height, and contact with electrical current. Approximately 75 percent of the PG&E employee Cal/OSHA recordables included in the RAMP model analysis are field employees. Based on the data, less than 1 percent of field related Cal/OSHA recordables have resulted in a serious injury or a fatality. Table 16-2 shows the percent risk exposure and percent risk for each tranche.

TABLE 16-2
RISK EXPOSURE AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Percent Exposure	Safety Risk Score	Financial Risk Score	Total Risk Score	Percent Risk Score
1	Field Employees	40 percent	79.1	3.3	82.4	92 percent
2	Office Employees	60 percent	6.5	0.9	7.5	8 percent
3	Total	100 percent	85.6	4.3	89.9	100 percent

5. Drivers and Associated Frequency

Drivers utilize the injury categories from the RAMP 2017 analysis and are further divided into 35 drivers based on injury claim cause data. Direct cause data were used to support the analysis.

Driver Category One (1) – Contact with Objects and Equipment: This driver category accounts for approximately 13 percent of PG&E Cal/OSHA-recordable injuries and includes:

a) Caught in or compressed by equipment or objects;
b) Caught or crushed in collapsing materials (e.g., cave-in);
c) Contact with objects and equipment;
d) Jarred by tool, equipment, or vibration;
e) Rubbed or abraded by foreign matter in eye;
f) Stepped on object;
g) Struck against moving object;
h) Struck against stationary object;
i) Struck by falling object;
j) Struck by flying object; and
k) Struck by swinging or slipping object.

Driver Category Two (2) – Exposure to Harmful Substances or Environment: This driver category accounts for approximately 9 percent of PG&E Cal/OSHA-recordable injuries and includes:

a) Contact with electrical current;
b) Contact with hot or cold objects/substances;
c) Contact with skin or other exposed tissue;
d) Exposure to noise; and
e) Inhalation of substance.

Driver Category Three (3) – Falls, Slips and Trips: This driver category accounts for approximately 12 percent of PG&E Cal/OSHA-recordable injuries and includes:

a) Fall down stairs or steps/escalator;
b) Fall from ladder or scaffolding;
c) Fall from non-moving vehicle;
d) Fall onto or against objects;
e) Fall to floor, walkway, or other surface on same level;
f) Fall to lower level; and
g) Slip, trip, loss of balance—without fall.

Driver Category Four (4) – Fire and Explosion: Includes fire and explosion related injuries such as burns (chemical and electrical), welder's flash, and heatstroke. This driver accounts for less than 1 percent of PG&E Cal/OSHA-recordable injuries.

Driver Category Five (5) – Bodily Reaction and Exertion, Unspecified: This driver category accounts for approximately 60 percent of PG&E Cal/OSHA-recordable injuries and includes:

a) Strain in twisting/turning;
b) Bodily reaction and exertion, unspecified;
c) Overexertion in holding, carrying, turning, or wielding;
d) Strain in lifting/lowering;
e) Strain in pulling or pushing;
f) Repetitive placing, grasping, moving objects, except tools;
g) Repetitive use of tools; and
h) Typing or key entry or mousing.

Driver Category Six (6) – Violence and Other Injuries by Persons or Animal: This driver category accounts for roughly 4 percent of PG&E Cal/OSHA-recordable injuries and includes:

a) Assaults and violent acts by person(s);
b) Assaults by animals; and
c) Venomous bites, stings, injections.

6. Cross Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Employee Safety Incident risk are shown in Table 16-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 16-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	X	
2	Physical Attack	X	
3	Records and Information Management		X
4	Skilled and Qualified Workforce	X	

7. Consequences

The basis for measuring the consequences of the Employee Safety Incident risk are: (1) serious injury according to the Cal/OSHA definition or fatality; or (2) financial. There are no electric or gas reliability consequences.

The outcomes which characterize Employee Safety Incident risk event:

- Overexertion and bodily reaction (60 percent of the Cal/OSHA-recordable injuries; approximately 67 percent of these are field employees).
- Contact with object and equipment (13 percent of the Cal/OSHA-recordable injuries; approximately 92 percent of these are field employees).
- Falls, slips, or trips (12 percent of the Cal/OSHA-recordable injuries; approximately 78 percent of these are field employees)
- Exposure to harmful substances or environments (9 percent of the Cal/OSHA-recordable injuries; approximately 88 percent of these are field employees).
- Violence and other injuries by persons or animal (4 percent of the Cal/OSHA-recordable injuries; approximately 84 percent of these are field employees).
- All other Cal/OSHA-recordable injuries occur approximately 1 percent of the time; approximately 61 percent of these are field employees.
- Fires and explosions Cal/OSHA-recordable injuries occur less than 1 percent of the time; approximately 90 percent of these are field employees.

PG&E relied on the PG&E Serious Incidents Reports from 2012 through 2019 and previous serious incidents reporting for 2008 through 2011 to analyze the safety consequences of an employee-recordable injury. The Serious Incidents Report provides details on the conditions that led to incidents.

PG&E used the PG&E SEMS database in conjunction with the average workers' compensation claim cost from the most recent GRC to evaluate the financial consequences of an employee safety incident. The SEMS database includes the OSHA recordables cases that were classified as Days Away, Restricted or Transferred (DART) cases. Historical data were used to quantify the risk baseline with the RAMP model. These same data were used to assess mitigation effectiveness, along with case studies, benchmarking and PG&E Subject Matter Expert judgment. Greater detail of the mitigation effectiveness methodologies can be found in the workpapers.

Table 16-4 shows the consequences of the risk model. Model attributes are described in Chapter 3, "Risk Modeling and Risk Spend Efficiency."

TABLE 16-4
RISK EVENT CONSEQUENCES

					Natural Units Per Event		CoRE		Natural Units per Year		Attribute Risk Score	
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Financial $M/event	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety	Financial
Overexertion and bodily reaction	0.14	60%	59%	364	0.0028	0.0140	0.1380	0.0070	1.0	5.1	50.1	2.5
Falls slips trips	0.16	12%	13%	71	0.0031	0.0143	0.1543	0.0071	0.2	1.0	11.0	0.5
Contact with object or equipment	0.13	13%	12%	81	0.0025	0.0147	0.1255	0.0073	0.2	1.2	10.2	0.6
Exposure to harmful substances or environments	0.18	9%	10%	52	0.0034	0.0146	0.1683	0.0073	0.2	0.8	8.8	0.4
Violence and other injuries by persons or animal	0.17	4%	5%	25	0.0033	0.0145	0.1635	0.0072	0.1	0.4	4.0	0.2
All Other	0.15	1%	1%	6	0.0028	0.0140	0.1384	0.0070	0.0	0.1	0.8	0.0
Fires explosions	0.18	1%	1%	4	0.0034	0.0146	0.1724	0.0073	0.0	0.1	0.6	0.0
Aggregated	**0.15**	100%	100%	603	0.0028	0.0142	0.1421	0.0071	1.7	8.5	85.6	4.3

C. Controls and Mitigations

Tables 16-5 and 16-6 list all the controls and mitigations PG&E included in its 2017 RAMP for both the Employee Safety and FFD Program Awareness risks, 2020 GRC, and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view of the controls that are in place, the mitigations that are continuing implementation, and new mitigations. It also includes controls and mitigations that have been removed. In the following sections PG&E describes the controls in place in 2019 as part of the 2020 RAMP baseline, changes to the 2017 RAMP mitigations and controls, and then discusses the 2020 RAMP program which includes new mitigations and mitigations continuing to be implemented during the 2020-2022 and 2023-2026 periods.

In the 2017 RAMP PG&E presented two risks related to employee safety: Employee Safety (Chapter 15) and Lack of FFD Program Awareness (Chapter 17). In this 2020 RAMP the FFD controls and mitigations are now incorporated into the Employee Safety Incident risk. This is discussed more fully in the Risk Background and Evolution discussion above.

TABLE 16-5
CONTROLS SUMMARY

Line No.	Control Name and Number (reference)	2017 RAMP Risk Category[a]	2017 RAMP	2020-2022 GRC 2017-2020 Controls	2020 RAMP 2020-2022 Controls	2020 RAMP 2023-2026 Controls
1	C1 – PG&E Safety and Health Compliance Standards	Emp. Safety	X	X	X	X
2	C2 –CAP	Emp. Safety	X	X	X	X
3	C3 – Employee Knowledge and Skills Assessments (Including Academy Training)	Emp. Safety	X	X	X	X
4	C4 (inc. Emp. Safety M3)– Safety Observation Program	Emp. Safety	X	X	X	X
5	C5 – Personal Protective Equipment Requirements	Emp. Safety	X	X	Removed (included with C1)	
6	C6 (inc. Emp. Safety M10) – SLD				X	X
7	C7 (inc. Emp. Safety M2) – SIF Incident Investigation Review				X	X
8	C7a (inc. Emp. Safety M2) SIF Incident Investigation Review				X	X
9	C8 (inc. Emp. Safety M9) – Learning Organization				X	X
10	C9 (inc. Emp. Safety M7) – Benchmarking				Removed as foundational	
11	C10 (inc. Emp. Safety M10) – SLD				X	X
12	C11 (inc. Emp. Safety M8) – Enterprise Safety Communication Plan				X	X
13	C12 (inc. Emp. Safety M12) – Employee Wellness (formerly FFD C2)				X	X

TABLE 16-5
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Name and Number (reference)	2017 RAMP Risk Category[(a)]	2017 RAMP	2020-2022 GRC 2017-2020 Controls	2020 RAMP 2020-2022 Controls	2020 RAMP 2023-2026 Controls
14	C13 – Training and Communication (formerly FFD C1)				X	X
15	C14 (inc. FFD M5) – Enhanced FFD Metrics				X	X
16	C15 (inc. FFD M9) – Benefit Plans and Policy (formerly FFD C3)				X	X
17	C16 – Nurse Care Line (NC) (inc. Emp Safety M11)				X	X
18	C17 – Return to Work Task Program (Inc. Emp. Safety M11)				X	X
19	C1 –Training and Communication	FFD	X		Updated to C13	
20	C2 (inc. M12) – Employee Wellness	FFD	X		Updated to C12	
21	C3 – Benefit Plans and Policy	FFD	X		Updated to C15	

(a) "Emp Safety" indicates a control that was listed in the Employee Safety chapter (Chapter 15) in PG&E's 2017 RAMP. "FFD" indicates a control that was listed in the FFD Awareness chapter (Chapter 17) in PG&E's 2017 RAMP.

TABLE 16-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP Risk Category[(a)]	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1A – Safety Management System (SMS) Planning	Emp. Safety	X	Complete		
2	M1B – ESMS Implementation	Emp. Safety		X	X	
3	M2 – Serious Injury and Fatalities Incident Investigation Review	Emp. Safety	X	X	Becomes control C7	
4	M3 – Safety Observation Tool	Emp. Safety	X	Included with C4		
5	M4 – Job Hazard Analysis	Emp. Safety	X	Removed – included with M1A		
6	M5 – Safety Plan	Emp. Safety	X		X	
7	M6 – Musculoskeletal Disorder (MSD) Program	Emp. Safety	X	X	Now (M6a through M6d)	Now (M6a through M6d)
8	M6a – Office Ergonomics Program				X	X
9	M6b – Industrial Ergonomics Program				X	X
10	M6c – Industrial Athlete Program				X	X
11	M6d Vehicle Ergonomics Program				X	X
12	M7 – Benchmarking	Emp. Safety	X		Becomes control C9	
13	M8 – Enterprise Safety Communication Plan	Emp. Safety	X		Becomes control C11	
14	M9 – Learning Organization	Emp. Safety	X		Becomes control C8	
15	M10 – SLD	Emp. Safety	X	Inc. with C6		
16	M11 – On-Site Clinics	Emp. Safety	X	X	X	X
17	M12 – Health and Wellness	Emp. Safety	X	X	Becomes control C12	

TABLE 16-6
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP Risk Category[(a)]	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
18	M2 – Identify and Track Population to Receive FFD Training (Knowledge, Mandatory Training)	FFD		X	Included in C14	
19	M3 – Redesign Time-Off Policy, Management and Union Employees	FFD	X	Combined with M9		
20	M4 – Observations – FFD Trained Field Safety Specialists	FFD	X	Removed		
21	M5 – Enhanced FFD Metrics	FFD	X	Becomes a control	Updated to C14	
22	M6 – FFD Data Sources Review	FFD	X	Complete		
23	M7 – Knowledge, Mandatory Training	FFD		X	Updated to C14	
24	M9 – Process Improvements, Redesign Time-Off Policy	FFD		X	Included in Employee Safety Incident C15	
25	M10 – Tools and Technology Kiosks	FFD		X	Discontinued	
26	M11 – Tools and Technology – Clinics	FFD		X (FFD risk chapter)	Now included with Emp. Safety Incident as M11	Now included with Emp. Safety Incident as M11
27	M13 – Enhancing SafetyNet Use				X	X
28	M14 – Industrial Hygiene (IH) Program Compliance Improvements – Phase 1				X	
29	M15 – IH Program Compliance Improvements – Phase 2				RAMP alternative	RAMP alternative

TABLE 16-6
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP Risk Category[a]	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
30	M16 – Fit4U Pilot				X	
31	M17 – Mobile Medics				X	X
32	M18 – Employee Safety Field Inspections				RAMP alternative	RAMP alternative

(a) "Emp. Safety" indicates a control that was listed in the Employee Safety chapter (Chapter 15) in PG&E's 2017 RAMP. FFD indicates a control that was listed in the FFD Awareness chapter (Chapter 17) in PG&E's 2017 RAMP.

1. 2019 Controls

The controls and mitigations proposed in the 2017 RAMP for the Employee Safety and FFD risks were primarily programmatic in nature and provided the infrastructure to support strengthening the compliance and safety culture. The controls for both risks address each of their respective drivers. The list of controls below reflects the 2019 baseline for the Employee Safety Incident risk. These controls are anticipated to remain in place through 2026.

C1 – PG&E Safety and Health Compliance Standards: Safety and Health Compliance Standards provide an in-depth overview of Cal/OSHA and OSHA compliance requirements. In addition to the compliance requirements, the Standards provide common understanding of the risks across the Company regarding the exposure mitigation. The LOBs use the Standards to develop and/or revise work methods and procedures. In conjunction with this the Safety and Health organization has the responsibility to review required compliance training and provide input to the PG&E Academy on changes needed to the training materials resulting from new or changed Cal/OSHA and OSHA regulatory requirements.

C2 – Corrective Action Program: The CAP is a companywide program that provides employees and contractors a speak-up method to identify and report issues, or ideas, related to gas assets, and processes. The CAP process ensures that issues are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. Both employees and contractors have the option of submitting a CAP anonymously.

C3 – Employee Knowledge and Skills Assessments: In conjunction with the PG&E Learning Academy, PG&E’s LOBs are developing specific Employee Safety knowledge and skills assessments. The training provides classroom and hands-on instruction by experienced instructors to teach and assess the specialized skills that are critical to field employees executing high risk tasks.

C4 – PG&E Implemented SafetyNet Safety Observations: LOB supervisory and corporate Safety Specialists conduct worksite observations using checklists developed using SafetyNet (PG&E's Safety Observation database tool) as part of the SIF Program implementation.

C6 – Safety Leadership Development: All PG&E employees in leadership positions, up to and including the Chief Executive Officer, who have union represented employees within their reporting structure/chain of command who work in a capacity that has a SIF potential are automatically profiled to take the revised SLD workshop series which consists of two all-day workshops. The workshops teach and focus on leadership skills and practices that promote and sustain safety performance. The PG&E Academy is responsible delivering, maintaining, and updating the workshops. Workshops are updated annually to address areas of improvement identified by the field safety observation data.

C7 and C7a – PG&E's Serious Injury or Fatality Prevention Program: The SIF Prevention program focuses on SIFs at PG&E. All injuries and reported near hits are evaluated to determine the hazards classification and if the situation results in a SIF-actual or SIF-potential event. The SIF Strategy and Prevention team conducts or coordinates in-depth cause evaluations for all incidents classified as SIF-potential or SIF-actual. The results of these investigations and the identified corrective actions are monitored through the CAP to ensure timely completion and effectiveness. Focusing its investigative resources on SIF-potential and SIF-actual incidents assists with understanding these situations and the development of corrective actions to eliminate or mitigate recurrence. The SIF program is continuously improved through the review of existing SIF program and processes for enhancements and optimization on an annual basis, ensuring alignment with all LOBs for consistency and continuity enterprise-wide.

C8 – Operational Learning: PG&E's Operational Learning uses several different methods that are focused on learning about how work is performed. Learning Teams, a critical component of Operational Learning, are facilitated discussions with representative groups of front-line employees, led by a trained facilitator, about how work is performed, what works well, and what are the barriers to success. Learning Teams leverage our employees' extensive expertise and experience to identify best practices and to develop practical and sustainable solutions to improve operating and safety performance. This effort helps PG&E LOBs understand how work is done and to develop approaches and solutions to reduce risk and improve workplace safety. Recommended improvements are entered and evaluated through the CAP.

C10 – PG&E's Leader in the Field: The Leader in the Field initiative focuses on having leaders spend more time in the field and coaches them on how to provide consistent feedback to workers, engage with them in discussions with how they are working safely, and how to offer specific guidance on how to improve.

C11 – Enterprise Safety Communication Plan: The enterprise safety communication plan is part of the Corporate Communication Plan to deliver a consistent safety and health communication strategy which helps employees understand the risk factors for their safety and health. This allows employees to understand, engage with, and appreciate the safety and health programs available to them and build credibility with employees and contractors by showing that PG&E is a company committed to worker safety.

C12 – Employee Health and Wellness: These programs align health and wellness activities with safety prevention efforts to drive better outcomes. Research has shown a direct correlation between the health and well-being of employees and their frequency of being injured on the job. Expanded and enhanced health and wellness services/controls that promote access to medical services and other programs and focus on prevention to assist employees in managing their health. On-site health coaching had been added and a new employee health and wellness portal was implemented with tools and additional self-directed resources. There are two main categories of Health and Wellness controls:

a) Emotional Health – Employee Assistance Program (EAP) and Peer Volunteer Program.
b) Physical Health – Employee Health Screenings and Health Coaching.

C13 – Health and Wellness Training and Communication: Training and communication controls enhance people leader awareness and effectiveness in detecting behaviors that raise FFD concerns. There are four controls included in this group:

a) Compliance and Ethics and Code of Conduct training. This Annual mandatory training includes an FFD module to help leaders and employees understand how to identify and react to observed behaviors which may impact the employees' ability to perform their work safely.

b) FFD Cross Program Manager Training. Resources were identified and cross trained on the program. In addition, a process was established to ensure adequate coverage for the program.

c) Voluntary FFD situational awareness training for leaders. In addition to mandatory FFD training for all new leaders the FFD Program Manager regularly provides ad hoc FFD training to leaders upon request. These sessions allow for leaders to ask questions and interact directly with the FFD Program Manager.

d) A quarterly process to communicate new or changing issues during Risk and Compliance Committee (RCC) meetings. Each quarter new or changing regulations involving local, state or federal laws and regulations affecting benefit programs are communicated to the RCC. Reports include the plan in place to incorporate the new requirements.

C14 – Enhanced FFD Metrics: Enhanced FFD data tracking metrics to include risk ranking, late or timely reporting. Mandatory FFD training for people leaders, Directors and below, is tracked through Learning Academy.

C15 – Benefit Plans and Policy: Implemented a third party to administer multiple benefit program offerings, including long-term disability, short-term disability, paid family leave, the PG&E's Voluntary Disability and Paid Family Leave Benefit Plan (offered in lieu of State Plan benefits) and leaves of absence to improve employee access to benefit information. Having a single administrator helps to ensure proper administration of benefits which ensures proper and prompt delivery of benefits. New benefits provide eligible employees with a financial safety net to be able to take the time off needed to seek treatment and help in recovery, thus improving and/or maintaining the health of the workforce and assuring quality of care and fitness to return-to-work.

C16 – Nurse Care Line: This enhanced injury reporting process improves the employee experience when reporting minor injuries. Early intervention is the key to successfully managing physical discomfort or stress. The NCL allows employees to speak up, without fear, when faced with a work-related health challenge, strengthening the message that employee health is essential. Employees receive medical advice, self-care information and clinic referrals. Using the NCL results in a decrease of injury severity, and a reduction in workers compensation claim costs. While the number of calls to the NCL has increased, the percentage of those calls resulting in OSHA recordables has decreased by 15 percent from 2013-2018. In addition, there was a reduction in average cost per claim of approximately 50 percent in 2018, as compared to 2013. It also identifies training opportunities to further promote a safe working environment.

C17 – Return to Work Task Program: The enhanced return to work task program provides more return to work opportunities for employees with injuries or illnesses (industrial and non-industrial) whose temporary work restrictions cannot be accommodated in their base classification. The Program was launched in 2017. At that time, it was included in 2017 RAMP with the Injury Management mitigation (M11) in the Employee Safety risk. This control provides temporary assignments to help ease the transition from temporary restricted status to full duty. Early return to work helps injured employees recover faster and have better recovery outcomes. The program has resulted in a significant reduction of lost workdays.

2. 2019 Mitigations

a. Employee Safety Risk Mitigations

M1A – Safety Management System Planning: As preparation for implementation of a SMS, perform a gap analysis, prioritize gaps for closure and finalize the SMS policy and guidance for publication. Develop a system for managing job hazards analysis data, which is an integral part of the SMS foundation, and integrate a communication and education plan for hazard awareness and avoidance.

M2 – Serious Injury and Fatalities – Incident Investigation Review: Align the investigations process to improve the quality of the investigations/causal evaluation, documentation, and corrective actions. Improve communications strategies to share learnings.

M3 – Safety Observation Tool: PG&E is improving the SafetyNet safety observation tool, developed by Predictive Solutions, for use with field employees and contractor safety programs. The benefits of SafetyNet are that it leverages a large and comprehensive database of 500 million data points from completed observations throughout the industry and includes algorithms to provide predictive injury analysis, dashboards, and help with improving the quality of the submitted observations. The prior safety observation tool, Guardian, does not have a database of observations from other companies or the capability to use algorithms that provide predictive injury analysis; nor does it provide information regarding the quality of the observations. This mitigation is an enhancement of C4.

M4 – Job Hazard Analysis: Develop a system for managing job hazards analysis data which is an integral part of the SMS foundation and integrate a communication and education plan for hazard awareness and avoidance.

M5 – Safety Plan: Publish and implement the One PG&E One Plan to establish shared accountability, ownership and commitment.

M6 – Musculoskeletal Disorder Program: 64 percent of the injuries from 2014-2017 are MSDs, and sprains and strains. The ergonomics program focuses on office, industrial and vehicle ergonomics by utilizing early intervention activities and ergonomic assessments. The program also establishes systems to utilize injury data and risk assessments to target interventions at the areas of greatest need.

M7 – Benchmarking: Participation on industry roundtables with peer organizations to share lessons learned and best practices and implement, as applicable, at PG&E. Implementing best practices and help to reduce risk of SIF.

M8 – Enterprise Safety Communication Plan: Deliver a consistent safety and health communication strategy which helps employees understand the risk factor for their safety and health. This will allow employees to understand, engage with, and appreciate the safety and health programs available to them and build credibility with employees and contractors by showing that PG&E is a company committed to worker safety.

M9 – Learning Organization: PG&E will use Learning Teams of 5-7 front-line employees led by a credible facilitator, who has the respect of both front-line employees and management. These teams build on employees' extensive first-hand experience and skills to develop durable and practical solutions to on-going safety issues. This effort will help PG&E develop approaches and solutions to this risk and ensure that each LOB is accountable for implementing the Learning Teams' recommendations.

M10 – Safety Leadership Development: In 2017, Corporate Safety expanded the delivery of the SLD workshops under the name *Leading Forward: Safety Leadership.* This program provides training to all 1,700 crew leads, planned over a 3-year timeframe, and will continue to train new leaders as they are hired into these positions. Training is being developed to teach a group of facilitators how to conduct Learning Teams, as referenced in M9.

M11 – Injury Management: Enhance the injury reporting process to improve the employee experience when reporting minor injuries. Additionally, enhance the return to work program for injured employees whose temporary work restrictions cannot be accommodated in their base classification. The enhancements will demonstrate to employees that PG&E cares about them and will promote healing and early return to work.

M12 – Health and Wellness: Align health and wellness activities with safety prevention efforts to drive better outcomes. Research has shown a direct correlation between the health and well-being of employees and their frequency of being injured on the job. Expand and enhance health and wellness services by focusing on prevention and condition management to assist employees in managing their health. Provide additional on-site health coaching and enhance the existing platform with a new user interface and tools and deploy new self-directed resources.

b. FFD Awareness Mitigations

M4 – Observations – Fitness for Duty trained Field Safety Specialists Observations: Adding FFD awareness to field observations conducted by 65 Safety Specialists in 2018. The checklists are already being revised, therefore no added cost for including the FFD language similar to the recommendation for the driver ride-along checklist. The intent of this mitigation was to improve people leader awareness of the FFD Program. It was later removed as it is training specific to employee supervisors.

M5 – Enhanced FFD Metrics: Enhance FFD data tracking metrics to include risk ranking, late or timely reporting, and a determination of the efficacy of mandatory FFD training for people leaders for all referrals. This was a new mitigation for 2017 and will be continued in subsequent years. This mitigation improves the ability to measure the effectiveness of changes to the FFD Program since it was removed from EAP and thus helps to understand the effectiveness of the program as a control.

M6 – FFD Data Sources Review: Evaluate other sources of employee data for use with risk quantification, validate current results and revise as necessary. This mitigation was completed in 2017 and the data was reviewed during the risk model development process.

D. 2020-2022 Controls and Mitigations

1. Changes to Controls

PG&E will continue to implement the controls described above and shown on Table 16-5.

2. Changes to Mitigations

This list includes updates to mitigations currently being implemented and new mitigations that will become controls during 2020 through 2022.

M1B – Enterprise Safety Management System Implementation: PG&E has committed to implementing an ESMS. The ESMS consists of a series of capabilities (people, process, governance, and technology systems) required to define, plan, implement, and continuously improve workforce safety. The ESMS becomes the way PG&E "delivers the business of safety" and is based on a consistent and comprehensive enterprise safety controls framework reinforced with system assurance. PG&E's commitment is to implement the system by 2022.

Key components of the system include:

a) Management of Change (MOC) Capability and MOC Software (program manager and software)
b) OSHA and Cal OSHA Compliance Baseline and Workforce Safety Control Program Owners Framework
c) Safety Compliance Register
d) Hazard Tracking System
e) Safety Architect for Safety (Controls) Engineering
f) Safety Certification
g) Safety Values and Actions – Governance for safety culture improvements including a coordinator, surveys, and training
h) ESMS implementation (including updates to people, process, technology, and governance documents)

More information about the ESMS is included in workpapers.[4]

M13 – Enhancing SafetyNet use: PG&E is enhancing its use of the SafetyNet safety observation tool, developed by Predictive Solutions, for use with field employees and contractor safety programs. The benefits of SafetyNet are that it leverages a large and comprehensive database of several million completed observations and includes algorithms that have the potential to provide predictive analysis and dashboards regarding unsafe conditions or behaviors enterprise-wide. Safety Observation Tool improvements include observation data improvements and expansion of training and documentation for front-line users to bolster the quality of the data such that reports, and predictive modeling can be utilized by PG&E leadership to improve workplace safety. PG&E anticipates that the tool will be fully optimized in 2021.

M14 – Industrial Hygiene Program Compliance Improvements – Phase 1: Develop and implement overall IH Standard that includes roles and responsibilities (execution and support governance by IH team) for the

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4 See WP 16-3.

IH program (including the current Safety and Health IH Standards). LOB procedures will align with the current Standards including execution of the compliance programs within their organizations. The compliance function within Enterprise Safety and Health will assess the status of implementation within the LOBs. Implement gap assessment findings including:

- Consolidating monitoring records and compliance recordkeeping, exposure assessments, and medical surveillance program in an IH data management software system that leverages current plan for evaluation of a Safety and Health software solution; and
- Install monitoring equipment for IH team's use and to support program execution.

M16 – Fit4U Pilot: This program focuses on improving the health and well-being of employees who have sustained multiple workers compensation injuries, by providing them with the resources to maintain a healthy lifestyle. Access to health coaching, personal training, meditation/mindfulness, and EAP services should prevent repeat injuries, provide coping skills and accelerate their recovery and return to work. Long term benefits may include a reduction in workers compensation claims, health plan costs, work-related injuries or illnesses increasing DART rate, and health related lost workdays. Analysis of pilot results will determine whether to expand this mitigation past the pilot stage.

PG&E will implement several mitigations between 2020 and 2022 that will become controls in the 2023 through 2026 period:

M6a – Office Ergonomics Program: Continue effort on change management including Supervisor training within the organization for early symptom recognition and action, working with facilities partners to ensure furnishings meet ergonomic design specifications, enhanced reporting moving toward predictive modeling.

M6b – Industrial Ergonomics Program: Continued effort in education about industrial ergonomics risk factors, while making the Velocity software fully operational across enterprise with prevention specialists and industrial ergo teams. The Velocity software is used to assess ergonomics risk factors associated with worker activities and tasks and determine possible risk reduction measures. This mitigation also includes building a business case for a centralized pilot to evaluate potential solutions, increase partnerships with the vendor to receive products to pilot across enterprise needs, robust tracking, reporting, and visibility of impacts and risk reduction from solution implementation.

M6c – Industrial Athlete Program: The future state is to expand from early symptom intervention to a strategic-based plan to reduce discomfort cases and prevent muscle strains and sprains. Program objectives include targeted interactions with an on-site prevention specialist by focusing on high risk areas identified by Supervisors, Safety Net observations, brief surveys, and biomechanical observations. Industrial Athlete program will consider moving from external third party to internal employee positions with an IT solution.

M6d – Vehicle Ergonomics Program: All PG&E-owned vehicles included in PG&E's fleet have a design review committee that includes front-line workers, safety, ergonomics, and human factors. The objective is to fully understand the work performed while using the vehicles—such as equipment most frequently used, access, lighting, environmental concerns, smart driving, ease of access, mechanical advantage—and forecast potential future technology impacts, using 5-95 percent anthropometric data and human factors principles.

M11 – On-Site Clinics: Establish on-site clinics available to PG&E employees. The on-site clinics are expected to provide employees with convenient access to health care services which will lead to a healthier workforce by reducing the duration of Days Away From Work and Restricted Duty cases.

M15 – IH Program Compliance Improvements – Phase 2 (Alternative 1). Add consultant support and increased staff to expand program and provide additional LOB support with IH Program compliance assurance/implementation including surveillance.

M17 – Mobile Medics: PG&E will place Emergency Medical Technicians (EMT) throughout seven territories with the highest OSHA-recordable injuries over the last three years. EMTs will be available during regular business hours to respond to injuries and provide immediate care which will mitigate the severity of injuries and reduce OSHA and DART cases.

M18 – Employee Safety Field Inspections: Conduct Cal/OSHA employee safety field inspections across PG&E in alignment with the ESMS and the Safety and Health audit procedure. This supports increased field oversight of Cal/OSHA compliance and safe work.

Table 16-7 below shows the forecast costs for the mitigations planned for the 2020-2022 period.

TABLE 16-7
FORECAST COSTS
2020-2022
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M1B	ESMS Implementation	FL	$1,575	$1,725	$925	$4,225
2	M6a	Office Ergonomics Program	FL, ZC	2,235	2,235	2,235	6,705
3	M6b	Industrial Ergonomics Program	FL, ZC	1,050	1,050	1,050	3,150
4	M6c	Industrial Athlete Program	FL, ZC	4,274	4,274	4,274	12,822
5	M6d	Vehicle Ergonomics Program	FL, ZC	275	275	275	825
6	M11	On-Site Clinics	ZC	1,011	1,505	1,510	4,025
7	M13	Enhancing SafetyNet Use	FL	127	64	–	191
8	M14	IH Program Compliance Improvement-Phase 1	FL	100	100	–	200
9	M16	Fit4U Pilot	ZC	526	–	–	526
10	M17	Mobile Medics	ZC	1,800	1,544	1,323	4,667
11	Total			$12,973	$12,771	$11,592	$37,336

Note See WP 16-1.

E. 2023-2026 Proposed Mitigation Plan

PG&E will continue implementing the mitigations started in the 2020-2023 period. No new mitigations are planned.

The ESMS, first proposed in the 2017 RAMP, is expected to be in place by year-end 2021 with ongoing refinement of LOBs implementation procedures into 2023.

The four proposed MSD Program mitigations (M6a through M6d in Table 16-6 above) include programs to address overexertion and bodily reaction injuries which comprise 60 percent of the Cal/OSHA recordables on average based on historical data. Approximately 67 percent of the Cal/OSHA recordables are field employees. The Industrial Athlete, Industrial Ergonomics, and Vehicle Ergonomics programs (M6b through M6d) are designed to focus on field personnel.

Table 16-8 below shows the forecast cost, RSEs and risk reduction scores for the mitigations planned for the 2023-2026 period.

TABLE 16-8
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M1B	ESMS Implementation	FL	$725	$725	$925	$725	$3,100	12.99	29.6
2	M6a	Office Ergonomics Program	FL, ZC	2,410	2,410	2,410	2,410	9,640	0.37	2.6
3	M6b	Industrial Ergonomics Program	FL, ZC	1,050	1,050	1,050	1,050	4,200	1.13	3.5
4	M6c	Industrial Athlete Program	FL, ZC	4,402	4,402	4,402	4,402	17,608	0.64	8.4
5	M6d	Vehicle Ergonomics Program	FL, ZC	283	283	283	283	1,133	7.11	5.9
6	M11	On-Site Clinics	ZC	1,789	4,350	2,810	2,810	11,757	2.21	19.0
7	M13	Enhancing SafetyNet Use	FL	–	–	–	–	–	–	–
8	M14	IH Program Compliance Improvement-Phase 1	FL	–	–	–	–	–	–	–
9	M16	Fit4U Pilot	ZC	–	–	–	–	–	–	–
10	M17	Mobile Medics	ZC	1,103	882	882	882	3,749	0.68	1.9
11		Total		$11,761	$14,102	$12,762	$12,562	$51,187	–	–

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.
Note See WP 16-1.

Based on the results of the risk modeling analysis shown in Table 16-8 above, PG&E is proposing to spend approximately one-third 2023-2026 planned funding on the three programs with the highest RSEs and highest risk reduction scores: MSD Program-Vehicle Ergonomics, ESMS Implementation, and On-Site Clinics.

While MSD Program-Office Ergonomics has the lowest RSE and second lowest Risk Reduction score, PG&E supports this program because it helps to minimize the workers compensation injuries and injury severity.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs, and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: IH Program Compliance Improvements – Phase 2

Alternative 1 considers implementing additional IH Program Compliance improvements to expand the program and provide additional LOB support with compliance assurance and program implementation including IH monitoring and surveillance. Field surveillance is an important part of reducing work location exposures to hazardous substances and environments. This alternative was not chosen because it has a lower RSE and lower risk reduction score than the proposed mitigations.

TABLE 16-9
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE)[(a)]	Risk Reduction
1	A1	IH Program Compliance Improvements – Phase 2	$540	$540	$540	$540	$2,160	–	–
2		Total	$540	$540	$540	$540	$2,160	0.14	0.2

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
Note See WP 16-1.

2. Alternative Plan 2: Employee Safety Field Inspections for PG&E Work Locations

Alternative 2 considers implementing Employee Safety Field Inspections for PG&E employee workplaces and locations. The inspections would be compliance focused and in addition to the field safety observations with SafetyNet currently taking place. This program would be similar to the Contractor Safety Field Inspections and is anticipated to require additional resources in order to inspect all PG&E field and office locations. Inspection programs are an important part of reducing recordable injuries and fatalities as they place increased attention on adhering to safety and health compliance requirements and working safely. This alternative was not chosen because it has a lower RSE than many of the proposed programs and a higher cost.

TABLE 16-10
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A2	Employee Safety Field Inspections	$5,958	$5,958	$5,958	$5,958	$23,832	–	–
2		Total	$5,958	$5,958	$5,958	$5,958	$23,832	0.13	2.3

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

Note See WP 16-1.

1 Table 16-11 compares the proposed and alternative mitigation plans.

TABLE 16-11
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)[(b)]	RSE
1	Proposed	M1B, M6a-M6d, M11, M17	$51,187	–	70.9	$37,672	1.88
2	Alternative 1	Proposed + A1	$53,347	–	71.1	$39,263	1.81
3	Alternative 2	Proposed + A2	$75,017	–	73.1	$55,226	1.32

(a) Plan Components refers to the Mitigations presented in Table 16-6.

(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.

Note See WP 16-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 17

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: CONTRACTOR SAFETY INCIDENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 17
RISK ASSESSMENT AND MITIGATION PHASE
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 17
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: CONTRACTOR SAFETY INCIDENT

A. Executive Summary

Contractor Safety Incident refers to any event resulting in a contractor Occupational Safety and Health Administration (OSHA) recordable injury or fatality,[1] excluding events resulting from asset failure. Contractors included in the Contractor Safety Incident Risk Assessment and Mitigation Phase (RAMP) are those that perform medium or high-risk work on behalf of PG&E. Events related to asset failure are covered in the asset management risks within Electric Operations, Gas Operations, and Power Generation. The drivers for this risk event are: sprains, strains, tears; cuts and lacerations; bruises and contusions; fractures; back pain, hurt back; abrasions, scratches; animal or insect bites; punctures, except bites; and other. The cross-cutting factor Records and Information Management also impacts this risk.

Exposure to this risk is measured as the approximately 26,000 contractors Pacific Gas and Electric Company (PG&E) employs each year. The risk model includes an annual average of approximately 185 recordable injuries divided into the following workplace injury categories: other; sprains, strains, tears; cuts and lacerations; bruises and contusions; fractures; back pain, hurt back; punctures, except bites; abrasions, scratches; animal or insect bites. Approximately 2 percent of the risk events result in a serious injury or fatality (SIF). The mitigations PG&E will implement from 2020-2026 are designed to address the known risk drivers.

PG&E identified one tranche for this risk which includes contractor high and medium-risk work activities. High-risk work includes activities such as: excavation and trenching beyond four feet; heavy equipment operation; utility tree trimming, clearance work and vegetation management; general construction

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1 An OSHA-recordable-event is defined as work related injuries or illnesses that must be reported to OSHA and that results in any of the following: medical treatment beyond first aid; loss of consciousness; one or more days away from work following the incident; restricted work or transfer to another job; any significant injury or illness diagnosed by a physician; any work-related fatality.

activities; welding and/or hot tapping of gas lines; and fault protection/grounding. Medium-risk work includes activities such as: geotechnical investigation; surveying and field inspection; material handling and compressed natural gas/liquified natural gas handling.

Contractor Safety Incident has the fourth highest 2023 test year (TY) safety score (94) and the seventh highest 2023 TY total score (94) of PG&E's 12 RAMP risks. The 2020 baseline risk score of 121 improves by 41 percent when the planned mitigations are applied: the 2023 TY risk score is 94 and the 2026 post-TY risk score is 72.

PG&E is proposing a series of controls and mitigations to address the Contractor Safety Incident risk. The Work Permits and OSHA Programs Training Requirements mitigations have the highest Risk Spend Efficiency (RSE) scores. The Work Permits, Contractor On-Boarding and Tracking Contract Workers programs have the highest total risk reduction scores.[2]

TABLE 17-1
RISK OVERVIEW

Line No.	Risk Name	Contractor Safety Incident
1	In Scope	An event resulting in a contractor[(a)] recordable injury or fatality, excluding events resulting from asset failure.
2	Out of Scope	PG&E contractor recordable injuries or fatalities resulting from the failure of an asset.
3	Data Quantification Sources[(b)]	ISNetworld (ISN) from 2017 to October 2019. ISN is a vendor that specializes in contractor safety prequalification and supplier management data. ISN's data is based on the contractor's OSHA-recordable injuries and illnesses for PG&E work.

(a) Contractors in scope for this risk are those contractors who perform high risk and medium risk work for PG&E. High risk and medium risk work are defined in Section B.4 below.
(b) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

In 2019 PG&E employed approximately 2,200 contracting companies, which included approximately 26,000 individuals working more than 44 million hours supporting PG&E's diverse efforts across its lines of

2 The information herein is subject to those limitations described in Chapter 2, Section D.

business (LOB). PG&E's team of safety and health professionals is focused on preventing illness and injuries for both PG&E team members and the contractors who work with us. Beginning in 2016, PG&E implemented a formal Contractor Safety Program to help our contractor partners reduce illness and injuries when working with PG&E. The program was implemented as required by the Kern Order Instituting Investigation Settlement Agreement with California Public Utilities Commission (CPUC).

PG&E's Safety and Health organization develops, enables, and integrates innovative, proactive safety and health solutions, including: strategic planning and trending analysis; expert field safety support; continuous improvement of safety programs; promoting safety culture; and investigation and human factor analysis. This organization establishes the framework for PG&E's safety and health programs, monitors their effectiveness, identifies areas for improvement, and monitors compliance with applicable regulatory requirements.

PG&E's Contractor Safety Program is supported by professionals with specific expertise in PG&E's Contractor Safety Program, as well as with the work performed by PG&E's contractors. The Contractor Safety Program Manager and Analysts are responsible for the program governance and mitigation enhancements, while the Field Safety Managers and Safety Specialists conduct LOB and contractor assessments, observe contractor work for OSHA compliance, provide feedback to contractors, and coach and support LOB resources to improve safety performance.

PG&E's Contractor Safety Program includes all contractors and subcontractors performing medium- and high-risk work on PG&E facilities and assets.[3] The Contractor Safety Program includes: contractor and subcontractor pre-qualification prior to executing contracts and beginning work; safety planning integrated into the overall job plan; oversight procedures to monitor safe planning and work execution; and post-job evaluations to capture contractor safety performance including lessons learned, identifying quality safety programs and pursuing continuous improvement.

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3 High risk and medium risk work are described in Section B.4 below.

In 2018, PG&E strengthened the contractor pre-qualification criteria to evaluate contractors that experience a significant increase in worker headcount for PG&E-related work and for contractors that have been in business less than three years. PG&E conducts additional evaluations of these contractors' safety management systems. Contractors that are not approved can no longer work for PG&E.

2. Risk Definition

The risk is defined as any event resulting in a contractor recordable injury or fatality, excluding events resulting from asset failure. Events related to asset failure are covered in the asset management risks within Electric Operations, Gas Operations, and Power Generation.

B. Risk Assessment

1. Background and Evolution

The Contractor Safety risk was included in PG&E's 2017 RAMP[4] and was defined as "the failure to identify and mitigate occupational exposures that may result in a contractor injury or illness that is fatal, life threatening or life altering." In the 2020 RAMP the contractor safety risk name has changed to Contractor Safety Incident and the risk definition was changed to align with an event-based risk register.

The risk drivers in the 2020 RAMP have also evolved. In the 2017 RAMP the drivers were categorized according to the Bureau of Labor Statistics Occupational Injury and Illness Classification Manual and were supported by PG&E employee data. In the 2020 RAMP the risk drivers are based on OSHA injury classifications and supported by PG&E-specific contractor ISN data. PG&E determined that the ISN classification is a better way to both measure risk exposure and to define the risk drivers because the ISN classification is aligned to the contractor's OSHA-recordable injuries and illnesses for PG&E work. The risk drivers use the same classification categories as OSHA defines for reporting.

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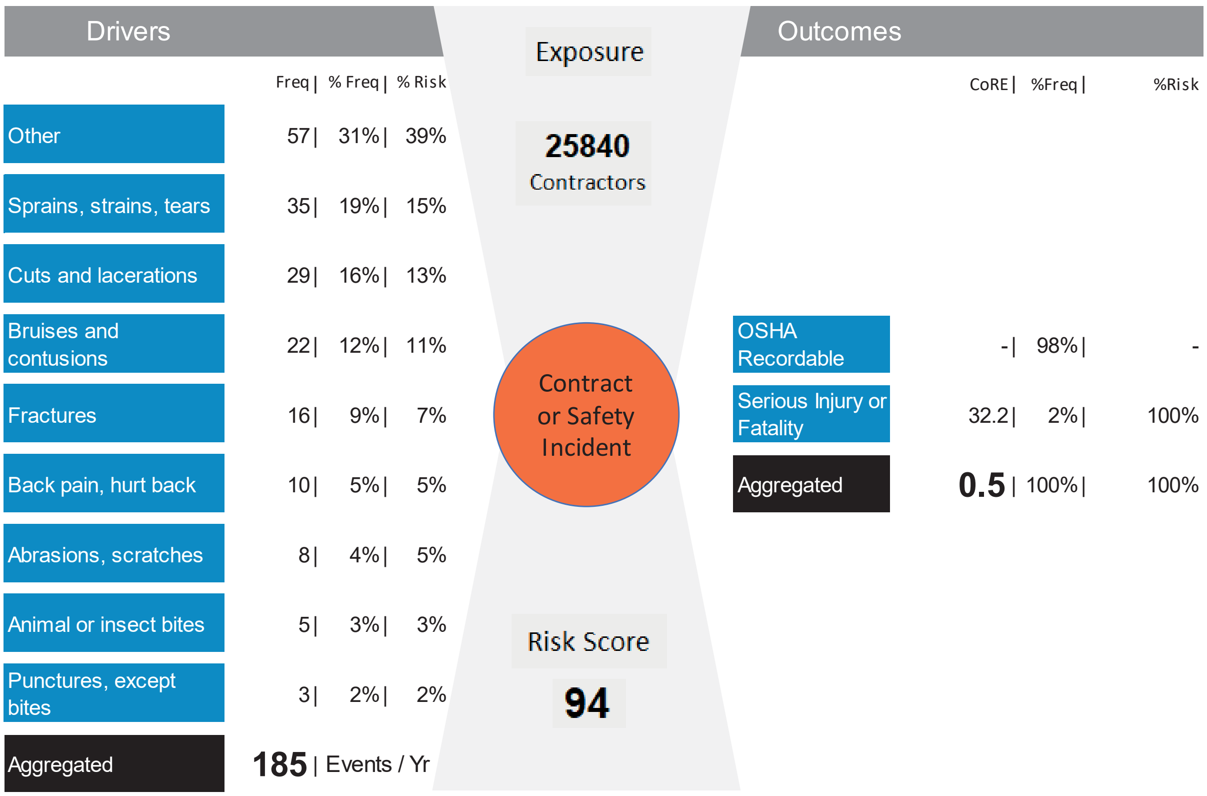
4 PG&E's RAMP Report, Investigation 17-11-003, Nov. 30, 2017 (PG&E's 2017 RAMP Report), Chapter 14.

2. Risk Bow Tie

FIGURE 17-1
RISK BOW TIE – 2023 TY



a. Difference from the 2017 Risk Bow Tie

The risk exposure in the 2017 RAMP bow tie and the 2020 RAMP bow tie are generally the same, however for 2020 the number of contractors is used to measure exposure rather than contractor hours. In the 2020 RAMP, consequences are measured in terms of serious injuries or fatalities whereas in the 2017 RAMP consequences were California Occupational Safety and Health Administration (Cal/OSHA)-recordable injuries and fatalities.

3. Exposure to Risk

Exposure to the risk is measured as number of contract employees performing high and medium risk work. The total exposure in the risk bow tie is based on an annual average of 25,840 contract employees. PG&E contractors conduct a wide variety of activities for PG&E across its LOBs. From 2018-2019 the contractor workforce population increased by

11 percent. In 2019 PG&E contractors self-reported more than 44 million hours for PG&E specific work.

The scope of this risk includes PG&E contractors who perform medium and high-risk activities such as digging and trenching, vegetation management or material handling that can result in a contractor safety incident. Designing and implementing mitigations and controls focused on the most serious and most often occurring safety events will help to reduce contractor safety events and contractor safety risk.

PG&E relies on ISN data for developing the risk analysis. Exposure to risk was modeled using data in the ISN Site Tracker reports that include PG&E specific data for; OSHA-recordable injuries and contractor workplace injury types, and number of PG&E contract employees in scope for the risk.

4. Tranches

PG&E identified one tranche for the Contractor Safety Incident risk based on a review of contractor safety data. This tranche includes high- and medium-risk work activities as described in the PG&E Contractor Safety Program Risk Matrix that is aligned to the PG&E Utility Standard, SAFE-3001S.

High-risk work includes activities such as: excavation and trenching beyond four feet; heavy equipment operation; utility tree trimming, clearance work and vegetation management; general construction activities; welding and/or hot tapping of gas lines; and fault protection/grounding.

Medium-risk work includes activities such as: geotechnical investigation; surveying and field inspection; material handling and compressed natural gas/liquified natural gas handling.

At this time, PG&E tracks contractors by prime contractors (primes), those contractors who work directly for PG&E, and sub-contractors (subs), those contractors that have been retained by a prime contractor to provide services on behalf of PG&E. Going forward, PG&E will consider whether the collection of PG&E contractor incident information specific to the LOBs will provide further insight into where Contractor Safety mitigation programs should be focused.

5. Drivers and Associated Frequency

PG&E identified nine drivers for the Contractor Safety Incident risk. Each driver and its associated 2023 TY baseline frequency is discussed below. There are no sub-drivers for the Contractor Safety Incident risk. The nine risk drivers are based on the OSHA-recordable classifications in ISN that are aligned to the contractor's OSHA-recordable injuries and illnesses for PG&E work.

D1 – Other: Refers to a contractor safety incident other than those addressed by drivers D2 through D9. Other contractor safety events accounted for 57 (31 percent) of the 185 expected annual number of events reportable to the Cal/OSHA.

D2 – Sprains, Strains and Tears: Refers to a contractor safety incident that results in soft tissue injury such as a muscle, ligament or tendon sprain, strain or tear that is reportable to Cal/OSHA. Sprain, strain or tear events accounted for 35 (19 percent) of the 185 expected annual number of events.

D3 – Cuts and Lacerations: Refers to a contractor safety incident that results in a cut or laceration that is reportable to Cal/OSHA. Cuts and lacerations accounted for 29 (16 percent) of the 185 expected annual number of events.

D4 – Bruises and Contusions: Refers to a contractor safety incident that results in a bruise or contusion that is reportable to Cal/OSHA. Bruises and contusions accounted for 22 (12 percent) of the 185 expected annual number of events.

D5 – Fractures: Refers to a contractor safety incident resulting in a broken bone that is reportable to Cal/OSHA. Fractures accounted for 16 (9 percent) of the 185 expected annual number of events.

D6 – Abrasions and Scratches: Refers to a contractor safety incident resulting in abrasions or scratches that is reportable to Cal/OSHA. Abrasions and Scratches events accounted for 8 (4 percent) of the 185 expected annual number of events.

D7 – Back Pain, Hurt Back: Refers to a contractor safety incident resulting in back pain or a hurt back that is reportable to Cal/OSHA. Back pain or hurt back events accounted for 10 (5 percent) of the 185 expected annual number of events.

D8 – Animal or Insect Bites: Refers to a contractor safety incident due to an animal or insect bite that is reportable to Cal/OSHA. Animal or insect bite events accounted for 5 (3 percent) of the 185 expected annual number of events.

D9 – Punctures (Except Bites): Refers to a contractor safety incident due to a puncture wound, excluding bites, that is reportable to Cal/OSHA. Puncture events accounted for 3 (2 percent) of the 185 expected annual number of events.

6. Cross-Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factors that impact the Contractor Safety Incident risk are shown in Table 17-2 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 17-2
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Records Information Management		X

PG&E is continuing to evaluate the impact that Physical Attack has on RAMP risks and expects to present Physical Attack as a cross-cutting factor relative to additional RAMP risks in the 2023 General Rate Case (GRC).

7. Consequences

The basis for measuring the consequences of the Contractor Safety Incident risk are a serious injury (Cal/OSHA definition) or fatality.

The consequences of a Contractor Safety Incident risk event occurring are:

- A serious injury[5] or fatality occurs 2 percent of the time and accounts for 100 percent of the risk consequences; and
- An OSHA-recordable event occurs 98 percent of the time but does not account for any of the risk consequences.

PG&E relied on the PG&E Serious Incidents Reports from 2012 through 2019 to analyze the safety consequences of a contractor safety incident. The Serious Incidents Report provides the details of the incident including injury type, actions taken, and the date that injury occurred consistent with Cal/OSHA reporting requirements. The review and analysis of the data was supported by PG&E Subject Matter Expert (SME) judgement to confirm the initial the incident information.

Table 17-3 below shows the risk event consequences. Model attributes are described in Chapter 3, “Risk Modeling and Risk Spend Efficiency.”

TABLE 17-3
RISK EVENT CONSEQUENCES

					Natural Units Per Event	CoRE	Natural Units per Year	Attribute Risk Score
					Safety	Safety	Safety	Safety
	CoRE	%Freq	%Risk	Freq	EF/event		EF/yr	
OSHA Recordable	-	98%	-	182.4	-	-	-	-
Serious Injury or Fatality	32.2	2%	100%	2.9	0.64	32.2	1.88	94
Aggregated	**0.5**	100%	100%	185.3	0.01	0.5	1.88	94

C. Controls and Mitigations

Tables 17-3 and 17-4 list all the controls and mitigations. PG&E included in its 2017 RAMP, 2020 GRC and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are on-going, those that are no longer in place, and new mitigations. In the following sections

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5 A significant injury or illness is diagnosed by a physician or other licensed health care professional. OSHA believes that most significant injuries and illnesses will result in one of the criteria listed in § 1904.7(a): death, days away from work, restricted work or job transfer, medical treatment beyond first aid or loss of consciousness. OSHA believes that cancer, chronic irreversible diseases, fractured or cracked bones, and punctured eardrums are generally considered significant injuries and illnesses. . . even if medical treatment or work restrictions are not recommended, or are postponed, in a particular case. United States Department of Labor, Occupational Safety and health Administration, Standard Number 1904.7, Note to § 1904.7.

PG&E describes the controls in place in 2019 as part of the 2020 RAMP baseline, changes to the mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and mitigations continuing to be implemented during the 2020-2022 and 2023-2026 periods.

TABLE 17-4
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP 2017-2019	2020-2022 GRC 2017-2020	2020 RAMP 2020-2022	2020 RAMP 2023-2026
1	C1 – Enhanced Standard Contract Terms and Conditions	X	X	X	X
2	C2 – Contractor Safety Pre-Qualifications	X	X	X	X
3	C3 – Contractor Safety Standard and LOB Contractor Oversight Procedures	X	X	X	X
4	C4 – Contractor Safety Plans	X	X	X	X
5	C5 – Contractor Hazard Analysis	X	X	X	X
6	C6 – LOB Contractor Safety Oversight	X	X	X	X
7	C7 – LOB Compliance Assessments	X	X	X	X
8	C8 – Corrective Action Program (CAP) for Contractor Issues	X	X	X	X
9	C9 – Contractor Post-Job Safety Performance Review	X	X	X	X
10	C10 (M1B) – SIF Incident Governance and Oversight		X	X	X
11	C11 (M2) – Contractor Safety Officer Criteria		X	Being Enhanced as M18	X
12	C12 (M3) –CAP Issues Criteria		X	Removed as Ineffective	
13	C13 (M4) – ISN Rapid Growth Tracking		X	X	X
14	C14 (M6) – OSHA Program Training Requirements		X	Being Enhanced as M17	
15	C15 (M7) – Standardized Safety Plan and Job Safety Analysis (JSA) Templates		X	X	X
16	C16 (M8) – PG&E Specific Hazards Communication Process		X	Removed as Duplicative	
17	C17(M12) – Tools and Technology		Mitigation Bundle	Unbundled – Removed	

TABLE 17-4
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Name and Number	2017 RAMP 2017-2019	2020-2022 GRC 2017-2020	2020 RAMP 2020-2022	2020 RAMP 2023-2026
18	C18 (M9 – Contractor Governance) LOB to Conduct Contractor Forums			X	X
19	C19 (M10 Contractor Knowledge bundle) – All impacted PG&E Employees Bi-Annual Program Compliance Training			X	X
20	C20 (M9 – Contractor Governance) Enhance Contractor Post-Job Performance Evaluation			X	X
21	C21 (M9 – Contractor Governance) Automated System for Improving Processes through ISN			X	X

TABLE 17-5
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
1	M1B – SIF Incident Governance and Oversight	X	Becomes a Control C10		
2	M2 – Contractor Knowledge: Contractor Safety Officer Criteria	X	Becomes a Control C11	Being Enhanced as M18	
3	M3 – CAP Issues Criteria	X	Becomes a Control	Removed as Ineffective	
4	M4 – ISN Company Rapid Growth Tracking	X	Becomes a Control C13		
5	M5 – Contractor Blocking Automation	X	Removed as infeasible		
6	M6 – Contractor Knowledge: OSHA Program Training Requirements	X	Becomes a Control	Being Enhanced as M17	
7	M7 – Standardized Safety Plan and JSA Templates	X	Becomes a Control C15		
8	M8 – PG&E Specific Hazards Communication Process	X	Becomes a Control	Removed as duplicative	
9	M9 – Contractor Governance		Mitigation Bundle	Unbundled – now C18, C19, C20	
10	M10 – Contractor Knowledge		Mitigation Bundle	Unbundled – now C10	

TABLE 17-5
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigations	2020 RAMP 2023-2026 Mitigations
11	M11 – Contractor Process Improvements (PI)		Mitigation Bundle `	Unbundled – now M11a and M11b	
12	M11A - Safety Scorecard		X (Inc. in M11)	X	Becomes a Control
13	M11B – Work Permits		X (Inc. in M11)		X
14	M12 – Tools and Technology		Mitigation Bundle	Unbundled – now M12a and M12b	
15	M12a – ISN's Individual Badge Feature			X	Becomes a Control
16	M12b – Establish Tool for Capturing Contractor Near-Hits and Good-Catches			X	Becomes a Control
17	M13 – Contractor On-Boarding Requirements			X	X
18	M14 – Contractor Safety Field Inspections			X	X
19	M15 – Contractor Safety Handbook			X	Becomes a Control
20	M16 – Tracking Contractor Workers				X
21	M17 (enhancement to C14) –OSHA Programs Training Requirements			X	X
22	M18 (enhancement to C11) – Contractor Safety Officer Criteria			X	Becomes a Control

1. 2019 Controls and Mitigations

a. Controls

PG&E identified nine controls in its 2017 RAMP that are anticipated to remain in place through 2026.

C1 – Enhanced Standard Contract Terms and Conditions: The enhanced Standard Contract Terms and Conditions, which are inserted into each of the prime contractors' contracts, are specific safety-related expectations and conditions based on the Contractor Safety Program Standard SAFE-3001S. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

C2 – Contractor Safety Pre-Qualification: The Contractor Safety program's pre-qualification process establishes criteria for contractors to qualify in order to perform work for PG&E. The criteria include total recordable injury and days away/restricted duty/transferred rates, number of fatalities, and confirmed OSHA citations. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

C3 – Contractor Safety Standard and LOB Contractor Oversight Procedures: The Contractor Safety Standard and the associated LOB contractor safety oversight procedures set requirements for managing medium and/or high risk contract work, including procedural steps for each LOB in providing work oversight and management for their contractors. These procedures include providing post-job safety performance evaluation of contractor work and sharing lessons learned resulting from safety incidents. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps in procedure implementation. Corporate Contractor Safety has established a formal review and approval process in 2019 for any new or revised procedures and included an approval requirement in the Contractor Safety Standard SAFE-3001S.

C4 – Contractor Safety Plans: Safety plans are developed by the contractor and are reviewed and approved by PG&E prior to commencing high risk work. These plans are required to address the Scope of Work (SOW) to be performed and identify specific site or task hazards, and mitigations of those hazards prior to beginning work. Additionally, these plans include a requirement to perform a hazard analysis (Refer to C5 for Job Hazard Analysis/tailboard requirements) prior to beginning medium and/or high-risk work activities. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps. In 2019, this process was strengthened by establishing minimum safety training requirements and qualifications for safety plan approvers.

C5 – Contractor Hazard Analysis: Contractors perform a job hazard analysis as part of their daily tailboard process as a method of identifying, mitigating and communicating known or potential hazards to their employees and subcontractors prior to commencing work. These analyses are required prior to the execution of work and re-enforce the requirements established in the approved safety plans (refer to C4 for Contractor Safety Plans). Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

C6 – LOB Contractor Safety Oversight: The LOBs and Corporate Field Safety provide oversight of contactors by conducting field safety observations of crews, using observation software, to validate compliance with PG&E and regulatory safety requirements, while identifying safe/unsafe behavior and/or conditions. SafetyNet® is a software tool that was made available across the enterprise in 2019 to capture contractor safety observations performed by the LOB. This allows PG&E to aggregate large quantities of data from observed at-risk behaviors and/or conditions from multiple job sites and projects. Analysis of this data allows each LOB to better understand the specific areas of risk exposure and to target mitigation resources to those specific risks.

C7 – LOB Compliance Assessments: These assessments focus on compliance with the requirements outlined in the LOB procedures, including identifying any nonconformance and correcting them through PG&E's CAP. The assessments also focus on PG&E work that utilizes contractors performing medium and/or high-risk activities and are conducted across all LOBs by members of the Corporate Contractor Safety team. The assessment results, including any related findings, are reported out post-assessment at the LOB level and also quarterly at an enterprise level. PG&E has completed 208 Contractor Safety Program LOB Compliance Assessments across the enterprise in 2019. 10.3 percent of these assessments resulted in one or more identified non-conformances.

C8 – CAP for Contractor Issues: CAP continues to be used for contractor LOB assessment non-conformances issues. CAP provides a process to document non-conformances identified from the LOB compliance assessments (Refer to C7 for LOB Compliance Assessment Control) and track issues to closure. To enhance the visibility into the issues being identified from these assessments, PG&E created a dashboard in 2019 that displays all assessment findings by LOB that can be accessed by any PG&E employee.

C9 – Contractor Post Job Safety Performance Review: LOBs complete safety performance evaluations for contractors at the end of project work or at least annually for multi-year projects. Post-job performance evaluations are entered into each contractor's ISN account and factor into each contractor's pre-qualification status. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

b. Mitigations

PG&E identified 8 mitigations in the 2017 RAMP for the 2017 to 2019 period.

M1B – SIF Incident Governance and Oversight: This mitigation is broken up into three sub-mitigations and is performed by a cross-functional team of PG&E SMEs. By doing this work, PG&E will be able to establish a standardized framework for effectively on-boarding contractors, improve identification and mitigations of hazards and investigate and respond to serious injury and fatality events. The sub-mitigations are:

- Implementation of an agreed-upon Safety and Health oversight structure to assist in the identification and controls of hazardous conditions;
- Perform end-to-end process review as part of contractor fatality investigation and implement corrective actions; and
- Design the framework for a contractor on-boarding program (5-year plan, contractor training requirements, and PG&E criteria for on-boarding).

M2 – Contractor Safety Officer Criteria: Develop and implement criteria for when contractors are required to provide a Safety Officer, or a designated safety representative. This mitigation is an enhancement of C6 (LOB Contractor Safety Oversight) noted in Section III above. By implementing this requirement, the contractor will provide additional safety oversight during the execution of work.

M3 – Corrective Action Program Issues Criteria: This mitigation will provide contractors with the ability to use CAP. The program had previously been available only to PG&E employees. This mitigation will allow PG&E to efficiently track and review the contractor's progress on closure of corrective actions. This also includes the development and implementation of criteria for requiring CAP issues to be reported when there are contractor safety identified findings and/or corrective actions from safety incident investigations. This mitigation is an enhancement of C8 (CAP for contractor issues).

M4 – ISN Company Rapid Growth Tracking: Utilize ISN to track the rapid growth of contractors that have expanded their Company employee count by 20 percent or greater in a single quarter. This will enable PG&E to perform a review of the contractors' safety management systems in place to support the workforce expansion. This mitigation is an enhancement of C2 (Contractor Safety – Pre-Qualifications).

M5 – Contractor Blocking Automation: Automate the ability to block contractors who do not meet PG&Es pre-qualification requirements in SAP. Implement a daily a direct feed from ISN to SAP that will block contractors based on their pre-qualification status in ISN. The SAP block will not allow a new contract to be executed with the contractor. This will lead to a reduction in the risk associated with executing a contract with an unqualified contractor. This mitigation is an enhancement of C2 (Contractor Safety – Pre-Qualifications).

M6 – (Contractor Knowledge) OSHA Programs Training Requirements: Identify safety training for contractors and PG&E employees overseeing contractors to ensure they have the appropriate qualifications and training required to oversee the work from a safety perspective. This is in addition to any required OSHA training. This mitigation is an enhancement of C6 (LOB Contractor Safety Oversight).

M7 – Standardized Safety Plan and JSA Templates: Standard templates for safety plans and JSAs will allow PG&E to establish baseline requirements across all LOBs. This mitigation is an enhancement of C4 (Contractor Safety Plans) and C5 (Contractor Hazard Analysis).

M8 – PG&E Specific Hazards Communication Process: Develop a process for communicating PG&E specific hazards to enable contractors to better identify and plan to mitigate those hazards associated with sites, assets and facilities prior to commencing work. This mitigation is an enhancement of C4 (Contractor Safety Plans) and C5 (Contractor Hazard Analysis).

c. 2017 RAMP Update

PG&E concluded in the 2017 RAMP that the best way to mitigate contractor safety risks was through mitigation bundles that focused on key Contractor Safety Program objectives: Contractor Safety Program PI; Governance; Knowledge; and Tools and Technology. PG&E also designed and implemented controls to comply with PG&E’s internal contractor safety program and with applicable OSHA and CPUC requirements.

In addition, PG&E presented eight mitigations (M1B through M8)[6] in the 2017 RAMP to further manage risk by enhancing the pre-qualification contractor management process and by improving contractor safety planning, training and oversight. The mitigations were developed based on the results of a Contractor Safety Program gap analysis that PG&E conducted. Of those eight mitigations:

- As shown in Table 17-5 above, seven mitigations (M1, M2, M3, M4, M6, M7, and M8) are now controls in the 2020 RAMP and the SOW presented in the 2017 RAMP remains the same; and
- One mitigation (M5) was removed because it is not possible to feed data directly from ISN into PG&E's SAP.

In the 2020 GRC PG&E provided an update as to the state of managing the Contractor Safety risk.[7] In the 2020 GRC PG&E identified three remaining mitigation bundles: Contractor Governance; Contractor Knowledge; and Contractor PIs. While the individual mitigations have changed, the three new mitigations proposed in the 2020 GRC are closely aligned to the key Contractor Safety Program objectives set forth in the 2017 RAMP. The mitigations PG&E presented in the 2017 RAMP became controls in the 2020 GRC as the mitigations matured and became established, on-going processes for managing risk.[8]

In the 2017 RAMP PG&E presented nine controls (C1-C9)[9] that were on-going activities for managing the risk drivers for Contractor Safety risk. These same nine controls were included in PG&E's 2020 GRC and are again presented in the 2020 RAMP, though the scope of many of the controls has been updated.

In the 2020 GRC identified eight new controls, most of which continue into the 2020 RAMP. The additional controls and changes to controls are included in Table 17-4 above.

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[6] PG&E's 2017 RAMP Report, p. 14-11.

[7] Application (A.) 18-12-009, Exhibit (PG&E-7), Chapter 1.

[8] A.18-12-009, Exhibit (PG&E-7), Table 1-4, p. 1-30.

[9] PG&E's 2017 RAMP Report, p. 14-9.

For the 2020 RAMP, the three mitigation bundles remaining from the 2020 GRC; M9 (Contractor Governance), M10 (Contractor Knowledge), and M11 (Contractor PI) have been removed and updated as individual mitigations

D. 2020-2022 Controls and Mitigations Plan

1. Changes to Controls

In the 2020 RAMP PG&E continues to implement the nine controls included in the 2017 RAMP and adds seven new controls that are described below. Changes to controls included in PG&E's 2020 GRC are shown in Table 17-4 above.

C10 –SIF Incident Governance and Oversight. PG&E has two established procedures to address this: (1) The SIF Manual, SAFE-1100M, that outlines the process for after a SIF occurs (PG&E employee or contractor) from the necessary notifications through the full investigation process; and (2) The procedure for non-SIF incidents involving contractors, SAFE-1100P-2, that provides a structure for evaluating the quality of the required contractor investigation and associated corrective actions, determining the extent of condition throughout PG&E, and developing and implementing corrective actions based on the extent of condition. Both procedures have processes required for entering issues into CAP for evaluation and corrective actions that were previously identified in C12 (CAP Issue Criteria), which has now been removed and incorporated into this control.

C13 – ISN Rapid Growth Tracking and Contractor Evaluations. Utilize ISN to track the rapid growth of contractors that have increased their headcount significantly for PG&E work. PG&E's Corporate Contractor Safety team performs Management and Organizations reviews of the contractor's safety management systems in place to support the workforce expansion. In 2019, 52 evaluations were competed resulting in 44 approved contractors. This control is an enhancement of C2 (Contractor Safety Prequalification).

C15 – Standardized Safety Plan and JSA Templates. Standard templates for safety plans and JSAs will allow PG&E to establish baseline requirements across all LOBs. In 2018, PG&E established minimum requirements for Job Hazard Analysis templates and included these requirements in the contract terms and conditions. This program is an enhancement of control for C4 (Contractor Safety Plans) and C5 (Contractor Hazard Analysis/Daily Tailboards). Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

C18 – LOBs to Conduct Contractor Forums. LOBs conduct safety forums with contractors to partner on safety topics, lessons learned and performance feedback. Ongoing evaluations are conducted through the LOB compliance assessment process to assess effectiveness and identify any gaps.

C19 – Contractor Safety Program Orientation. The Contractor Safety Program Orientation SAFE-0102 web-based training (WBT), was created for PG&E employees who oversee contractors. This WBT was approved in 2018 by the Learning Academy as an optional course and does not require mandatory enrollment. PG&E will re-evaluate in 2020 if this WBT needs to be required and assigned to employees who oversee contracted work. This control was Mitigation M9 in the 2020 GRC.

C20 – Enhance Contractor Post-Job Performance Evaluation. Contractor post-job performance evaluation scorecard criteria have been in place as a control since 2018. This control was Mitigation M9 in the 2020 GRC.

C21 – Automated System for Improving Processes through ISN. An automated system for tracking, trending and generating reports to improve processes through ISN has been in place as a control since 2018. This control was Mitigation M9 in the 2020 GRC.

2. Changes to Mitigations

PG&E will implement eight new mitigations in the 2020-2022 period. Certain mitigations will continue into the 2023-2026 period as well.

M11a – Safety Scorecard. Implement a safety performance evaluation scorecard to determine whether contractors need improvement in their performance or if they need a probationary period with a possible safety improvement plan or a deep-dive safety assessment. The results may be used in determining future work awards. Expected implementation year-end 2021 with integration into contractor work activities through 2023 transitioning to a control and in place through 2026 (RAMP 2020 timeline)

M12a – Use ISN's Individual Badge Feature. Use ISN's individual badge feature to verify contractor employee training and qualifications at the job site. Year end 2020 completion is estimated.

M12b – Contractor Near-hits/Good-Catches. Establish a method for capturing both PG&E employee and contractor near-hits/good-catches in one platform. This mitigation is expected to be implemented in 2021.

M13 – Contractor Onboarding. This is a new mitigation and an enhancement related to C10 (SIF Incident Governance and Oversight). This mitigation will include minimum criteria for requirements for consistently onboarding contractors throughout the enterprise.

M14 – Contractor Safety Field Inspections. Corporate Safety will perform unannounced field visits. This is a new mitigation and an enhancement related to C6 (LOB Contractor Safety Oversight) and C7 (LOB Compliance Assessments). The Contractor Safety Standard SAFE-3001S requires the LOBs to perform safety observations of their contractors. Additionally, the Corporate Contractor Safety team conducts LOB compliance assessment of the LOBs adherence to their approved contractor oversight procedures (refer to C3 Contractor Safety Standard and LOB Contractor Oversight Procedures). This is an expansion to focus on contractor adherence to OSHA compliance.

M15 – Contractor Safety Handbook. This mitigation is an enhancement of C1 (Enhanced Standard Contract Terms and Conditions). Develop a comprehensive Environmental and Health and Safety (EHS) handbook to includes policies, programs, procedures, and other documents that explain PG&E's requirements and expectations to provide consistent guidance to contractors. Integrate the EHS Handbook into contractor work activities. This mitigation will be implemented 2022.

M17 – OSHA Programs Training Requirements. Identify safety training for contractors and PG&E employees overseeing contractors to ensure they have the appropriate qualifications and training required to oversee the work from a safety perspective. This is in addition to any required OSHA training. This mitigation is an enhancement of C6 (LOB Contractor Safety Oversight).

M18 – Contractor Safety Officer Criteria (enhancement to C11). Develop and implement criteria for when contractors are required to provide a Safety Officer, or a designated safety representative. This mitigation is an enhancement of C6 (LOB Contractor Safety Oversight). By implementing this requirement, the contractor will provide additional safety oversight during the execution of work. This mitigation will be evaluated in 2020 for 2021 implementation.

Table 17-6 below shows the forecast costs for the mitigation work planned for the 2020-2022 period.

TABLE 17-6
FORECAST COSTS
2020-2022 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M11a	Safety Scorecard	FL	–	$181	–	$181
2	M11b	Work Permits	FL	–	–	–	–
3	M13	Contractor On-Boarding	FL	–	–	$1,625	1,625
4	M14	Contractor Safety Field Inspections	FL	–	3,740	3,740	7,480
5	M15	Contractor Safety Handbook	FL	–	216	–	216
6	M16	Tracking Contractor Workers	FL	–	–	–	–
7	M17	OSHA Programs Training Requirements	FL	–	492	148	640
8	M18	Contractor Safety Officer Criteria	FL	–	17	17	34
9		Total		–	$4,646	$5,530	$10,176

Notes See WP 17-1.

E. 2023-2026 Proposed Mitigation Plan

PG&E is proposing two new mitigations between 2023 and 2026 that are described below. In addition, three mitigations started in the 2020-2022 period continue (M13, M14 and M17) and five mitigations started in the 2020-2022 period become controls (M11A, M12A, M12B, M15, and M18).

M11b – Work Permits: Establish a process for PG&E to evaluate critical high-risk work activities and ensure all safety controls are in place before commencement.

M16 – Tracking Contractor Workers: Establish a platform for tracking contractor work status and crew locations. The proposed system will enhance existing processes to allow tracking of work schedules and locations. PG&E expects implementation year-end 2023 with transition to control through the RAMP 2020 timeline of 2026.

Table 17-7 below shows the forecast costs, RSEs and risk reduction scores for the mitigation work planned for the 2023-2026 period.

TABLE 17-7
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	M11a	Safety Scorecard	FL	–	–	–	–	–	–	–
2	M11b	Work Permits	FL	$58	$17	$17	$17	$109	215.9	18.0
3	M13	Contractor On-Boarding	FL	1,625	1,625	1,625	1,625	6,500	3.8	18.0
4	M14	Contractor Safety Field Inspections	FL	3,740	3,740	3,740	3,740	14,960	1.3	14.4
5	M15	Contractor Safety Handbook	FL	–	–	–	–	–	–	–
6	M16	Tracking Contractor Workers	FL	1,501	1,501	1,501	1,501	6,005	4.1	18.0
7	M17	OSHA Programs Training Requirements	FL	148	148	148	148	591	33.0	14.4
8	M18	Contractor Safety Officer Criteria	FL	–	–	–	–	–	–	–
9		Total	–	$7,071	$7,031	$7,031	$7,031	$28,164		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

Note See WP 17-1.

Based on the results of the risk modeling analysis shown in Table 17-7 above, PG&E is proposing to spend approximately half of its 2023-2026 funds on the Contractor Safety Field Inspections program even though it has one of the lower RSEs. The Contractor Safety Field Inspections Program is critical because it allows PG&E to confirm that its Contractors are executing high and medium risk work safely. It is the way to verify that Contractors are complying with OSHA and PG&E safety requirements and that they are adhering to the project specific safety plans approved by PG&E.

The proposed Work Permits mitigation has the highest RSE though PG&E is proposing to spend less than one percent of its budget on it. The program is available through ISN and allows for permit management on the move, through phones and tablets. PG&E will look for opportunities to expand this program.

F. Alternative Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: Do Not Implement the Contractor Work Management System

This alternative considers removal of the Contractor Work Management System for tracking contractor work status and crew locations. Because the Contractor Work Management System supports increased oversight and is critical to the success of the Contractor Safety Program PG&E will proceed with its proposal to implement the system. This alternative was not chosen because it could reduce contractor safety.

2. Alternative Plan 2: Increased Contractor Safety Field Inspection Resources

This alternative would expand the Contractor Safety Field Inspections program by increasing the number of PG&E resources assigned to the program. As shown in Table 17-8, expanding this program would significantly increase the cost without a commensurate increase in safety risk reduction. PG&E chose not to pursue this alternative due to the high cost.

TABLE 17-8
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A2	Increased Contractor Safety Field Inspections	$3,740	$3,740	$3,740	$3,740	$14,960		
2		Total	$3,740	$3,740	$3,740	$3,740	$14,960	0.9	9.8

(a) See MW included in the source document modeling package for information used to calculate the RSE.
Note: See WP 17-1.

Table 17-9 compares the proposed and alternative mitigation plans.

TABLE 17-9
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSAND OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)[(b)]	RSE
1	Proposed	M11b, M13, M14, M16, M17	$28,165	–	82.9	$20,749	4.0
2	Alternative 1	M11b, M13, M14, M17	$22,160	–	68.2	$16,326	4.2
3	Alternative 2	Proposed +A2	$43,125	–	90.5	$31,768	2.8

(a) Plan Components refers to the Mitigations presented in Table 17-4.
(b) Information presented in terms of Net Present Value (NPV) to account for the discounting of benefits.
Note: See WP 17-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 18

RISK ASSESSMENT AND MITIGATION PHASE

RISK MITIGATION PLAN: MOTOR VEHICLE SAFETY INCIDENT

PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 18
RISK ASSESSMENT AND MITIGATION PHASE
RISK MITIGATION PLAN: MOTOR VEHICLE SAFETY INCIDENT

A. Executive Summary

Motor Vehicle Safety Incident (MVSI) risk includes any motor vehicle accident involving a Pacific Gas and Electric Company (PG&E or the Company) vehicle (or a personal vehicle being operated on company business) resulting in injuries or fatalities to, either PG&E employees or the public, and/or property damage. However, certain PG&E vehicles such as off-road vehicles and unique or specialized vehicles are out of scope for this risk. The drivers for this risk event are: non-preventable motor vehicle incident (NPMVI); preventable motor vehicle incident (PMVI) – PG&E hit stationary object; PMVI – PG&E backing; PMVI – PG&E struck third party; PMVI – rear ended third party; PMVI – PG&E initiated (all others); and PMVI – PG&E hit PG&E equipment. The cross-cutting factor Records and Information Management also impacts this risk.

Exposure to this risk is based on the approximately 141 million miles driven each year. The risk model includes an Average Annual Frequency of approximately 914 risk events each year. NPMVI accounts for 523 events/incidents or 57 percent of the risk events and 57 percent of the risk. PMVI accounts for 43 percent of the risk events and 43 percent of the risk.

PG&E identified eight tranches for 2020 based on a review of motor vehicle types and weight classes between 2016 and 2019. PG&E-owned trucks less than 10,000 pounds and PG&E-owned trucks 10,000 to 26,000 pounds account for 594 of the 914 risk events or 65 percent of the tranche-level risk for both Preventable and Non-Preventable incidents.

MVSI has the tenth highest 2023 test year baseline safety score (16.0) and the tenth highest 2023 test year baseline total risk score (16.6) of PG&E's 12 RAMP risks. The 2020 baseline total risk score of 21.4, improves by 24 percent when the planned mitigations are applied: the 2023 test year baseline total risk score is 16.6 and the 2026 post-mitigation risk score is 16.2.

PG&E is proposing a series of controls and mitigations to address MVSI risk. The Cell Phone Activity Blocking mitigation is PG&E's proposed mitigation.

It will be subject to further review as part of the General Rate Case (GRC) mitigation analysis using a third-party consultant (University of California, Los Angeles (UCLA)) who will incorporate the use of Bayesian Belief Networks to perform calculations considering the joint effect of factors in human error in PMVIs. Based on the current RAMP analysis, the Smith Driving and Driver Selection Program mitigations have highest risk reduction score.[1]

TABLE 18-1
RISK OVERVIEW

Line No.	Risk Name	Motor Vehicle Safety Incident
1	In Scope	Any recordable MVI, both preventable and non-preventable involving a PG&E vehicle (or operated on behalf of PG&E). A recordable incident requires PG&E line of business filing a report on the incident. Non-preventable motor vehicle incidents involving third party interaction are in scope.
2	Out of Scope	Motorized equipment, off-road vehicles, off-road driving, and unique or specialized vehicles (included in the Employee Safety Incident risk), as well non-staff augmentation contractors, and other drivers.[a]
3	Data Quantification Sources	PG&E fleet data and MVI data, from January 2016 to December 2019[b]

(a) Incidents associated with motorized equipment, off-road vehicles, off-road driving, and unique or specialized vehicles that are not in scope for this risk are included in the Employee Safety Incident risk, Chapter 16.
(b) Source documents will be provided with the workpapers on July 17, 2020.

1. Risk Overview

PG&E's Transportation Services (TS) organization supports more than 13,800 vehicles and related equipment including construction equipment, trailers and aircraft. Annually, PG&E employees drive more than 141 million miles in PG&E vehicles to provide service to customers.

PG&E's Transportation Safety organization ensures compliance with federal Department of Transportation (DOT) regulations and state requirements. The Transportation Safety team manages a centralized compliance system of driver profiles (i.e., Commercial Driver's License (CDL), medical, drug, alcohol, clearinghouse and other compliance testing requirements) that provides PG&E with the ability to view and pair qualified

1 The information herein is subject to those limitations described in Chapter 2, Section D.

drivers to vehicles they are qualified to drive and to track Drug and Alcohol Program enrollment and compliance. The department also tracks DOT-covered positions for the Pipeline and Hazardous Materials Safety Administration drug testing pool, for the Gas Operations.

The TS organization requires adherence to the MVSI controls, including safe driving programs, to reduce preventable motor vehicle incidents.

2. Risk Definition

Any motor vehicle accident involving a PG&E vehicle (or a personal vehicle being operated on company business) resulting in injuries or fatalities to, either PG&E employees or the public, and/or property damage. Certain PG&E vehicles such as off-road vehicles and unique or specialized vehicles are out of scope for this risk and are included in the Employee Safety Incident risk as part of the Serious Injury or Fatality (SIF) Prevention program.

B. Risk Assessment

1. Background and Evolution

MVSI is an updated risk in the 2020 RAMP. PG&E's 2017 RAMP included a motor vehicle risk, Motor Vehicle Safety.[2] For both the 2017 RAMP Motor Vehicle Safety and the 2020 RAMP MVSI risks, the risk event is the same—MVI both preventable (43 percent of the time) and non-preventable (57 percent of the time).

The MVSI risk definition has been updated since 2017. In the 2017 RAMP, this risk was defined as the failure to identify and mitigate motor vehicle incident exposures that may result in serious injuries or fatalities for employees or the public, property damage, and other consequences. The new risk definition aligns to PG&E's transition to an event-based risk register.

In the 2017 RAMP, PG&E identified three MVSI drivers: Equipment; Human Errors; and Outside Forces. Human errors, i.e., incidents resulting from human mistakes, accounted for 94 percent of the 2,256 events.[3]

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[2] PG&E's RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017) (PG&E's 2017 RAMP Report), Chapter 16.

[3] PG&E's 2017 RAMP Report, p. 16-4.

The seven drivers for MVSI 2020 RAMP are classified into two groups: non-preventable incidents—where the PG&E driver could not have reasonably prevented the incident from occurring (which accounts for 57 percent of the incidents); and, preventable incidents—where the PG&E driver could have reasonably prevented the incident from occurring (which accounts for 43 percent of the incidents). As part of the UCLA risk analysis planned for later this year (discussed in greater detail in Section 8), PG&E will revisit the tranches and the data to better understand and illustrate the risk areas. Two of the 2017 drivers (Equipment and Outside Forces) are no longer drivers in 2020 because the data associated with these drivers did not reasonably represent factors leading to MVSIs.

PG&E's 2017 RAMP relied on both PG&E and national data (from DOT) to develop weightings for each risk driver.[4] In 2020, PG&E is relying exclusively on PG&E data to develop weightings for each risk driver. PG&E will review the data again in 2021 and may further revise the weightings for the risk drivers. The new drivers and new risk definition, which resulted from the transition to using PG&E data instead of national data, provide a more focused approach to PG&E-specific risk because it takes into account controls that are already in place but that may not be accounted for in other fleets and statistics.

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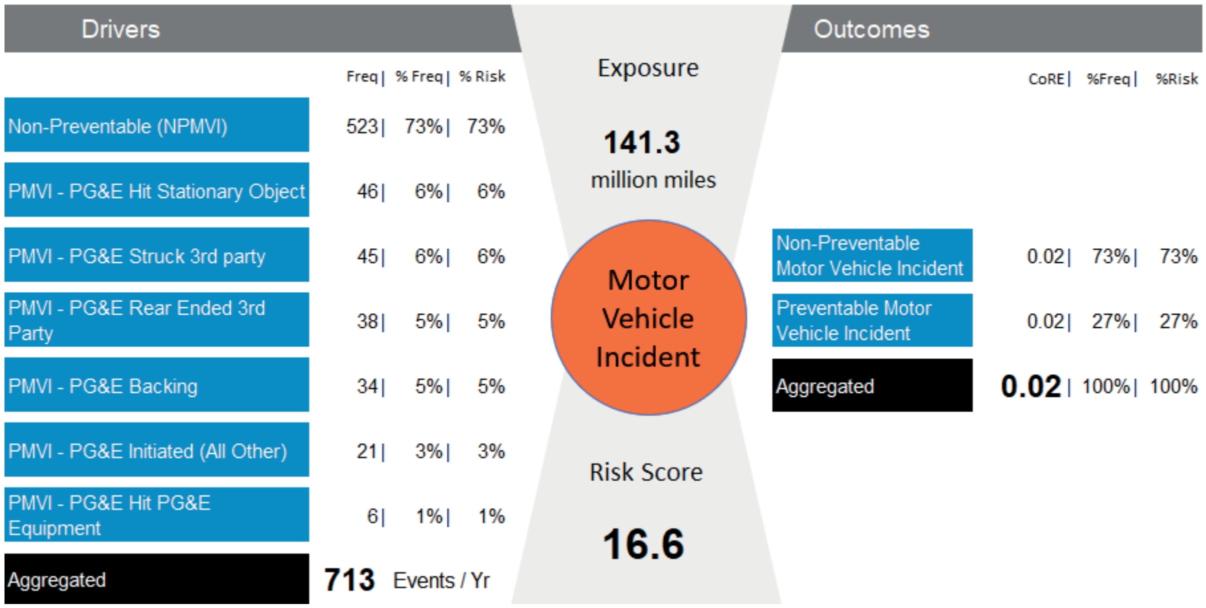
4 PG&E's 2017 RAMP Report, p. 16-4.

2. Risk Bow Tie

FIGURE 18-1
RISK BOW TIE – 2023 TEST YEAR BASELINE



3. Exposure to Risk

Driving or riding in a PG&E vehicle or vehicle operated on behalf of PG&E creates exposure to the MVSI risk. PG&E uses miles driven as the measure of risk relative to exposure and the number of events per vehicle miles driven as the measure of risk relative to exposure.

PG&E's exposure for this risk is 141.3 million miles driven per year, which is based on PG&E Transportation Services data.

4. Tranches

PG&E identified eight tranches for MVSI risk, based on a review of motor vehicle types and weight classes for 2020. PG&E anticipates that the number of tranches will change in 2021.

- PG&E owned – trucks weighing less than 10,000 pounds;
- PG&E owned – trucks weighing between 10,000 and 26,000 pounds;
- PG&E owned – trucks weighing more than 26,000 pounds;
- PG&E owned – passenger vehicles;
- PG&E owned – trailers (will not apply in 2021 because trailers do not operate under their own power);

- PG&E owned – carpool vans (will not apply in 2021 because PG&E does not own carpool vans);
- Employee owned vehicles; and
- Rental vehicles.

TABLE 18-2
RISK EXPOSURE AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Annualized Mileage	Percent Exposure	Safety Risk Score	Financial Risk Score	Total Risk Score	Percent Risk[(a)]
1	PG&E-Owned – Trucks Less Than 10,000 lbs.	66.5	47%	6.7	0.28	6.9	42%
2	Employee-Owned Vehicles	30.0	21	1.6	0.07	1.7	10
3	PG&E-Owned – Trucks 10,000 – 26,000 lbs.	25.0	18	3.3	0.14	3.5	21
4	PG&E-Owned – Trucks Greater Than 26,000 lbs.	11.0	8	1.2	0.05	1.2	7
5	Rental Vehicles	7.4	5	1.2	0.05	1.3	8
6	PG&E-Owned – Passenger Vehicles	1.3	1	1.8	0.07	1.9	11
7	PG&E-Owned – Trailers	0.0	0	0.1	0.01	0.1	1
8	PG&E-Owned – Carpool Vans	0.0	0	0.0	0.00	0.0	0
9	Total[(b)]	141.3	100%	16.0	0.66	16.6	100%

(a) Percent risk is calculated risk based on frequency and consequence. The percent risk is the contribution of risk for each tranche to the overall risk.

(b) Differences due to rounding.

5. Drivers and Associated Frequency

PG&E identified seven drivers and six sub-drivers for the MVSI risk. Each driver and its associated historical frequency, and key sub-drivers are discussed below.

D1 – NPMVI: Refers to a recordable MVI wherein the PG&E driver is not at fault. NPMVI events accounted for 523 (57 percent) of the 914 average annual number of events. PG&E identified six sub-drivers NPMVI sub-drivers: (1) third-party struck PG&E from behind; (2) all other; (3) third-party struck PG&E; (4) third-party struck PG&E property, parked; (5) third-party struck stopped PG&E; and (6) rock/road debris struck PG&E.

D2 – PMVI: PG&E Hit Stationary Object: Refers to a recordable MVI wherein the PG&E driver hit a stationary object. PG&E Hit Stationary Object events accounted for 107 (12 percent) of the 914 average annual number of events.

D3 – PMVI, PG&E Backing: Refers to a recordable MVI wherein the PG&E driver backed their vehicle into an object. PG&E Backing events accounted for 98 (11 percent) of the 914 average annual number of events.

D4 – PMVI, PG&E Struck Third-Party: Refers to a recordable MVI wherein the PG&E driver struck a third-party vehicle. PG&E Struck Third-Party events accounted for 78 (8 percent) of the 914 average annual number of events.

D5 – PMVI, PG&E Rear-Ended Third-Party: Refers to a recordable MVI wherein the PG&E driver struck the rear end of a third-party vehicle. PG&E Rear-Ended Third-Party events accounted for 64 (7 percent) of the 914 average annual number of events.

D6 – PMVI, PG&E Initiated (all others): Refers to a recordable MVI wherein the PG&E driver is at fault (other than as described by the PMVI drivers). PG&E Initiated events accounted for 35 (4 percent) of the 914 average annual number of events.

D7 – PMVI, PG&E Hit PG&E Equipment: Refers to a recordable MVI wherein the PG&E driver struck PG&E equipment. PG&E Hit PG&E Equipment events accounted for 11 (1 percent) of the 914 average annual number of events.

6. Cross Cutting Factors

A cross-cutting factor is a driver or control that is interrelated to multiple risks. PG&E is presenting eight cross-cutting factors in the 2020 RAMP. The cross-cutting factor that impacts the MVSI risk are shown in Table 18-3 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors are described in Chapter 20.

TABLE 18-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Records and Information Management		X

When analyzing this risk PG&E considered the cross-cutting risk Climate Change even though it is not listed in the table above. Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities it serves. During this RAMP period PG&E will conduct a Climate Vulnerability Assessment (CVA) to further assess how its assets, operations, and employees are vulnerable to the projected impacts of climate change. PG&E intends to use findings from the CVA as well as developments in climate science and internal data gathering to continue to advance the quantification of all event-based risks, including RAMP risks, over this RAMP period.

7. Consequences

The basis for measuring the consequences of the MVSI risk is the finding that a PG&E driver in a recordable MVI is either at fault or not at fault.

The consequences of a MVSI risk event occurring are:

- An NPMVI occurs 73 percent of the time, and accounts for 73 percent of the safety risk; and
- A PMVI occurs 27 percent of the time and accounts for 27 percent of the safety risk.

Both PG&E employees and the public can be impacted by a PMVI or NPMVI. There is a financial consequence for both PMVI and NPMVI.

To analyze the safety consequences of the MVSI risk, PG&E relied on the PG&E Serious Injuries Report or the years of 2012-2019 using Fleet information data. PG&E focused on the period 2016-2019 for MVS incident reporting. The Serious Injuries Report provides information on serious injuries and fatalities for Employee, Contractor and Third-Party Public. SIF reporting incorporates a defined set of injuries that meets or exceeds Cal/OSHA reporting. Incident fault is not defined in the data.

PG&E relied on the PG&E GRC and Cal/OSHA recorded days away from work/restricted/transferred (DART) cases to analyze the financial consequences of the MVSI risk. The data used to evaluate this risk was supported by PG&E subject matter expertise best judgment.

Table 18-4 shows the consequences of the risk event. Model attributes are described in Chapter 3, Risk Modeling and Risk Spend Efficiency (RSE).

TABLE 18-4
RISK EVENT CONSEQUENCES

					Natural Units Per Event		CoRE		Natural Units per Year		Attribute Risk Score	
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Financial $M/event	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety	Financial
Non-Preventable Motor Vehicle Incident	0.02	73%	73%	523	0.0004	0.002	0.0223	0.001	0.2	1.0	11.7	0.5
Preventable Motor Vehicle Incident	0.02	27%	27%	190	0.0004	0.002	0.0226	0.001	0.1	0.4	4.3	0.2
Aggregated	**0.02**	100%	100%	713	0.0004	0.002	0.0224	0.001	0.3	1.3	16.0	0.7

8. Next Steps in Modeling the Motor Vehicle Safety Incident Risk

PG&E has contracted with the B. John Garrick Institute for the Risk Sciences at UCLA to do an assessment that will lead to PG&E's updating its risk analysis so that the MVI risk drivers are expressed as accident causes (distraction, fatigue, etc.) as opposed to accident types.

PG&E is working with UCLA to study the causes of PG&E MVIs and assist in developing recommendations for mitigations. The first step in the UCLA/PG&E work was to identify and understand the relative contribution of causes to MVIs. The team analyzed PG&E preventable MVI investigation narrative records in order to identify the primary causes of the accident. Identified causes include fatigue, distraction, cellphone usage, and eating/drinking. In many cases, multiple causes were contributors to a single MVI. The causal analysis was performed globally and at a tranche level for each of the different accident types (e.g., PG&E strikes road hazard, PG&E backing etc.).

The second aspect of the UCLA/PG&E MVI study was to understand how important each of the causes was in the likelihood and severity of MVIs. This part of the study used the results from the investigative narrative causal analysis to rank the importance of causes for different accidents. Results from the cause ranking along with national data on MVIs was used to develop some initial recommendations for risk reduction.

Going forward, PG&E is considering an improvement to the MVI risk model such as developing event sequence models for each of the different accident types. This will lead to expressing the risk drivers as accident causes as opposed to accident types. Reconfiguring the bowtie in this manner will improve PG&E's ability to focus mitigation efforts on the actual causes of accidents. PG&E expects to update its model and include the findings in the upcoming 2023 GRC.

C. Controls and Mitigations

Tables 18-5 and 18-6 list all the controls and mitigations PG&E included in its 2017 RAMP, 2020 GRC and 2020 RAMP (2020-2022 and 2023-2026). The tables provide a view as to those controls and mitigations that are on-going, those that are no longer in place, and new mitigations. In the following sections

PG&E describes the controls and mitigations in place in 2019, changes to the 2019 mitigations and controls presented in the 2017 RAMP, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2020-2022 and 2023-2026 periods.

TABLE 18-5
CONTROLS SUMMARY

Line No.	Control Name and Number	2017 RAMP	2020 GRC 2020-2022 Controls	2020 RAMP 2020-2022 Controls	2020 RAMP 2023-2026 Controls
1	C1 – Commercial Driving School	X	X	X	X
2	C2 – Driver Qualification	X	X	X	X
3	C3 – Smith Driving Courses	X	X	X	X
4	C4 – Distracted Driving	X	X	X	X
5	C5 – Smith Driving Course	X	X	Mitigation – M22	X (Alternative)
6	C6 – Defensive Driving, the Critical 5	X	X	X	X
7	C7 – Vehicle Tie Down Equipment Training	X	X	X	X
8	C8 – Reasonable Suspicion Supervisor Training	X	X	X	X
9	C9 – DMV Employee Pull Notice Program	X	X	X	X
10	C10 – Fitness for Duty Training	X	X	X	X
11	C11 – Phone Free Driving Standard	X	X	X	X
12	C12 – Company Pool Vehicle Standard	X	X	X	X
13	C13 – Commercial Driver's Fatigue Management Procedure	X	X	X	X
14	C14 – Drug/Alcohol Testing Program (DOT and Gas Employees)	X	X	X	X
15	C15 – "How am I Driving" Hotline Reporting and Supervisor's Review	X	X	X	X
16	C16 – Preventive Maintenance On Time Performance and Monitoring	X	X	X	X
17	C17 – Driver Visual Inspection Report (DVIR) and Audit	X	X	X	X
18	C18 (M1) – MVS Standard			X	X
19	C19 (M2A and M3)– Vehicle Safety Technology (VST) Program			X	X
20	C20 (M4) – TECH-0081WBT: Driving Expectations and New Laws			X	X
21	C21 (M5) – Standardized Employee MV Training Requirements			X	X
22	C22 (M6) – Training Acknowledgement for Valid License			X	X
23	C23 (M7) – Implement Driver Accountability			X	X

TABLE 18-6
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigation	2020 RAMP 2023-2026 Mitigations
1	M1 – MVS Standard	X	X	Becomes a control	
2	M2A – VST Program		X	Becomes a control	
3	M2B – 2017 and 2018 Vehicle Safety Technology Install and Activate	X		X	
4	M3 – VST Program Standardized Reporting	X			
5	M4 – Driving Expectations and New Laws		X	Becomes a control	
6	M5 – Standardized Employee MV Training Requirements		X	Becomes a control	
7	M6 – Training Acknowledgement for Valid License	X	X	Becomes a control	
8	M7 – Implement Driver Accountability	X	X	Becomes a control	
9	M8 – Revise License Verification Processes for Non-DOT Covered Drivers	X	X		
10	M9 – Deploy Vehicle Safety Technology in Personal Vehicles:			Removed as infeasible	
11	M10 – Driver Selection Program:				X (Alternative)
12	M13 – Motor Vehicle Safety Management System:			Removed – integrated into ESMS	
13	M14 – Post Incident Review			X	
14	M15 – 360 Walk Around App			X	
15	M16 – UCLA Study and Risk Analysis			X	
16	M17 – Data Enhancement/Improvement Plan				X
17	M18 – Safe Backing Training (TECH-9161)			X	

TABLE 18-6
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Name and Number	2017 RAMP 2017-2019 Mitigations	2020 GRC 2020-2022 Mitigations	2020 RAMP 2020-2022 Mitigation	2020 RAMP 2023-2026 Mitigations
18	M19 – Cell Phone Activity Blocking				X
19	M20 – Enhancement to Pool Vehicle Reservation System				X (Alternative)
20	M21 – In-Cab camera technology				X (Alternative)
21	M22 – Smith Driving Course				X (Alternative)

1. 2019 Controls and Mitigations

a. Controls

C1 – Commercial Driving School: This course (EQIP-0006) is recommended for those employees that are required to obtain a CDL. The Commercial Driver School will prepare successful candidates to obtain a CDL. The course also includes practice on backing skills, proper shifting and various driving scenarios and road conditions.

C2 – Driver Qualification: This course (EQIP-0034) is required for employees that have their CDL and need to drive Commercial vehicles for PG&E. The driver must demonstrate safety, knowledge of laws, six step air brake check, and pre-trip inspection. The driver must also demonstrate skills driving with a trailer, under various conditions and scenarios. This is a three-day course.

C3 – Smith Driving Courses: These courses are designed for any PG&E employee who drives a Company vehicle as part of their job function. The focus of the course is to present the proper methods for safe, defensive driving and provide the skills (reinforced through practical application) to help the driver avoid (or reduce the severity of) MVIs.

C4 – Distracted Driving: This course (TECH-9164WBT) is designed to deter drivers from using cell phones and other hand-held devices while driving. The course explains the effects of four types of distractions, including cognitive, physical, visual, and auditory, in order to mitigate the impact of these distractions on drivers.

C5 – Smith Driving Course: This course (TECH-0089) is for those who drive a personal vehicle for work. Training is conducted with the employees' personal vehicle.

C6 – Defensive Driving – The Critical 5: This course (TECH-9162WBT) discusses common driving patterns that expose motorists to unnecessary risks.

C7 – Vehicle Tie-Down Equipment Training: This course (EQIP-0062) instructs participants on how to perform safe equipment tie-down procedures.

C8 – Reasonable Suspicion Supervisor Training: This course (TECH-0049) is designed to qualify supervisors: to recognize the warning signs of alcohol abuse or drug use; to know how to handle the substance abusing employee; and to follow proper procedures for reasonable suspicion drug and/or alcohol testing, documentation, and reporting as required by current federal regulations and Company policy.

C9 – Department of Motor Vehicle (DMV) Employer Pull Notice Program: This control confirms PG&E commercial drivers are in good standing.

C10 – Fitness for Duty Training: This training (CORP-9134 VL) will help supervisors recognize when they may have reason to question whether or not an employee is physically or mentally able to perform their work.

C11 – Phone Free Driving Standard: This standard (SAFE-1018S) describes the requirements and prohibitions for using cellular phones and Bluetooth® devices while driving on Company business, or while driving a Company owned, leased or rented vehicle. The purpose of this standard is to reduce the potential for distraction and promote employee and public safety.

C12 – Company Pool Vehicle Standard: This standard (TRAN-1012S) establishes requirements and responsibilities for checking-out, operating, fueling performing repairs or maintenance work, and returning PG&E pool vehicles. The standard requires the presentation of a valid driver's license prior to rental of Company pool vehicles.

C13 – Commercial Driver's Fatigue Management Procedure: This procedure (TRAN- 2001P-01) provides instructions for managing driver fatigue for commercial drivers.

C14 – Drug/Alcohol Testing Program (DOT and Gas Employees): All DOT-covered employees are subject to drug testing managed by the DOT Compliance Team (49 CFR parts 40, 199 and 382), including: Pre-employment Drug Testing; Post-accident Drug Testing; Random Drug Testing; Drug Testing resulting from Reasonable Suspicion and/or Reasonable Cause; Return to Duty Drug Testing; and Follow-up Drug Testing. The Drug and Alcohol Clearinghouse affects only CDL drivers.

C15 – "How Am I Driving" Hotline Reporting and Supervisor Review: Driver complaints are received from the "How Am I Driving" hotline. Supervisors are required to investigate, take corrective measures and submit the investigation report for "How Am I Driving" notifications within 15 days.

C16 – Preventive Maintenance On-Time Performance and Monitoring: Garage mechanics perform preventive maintenance and inspections and record the work via work orders entered in the Fleet Anywhere application. Mechanics use preventive maintenance checklists as guidelines for performing maintenance and inspections. Garage Supervisors run daily and monthly reports to review preventive maintenance and inspections coming due and on-time rates. The target is 95 percent or greater for on-time completion rates. The PM On-time Performance metric is reported monthly.

C17 – DVIR and Audit: Drivers perform an inspection of their vehicles at the end of the day. Any issue identified with the vehicle results in the vehicle being pulled out of service until the necessary repairs are completed. PG&E performs audits of these reports to ensure drivers are completing them, and that repairs are completed when identified. This addresses potential equipment failures that may arise between scheduled preventive maintenance work.

b. Mitigations

M6 – Training Acknowledgement for Valid License: Revise all employee web based training to include an acknowledgement statement for positive confirmation that the employee must have a valid license for the class of vehicle they drive on company business and are aware that they must notify their supervisor if their license status changes for any reason. The expected impact is to reduce the number of drivers operating vehicles without the necessary qualifications, and out of compliance.

M7 – Implement Driver Accountability: Use Vehicle Safety Technology (VST) and How's My Driving program to identify risky drivers and build an automated accountability structure. The impact of this mitigation is to identify risky drivers and take the appropriate measures to address performance.

M2B – 2017 and 2018 Vehicle Safety Technology (VST) Install and Activate: VST is Global Positioning System (GPS) – based, and the tool provides real-time, audible feedback to the driver when risky behaviors occur, such as speeding, hard acceleration and hard braking.

M8 – Revise License Verification Process for Non-DOT Covered Drivers: Implement license and insurance verification plan for employees who are not a part of the commercial driver pool. This mitigation is an expansion of C9 – DMV Employer Pull Notice Program. The expected impact is to ensure that drivers on the road have the appropriate licenses and are compliant with California laws.

c. 2017 RAMP Update

In the 2017 RAMP, PG&E outlined its 2017-2019 mitigation plan which focused on mitigating human error, a risk driver that was the source of 94 percent of motor vehicles incidents. PG&E proposed four mitigations, three of which (M2B, M6, and M7) expand on the Vehicle Safety Technology Program, a tool that provides real-time, audible feedback to the driver when it senses risky behavior such as hard braking, speeding and hard acceleration. The other mitigation related to further ensuring that drivers have the minimum qualifications for safely operating a PG&E or personal vehicle used for PG&E business (M8).

M2B, Vehicle Safety Technology (VST) Installation and Activation, is an on-going mitigation. Since the 2017 RAMP PG&E has installed VST in 8000 vehicles, approximately 85 percent of PG&E's fleet. By the end of 2023 PG&E plans to install VST in all on-road PG&E owned vehicles, approximately 10,000 vehicles, and updated to a new VST vendor solution.

M6, Training Acknowledgement for Valid License, involved updating all web-based training to include an acknowledgement by employees to acknowledge that they had a valid license for the class of vehicle they drive on company business or notify their supervisor if their license status changes. PG&E completed this mitigation by updating the web-based training to include this acknowledgement. This mitigation becomes a control in the 2020 RAMP.

M7, Implement Driver Accountability, used VST and1-800-How's My Driving Program to identify risky drivers and build an automated accountability structure. PG&E completed this mitigation by building the automated accountability structure report. This mitigation becomes a control in the 2020 RAMP.

PG&E removed M8, Revise License Verification Process for Non-DOT Covered Drivers, because it is not currently desired by the TS organization. This mitigation is still being considered as a future RAMP mitigation and is part of Alternative 1 described in Section D below.

D. 2020–2022 Controls and Mitigation Plan

1. Changes to Controls

The scope of the following controls has been updated since they were first included in the 2017 RAMP:

C2 – Driver Qualification: An additional course is available (EQUIP-0059) for Class A Commercial Driver's License (CDLA) drivers who have a CDL but require more training.

C9 – Department of Motor Vehicle (DMV) Employer Pull Notice Program: This program provides timely motor vehicle records and includes reports of accidents or tickets associated with any PG&E CDL drivers licenses. These accidents or tickets are documented and letters sent to the employee and their leadership. This program is a requirement under California Code, CVC § 1801.1.

C15 – "How Am I Driving" Hotline Reporting and Supervisor Review: Driver complaint reports fed into the Safe Driver Coaching Program.

C16 – Preventive Maintenance On-Time Performance and Monitoring: Garage mechanics perform preventive maintenance and inspections and record the work via work orders entered in the Fleet Anywhere application. Mechanics use preventive maintenance checklists as guidelines for performing maintenance and inspections. Garage Supervisors run daily and monthly reports to review preventive maintenance and inspections coming due and on-time rates. The Preventive Maintenance On-time Performance metric is reported monthly.

In the 2020 RAMP, six 2017 RAMP mitigations are now controls: M1, M2A, M4, M5, M6, and M7. The descriptions of the former mitigations, now controls, follow:

C18 – Motor Vehicle Safety Standard: This standard (SAFE-1002S) describes PG&E's MVS program, the intent of which is to minimize injuries to employees and members of the public, to prevent property damage and to control risks that may be caused by the operation of a motor vehicle. The mitigation was completed in 2016, and the standard was most recently updated in 2017.

C19 – Vehicle Safety Technology Program Standardized Reporting (hard brake, hard acceleration and speed indicators): Data feed from vendor is used to develop a rate (by vehicle) per 1,000 miles of hard brakes, hard acceleration, and max speed.

C20 – TECH-0081WBT Driving Expectations and New Laws: This annual training updates employees regarding new driving regulations and requires employees who drive for business to certify they have a valid driver's license. This training began in 2017.

C21 – Standardized Employee Motor Vehicle Training Requirements: This mitigation established standard training requirements for drivers and was published as an appendix to SAFE-1002S. This mitigation provides structure for several training requirements and was completed in 2016.

C22 – Training Acknowledgement for Valid License: Revise all employee web-based training to include an acknowledgement statement for positive confirmation that the employee must have a valid license for the class of vehicle they drive on company business and are aware that they must notify their supervisor if their license status changes for any reason. If employee response is to decline the validation, the training will remain as incomplete, Supervisor must take appropriate action.

C23 – Safe Driver Coaching Program (SAFE -1002P): Use VST and How's My Driving Program to identify risky drivers and build an automated accountability structure. Utilize the How's My Driving (vendor – Driver's Alert) observation system and process to address VST data for vehicles that are over the threshold for HB, HA and Excessive Speed. VST data is fed into the system.

2. Changes to Mitigations

PG&E is including six new mitigations in the 2020 RAMP. (This includes M17.)

M14 – Post Incident Review: This procedure outlines leadership requirements to perform a consistent document review and corrective actions for an employee following an MVI. This procedure is designed to provide employees with timely coaching and to reduce overall risk. The procedure will be rolled out enterprise-wide, with a dashboard for leaders to have access to a single source containing multiple data points related to driver/vehicle risk.

M15 – 360 Walk Around App: Mobile application designed to require 360 degree walkaround prior to driving. Developed for non-regulated company drivers.

M16 – UCLA Study and Risk Analysis: The TS and Transportation Safety organizations are partnering with UCLA to conduct risk assessment of Motor Vehicle Safety Program. Desired outcomes are to identify gaps, inform future mitigations, alternatives, and develop program recommendations.

M18 – Safe Backing Training (TECH-9161): This course is for all company drivers. This course reviews safe backing principles, company policies and proper use of spotter/backers. Available to all PG&E employees.

One mitigation – M8, Revise License Verification Process for Non-DOT Covered Drivers – was removed because this action is not currently part of Transportations Services' plans.

Table 18-7 below shows the estimated costs for the mitigation work planned for the 2020-2022 period.

TABLE 18-7
FORECAST COSTS
2020-2022
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	Total
1	M2B	Update VST Installation and Activation	FL	$2,570	$2,570	$2,570	$7,710
2	M14	Post Incident Review	FL	68	68	–	136
3	M15	360 Walk Around App	FL	63	–	–	63
4	M18	Safe Backing Training TECH-9161	FL	36	–	–	36
5	M19	Cell Phone Activity Blocking	FL	–	–	–	–
6		Total		$2,737	$2,638	$2,570	$7,945

Note: See WP 18-1.

E. 2023-2026 Proposed Mitigation Plan

M17 – Data enhancement/improvement plan for improved collection and usage of data: Informed by UCLA Risk Assessment Study recommendations.

M19 – Cell Phone Activity Blocking – Enhanced Control for Phone Free Driving Policy: An engineering control to block phone activity and use while driving. The technology will not block emergency cell phone features. This mitigation is in the initial proposal phase and will be informed by information developed in the proposed UCLA analysis.

Table 18-8 below shows the estimated costs, RSE and risk reduction score for the mitigation work planned for the 2023-2026 period.

TABLE 18-8
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026
(THOUSANDS OF DOLLARS

Line No.	Mit. No.	Mitigation Name	MWC	2023	2024	2025	2026	Total	RSE[a]	Risk Reduction
1	M14	Post Incident Review	FL	–	–	–	–	–		
2	M15	360 Walk Around App	FL	–	–	–	–	–		
3	M18	Safe Backing Training TECH-9161	FL	–	–	–	–	–		
4	M19	Cell Phone Activity Blocking	FL	$1,035	$2,070	$3,050	$4,140	$10,295	0.42	3.1
5	M2B	Update VST Installation and Activation	FL	–	–	–	–	–	–	
6		Total		$1,035	$2,070	$3,050	$4,140	$10,295		

(a) See Mitigation Effectiveness workpapers (MW) included in the source document modeling package for information used to calculate the RSE.

Note See WP 18-1.

F. Alternative Analysis

In addition to the proposed mitigation described in Section E above, PG&E considered alternative mitigations as well. The mitigation described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, RSEs and risk reduction scores for each of the Alternative Plans. Each of the alternatives is in the initial proposal phase. Initial risk reduction estimates and RSE calculations will be subject to further review with the proposed UCLA analysis

1. Alternative Plan 1: A1 (M10) Driver Selection Program

As a part of PG&E's driver selection process, PG&E will integrate all sources of information with respect to the driver in order to create a holistic assessment of individual driver risk. This mitigation is an expansion of the previous mitigation M8: Revise License Verification Process for Non-DOT Covered Drivers. This mitigation would include a license and insurance verification plan for employees who are not a part of the commercial driver pool.

TABLE 18-9
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A1	Driver Selection Program	$81	$81	$81	$81	$324		
2		Total	$81	$81	$81	$81	$324	15.89	3.8

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
Note See WP 18-1.

2. Alternative Plan 2: A2 (M20) Enhancement to Pool Vehicle Reservation System

Enhancement to existing control C12, requiring electronic proof of valid license prior to reserving pool vehicles. This mitigation is contingent on M8.

TABLE 18-10
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A2	Enhancement to Pool Vehicle Reservation System	$25	$25	$25	$25	$100	N/A	N/A
2		Total	$25	$25	$25	$25	$100		

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
Note See WP 18-1.

3. Alternative Plan 3: A3 (M21) In-Cab Camera Technology

This mitigation would install an in-cab camera that monitors both external and in-cab activities and is triggered off of specific parameters and operation of the vehicle (i.e., braking, cornering, acceleration, speeding).

TABLE 18-11
FORECAST COSTS, RSE, AND RISK REDUCTION
2023-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	2023	2024	2025	2026	Total	RSE[(a)]	Risk Reduction
1	A3	In – Cab Camera Technology	$100	$100	$100	$100	$400		
2		Total	$100	$100	$100	$100	$400	19.08	5.6

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

4. Alternative Plan 4: Smith Driving (M22)

This Alternative is the Smith Driving course (TECH-0089) for those who drive a personal vehicle for work. Training is conducted in the employee's personal vehicle. PG&E is not forecasting any costs for this work. The risk reduction value for this Alternative Mitigation is 3.8.

Table 18-12 compares the proposed and alternative mitigation plans.

TABLE 18-12
MITIGATION PLAN ALTERNATIVES ANALYSIS
(THOUSANDS OF DOLLARS)

Line No.	Risk Mitigation Plan	Plan Components[(a)]	Total Expense (2023-2026)	Total Capital (2023-2026)	Risk Reduction (NPV)[(b)]	Total Spend (NPV)	RSE
1	Proposed	M19	$10,295	–	3.11	$7,324	0.42
2	Alternative 1	A1	$324	–	3.79	$239	15.89
3	Alternative 2	A2B	–	–	--	–	–
4	Alternative 3	A3	$400	-	5.62	$295	19.08
5	Alternative 4	A4	–	–	3.79	–	–

(a) Plan Components refers to the Mitigations presented in Table 18-6.

(b) Information presented in terms of NPV to account for the discounting of benefits.

Note See WP 18-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 19

RISK ASSESSMENT AND MITIGATION PHASE

OTHER SAFETY RISKS

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PACIFIC GAS AND ELECTRIC COMPANY
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OTHER SAFETY RISKS

A. Introduction

1. Identifying the 2020 RAMP Risks

Pacific Gas and Electric Company's (PG&E or the Utility) 2019 Corporate Risk Register (CRR) includes 25 safety risks.[1] PG&E is presenting 13 of those safety risks[2] in its 2020 Risk Assessment and Mitigation Phase (RAMP) filing consistent with the requirements set forth in the Phase Two Safety Model Assessment Proceeding Settlement Agreement (the Agreement).[3]

As prescribed by the Agreement, PG&E evaluated all of the risks on its CRR, identified the safety risks and computed a Safety Risk Score for each risk. PG&E sorted the CRR list by the Safety Risk Score and selected the top 40 percent of the CRR risks with a safety risk score greater than zero.[4] PG&E also selected risks for inclusion in RAMP where the Safety Risk Score was within 20 percent of the lowest top 40 percent Safety Risk Score.

PG&E considers all its safety risks important and, as such, monitors and manages them through its normal course of business. While 13 of the 25 risks on the CRR are not being assessed as a 2020 RAMP risk, PG&E will provide information about them in this chapter including an overview of the risk, changes in the risk since the 2017 RAMP, risk mitigation efforts and responses to stakeholder feedback (including feedback received at the PG&E 2020 RAMP Workshop #3, held February 4, 2020, "Workshop #3").

The 13 safety risks presented in this chapter are:

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[1] PG&E recently changed the name of its risk register to CRR. It was previously known as the Enterprise Risk Register. See Chapter 2.

[2] Two individual risks – LOC, Gas Distribution Pipeline, Non-Cross Bore and LOC, Gas Distribution, Cross Bore – are presented as a single risk in the 2020 RAMP filing. The name of the combined risk is LOC on Distribution Main or Service

[3] Decision (D.)18-12-014.

[4] D.18-12-104, Attachment A, Settlement Agreement, Step 2A, Item 9.

1) Aviation – Fixed Wing Incident;
2) Aviation – Helicopter Incident;
3) Failure of Electric Distribution Underground Assets;
4) Failure of Substation Assets;
5) Failure of Electric Transmission Overhead Assets;
6) Failure of Electric Transmission Underground Assets;
7) Hazardous Materials Release;
8) Loss of Containment (LOC) on Compressed Natural Gas (CNG) Station Equipment;
9) LOC on Gas Customer Connected Equipment;
10) LOC at Gas Measurement and Control (M&C) or Compression and Processing (C&P) Facility;
11) LOC at Natural Gas Storage Well or Reservoir;
12) LOC on Liquified Natural Gas (LNG)/CNG Portable Equipment; and
13) Nuclear Core Damaging Event.

2. PG&E's 2020 RAMP Risks – Responding to Stakeholder Feedback

At Workshop #3 PG&E presented its proposed list of 12 safety risks that would be included in the 2020 RAMP. The California Public Utilities Commission (CPUC) Safety Enforcement Division, the CPUC Public Advocates Office and other parties were concerned that important safety risks (such as Nuclear Core Damaging Event, and LOC, Distribution Pipeline, Cross Bore) were not included in the proposed list of risks that PG&E would include in its 2020 RAMP.

PG&E considered this feedback and agrees that all of the CRR safety risks should be presented in some way in the 2020 RAMP. To address this feedback PG&E decided to:

- Incorporate the LOC, Distribution Pipeline, Cross Bore risk into the LOC, Distribution Main or Service risk, as one of the 12 RAMP risks evaluated in this Report. The cross bore risk is incorporated as a sub-driver of the gas distribution risk that is now called, "Loss of Containment – Distribution Main and Service" risk; and
- Provide a description of the remaining 13 CRR safety risks that are not designated as one of the 12 RAMP risks. We describe these risks and the mitigations proposed or underway.

B. Aviation – Fixed Wing Incident

1. Risk Overview

Aviation – Fixed Wing Incident is defined as an accident associated with the operation of fixed wing aircraft during the time any person boards the aircraft with the intention of flight, and until all persons have disembarked. This risk includes fixed wing aircraft owned or operated by PG&E that meets Title 49 Code of Federal Regulations (CFR) 830.

PG&E's Aviation Services organization is responsible for its fixed wing aircraft which consists of four Cessna aircraft (that regularly survey electric and gas infrastructure). Aviation Services also provides the fixed wing patrol aircraft equipped with Electro-Optical/Infra-Red capable camera systems, for monitoring gas transmission pipeline rights-of-way, or for potential encroachment hazards.

2. Changes Since the 2017 RAMP

Aviation Fixed Wing Incident was not a 2017 RAMP risk.

3. Risk Mitigations

The fixed wing aircraft are maintained and operated under 14 CFR Part 91 General Aviation. The fixed wing pilots have Federal Aviation Administration (FAA) pilots' licenses and use a Flight Operations Manual. A flight hazard assessment process and fatigue risk management program are in place. Pilots undergo annual simulator training for normal and emergency procedures and require upset prevention and recovery techniques training every 24 months.

The pilots use FAA certified dispatches in Helicopter Operations and have an onboard GPS tracking tool for flight following. All aircraft maintenance, inspections and repairs are performed under 14 CFR Part 43 Maintenance and Repair by PG&E FAA certified Aviation Maintenance Technicians or approved FAA certified contract technicians or an approved aircraft maintenance organization under 14 CFR Part 145 Repair Station Certification. PG&E aircraft maintenance uses a computerized maintenance tracking tool and a General Maintenance Manual as parts of the maintenance program. All maintenance, inspection, service and scheduled overhaul, replacement of time-controlled components/life-limited parts are accomplished with timeframes established by the manufacturer and approved by applicable regulatory authorities.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Aviation – Fixed Wing Incident risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

C. Aviation – Helicopter Incident

1. Risk Overview

Aviation – Helicopter Incident is an accident associated with the operation of rotary wing aircraft, during the time any person boards the aircraft with the intention of flight, and until all persons have disembarked. This risk includes those rotary wing aircraft owned or operated by PG&E that meet the definition of Title 49 CFR 830.

In 2018 PG&E purchased four heavy lift helicopters to support service restoration work and emergency response to wildfire threats. During the fire season, the helicopters will be available for use by both PG&E and the California Department of Forestry and Fire Protection for emergency response. Outside of fire season, they will be available to support internal PG&E heavy lift maintenance and construction work.

2. Changes Since the 2017 RAMP

Aviation – Helicopter Incident was not a 2017 RAMP risk.

3. Risk Mitigations

PG&E's Helicopter Operations department is responsible for managing the helicopter contractor portfolio, which includes overseeing all helicopter vendors, pilots and ISNetworld qualification. The department is also responsible for maintaining safe helicopter operations by ensuring that vendor audits, health checks and flight safety reviews are completed. PG&E's Helicopter Operations department is also responsible for leading Aviation Incident/Accident Investigations. The investigation process uses the Enterprise Corrective Action Program to document and manage corrective actions identified as part of the investigation.

All PG&E lines of business and contractors are required to use the Helicopter Operations Field Manual. This manual provides detailed instructions for required training, procedures and critical tasks for helicopter operations. All helicopter vendors are required to have a 14 CFR Part 135 Air Carrier Operating Certificate and if they are lifting external loads, a Part 133 External Load Certificate as well. These certificates cover pilots, flight and maintenance operations. In addition, Helicopter Operations requires a pilot training validation and an external loads skill assessment. Helicopter Operations uses flight scheduling software and a work request review process to manage operations and employs FAA certified dispatchers to oversee and monitor flights. Each flight completes a Flight Risk Assessment and an operations briefing with the Helicopter Dispatcher in addition to preflight briefings and tailboard safety meetings at work locations. Operating helicopters carry a GPS tracker onboard to support flight following. Employees and Contractors who are qualified for specified tasks are tracked and identified through an identification card system.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Aviation – Helicopter Incident risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

D. Failure of Electric Distribution Underground Assets

1. Risk Overview

Failure of Electric Distribution Underground (UG) Assets is defined as a failure of distribution UG assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage or an inability for PG&E to deliver power to its customers.

PG&E manages its UG distribution assets in its Underground Asset Management (UAM) Program. PG&E's UG assets include over 26,000 circuit miles of UG primary distribution cable. Most of the UG cables are installed in urban and suburban areas.

The scope of this risk includes a failure of assets associated with the UG electrical distribution system including primary and secondary UG cables, line equipment, subsurface and pad-mount transformers.

2. Changes Since the 2017 RAMP

Failure of Electric Distribution UG Assets was not a 2017 RAMP risk. Since 2017 Electric Operations (EO) has consolidated certain risks on the EOs risk register and is now presenting two underground asset related risks: Failure of Electric UG Assets in this Other Safety Risk Chapter and Failure of Electric Distribution Network Assets in Chapter 12, one of the 12 RAMP risks.

3. Risk Mitigations

The UAM Program generally manages risk by replacing primary distribution cables and components due to reliability performance, asset age and condition, compliance, and potential safety risk to the public and employees.

PG&E has several controls in place to manage risk associated with UG cable and line equipment, including: equipment replacement; equipment diagnostics, testing and rejuvenation; engineering equipment standards and specifications; public awareness programs such as locate and mark; 811 public awareness; and, inspection and maintenance programs.

Summarized below are the programs included in PG&E's 2020 General Rate Case (GRC) designed to manage electric distribution system UG asset risk.[5]

a) Reliability Related Cable Replacement: Proactive replacement of cable based on age and type, reliability performance or a combination of these factors and other influences. UG primary distribution failures that impact reliability performance and safety issues can occur as UG cables deteriorate.

b) Cable Rejuvenation and Testing: Cable testing helps identify specific cables that are problematic so that they can be targeted for replacement and provides a baseline of the cable's condition that is used for future condition assessments. Cable rejuvenation involves injecting silicon

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[5] Application (A.)18-12-009, Exhibit (PG&E-4), Chapter 11.

fluid into certain types of cables under certain conditions with the goal of extending operating life.

c) Critical Operating Equipment (COE) Cable Replacement: When failures occur on primary cable UG systems with looped designs, the faulted section of line is isolated and de-energized until an evaluation of its operating condition and repair scope is determined. Upon evaluation the failed cable sections becomes a COE Cable Replacement project.

d) Load Break Oil Rotary (LBOR) Switch Replacement: PG&E is proactively replacing LBOR switches. LBOR switches lack oil inspection sight glasses which poses a greater safety risk than other types of switches because crews cannot visually verify the oil level and condition of an LBOR switch before operating it. Recognizing the importance of replacing LBOR switches, PG&E proposed replacing 90 pre-1975 switches per year for the 2020 GRC period as part of the 2020 GRC settlement.[6]

e) Underground Patrols and Inspections: PG&E patrols its underground facilities on a regular basis and conducts a more detailed examination of each underground enclosure and associated facilities every three years. Compliance inspectors perform minor repair and maintenance work during underground inspections and patrols.

f) Underground Preventive Maintenance and Equipment Repair: PG&E's Underground Notifications program is the program designed to improve system reliability, improve safety and ensure regulatory compliance by correcting abnormal maintenance conditions related to PG&E's underground facilities.

g) Venting Manhole Cover Replacements: This is an ongoing program to replace existing solid and grated manhole covers on vaults with hinged venting manhole covers designed to stay in place in the event of a vault explosion. A venting cover that stays in place during a vault explosion reduces the potential for exposure to hot gasses from the vault,

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[6] A.18-12-009, Joint Motion for Approval of Settlement Agreement, (Dec. 20, 2019), p. 48.

eliminates the risk of a projectile manhole cover, and reduces the force of the explosion.

h) Design Standards Review: Supports electric designs including UG assets are on a five year review process. These reviews address evolving risks and issues associated with such items as supplier quality, field conditions, new products, and trends in the industry.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Failure of Electric Distribution UG Assets risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

E. Failure of Substation Assets

1. Risk Overview

Failure of Substation Assets is defined as the failure of substation assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources or inability to deliver energy.

PG&E has 945 transmission and distribution substations, consisting of power transformers, circuit breakers, switchgears, protective relays, bus structures, and voltage regulation equipment. Each substation transforms high voltage electricity from PG&E's electric transmission system to lower voltage for delivery to PG&E's customers.

The drivers of substation risk are: equipment failure; work procedure error; animal; weather; cyber attack; geomagnetic storm;[7] sabotage; seismic; and gas collocation.

2. Changes Since the 2017 RAMP

In 2017 PG&E did not consider risks associated with substations to be a top safety-related risk and, as such, they were not identified as a RAMP risk. PG&E did, however, discuss its risk methodology and mitigation approach to substation risks in Appendix 1. Since 2017 PG&E has formally consolidated

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7 A geomagnetic storm, or solar storm, is a temporary disturbance of the Earth's magnetosphere caused by a solar wind shock wave and/or cloud of magnetic field that interacts with the Earth's magnetic field.

the risks associated with individual substation asset categories into the single Failure of Substation Asset risk. Consolidating the risk enables PG&E to better analyze how the different types of substation risks interact with one another and enables PG&E to compare and weigh the overall contributions of each for the former risks towards a single substation failure risk event.

3. Risk Mitigations

PG&E employs two primary mitigations to address substation asset risk. The first mitigation, the Bus Reliability and Upgrade Program, includes work to modify and/or replace substation buses to reduce the likelihood of bus level outages that could lead to larger and prolonged substation outages.

The second mitigation includes projects to reduce the risk of substation outages caused by potential failure of gas pipelines collocated with PG&E substations. This program involves reviewing studies on collocated pipelines and performing work such as pipeline/substation equipment relocation, ground grid modifications, and/or fencing replacement to reduce the risk and impacts of collocated pipeline failure if it were to occur.

Along with these two mitigations, PG&E uses controls to manage substation asset risk including: proactive asset replacement; perimeter vegetation clearance; lightning protection; design criteria; drawings and facility markings; damage modelling and; grounding systems. PG&E also employs inspection and maintenance controls (e.g., substation inspections, intrusion detection, on-site security guards and gas line corrosion protection) and controls to reduce the consequences of substation failure (e.g., fire protection systems, oil containment/spill prevention and community outreach and outage communications).

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Failure of Substation Assets risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

F. Failure of Electric Transmission Overhead Assets

1. Risk Overview

Failure of Electric Transmission Overhead Assets risk is defined as a failure of transmission overhead assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources and inability to deliver energy. The risk includes failure of assets associated with transmission overhead lines including conductor, steel structure, non-steel structures, and other components such as insulators, switches and other hardware that form the electric transmission network.

Wildfire impacts from the overhead transmission assets are not included in the Failure of Transmission Overhead Assets risk but are incorporated into the Wildfire risk (Chapter 10).

Overhead transmission lines are energized at high voltages, and form the backbone of PG&E's electrical system. PG&E's transmission system includes approximately 18,000 circuit miles of overhead transmission lines and related equipment.

The drivers of transmission overhead asset risk are: transmission line equipment failure; natural hazard; vegetation; animal; human performance; environmental factors; and other. In addition to wires down, key areas of exposure include wildfire, environmental factors such as corrosion and wind as well as aging infrastructure.

2. Changes Since the 2017 RAMP

The 2017 RAMP included a Transmission Overhead Conductor risk.[8] As discussed in Section A.1, this risk did not score in the top 40 percent of PG&E's enterprise safety risks in 2020 and, therefore, is not included as a 2020 RAMP risk.

PG&E has made significant progress understanding failure modes for Transmission overhead assets, enhancing inspection methods to look for these failure modes and prioritizing these enhanced inspections, repairs, projects, and programs in the High Fire-Threat District (HFTD) areas.

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8 PG&E's RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017), Chapter 10.

In the 2017 RAMP PG&E described a group of ten controls that were designed to help control the frequency or consequence of one or more drivers of the Transmission Overhead Conductor risk.[9] PG&E plans to continue implementing similar controls during the 2020 RAMP period and thereafter as applicable.

In the 2017 RAMP PG&E listed four mitigations that it planned to undertake between 2017 and 2019: overhead conductor replacement; insulator replacement; Right-of-Way (ROW) expansion; and public awareness outreach.[10] PG&E completed work in each of those mitigation programs between 2017 and 2019.

3. Risk Mitigations

PG&E is implementing several mitigations to reduce overhead transmission asset failure risk including: enhanced maintenance program (inspections and repairs), Public Safety Power Shutoff (PSPS), asset replacement and retirements; enhanced vegetation management; system configuration design (sectionalizing); seasonal insulator washing; animal abatement; anti-climbing guards; bridging on underbuild; FAA line markers; and tower coating.

- PG&E implemented its Wildfire Safety Inspection Program in 2019 and plans to complete maintenance repair notifications generated through the program during the next three years. This enhanced inspection method is expected to continue going forward to drive condition-based asset management decisions. Maintenance repairs can extend the lifespan and ensure the safety of transmission line overhead assets. Examples of repairs include structure replacement, hardware replacement, and foundation crack sealing.
- The Transmission Vegetation Management Reliability (TVMR) program, also known as the ROW Expansion program, focuses on circuits involved in the most tree-related outages and will also help potentially reduce the scope of future Public Safety Power Shutoff events. The TVMR program aims to increase transmission line vegetation

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[9] PG&E’s 2017 RAMP Report, p. 10-12, Table 10-1.

[10] PG&E’s 2017 RAMP Report, p. 10-15, Table 10-2.

clearances by voltage. This increased clearing improves reliability and can reduce potential wildfire ignitions in HFTD areas.

- PG&E evaluates as applicable the possibility of replacement alternatives as lines are identified for mitigation. These alternatives go beyond standard like-for-like replacement of assets and can include UG, microgrid/battery storage, line removal, and line relocation. Evaluating alternate paths, redundant paths, or reduction of paths can alleviate capacity, vegetation, fire spread, compliance, and reliability concerns.

PG&E also implements controls to manage overhead transmission asset risk including: asset inventory; asset health; cathodic protection; design standards; ground, climbing and aerial enhanced inspections; ground/non-routine air patrols; infrared inspections; planning, simulation and capacity program; product inspection; routine air patrols; routine vegetation management; and wood pole intrusive inspection.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Failure of Transmission Overhead Asset risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

G. Failure of Electric Transmission Underground Assets

1. Risk Overview

Failure of Electric Transmission UG Assets is defined as the failure of transmission UG assts or lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, reduced operational redundancy in critical urban centers, or large-scale prolonged outages. This risk includes failure of assets associated with pipe type cable, including cable carrier, cross-line polyethylene cable, cable terminations, pumping plant, vaults, splices, low pressure tripping system and SCADA systems.

The transmission UG asset risk drivers are: other PG&E assets or processes (e.g., substation causes, system design, etc.); PG&E activity (e.g., safety clearance); human performance; other (e.g., unknown outage causes); and transmission UG line equipment.

2. Changes Since the 2017 RAMP

Failure of Transmission UG Assets was not a 2017 RAMP risk.

3. Risk Mitigations

PG&E is executing several mitigations to reduce the risk to transmission UG assets:

- Cathodic protection assessments to critical pipe type cable circuits. The carrier pipe of the pipe type cable is made of carbon steel and can corrode if the cathodic protection is not in place. The substance inside the cable and the carrier pipe can leak out to the soil potentially damaging the environment and harming the cable by keeping it from properly cooling.
- Developing solutions to ensure proper inventory of pipe type cable is available in case of a major disaster. Two of these solutions are: (1) investigating a new design for pipe type cable systems as the manufacturer of certain cable types no longer produces it; and (2) ensuring the availability of cable reels and equivalent overhead equipment for emergency response preparedness. This mitigation is designed to ensure spare material is available for repairs to enable restoration of transmission paths via both UG and/or temporary overhead.
- Repairing or replacing transmission UG cables and associated components as part of routine and detail inspections of UG assets. These actions can reduce potential public and employee safety hazards due to equipment failures, can lessen environmental impact by reducing potential oil spills, and can help to maintain adequate reliability performance.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Failure of Transmission UG Assets risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A(2) above.

H. Hazardous Materials Release

1. Risk Overview

The Hazardous Materials Release risk is defined as the release of hazardous materials (excluding natural gas) by PG&E or by an agent acting on behalf of PG&E or under PG&E's authority. This risk excludes transport events, asset failure outcomes, and employee safety events addressed in other event based risk assessments. The Environmental Management and Remediation group within PG&E's Shared Services organization is responsible for managing this. This risk encompasses all the stages of the hazardous materials' lifecycle at PG&E from procurement to disposal. It includes spills and air release as well as events that occurred in the past and for which PG&E is now responsible for remediating.

2. Changes Since the 2017 RAMP

Hazardous Materials Release was not a 2017 RAMP risk.

3. Risk Mitigations

PG&E manages Hazardous Materials Release through a series of existing controls that consist of:

- Engineering controls such use of proper storage containers and containment to prevent the spread of a hazardous material if it is released;
- Detective controls including remote monitoring and inspections; and
- Administrative controls including handling and storage procedures, spill prevention, control and countermeasure plans, personnel training, and procurement management to reduce or eliminate the use of hazardous substances.

Risk control and mitigations for hazardous materials are closely aligned with PG&E's compliance program for regulatory requirements at the Federal, State and Local level which specify preventive measures to be taken to minimize the risk of hazardous materials release, and to assure rapid and effective control should a release occur.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Hazardous Materials Release risk. Stakeholder feedback related to PG&E's

exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

I. Loss of Containment on Compressed Natural Gas Station Equipment

1. Risk Overview

LOC on CNG Station Equipment is defined as any LOC during operations at a PG&E owned CNG station that can lead to significant impact on public safety, employee safety, contractor safety, financial losses, and/or the inability to deliver natural gas to customers.

The LNG/CNG asset family includes both CNG stations (defined as gas distribution assets for rate case purposes) and LNG/CNG portable assets (defined as gas transmission assets for rate case purposes). The LNG/CNG portable equipment risk is described in Section M below.

PG&E's CNG Stations Program includes 32 PG&E-owned CNG stations, 24 of which are accessible by third-party customers. CNG stations provide fuel to over 6,500 third-party customer vehicles and more than 100 CNG vehicles in PG&E's fleet and are used to refill portable CNG trailers.

PG&E also has several mobile compressor units that provide backup compression for CNG stations during outages of CNG station compressors and provide compression to fill portable CNG trailers.

The top asset-related risks identified for the CNG station assets are equipment-related and are primarily associated with obsolescence and end-of-service-life conditions, and in particular, third-party customer equipment integrity shortfalls and code non-compliance that can result in LOC events while in PG&E's stations.

2. Changes Since the 2017 RAMP

LOC on CNG Station Equipment was not a 2017 RAMP risk.

3. Risk Mitigations

CNG station risks are primarily monitored via information collected during regular maintenance and operation, through subject matter expert (SME) knowledge, and through processes designed to minimize the likelihood of customers in PG&E stations with higher risk vehicles and CNG system condition. PG&E complies with federal and state codes that require periodic maintenance to minimize safety risks by confirming or correcting the condition and function of station components and incorporates best practices to manage risks that sometimes go beyond code requirements. PG&E also performs station capital investment rebuild and replacement work to address safety, reliability, and economic risks that typically includes replacement of equipment that is assessed to involve higher performance risks or that is obsolete.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the LOC on CNG Station Equipment risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

J. Loss of Containment on Gas Customer Connected Equipment

1. Risk Overview

LOC on Gas Customer Connected Equipment is defined as a LOC from a leak or rupture, with or without ignition, that can result in significant impacts to public safety, employee safety, contractor safety, property damage, financial loss, and/or the inability to deliver natural gas to PG&E customers.

Customer connected equipment includes gas meter set assemblies (including regulators, valves, piping and meters). There are approximately 4.6 million gas meters in service in PG&E's service territory, the majority of which are located above ground and outside of the facility being served. The top risks related to customer connected equipment assets are: (1) incorrect operation and use of unapproved materials; (2) material traceability issues that would prevent accurately locating and eliminating known defective material; (3) failure of indoor meter sets; (4) and equipment failure due to outside forces, such as building meter interaction during an earthquake.

The scope of this risk includes a failure of assets associated with customer connected equipment, leading to a LOC.

2. Changes Since the 2017 RAMP

LOC on Gas Customer Connected Equipment was not a 2017 RAMP risk.

3. Risk Mitigations

PG&E conducts a 3-year compliance gas leak survey, along with special leak surveys and leak rechecks, that covers gas distribution pipeline systems, including services, mains and other gas assets. Once a leak is verified and graded, PG&E schedules repair or replacement work to remediate the leak. PG&E also responds to emergencies by replacing or repairing damaged facilities, due to external forces.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the LOC on Gas Customer Connected Equipment risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

K. Loss of Containment at Gas Measurement and Control or Compression and Processing Facility

1. Risk Overview

The Loss of Containment at Gas Measurement and Control or Compression and Processing Facility ("LOC at Gas M&C or C&P Facility") risk is defined as failure at a gas M&C or C&P facility resulting in a loss of containment that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers.

The M&C assets include gas transmission and distribution regulating and metering stations and associated equipment. The M&C assets also include transmission large volume customer regulating and metering stations, selected large customer meter sets, and equipment for monitoring gas quality. The M&C assets monitor, measure, and control pressure and flow within the gas transmission and distribution systems. There is significant diversity in terms of design and equipment installed at these stations. The age and condition of the M&C assets also varies across the asset population. Condition of the assets is assessed based on age, obsolescence, physical condition, functional performance, maintenance history, and SME input.

The C&P assets include compressor units and associated equipment installed at PG&E's nine compressor stations. Also included in the C&P asset family are compressor units and gas processing equipment installed at PG&E's three underground storage facilities. The purpose of the C&P facilities is to meet customer demands by moving gas from receipt points to customer delivery locations as well as providing for injection and withdrawal of gas at PG&E's underground storage facilities. Gas processing equipment provides gas that is free from particulates and is sufficiently dehydrated and odorized to meet gas quality requirements on the transmission and distribution pipeline systems. Most of the compressor and underground gas storage facilities were put into service between the early 1950s and the early 1970s. Much of the equipment, controls and systems at these facilities systemwide are more than 40 years old and are showing signs of wear and deterioration.

Threats identified for the M&C and C&P assets include: equipment-related; incorrect operations; manufacturing-related; welding/fabrication defects; corrosion; weather-related and outside forces; and third-party damage. The ongoing evaluation of threats and risks associated with M&C and C&P assets and the identification of mitigation measures are largely based on the experience and judgment of PG&E SMEs. PG&E has conducted studies to collect information for monitoring threat status and asset health, including: benchmarking studies to identify potential new threats and assess PG&E's current performance; process safety assessments to understand hazards that may apply to stations; and, causal analysis for significant events to understand the underlying causes of the event and to define actions to prevent recurrence. Relative to the evaluation of asset health, PG&E has conducted: control assessments to assess proper regulation function and identify necessary maintenance and equipment replacement; reliability centered maintenance; condition assessments based on age, functional performance, physical condition and other metrics to assess component and overall station health.

2. Changes Since the 2017 RAMP

PG&E's 2017 RAMP included two risks related to M&C failure and one risk related to C&P failure. The two M&C risks were: M&C Failure – Release of Gas with Ignition Downstream;[11] and, M&C Failure – Release of Gas with Ignition at M&C Facility.[12] The one C&P risk was C&P Failure – Release of Gas with Ignition at Manned Processing Facility.[13]

The M&C and C&P risks identified as 2020 RAMP risks have changed. In the 2020 RAMP:

- Large Overpressure Event Downstream of Gas M&C Facility is a RAMP risk (Chapter 9); and
- LOC at Gas M&C or C&P Facility is not one of the 2020 RAMP risks but is included in this "Other Safety Risk" chapter.

3. Risk Mitigations

a. Measurement and Control Failure – Release of Gas with Ignition at Measurement and Control Facility

For the M&C Failure – Release of Gas with Ignition at M&C Facility risk, the 2017 RAMP included six mitigations: The current status of each mitigation is provided below.

M1B – Critical Documents Program: The Critical Documents Program was proposed as a mitigation in the 2017 RAMP. This is a non-unitized program. To incorporate this mitigation into the 2017 RAMP model, PG&E developed representative units of work (number of stations) for the years 2017, 2018 and 2019.[14] The Critical Documents program was also forecast as a non-unitized program in the 2019 Gas Transmission and Storage (GT&S) Rate Case with a targeted program completion date in 2021. The program is on track to complete all site visits by end of 2021 with the close out of some projects extending into 2022.

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11 PG&E's 2017 RAMP Report, Chapter 3.

12 PG&E's 2017 RAMP Report, Chapter 4.

13 PG&E's 2017 RAMP Report, Chapter 6.

14 See I.17-11-003, WP 3-3, footnote (fn.) 1 that describes how PG&E developed its units of work estimates.

M2B – Engineering Critical Assessment (ECA) Phase 1: This program was forecast in the 2019 GT&S rate case as a non-unitized program with a targeted completion in 2021. To incorporate this mitigation into the 2017 RAMP model, PG&E developed representative units of work (number of stations) for the years 2017, 2018 and 2019.[15] This program is on pace to be completed by the end of 2021.

M3B –ECA Phase 2: This program was forecast in the 2019 GT&S rate case as a non-unitized program with targeted completion in 2033. To incorporate this mitigation into the 2017 RAMP model, PG&E developed representative units of work (number of stations) for the years 2017, 2018 and 2019.[16] PG&E has advanced the program development by working with industry leaders to solidify engineering-based maximum allowable operating pressure reconfirmation methods by: evaluating non-destructive technologies for flaw detection and material property verification; setting up a database to host the data received from the inspections; developing data analysis methods; and, creating program processes and procedures. This program is still on pace to be complete by the end of 2033.

M4B – Physical Security Upgrades: PG&E's 2017 RAMP forecast included representative units of work (number of stations) of one M&C station and one C&P station per year in the 2017 RAMP. PG&E has completed a total of 6 physical security upgrades at both M&C and C&P facilities between 2017 and 2019 which is consistent with the 2019 GT&S forecasted units.

M5B – SCADA Visibility, Transmission and Distribution: PG&E committed to implementing SCADA visibility at 530 distribution stations and 24 transmission stations between 2017 and 2019. PG&E is on pace to complete the SCADA Visibility program by 2025.

M6A –Station Strength Testing: The Station Strength Testing Program is designed to address components that cannot be addressed

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15 I.17-11-003, WP 4-6, fn. 2 that describes how PG&E developed its units of work estimates.

16 I.17-11-003, WP 4-9, fn. 1 that describes how PG&E developed its units of work estimates.

via the non-destructive alternatives from the ECA 2 program. This program was forecasted as a non-unitized program in the 2019 GT&S rate case with a targeted completion in 2033. To incorporate this mitigation into the 2017 RAMP model, PG&E developed representative units of work (number of stations) for the years 2018 and 2019.[17] PG&E did not perform any station strength testing during 2017-2019 period. Depending on the findings from the stations that are currently being assessed in the ECA2 program, PG&E will perform station strength testing beyond 2021.

PG&E will continue to the implement the six mitigations described above during the 2020-2022 period.

b. Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility

For the Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility risk, the 2017 RAMP included five mitigations: The current status of each mitigation is provided below.

M1B – Critical Documents Program: This mitigation is described in Section G.3.a above.

M2B – ECA Phase 1: This mitigation is described in Section G.3.a above.

M3B – ECA Phase 2: This mitigation is described in Section G.3.a above.

M4B – Physical Security Upgrades: This mitigation is described in Section G.3.a above.

M5A – Station Strength Testing: This mitigation is the same as M6A in Section G.3.a above.

PG&E will continue to implement the five mitigations described above during the 2020-2022 time period.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Loss of Containment at Gas Measurement and Control or Compression and

[17] I.17-11-003, WP 4-20, fn. 1 that describes how PG&E developed its units of work estimates.

Processing Facility risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

L. Loss of Containment at Natural Gas Storage Well or Reservoir

1. Risk Overview

LOC at Natural Gas Storage Well or Reservoir is defined as a LOC, with or without an unplanned ignition, at a gas storage well or reservoir that can lead to significant impact on public safety, employee safety, contractor safety, financial losses, environmental consequences, and in rare cases, the inability to deliver natural gas to customers.

As of the end of 2019, PG&E's gas storage assets consisted of three storage fields that included 111 storage wells, of which 86 wells were equipped with downhole safety valves, more than 200 miles of casing and tubing; approximately 14 miles of transmission pipe and ancillary equipment; 204 surface safety valves for pipeline isolation; and, 152 well measurement meters, wellhead separators and flow controls.

As discussed in Section E.2. below, the gas storage assets that PG&E owns and operates will be changing as set forth in D.19-09-025, in P&GE's 2019 GT&S Rate Case.[18]

The threats and risks to gas storage assets include: internal and external corrosion and erosion; construction/fabrication threats resulting from an improperly completed and poorly constructed well; equipment failure or incorrect operation of one of the components.

PG&E manages gas storage risk through its UG Storage Risk and Integrity Management Plan (referred to as WELL). PG&E's WELL provides coordinated management and operation of PG&E's gas storage assets consistent with the integrity management approach for other natural gas assets. WELL includes several mitigation projects and programs, including: reworks and retrofits; integrity inspections and surveys; engineering studies, data analysis and development of gas storage emergency plans; control and continuous monitoring; and, repair and replace non-storage assets.

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[18] A.17-11-009.

2. Changes Since the 2017 RAMP

In the 2017 RAMP, PG&E outlined its proposed Natural Gas Storage Strategy (NGSS).[19] The proposed NGSS was developed in response to several new regulations that were enacted because of the October 2015 leak at the Aliso Canyon Natural Gas Storage Facility.

PG&E evaluated the new regulations and determined that complying with them would significantly increase the scope of work and cost to maintain and operate gas storage wells. In response, PG&E developed its NGSS and presented its proposal to change its storage assets portfolio in the 2019 GT&S Rate Case. PG&E's NGSS reduced PG&E's storage risk by ceasing certain operations and implementing risk mitigation efforts as required by the new regulations.

The 2017 RAMP outlined three proposals (the proposed NGSS and two alternatives). In September 2019, the CPUC issued its final decision (D.19-09-025) in PG&E's 2019 GT&S Rate Case. The CPUC adopted the NGSS with conditions, a two-way balancing account and reduction of the storage holdings to the amount necessary to provide reliability services. This involves the sale or decommissioning of the Los Medanos and Pleasant Creek storage fields.[20]

3. Risk Mitigations

In the 2017 RAMP PG&E identified one risk mitigation, M1B - Storage Well Inspection Program. Between 2017 and 2019, PG&E planned to complete baseline inspections of 64 wells (8 in 2017, 12 in 2018 and 44 in 2019), PG&E projected completing the baseline assessments as part of its plan to mitigate the single point of failure in all storage wells by 2020 to comply with proposed California Geological Energy Management (CalGEM)[21] regulations. CalGEM adopted regulations effective October 1, 2018 that extended the timeline for the baseline casing assessments and the elimination of the single point of failure. The new regulations require this

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[19] PG&E's 2017 RAMP Report, Chapter 8.

[20] D.19-09-025, pp. 327-328, 330, Ordering Paragraphs 40, 42, 43, 44, 45, 48, 49 and 59.

[21] CalGEM was formerly known as the California Division of Oil, Gas and Geothermal Resources.

work be completed by 2025. In 2017-2019, PG&E completed 31 baseline assessments bringing the total to 57 (2013-2019) or 49 percent of its well population. The federal PHMSA issued its final rules on January 2020 that requires completing the baseline casing inspections of all the wells by 2027. PG&E is on track to meet this deadline.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the LOC at Natural Gas Storage Well or Reservoir risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

M. Loss of Containment on LNG/CNG Portable Equipment

1. Risk Overview

LOC on LNG/CNG Portable Equipment is defined as a LOC during operations that can lead to significant impact on public safety, employee safety, contractor safety, financial losses, and/or the inability to deliver natural gas to customers.

The LNG/CNG asset family includes both CNG stations (defined as gas distribution assets for rate case purposes) and LNG/CNG portable assets (defined as gas transmission assets for rate case purposes). CNG station risk is described in Section I above.

Portable LNG/CNG equipment provides gas service to customers while pipelines are out of service during strength testing, upgrade or repair work, or emergency unplanned outages, and supplements pipeline flowing supply during peak winter demand periods.

This equipment consists of trailers that store and transport LNG and CNG, trailers that deliver portable supplies back into the pipeline system or directly to customers, and portable compression equipment (and associated portable electric generation) that is used to evacuate pipelines prior to construction work as an environmentally preferable alternative to blowing gas to atmosphere (blowdowns result in undesirable adverse environmental impact).

2. Changes Since the 2017 RAMP

Loss of Containment on LNG/CNG Portable Equipment was not a 2017 RAMP risk.

3. Risk Mitigations

LNG/CNG portable risk is primarily monitored via information collected during regular maintenance and operation and through SME knowledge. PG&E complies with federal and state codes that require periodic maintenance to minimize safety risks by confirming or correcting the condition and function of portable system components and incorporates best practices to manage risks that sometimes go beyond code requirements. PG&E also makes portable equipment capital investment rebuilds and replacements to manage safety, reliability and economic risks, that typically include replacement of equipment that is assessed to involve higher performance risks or that is obsolete.

4. Responding to Stakeholder Feedback

Stakeholders have not provided any specific feedback about the Loss of Containment on LNG/CNG Portable Equipment risk. Stakeholder feedback related to PG&E's exclusion of certain safety risks in the 2020 RAMP is addressed in Section A.2. above.

N. Nuclear Core Damaging Event

1. Risk Overview

The Nuclear Core Damaging Event risk is defined as a nuclear reactor core-damaging event with the potential for radiological release at the Diablo Canyon Power Plant (DCPP) due to equipment failure, natural disaster or some other significant event. The scope of this risk includes events caused by equipment failure, seismic events, internal fires or floods that lead to core damage at Diablo Canyon Units 1 and 2. This risk excludes events outside of the DCPP licensing basis not caused by equipment failure, seismic events, internal fires and floods that lead to core damage and events that do not lead to core damage.

DCPP Units 1 and 2 have a combined capacity of 2,240 megawatts and each year safely and reliably generate approximately 18,000 gigawatt-hours of clean electricity without greenhouse gas emissions. PG&E generates power safely and operates reliably by maintaining high safety standards and continuously improving its operations. DCPP has an excellent operating record in its 32 years of operation. PG&E's Nuclear Generation organization is responsible for the overall safe and efficient operation of DCPP.

DCPP relies on key measures and metrics to monitor safety and reliability. Safe operations are the number one priority for DCPP. Nuclear Regulatory Commission (NRC) inspectors are assigned to and provide daily inspection activities for all nuclear activities. The NRC's Reactor Oversight Process is the program through which the NRC measures nuclear safety, regulatory compliance and recognizes compliance with safety requirements.

In addition to public safety, PG&E is also focused on the safety of the PG&E employees and contractors working at DCPP. PG&E measures personal safety at DCPP by the Occupational Safety and Health Administration lost work day rate.

PG&E measures collective radiation exposure at DCPP by Person-REM (Roentgen Equivalent Man), a unit of absorbed doses of radiation or the collective radiation exposure when summed across all site personnel. PG&E's collective Person-REM exposure has been on the decline since 2016.

DCPP fulfills the federal requirements of all nuclear power facilities by maintaining a physical security program committed to preventing radiological sabotage and the theft of special nuclear material. The DCPP security program and security features are periodically inspected by the NRC to confirm compliance.

Nuclear Generation identifies, manages and mitigates risk through several programs and processes including:

- Probabilistic Risk Assessment (PRA): Based on NRC endorsed regulatory guidelines, the PRA is a quantified operational risk management model used to obtain insights and trends based on actual plant performance that provides a more accurate assessment and identification of risks;
- Risk-Informed Work Management Program: A program that manages risk to plant operations during maintenance activities and monitors the implementation of the risk management program. This program

involves use of the PRA model to assess maintenance related risk. Maintenance schedules are adjusted to minimize risk impact.

- Accredited and Non-Accredited Training Programs: Accredited training programs are performance-based programs that are highly integrated processes involving the participation and support of line management, training leaders, instructors and students. Operations, Maintenance, Engineering and emergency response personnel are trained to implement procedures for mitigating natural phenomena and external events within the current design basis.
- Corrective Action Program (CAP): The CAP is required by NRC regulation and it is the main process DCPP uses to identify, analyze, and resolve plant problems. The CAP process includes identifying issues, conducting significant issue reviews, causal analysis, develop and implement corrective actions and performance trending and monitoring. The program is used to develop corrective actions to prevent recurrence of problems.
- Operating Experience Program: The purpose of the Operating Experience Program is to share operating experience among nuclear power plans to evaluate event precursors so actions can be implemented to eliminate vulnerabilities.
- Design Control Processes: Nuclear Generation design activities are controlled per NRC regulations to ensure that design, technical and quality requirements are correctly translated into design documents and that changes to design are properly controlled.
- Security Program: DCPP operates physical security and cyber security programs based on NRC regulatory requirements.
- Long-Term Seismic Program: DCPP complies with an NRC commitment to continuously study and update the state of knowledge regarding seismic hazards impacting DCPP.
- Emergency Preparedness – The DCPP Emergency Planning Department administers the Emergency Plan which is a condition of the DCPP operating license and is heavily regulated by the NRC and the United States (U.S.) CFR. The Emergency Plan includes plans, processes, procedures, facilities, equipment, training and drills all in

support of protecting the health and safety of the public in the event of a radiological emergency.

2. Changes Since the 2017 RAMP

Nuclear Core Damaging Event was a 2017 RAMP risk.[22] PG&E performed an updated risk evaluation in 2019 to review the key risk drivers and evaluate their potential impact and to evaluate the effectiveness of existing mitigations to maintain the overall level of risk within NRC requirements. Through this risk evaluation process PG&E determined that this risk is well below the required regulatory threshold of one event for every 10,000 reactor years. The PRA modeling PG&E performed resulted in one event for every 11,299 reactor years.

PG&E will continue conducting seismic evaluations to evaluate the core damaging event risk. The NRC is evaluating if additional actions may be needed based on lessons learned from the 2011 Fukushima Nuclear accident.

Due to the impending shutdown of both DCPP Units in 2024 and 2025, a new enterprise risk associated with decommissioning activities is under development.

3. Risk Mitigations

PG&E did not propose mitigations for this risk for the 2017-2019 period in the 2017 RAMP. In the 2020 GRC PG&E identified certain projects and equipment purchases to mitigate risk as part of the Enterprise and Operational Risk Management process. PG&E has completed: Beyond Design Basis (BDB) regulatory requirements; seismic, flooding and tsunami studies; portable equipment procurement used in case of a BDB event with extended loss of power; staffing and communication studies to support BDB strategies; upgrade spent fuel pool instrumentation; and upgrade reactor cooling pump seals to prevent loss of reactor coolant.

PG&E will maintain current risk controls until the DCPP nuclear units are closed at the end of their respective NRC licenses.[23] These controls were

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22 PG&E's 2017 RAMP Report, Chapter 12.

23 In D.18-01-022, the CPUC approve the retirement of DCPP when its NRC operating licenses expire in November 2024 for Unit 1 and August 2025 for Unit 2.

listed in the 2017 RAMP and the 2020 GRC. Current risk controls include: maintaining plant systems; operating the facility; plant and system configurations; security from external and internal threats and emergency response; independent oversight and training; and regulatory requirement improvements and ongoing seismic evaluations.

4. Responding to Stakeholder Feedback

At Workshop #3 stakeholders provided feedback about PG&E's proposed list of RAMP risks. Both the Safety and Policy Division and The Utility Reform Network questioned the safety score assigned to the Nuclear Core Damaging Event risk and recommended that PG&E reconsider the list of risks to be included in the 2020 RAMP. In particular, these groups raised concerns regarding the low Safety CoRE value.

PG&E's first approach to estimate the safety consequences of a worst-case nuclear accident at Diablo Canyon was to review safety impacts from historical events and to use this data in the PG&E estimate. Data from the accidents at Three Mile Island, Fukushima and Chernobyl was reviewed. Ultimately, the Fukushima accident was determined to be the most closely aligned when Emergency Preparedness, Radioactive source term and accident severity were considered. Based on this comparison, the safety consequences from a direct impact of radiation were estimated to be very low.

Subsequent to this initial empirical approach, PG&E reviewed the results of analytical studies that were performed both for Diablo Canyon and other representative nuclear power plants including those performed by the U.S. NRC. Two studies were assessed to determine if they would provide a more accurate estimate of a severe accident. Ultimately, PG&E decided to rely on the DCPP specific Severe Accident Mitigations Alternatives (SAMA) analysis that is based on site specific meteorology, radiation source terms and population distribution/density.

PG&E performed the SAMA for DCPP license renewal purposes. This study includes conservative assumptions such as linear no dose threshold health impacts[24] and does not credit beyond design basis mitigation actions but was considered the most representative because of its specificity to Diablo Canyon. The published results from the SAMA study did not include per event safety impact numbers, rather the SAMA report included a safety risk metric[25] that incorporated the extremely low likelihood that an event like this could occur.

Additional information about PG&E's analysis is included in supporting workpapers.[26]

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24 Linear no-threshold model is a dose-response model used in radiation protection to estimate stochastic (random) health effects such due to exposure to ionizing radiation. This model assumes that any dose greater than zero will increase risk in a linear fashion.

25 This safety risk metric is a probabilistic evaluation of the potential safety impact wherein the consequence of an event is multiplied by the frequency of event. The result of the safety risk metric is provided in safety events per year.

26 See WP 19-1, MAVF Nuclear Safety Consequence Position Paper.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 20

RISK ASSESSMENT AND MITIGATION PHASE

CROSS-CUTTING FACTORS

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 20
RISK ASSESSMENT AND MITIGATION PHASE
CROSS-CUTTING FACTORS

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RISK ASSESSMENT AND MITIGATION PHASE
CROSS-CUTTING FACTORS

A. Introduction

1. Identifying the 2020 Risk Assessment and Mitigation Phase Cross-Cutting Factors

To develop its list of 2020 Risk Assessment and Mitigation Phase (RAMP) cross-cutting factors, Pacific Gas and Electric Company (PG&E or the Company) evaluated all the risks on its Corporate Risk Register (CRR).[1] As PG&E analyzed its CRR it identified items that were not risk events themselves, but rather impacted either the likelihood or consequence of other items on the CRR. Those items that were not risks themselves, but impacted other risks were identified as the cross-cutting factors in this 2020 RAMP.

The eight cross-cutting factors PG&E identified and is presenting in this report are:

1) Climate Change;
2) Cyber Attack;
3) Emergency Preparedness and Response (EP&R);
4) Information Technology (IT) Asset Failure;
5) Physical Attack;
6) Records and Information Management (RIM);
7) Seismic; and
8) Skilled and Qualified Workforce (SQWF).

Cross-cutting factors can impact RAMP risks in several ways. A cross-cutting factor can be a unique risk driver or a component of an existing driver, therefore impacting the likelihood of an event. It can also impact the consequence of an event, increasing the impact of potential outcomes.

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[1] PG&E recently changed the name of its Enterprise Risk Register to the Corporate Risk Register. See Chapter 2 of this report.

Unique Driver: The Seismic cross-cutting factor is a unique driver of the Large Uncontrolled Water Release (Dam Failure) risk. A dam failure risk event can occur as a result of a seismic event.

Component of an Existing Driver: The RIM cross-cutting factor does not cause risk events on its own but can contribute to a risk event and; therefore, is represented as a component of another driver. For example, the absence of important records and information or the inability to access that information quickly cannot cause a Loss of Containment on Gas Transmission Pipeline risk event on its own, but can contribute to the likelihood of this risk event occurring through either of two risk drivers—Incorrect Operations or Coordination Failure—if information is not readily available. RIM is represented as a separate driver in the Loss of Containment on Gas Transmission Pipeline Risk Bow Tie for visibility but is essentially a component of the Incorrect Operations risk driver.

Consequence: PG&E's planning for and response to emergencies, included in the EP&R cross-cutting factor, impacts the consequence of a risk event. If a Loss of Containment Gas Distribution Main or Service risk event occurred, initiating emergency response activities could reduce the consequence of the event.

2. Presenting the Cross-Cutting Factors in the 2020 RAMP

The cross-cutting factors appear in several locations in the 2020 RAMP report.

- In this chapter (Chapter 20, "Cross-Cutting Factors"), PG&E shows how the cross-cutting factors map to the RAMP risks, summarizes each cross-cutting factor, and briefly discusses how the cross-cutting factors impact the RAMP risks.
- In Chapter 20, Attachment A, PG&E describes each cross-cutting factor in more detail, explains how it impacts the 2020 RAMP risks, discusses any changes since the 2017 RAMP, describes the mitigations and controls planned for the 2020 through 2026 period, and provides the Risk Spend Efficiency (RSE) scores.
- In the 12 RAMP risk chapters (Chapter 7 to Chapter 18) PG&E lists the cross-cutting factors that impact that RAMP risk.

- In workpapers, PG&E provides a mitigation effectiveness analysis and the forecast costs for those cross-cutting factors where PG&E calculated an RSE.

3. Changes Since the 2017 RAMP

In PG&E's 2017 RAMP, the three cross-cutting factors (RIM, SQWF, and Climate Resilience, (now Climate Change)) were aggregated across individual risk models. PG&E had developed a cross-cutting model that was dependent on the outputs from the other stand-alone risk models. The cross-cutting models were not specific risk events, but an aggregation of the associated stand-alone model. For example, for the RIM cross-cutting factor, each of the stand-alone risks estimated what portion of the risk could be attributed to a records issue. The portion attributed to records issues was an input into the RIM cross-cutting model.

For the 2020 RAMP PG&E is using a new approach for presenting and modeling cross-cutting factors. This new approach is responsive to feedback from the Safety Policy Division, formerly the Safety Enforcement Division (SED), that PG&E's approach to modelling cross-cutting factors in the RAMP lacked specificity and transparency into the impact of the drivers and how they are causally linked to the risk event.[2] In the 2020 RAMP, PG&E is now integrating each applicable cross-cutting factor into the appropriate RAMP risk models as a driver, driver component, or consequence of that specific risk. This new approach increases transparency and better shows how the cross-cutting factors contribute to the frequency and/or consequence of the RAMP risk events.

B. Mapping the Cross-Cutting Factors to the 2020 RAMP Risks

Tables 20-1 and 20-2 below map the eight cross-cutting factors to the 12 RAMP risks. Table 20-1 shows how the cross-cutting factors impact the likelihood of a risk event while Table 20-2 shows how the cross-cutting factor

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[2] SED noted that PG&E's 2017 approach to modelling cross-cutting risks lacked the specificity and transparency into the impact of the drivers and how they are causally linked to the risk event. SED noted that it might be best to include the cross-cutting drivers in the appropriate stand-alone risk chapter to prevent duplication and better show how these components of risk contribute to the frequency of the risk event. (PG&E, Risk and Safety Aspects of RAMP Report I.17-11-003 (Mar. 30, 2018), p. 24).

impacts the consequence of a risk event. PG&E also provides an individual table for each of the cross-cutting factors in Attachment A that maps the cross-cutting factor to the applicable RAMP risks.

The risk bowties in each RAMP risk chapter show the applicable cross-cutting factors on both the frequency and consequences sides. Certain cross-cutting factors that impact the consequences of the risk event (right side of the bow tie) will not appear on the bow tie because the cross-cutting factor does not make a separate contribution to the outcome of the risk event. These cross-cutting factors are considered foundational because they support other mitigations rather than directly reducing the risk itself. For example, for the cross-cutting factor EP&R, 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)), the EOC activities will reduce the consequence of the risk event (e.g., enhanced coordination with first responders), but those EOC activities do not themselves directly reduce the risk associated with the loss of containment event.

TABLE 20-1
MAPPING THE CROSS-CUTTING FACTORS TO THE RAMP RISKS
CROSS-CUTTING FACTORS IMPACT THE LIKELIHOOD OF THE RISK EVENT

Line No.	RAMP Risk	Cross-Cutting Factor							
		Climate Change	Cyber Attack	EP&R	IT Asset Failure	Physical Attack	RIM	Seismic	SQWF
1	Contractor Safety Incident								
2	Employee Safety Incident	(b)				X	X		X
3	Failure of Electric Distribution Overhead Assets	X				X	X	X	X
4	Failure of Electric Distribution Network Assets	(b)				X	X	X	X
5	Large Overpressure Event Downstream of Gas Measurement and Control Facility						X		X
6	Large Uncontrolled Water Release (Dam Failure)	(b)	X		X	X		X	
7	Loss of Containment on Gas Distribution Main or Service	(b)				X	X	X	X
8	Loss of Containment on Gas Transmission Pipeline	(b)				X	X	X	X
9	Motor Vehicle Safety (MVS) Incident								
10	Real Estate and Facilities Failure	(b)				X		X	
11	Third-Party Safety Incident								
12	Wildfire	(b)						X	

(a) Given historical data, this cross-cutting factor impacts the RAMP risk, but was not extracted from the data and considered or modeled separately. This is referred to in Section B.1 as “Embedded.”

(b) This cross-cutting factor is considered by PG&E to impact the RAMP risk, but data limitations precluded a statistically meaningful quantification of its impact. See Attachment A, Section A for more information.

TABLE 20-2
MAPPING THE CROSS-CUTTING FACTORS TO THE RAMP RISKS
CROSS-CUTTING FACTOR IMPACT THE CONSEQUENCE OF THE RISK EVENT

Line No.	RAMP Risk	Cross-Cutting Factor							
		Climate Change	Cyber Attack	EP&R	IT Asset Failure	Physical Attack	RIM	Seismic	SQWF
1	Contractor Safety Incident								
2	Employee Safety Incident						X		
3	Failure of Electric Distribution Overhead Assets			(a)	X		X	X	
4	Failure of Electric Distribution Network Assets			(a)			X	X	
5	Large Overpressure Event Downstream of Gas Measurement and Control Facility		X	(a)	X		X		
6	Large Uncontrolled Water Release (Dam Failure)			(a)			X		
7	Loss of Containment on Gas Distribution Main or Service			(a)			X		
8	Loss of Containment on Gas Transmission Pipeline		X	(a)	X		X		
9	Motor Vehicle Safety (MVS) Incident						X		
10	Real Estate and Facilities Failure			(a)			X	X	
11	Third-Party Safety Incident								
12	Wildfire	X		(a)			X	X	

(a) Given historical data, this cross-cutting factor impacts the RAMP risk, but was not extracted from the data and considered or modeled separately. This is referred to in Section B.1 as "Embedded."

C. Modeling the Cross-Cutting Factors

1. Incorporating Cross-Cutting Factors Into the RAMP Risk Bowties

PG&E describes its RAMP risk model in Chapter 3, "Risk Modeling and Risk Spend Efficiency." As described in Chapter 3, the eight cross-cutting factors are incorporated into the applicable RAMP risks.

Since the cross-cutting factors impact the RAMP risks in different ways, PG&E used seven different modeling methods to incorporate them into the RAMP risk models. These methods are described below and are shown in the individual cross-cutting factor tables in Attachment A.

a) Drivers: To determine the likelihood of an event, PG&E modeled the cross-cutting drivers using two methods.

- Extracted from Existing: PG&E reviewed the historical causal data related to risk incidents and identified cross-cutting events that impacted the RAMP risk. The cross-cutting factor events were not extracted from the historical data and modeled or considered separately. Extracted from Existing generally represents the impact of cross-cutting factors considering the current application of controls. For example, when modelling the effect of the Physical Attack cross-cutting factor on the Employee Safety Incident risk, PG&E relied on and applied historical data related to the different types of employee safety incidents assuming the data incorporates existing controls to reduce the likelihood of physical attack.
- Added Frequency: PG&E added frequencies (risk events) based on separate quantification efforts. This method was generally used to represent low frequency events where additional quantification was added to the model to represent the potential impact of the cross-cutting factor. For example, for the Failure of Electric Distribution Network Assets risk, PG&E has no historical data on how major seismic events impact those assets, so to model the Seismic cross-cutting factor, PG&E used seismic model output rather than historical observations to characterize Seismic risk.

b) Consequence Multiplier: Reflects an adjustment to the Consequence of Risk Event, due to the impact of the cross-cutting factor. This method was generally used to represent the cumulative effect of the concurrent occurrence of the RAMP risk event and the cross-cutting factor. For example, RIM is a consequence multiplier to several risk events. The model considers that the lack of access or lack of timely access to records and information can impact a risk event. This impact is expressed in the model by adding a multiplying factor to an outcome. The impact of RIM is modeled by adding a factor that increases the financial outcome (costs) of an event.

c) Outcome: if an outcome of a Risk Event has different relationships to drivers than the non-cross cutting factor outcomes (e.g., the severe Seismic outcome is driven only by the Seismic driver).

d) Unique Driver/Outcome Combination: In certain instances PG&E recognizes a Unique Driver/Outcome Combination for the cross-cutting factors and the model introduces a unique combination of outcomes. For example, for the Loss of Containment on Gas Transmission Pipeline risk, if an IT asset failure occurs coincidently or immediately following a risk event, it could cause loss of visibility of the system and delayed response capability, resulting in a greater consequence of the risk event. The model expresses this unique event by adding two outcomes related to the coincident occurrence of the risk event and cross-cutting factor: Transmission Pipeline Rupture Coincident with IT Asset Failure; and Transmission Pipeline Leak Coincident with IT Asset Failure.

e) Escalating Frequency: Adjustment to driver frequency. This method is generally used to represent a cross-cutting factor that is expected to lead to an increase in the frequency of a risk event occurring. For example, for the Distribution Overhead Asset Failure risk, the model assumes that climate changes (cross-cutting factor: Climate Change) will increase the frequency of events in the Natural Hazard sub-driver category (like heatwave occurrence, lightening, fire, and flooding) over time and, as such, an escalating frequency multiplier is applied to the risk driver.

f) Embedded: The impact of the cross-cutting factor is already accounted for in the assessment of frequency and consequence of a risk event as control. For example, the model assumes that the impacts of the EP&R

cross-cutting factor are already accounted for in the current Loss of Containment – Distribution Main or Service bowtie and no additional EP&R data is added to the baseline risk assessments.

2. Calculating a RSE

PG&E describes the basic process by which each of the cross-cutting factors is represented in the risk model in Attachment A. The source documents used in each of the cross-cutting factor models is included in supporting workpapers.[3]

Calculating the RSE incorporates cost estimates and the perceived effectiveness of each mitigation. PG&E discusses RSEs in Chapter 3, "Risk Modeling and Risk Spend Efficiency." The cost estimates for the mitigations are included in Attachment A for each cross-cutting factor and in supporting workpapers.[4] The effectiveness of each mitigation is described in the Mitigation Effectiveness workpapers.[5]

In Attachment A PG&E describes the mitigation and control programs it is proposing for each cross-cutting factor during the RAMP period. Most of these programs apply to multiple risks, multiple drivers, multiple tranches, and multiple outcomes. Given the number of potential combinations of risks, drivers, tranches and outcomes, PG&E calculated one RSE for a cross-cutting factor as opposed to an RSE for each cross-cutting factor mitigation. For example, PG&E is proposing seven mitigations to address RIM risks but has calculated one RSE for RIM (all mitigations).

D. Introduction to the 2020 RAMP Cross-Cutting Factors

In this Section PG&E introduces the eight cross-cutting factors. Additional information about each one, including a discussion of the applicable risk modeling, impacts to the 2020 RAMP risks, changes since the 2017 RAMP, planned work and the RSE score is included in Attachment A.

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3 PG&E will provide all risk model workpapers on July 17, 2020.

4 References to the financial workpaper are provided in Attachment A.

5 Chapter 3 workpapers include the mitigation effectiveness workpapers for each cross-cutting risk for which PG&E calculated a RSE value.

1. Climate Change

Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and infrastructure adjacent communities. In the face of these risks, the California Public Utilities Commission (CPUC) has defined climate adaptation for energy utilities as an adjustment in utility systems using strategic and data-driven consideration of actual or expected climatic impacts and stimuli or their effects on utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable, and resilient operations.[6]

PG&E recognizes that adapting to and becoming resilient in the face of climate change is a critical responsibility and that integrating climate change into the Company's risk approach is a key step in understanding and preparing for projected climate-driven natural hazards. PG&E evaluated all RAMP risks for vulnerability to climate impacts. PG&E integrated available climate projections into the risk bowties for Wildfire and Failure of Electric Distribution Overhead Asset risks. Integrating the projected, quantitative impact of climate change into the other RAMP risk models was not possible for this report due to: the need for more data about the relationship between climate-driven natural hazards and risk events and the need for more or more specific PG&E data.

PG&E considers that most RAMP Risks are impacted by the climate change cross-cutting factor and intends to further integrate forward-looking climate data into risk analysis in future reports.

Because PG&E expects climate change to impact most RAMP risks additional risk assessment is prudent. A key mitigation planned for the 2020 to 2026 period is to conduct a Climate Vulnerability Assessment (CVA). PG&E will undertake a CVA to assess how its assets, operations, and employees are vulnerable to the projected impacts of climate change and consider how climate impacts to PG&E assets may impact customers and infrastructure adjacent communities. The final scope of the CVA will be determined by the forthcoming decision in Rulemaking (R.) 18-04-019.

Climate Change is discussed in more detail in Attachment A, Section A.

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[6] CPUC's Climate Adaptation Order Instituting Rulemaking (R.)18-04-019, (May 7, 2018).

2. Cyber Attack

Cyber Attack is a coordinated malicious attack purposefully targeting PG&E's core business functions and resulting in a loss of control of Company information or systems used for gas, electric or business operations. The consequences of a cyber attack are potentially catastrophic and could impact the safety and reliability of PG&E's operational systems. The Cyber Attack risk includes attacks on IT to obtain unauthorized access to PG&E's data, and attacks on operational technology to impact PG&E's ability to control the delivery of natural gas and/or electricity.

In the 2020 RAMP, PG&E is proposing a series of mitigations aligned to the four pillars of the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF): (1) Identify – Activities that develop organizational understanding in managing security risks to systems assets, and data; (2) Protect – Activities that develop and implement appropriate safeguards to provide secure delivery of critical infrastructure services; (3) Detect – Activities that identify the occurrence of a potential security risk, enabling timely discovery and reducing potential consequences; and (4) Respond – Activities that enable effective evaluation of a potential security risk-based event, and impact containment reducing potential consequences. Although there is a fifth NIST CSF category, (5) Recover – Activities that support timely recovery to normal operations following a cybersecurity incident—PG&E did not map projects to this domain.

Cyber Attack is discussed in more detail in Attachment A, Section B.

3. Emergency Preparedness and Response

The EP&R cross-cutting factor examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability, and regulatory impacts. EP&R advances PG&E's response to emergencies by improving governance, strengthening coordination among the lines of business (LOB), and improving collaboration with external partners such as the Federal Emergency Management Agency and the California Governor's Office of Emergency Services.

EP&R is proposing 12 controls and eight mitigations in the 2020 RAMP. Controls include emergency operations plans and standards, emergency response technology, projects related to PG&E's EOC, and control programs related to the operating LOBs. EP&R mitigations include EOC Enhancements and Mutual Aid Enhancements.

EP&R is discussed in more detail in Attachment A, Section C.

4. IT Asset Failure

IT Asset Failure risk is a failure of IT systems or infrastructure, resulting in outages, or system unavailability for mission critical assets impacting operations or the ability to support public safety events. Technology enables and supports virtually all of PG&E's day-to-day activities, including work execution, grid control, customer support, emergency response, asset management, and more. Because of PG&E's growing reliance on technology, the need to maintain the reliability of IT assets and systems becomes increasingly important for PG&E to function effectively.

PG&E is proposing four mitigations to address IT Asset Failure. Together these mitigations will enhance IT Asset Failure risk identification, failure detection and response capabilities; add IT asset capacity to support increased demand; remove single points of failure for improved continuity and resiliency; and replace end-of-life, at-risk and high failure rate IT assets.

IT Asset Failure is discussed in more detail in Attachment A, Section D.

5. Physical Attack

Physical Attack is defined as incidents related to break-ins, vandalism, theft, fraud, assault, and threats against PG&E's workforce and assets.

PG&E is continuing to develop a detailed work plan for the 2020 RAMP period. One of the mitigations PG&E is considering is a program to mitigate identified risks via an internally developed process called the Security Defined Protection Levels (SDPL). Using the SDPL risk framework, Corporate Security has assigned a risk level to approximately 2,600 PG&E facilities. Each risk level corresponds to a standard security package to counter the risk level at each location. Starting with the risk level "elevated" sites, the Corporate Security team will work towards closing any gaps in the security package at that facility.

Physical Attack is discussed in more detail in Attachment A, Section E.

6. Records and Information Management

PG&E identified RIM as a cross-cutting factor because the risk of not having an effective RIM program may result in the failure to construct, operate and maintain a safe system and may lead to property damage and/or loss of life. Managing records and information inconsistently can lead to an operational incident or adverse business result if records that are needed cannot be located in a timely fashion.

In the 2020 RAMP period the Enterprise Records and Information Management team will continue to implement existing mitigations and begin new mitigations in the areas of records and information compliance, retention, availability, governance, disposition, and integrity.

RIM is discussed in more detail in Attachment A, Section F.

7. Seismic

Seismic events can be a significant driver of failure in all LOB assets. PG&E's service territory is in an active seismic zone and as such PG&E assets from all LOBs are subject to the potential for damaging ground shaking and related ground failure that ranges from minor to catastrophic from a single event. Damaging effects may occur without warning over a large geographic area and impact PG&E's ability to serve its customers and respond to the event. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.

During the 2020 RAMP period PG&E's Geosciences team collaborated with LOB asset owners and risk managers to develop the means to consistently quantify seismic risk and to propose risk mitigations tailored to those LOB assets.

Seismic Scenario is discussed in more detail in Attachment A, Section G.

8. Skilled and Qualified Workforce

PG&E's Human Resources Department develops and delivers technical, leadership and other training that helps to maintain a skilled, safe and qualified workforce. Failing to maintain a SQWF is one of PG&E's top cross-cutting factors than can impact safety.

The SQWF mitigations and controls planned for the 2020 RAMP period are focused on Gas Operations and Electric Operations employees. One of the key mitigations for the 2020 RAMP period is the Enterprise Safety Management System (ESMS). The ESMS is a series of capabilities (people, process and technology systems) required to define, plan, implement and continuously improve workforce safety and includes an Enterprise Management of Change process to identify, understand, and evaluate the risks and hazards when changes are made to facilities, operations, or personnel to assure they are properly controlled.

SQWF is discussed in more detail in Attachment A, Section H.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 20

ATTACHMENT A

CROSS-CUTTING FACTORS

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A. Climate Change

1. Overview

Climate change presents ongoing and future risks to Pacific Gas and Electric Company's (PG&E or the Company) assets, operations, employees, customers, and the communities in which it serves. In the face of these risks, the California Public Utilities Commission (CPUC) has defined climate adaptation for energy utilities in the ongoing Order Instituting Rulemaking (OIR) as adjustments in utility systems using strategic and data-driven consideration of actual or expected climatic impacts and stimuli or their effects on utility planning, facilities maintenance and construction (M&C), and communications, to maintain safe, reliable, affordable, and resilient operations.[1]

In line with the ongoing OIR, PG&E is taking action to mitigate against and adapt to the potential consequences of a changing climate and associated weather patterns. This includes ongoing "foundational work" that seeks to improve PG&E's internal capabilities to understand, analyze, and use forward looking climate data in decision-making.

PG&E has identified six primary climate-driven contributors to risk: increased severity and frequency of storm events; sea level rise; land subsidence; change in temperature extremes; changes in precipitation patterns and drought; and wildfire. Consequences of these climate-driven events may vary widely and could include increased stress on the energy supply network due to new patterns of demand, reduced hydroelectric output, physical damage to PG&E's infrastructure, higher operational costs, and an increase in the number and duration of customer outages and safety consequences for both employees and customers.

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[1] *CPUC's Climate Adaptation OIR*, Rulemaking (R.)18-04-019 (May 7, 2018).

2. Modeling

Climate Change projections are uncertain. Given the range of potential future conditions and because historical data is often inadequate for understanding how future conditions may impact communities and infrastructure it is difficult to determine how climate change may impact the RAMP risks. To integrate climate data into the risk model, each risk was considered separately, and available climate projections matched to appropriate drivers or consequences. For certain risks a lack of data precluded integration of climate projections, even though PG&E expects these risks to be impacted by climate change.

Table 1 shows the status of climate data integration into the risk models.

TABLE 1
CROSS-CUTTING FACTOR SUMMARY: CLIMATE CHANGE

Line No.	Risk	Status of Climate Data Integration	Explanation of Climate Change Quantification Status
1	Wildfire	Integrated into Model	See Modeling Workpaper Climate
2	Failure of Electric Distribution Overhead Assets	Integrated into Model	See Modeling Workpapers Climate through Climate
3	Failure of Electric Distribution Network Assets	Applicable but not integrated, pending further research	Available data shows limited historical natural hazard impact Developing statistical relationship between climate-driven natural hazards and equipment failure
4	Loss of Containment on Gas Transmission Pipeline	Applicable but not integrated, pending further research	Available data shows limited historical natural hazard impact Developing statistical relationship between climate-driven natural hazards and equipment failure
5	Loss of Containment on Gas Distribution Main or Service	Applicable but not integrated, pending further research	Available data shows limited historical natural hazard impact Developing statistical relationship between climate-driven natural hazards and equipment failure
6	Large Overpressure Event Downstream of a Gas Measurement and Control Facility	Not applicable	Asset failure insensitive to natural hazards based on available data
7	Employee Safety Incident	Applicable but not integrated, pending further research	Available data shows limited historical natural hazard impact Developing statistical relationship between climate-driven natural hazards and employee safety
8	Contractor Safety Incident	Not Applicable	Difficult to build relationships between long-reaching climate change issues and risk events
9	Third Party Safety Incident	Not Applicable	Difficult to build relationships between long-reaching climate change issues and risk events

TABLE 1
CROSS-CUTTING FACTOR SUMMARY: CLIMATE CHANGE
(CONTINED)

Line No.	Risk	Status of Climate Data Integration	Explanation of Climate Change Quantification Status
10	Motor Vehicle Safety Incident	Applicable but not integrated, pending further research	Difficult to build relationships between long-reaching climate change issues and risk events
11	Real Estate and Facilities Failure	Applicable but not integrated, pending further research	Available data shows limited historical natural hazard impact Need for site-specific flood analysis
12	Large Uncontrolled Water Release	Applicable; De facto integrated via existing FERC risk methodology	Required Federal Energy Regulatory Commission (FERC) dam risk assessment is conservative by design and incorporates consideration of past observed and likely future events when considering the magnitude of extreme floods.

PG&E's Climate Resilience Team evaluated all RAMP risks in partnership with Risk Owners and asset family subject matter experts. This involved consideration of each risk's sensitivity to climate-driven natural hazards, and determination of whether existing climate data could be integrated into risk bowties in a statistically meaningful manner.

In many cases, the Climate Resilience Team and LOB representatives agreed that climate-driven natural hazards would likely impact or continue to impact the risk in the future, but given the data available, it was not possible to meaningfully quantify that impact without substantial further study. For example, future climate change-driven increases in extreme heat and vector-borne illnesses may pose safety risks to employees and contractors. However, a lack of historical data correlating heat to safety incidents precluded the ability to project how this risk will change over time. Similarly, climate change is likely to affect the condition of transportation infrastructure, which, combined with extreme weather events, could lead to an increase in Motor Vehicle Safety Incidents. In this case, it was difficult to build relationships between long-reaching climate change issues and risk events.

PG&E intends to continue to advance the inclusion of forward-looking climate data into PG&E's RAMP risk models in future filings. Additionally, PG&E's Climate Vulnerability Assessment will supplement the Company's understanding of how climate-driven natural hazards may impact PG&E in the future.

One way climate change can impact a risk is to increase the likelihood of a risk event and act as a frequency multiplier. The model considers how the climate variable will change (often, increase) over time and therefore impact PG&E employees and operations. For example, for the Failure of Electric Distribution Overhead Assets risk, PG&E conducted a heat wave analysis that projects how temperature will increase over time. The results of this analysis are used to estimate how rising temperatures will impact PG&E's electric assets by comparing the rising temperature data to the electric assets failure rates based on the temperature threshold at which equipment is likely to fail. PG&E also considered other natural hazards for this risk, including major rain events, major snow/ice events, extreme wind, lightening, flooding due to extreme precipitation, subsidence, and others. To reflect the impact of these changing climate conditions on this risk, PG&E used climate projections to determine how the frequency of these natural hazard sub-drivers could change over time and impact the frequency of risk occurrence.

In contrast, climate change is accounted for in PG&E's Wildfire risk model on the consequence side of the model by correlating the projected change in PG&E territory burned relative to the year 2020 with change in the frequency of ignitions that occur during Red Flag Warnings (RFW). This increases the proportion of ignitions due to PG&E equipment that occur under RFW conditions and therefore, lead to higher consequence wildfires. This correlation is valid because projections of future area burned and RFW events are both driven by underlying factors, like higher temperatures and drier fuels, that are expected to result in more frequent and extreme fires due to climate change.

In addition to quantifiably impacting the Failure of Distribution Overhead Assets and Wildfire risks, PG&E considers climate change to be an applicable sub-driver to all other Risk Assessment and Mitigation Phase (RAMP) risks except Large Overpressure Event Downstream of a Gas Measurement and Control Facility, Motor Vehicle Safety (MVS) Incident, and Third-Party Safety Incident.[2] PG&E was not able to quantify the impact of climate change on these risks at this time due to limited internal, industry, and/or academic research regarding how specific climate variables impact specific asset types. In many cases, the contribution of climate-impacted natural hazard sub-drivers to risk event frequency was negligibly low relative to other drivers based on historical data. Given that climate change is projected to increase the frequency and intensity of some natural hazard sub-drivers—thereby, making these sub-drivers greater potential contributors to risk in the future—PG&E plans to conduct further research to

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[2] Climate Change does not apply to Motor Vehicle Safety Incident and Third-Party Safety Incident because in each case the bowties focus on the actions of the actor in question, rather than environmental conditions leading to failure. In the case of Large Overpressure Event Downstream of a Gas Measurement and Control Facility risk, PG&E found no evidence that climate variables impact the type of equipment failures that are the dominant driver of this risk.

better quantify the impact of climate-driven hazards on these risks for the 2024 RAMP filing, and in the meantime is conducting a Climate Vulnerability Assessment (CVA) consistent with CPUC proceeding R.18-04-019 to supplement the Company's understanding of climate-driven risk.

3. Impacts to the 2020 RAMP Risks

Climate Change impacts nine RAMP risks as shown in Table 2 below. PG&E is proposing alternative mitigations to address Climate Change for five RAMP risks: (1) Real Estate and Facilities Failure; (2) Failure of Electric Distribution Overhead Assets; (3) Failure of Electric Distribution Network Assets; (4) Loss of Containment on Gas Distribution Main or Service; and, (5) Loss of Containment on Gas Transmission Pipeline.

TABLE 2
CROSS-CUTTING FACTOR SUMMARY: CLIMATE CHANGE

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Employee Safety Incident	Applicable, but unquantified	(a)	--
2	Failure of Electric Distribution Overhead Assets	Escalating Frequency	(a)	(a)
3	Failure of Electric Distribution Network Assets	Applicable but unquantified	(a)	--
4	Large Uncontrolled Water Release (Dam Failure)	Embedded	(a)	--
5	Loss of Containment Gas Distribution Main or Service	Applicable, but unquantified	(a)	--
6	Loss of Containment on Gas Transmission Pipeline	Applicable, but unquantified	(a)	--
7	Real Estate and Facilities Failure	Applicable, but unquantified	(a)	--
8	Wildfire	Consequence Multiplier	(a)	(a)

(a) This cross-cutting factor is considered by PG&E to impact the RAMP risk, but data limitations precluded a statistically meaningful quantification of its impact. See Attachment A, Section A for more information.

Note: The values in the Cross-Cutting Factor Summary tables come from the bow tie graphics in the RAMP risk chapters (Chapters 7 and 18). In certain instances the impact of the cross-cutting factor is such that it is not displayed on the bow tie graphic.

4. Changes Since the 2017 RAMP

a. Planned Work

PG&E designated Climate Resilience as an enterprise risk in 2017. In the 2017 RAMP, PG&E identified 12 mitigations that together comprised the foundational activities PG&E planned to undertake in order to better understand the risks posed to the Company by climate change and to increase the Company's climate resilience.[3]

In 2017 Climate Resilience was a stand-alone risk whereas in 2020 this risk has been redefined as a cross-cutting factor to acknowledge that climate-driven natural hazards are contributing drivers to many RAMP risks.

PG&E completed six of the mitigations proposed in 2017: (M1A – Develop and Pilot Climate Resilience Screening Tool; M2 – Establish Standardized Process to Respond to Community Request for Climate Impact Information; M4 – Administer the Better Together Resilience Community Grant Program; M7A1 – Sea Level Rise Deep Dive; M7A2 – Wildfire Deep Dive; and, M7A3 – Increasing Temperatures/Heatwaves Deep Dive).

PG&E is continuing to work on the other seven mitigations proposed in 2017.

M5C – Develop and Report Climate Resilience Metrics: PG&E is making progress on increasing its internal capabilities to understand, plan for, and adapt to climate change. To track and measure this progress a second assessment (the baseline assessment was conducted in 2018) will be conducted in early 2021.

M8 – Research Climate Science and Impacts: While most work in the coming years will be directed at the CVA and Adaptation Plans, future updates will be needed as new climate models are developed and additional research on climate risk is published.

M10 – Governance, Integration, and Continuous Improvement: Key projects within this mitigation including the ongoing development of

[3] PG&E's 2017 RAMP Report, Investigation (I.) 17-11-003 (Nov. 30, 2017) (PG&E's 2017 Ramp Report), p. 22-12, Table 22-4.

Climate Line of Business (LOB) Action Plans; ongoing work to integrate future climate risk into LOB project lifecycle plans; updating design standards to account for future climate risk; and ongoing training of staff to use climate risk tools.

M11 – Climate Vulnerability Assessment: PG&E is undertaking a CVA to assess how its assets, operations, and employees are vulnerable to the projected impacts of climate change. The final scope of the CVA will be determined by the forthcoming decision in R.18-04-019. Due to the size of PG&E's service territory, PG&E plans to conduct the CVA in phases, with each phase focused on one of PG&E's regions. Each phase will evaluate climate risk exposure, assess the sensitivity of assets in the region to this climate risk; examine the adaptive capacity of the assets, and use this information to determine vulnerability. PG&E will work with various stakeholders throughout the CVA process to keep customers and infrastructure-adjacent communities apprised of developments and findings from the assessment. The CVA is expected to take at least three years to complete.

M12 – Climate Adaptation Plans: Following the completion of each phase of the CVA, PG&E will begin developing Climate Adaptation Plans, by region to increase the resilience of its assets, operations, and employees. PG&E intends to work closely with local communities to coordinate with local stakeholders as these plans are developed.

M13 – Internal Consulting: The Climate Resilience team receives requests from the LOBs to undertake ad hoc projects related to integrating forward looking climate data into project planning and asset replacement.

The forecast costs for the planned mitigations are shown in Table 3 below.[4]

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[4] Costs for all cross-cutting factor mitigations are included on WP 20-1.

TABLE 3
FORECAST COSTS,
2020-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	Major Work Category (MWC)	2020	2021	2022	2023	2024	2025	2026	Total
1	M5C	Develop and Report Climate Resilience Metrics	LJA	–	$155	–	–	$87	–	–	$242
2	M8	Research Climate Science and Impacts	LJA	$52	–	–	$85	174	$225	$185	721
3	M10	Governance, Integration, and Continuous Improvement	LJA	156	160	123	169	174	225	185	1,192
4	M11	CVA	LJA	432	579	588	127	–	–	139	1,865
5	M12	Climate Adaptation Plans	LJA		270	397	446	412	330	139	1,993
6	M13	Internal Consulting	LJA	130	210	214	219	224	319	328	1,645
7		Total		$770	$1,373	$1,322	$1,047	$1,072	$1,098	$975	$7,657

b. **Mitigations With RSE Scores**

PG&E did not calculate an RSE for Climate Change because the Climate Change mitigations are foundational. Foundational mitigations do not directly reduce risk themselves, but they support other mitigations that do.

B. Cyber Attack

1. Overview

The Cyber Attack risk is defined as a coordinated malicious attack purposefully targeting PG&E's core business functions, resulting in a loss of control of company information or systems used for gas, electric or business operations. The consequences of a cyber attack are potentially catastrophic and could impact the safety and reliability of PG&E's operational systems. The Cyber Attack factor includes attacks on Information Technology (IT) in order to obtain unauthorized access to PG&E's data, and attacks on operational technology to impact PG&E's ability to control the delivery of natural gas and/or electricity. In 2018, the energy sector was among the top three most attacked critical infrastructure sectors in the United States (U.S.).[5]

Cybersecurity continues to be increasingly important to the overall safety of PG&E's operating environment as technology becomes more complex and PG&E becomes more dependent on technology-enabled assets to meet business objectives. Security risks must be mitigated to prevent an attack and secure technology in order to guard against safety, reliability, financial and customer trust impacts.

PG&E manages cybersecurity threats through its Cybersecurity organization that is solely focused on managing security risk to PG&E's workforce, critical infrastructure, information assets, customers, and business operations. Efforts to manage risk include: new security mitigation investments; monitoring and reporting cyber attacks; securing operational technology environments; mitigating critical asset risks; Identity and Access

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5 Scott Foster, Power Engineering International, "Cybersecurity: How Utilities Can Prepare the Next Generation of Smart Grid" (Feb. 12, 2018). Scott Foster is the Chief Executive of Delta Energy and Communications.

Management (IAM); educating PG&E's employees on common and emerging security threats; remediating vulnerabilities across the enterprise; managing enterprise security technology; and, investigating and mitigating insider threats.

2. Modeling

Cyber Attack can impact both the likelihood and consequence of a risk event. PG&E does not have internal data wherein a cyber attack resulted in a catastrophic risk event, therefore, PG&E relied on publicly-available data to model this cross-cutting factor. Collecting external data to analyze cyber attack is difficult because it is rare for a cyber attack to cause a catastrophic event and because data about a cyber attack is generally not released to the public. Even publicly-available data is not widely available for evaluating the likelihood of a cyber attack against an industrial control system (like a utility) that could result in a catastrophic outcome.

To model the impact this cross-cutting factor had on the frequency of a risk event, PG&E evaluated how frequently there were near cyber attack misses. The near-misses were correlated with the chance for a cyber attack to result in a catastrophic outcome—a PG&E control system is compromised such that it leads to a risk event.

On the consequence side of the bow-tie, PG&E determined how much worse the outcome of a risk event would be if a risk event and cyber attack occurred at the same time. The model expresses this relationship by applying a consequence multiplier to represent the impact a cyber attack has on a risk event.

3. Impacts to the 2020 RAMP Risks

Cyber Attack impacts three RAMP risks. PG&E is continuing to evaluate the impact that Cyber Attack has on RAMP risks and expects to present Cyber Attack as a cross-cutting factor relative to additional RAMP risks in the 2023 General Rate Case (GRC).

Tables 4 and 5, below, maps the Cyber Attack cross-cutting factor to the applicable RAMP risks.[6]

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[6] Information about how Cyber Attack impacts the RAMP risks is included on WP 20-3.

TABLE 4
CROSS-CUTTING FACTOR DRIVER SUMMARY: CYBER ATTACK

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Large Uncontrolled Water Release (Dam Failure)	Escalating Frequency	0.6 percent (0.0001)	0.3 percent

TABLE 5
CROSS-CUTTING FACTOR CONSEQUENCE SUMMARY: CYBER ATTACK

Line No.	RAMP Risk	Consequence	Percent Frequency	Percent of Risk
1	Large Overpressure Event Downstream of Gas Measurement and Control Facility	LOC and Cyber Attack	0.02 percent	0.3 percent
2	Loss of Containment on Gas Transmission Pipeline	Leak and Cyber Attack	0.2 percent	<0.01 percent
3	Loss of Containment on Gas Transmission Pipeline	Rupture and Cyber Attack	0.1 percent	0.3 percent

Cyber Attack can impact the likelihood of a Large Uncontrolled Water Release (Dam Failure) risk event. A Cyber Attack coincident with conditions that cause a dam failure (flood, seismic, internal erosion, or physical attack) will increase the likelihood that a catastrophic outcome will occur.

Cyber Attack can impact the consequences of a Large Overpressure Event Downstream of Gas M&C Facility or a Loss of Containment on Gas Transmission Pipeline. If a Cyber Attack that impacts gas Supervisory Control and Data Acquisition (SCADA) occurred during a risk event, it could amplify that event by reducing PG&E's visibility into the system, decreasing PG&E's ability to respond to the risk event.

4. Changes Since the 2017 RAMP

In the 2017 RAMP PG&E presented two security-related risks, Cyber Attack (Chapter 18) and Insider Threat[7] (Chapter 19). In the 2020 RAMP, Insider Threat is now positioned as a sub-driver of Cyber Attack.

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7 Insider threat is the likelihood that employee or non-employee workers (i.e., contractors, consultants, temporary employees, etc.) with current or previously authorized access to PG&E's assets would intentionally or inadvertently use their access and knowledge in a manner that adversely affects safety, reliability or privacy or that results in additional expense to PG&E.

In the 2017 RAMP PG&E proposed a series of controls and mitigations designed to manage one or more of the Cyber Attack drivers. The controls and mitigations were aligned to the four pillars of the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) (Identify, Protect, Detect, and Respond). The NIST CSF establishes the basic guidelines of an effective cyber security program.

Following the 2017 RAMP filing, PG&E's Cybersecurity organization reevaluated its mitigations to better align them with the Company's overall cybersecurity strategy. Additionally, PG&E identified opportunities for efficiency and identified new work streams that resulted in changes to the mitigation forecasts. These changes were presented in PG&E's 2020 GRC.[8]

Table 6 below provides a summary status for each of the mitigations presented in the 2017 RAMP.

[8] Application (A.)18-12-009, Exhibit (PG&E-7), Chapter 9, p. 9-17 to p. 9-40.

TABLE 6
STATUS OF CYBER ATTACK MITIGATIONS PRESENTED IN THE 2017 RAMP

Line No.	2017 RAMP Mitigation Name and Number	Mitigation Objective	Current Status
1	**M1 – Identify**		
2	Third-Party Risk Management	Implement an integrated vendor risk management system that will provide a central repository for all vendor risk assessments.	Initial objectives not complete. Instead of implementing a new tool the decision was made to enhance the existing system. Improvements will continue through 2020.
3	Critical Application Security Monitoring	Build a prioritized list of application logs and develop a road map to onboard the priority logs into PG&E's log review and correlation platform for monitoring and analysis.	Complete.
4	IAM Product Enhancements	Enhance the IAM solutions to support cloud identity management, developer security operations, database integrations, cloud access security, Department of Energy Part 810 export controls, unstructured high-risk data access management, and segregation of duties. The project also includes extending on-premise IAM solutions to cloud and enterprise mobility.	Partially complete. From the scope of anticipated IAM product enhancements work identified in the 2017 RAMP, a few areas were deprioritized, or ownership transitioned.
5	Next Generation Endpoint Security	Create an end-point security strategy, architecture, configuration, and profiles to support the key operating systems in use at PG&E. The capability augments or replaces signature-based antivirus protection, which is no longer fully effective against malware and other types of attacks.	Not complete. PG&E is currently executing on the implementation of the Endpoint Detection and Response (EDR) tool, targeted for June 2020.
6	Priority Application Integration	Evaluate systems for risk of inappropriate logical access, particularly systems critical for Sarbanes-Oxley compliance and systems critical for compliance with regulatory requirements for the custody of Customer Energy Usage Data.	Complete.

TABLE 6
STATUS OF CYBER ATTACK MITIGATIONS PRESENTED IN THE 2017 RAMP
(CONTINUED)

Line No.	2017 RAMP Mitigation Name and Number	Mitigation Objective	Current Status
7	Vulnerability Management	Develop and implement a comprehensive solution for vulnerability and patch management process across all of PG&E.	Complete.
8	**M2 – Protect**		
9	Application Integration	Expand role-based LOB access controls and third-party account integration with access provisions for users in order to mitigate the risk of users with inappropriate access to high risk applications.	Initial objectives complete. Program will extend beyond 2020.
10	Auto Cloud Security	Design and implement processes and tools for applications, computers, and storage and network deployment on the cloud to mitigate the risk of data stored in the cloud.	Initial objectives complete. Program will extend beyond 2020.
11	Operational Data Network (ODN) Security Improvements	Establish core security technologies and test their compatibility with Operations Technology devices. This will enable the development of technology architecture and designs to deploy at Distribution Control Centers, transmission substations, distribution substations, and customer service centers.	Project planned as a multi-year initiative that will extend into the 2020-2022 period. Initial objectives complete.
12	Cloud Security Training	Obtain training courses for employees related to cloud security in order to mitigate the risks of deploying and managing vendor-provided cloud systems. Additional training and job aids will be developed internally related to security best practices in secure system development, operations, configuration management, vulnerability management, and data loss prevention.	Complete.

TABLE 6
STATUS OF CYBER ATTACK MITIGATIONS PRESENTED IN THE 2017 RAMP
(CONTINUED)

Line No.	2017 RAMP Mitigation Name and Number	Mitigation Objective	Current Status
13	Customer Information Protection	Develop and implement a data security governance program to address and manage compliance and legal requirements so that sensitive data is protected as per the PG&E requirements. PG&E will use technology to locate sensitive information and assess the controls in place. Where controls are lacking, remediation measures will be identified and implemented in phases based on risk.	Initial objectives complete. Program will extend beyond 2020.
14	Enterprise Password Vault	Provide complex passwords for users.	Complete.
15	Gas SCADA Network	Multi-phase mitigation addressing asset management, network protection (segregation, reduce single point of failure), security monitoring, and technology evaluation and planning for operating system upgrades.	Complete.
16	Catalog Privileged Accounts and Access to Critical Systems	Secures the enterprise network by identifying and cataloging individual users who have custody of critical PG&E logical and/or physical assets. The project will also identify users with privileged access or access to both physical and logical critical systems.	Partially complete. From the scope of anticipated work in the Catalog of Privileged Accounts and Access to Critical Systems initiative identified in the 2017 RAMP, one set of activities was deprioritized and is being evaluated for inclusion in 2020 and beyond.

TABLE 6
STATUS OF CYBER ATTACK MITIGATIONS PRESENTED IN THE 2017 RAMP
(CONTINUED)

Line No.	2017 RAMP Mitigation Name and Number	Mitigation Objective	Current Status
17	**M3 – Detect**		
18	Mobile Threat Detection	Implement comprehensive threat protection for Bring Your Own Device and Corporate-Owned Personally Enabled device against mobile network, device, and application related cyber-attacks. Implement a solution that monitors mobile devices in real time to detect threats, analyze deviations from baseline behavior, and respond immediately.	Not complete. In 2017-2018 PG&E evaluated having a Mobile Threat Protection solution to be used in conjunction with the Company's Mobile Device Management (MDM) capabilities and determined the investments that would be made would not justify the risk reduction that would be obtained. Instead, PG&E relies on a set of MDM policies, Mobile Application Management policies enforced by the Mobile Iron solution currently used, and multiple layers of preventive controls to evaluate device state, to reduce the risk posed by a malicious actor getting hold of specific devices and applications.
19	Security Analytics and Advanced Monitoring Phase III	Enhance cybersecurity monitoring technology, algorithms, tools, processes, and techniques.	Complete.
20	Security Monitoring Capability Extension	Accommodate organic growth in security monitoring of systems, of system attributes, and log retention that requires the addition of storage, network capacity, software licensing, and hardware.	Complete.
21	**M4 – Respond**		
22	Advanced Persistent Threats (APT) Detection and Analysis Enhancement	Improve event analysis and accelerate the detection of attacks coming from APT by extending the amount of time that security event logs are retained to improve the ability to detect malicious activity from a range of possible sources allowing for a faster response and mitigating the overall impact of the attack.	Complete.
23	eDiscovery Capability and Resilience Improvement	Increase the capacity of the eDiscovery tool currently and create space for data backups from the tool.	Complete.

In the 2017 RAMP, PG&E proposed five Insider Threat risk mitigations.[9] Insider Threat mitigations and subsequent controls for this RAMP period are incorporated into the four proposed mitigations described below.

5. Mitigations and Controls 2020-2026

a. Planned Work

In the 2020 RAMP, PG&E is again proposing a series of mitigation programs aligned to the four pillars of the NIST CSF. The work PG&E is proposing for 2020 is described below. PG&E has not yet developed its specific project list for the 2021-2026 time period but will pursue projects closely aligned to each of the NIST CSF domains.

Domain 1 – Identify (Mitigation (M) 1): Activities that develop organizational understanding in managing security risks to systems, assets, and data. Resources supporting critical functions must have a clear understanding of the business context and related risks to prioritize risk mitigation efforts.

PG&E has developed its 2020 project list and is proposing mitigation projects primarily aligned to this domain. One of the Identify projects PG&E is proposing is a new tool that will run in parallel with the existing firewalls to ensure that any firewall misses are identified.[10]

Domain 2 – Protect (M2): Activities that develop and implement appropriate safeguards to provide secure delivery of critical infrastructure services. These activities limit the impact of security risk-based events, reducing both frequency and consequence.

PG&E has developed its 2020 project list and is proposing several mitigation projects primarily aligned to this domain. One of the Protect projects PG&E is proposing will prevent cybersecurity events in one operational facility from impacting other remote facilities by segregating critical assets.

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9 PG&E's 2017 RAMP Report, p. 19-12, Table 19-1.

10 Many of the cyber attack projects PG&E is proposing impact multiple NIST CSF domains. The new tool to ensure that firewall misses are identified primarily aligns to the Identify domain but applies to the Detect and Respond domains as well. The number of projects planned for 2020 counts each project only once based on the primary domain to which it applies.

Domain 3 – Detect (M3): Activities that identify the occurrence of a potential security risk, enabling timely discovery and reducing potential consequences.

PG&E has developed its 2020 project list and is proposing mitigation projects primarily aligned to this domain. One of the Detect projects PG&E is proposing will improve access certification through technology and business process updates and establish methods to identify and address potentially unauthorized system accounts in an automated manner.

Domain 4 – Respond (M4): Activities that enable effective evaluation of a potential security risk-based event, and impact containment reducing potential consequences.

PG&E has developed its 2020 project list and is proposing a mitigation project primarily aligned to this domain. The Respond project PG&E is proposing will integrate key security tools to improve effectiveness and efficiency of cyber incident response programs.

In addition to the mitigations planned for 2020-2026, PG&E will also continue to implement a series of controls to manage cybersecurity risk. These controls provide the operations and maintenance (O&M) framework for cybersecurity and include:

Control 1 – Security Intelligence and Operations Center: Monitors and reports cyber threats, provides real time event monitoring and incident response, deploys and supports security tools, and performs digital forensic analysis;

Control 2 – Cybersecurity Risk and Strategy: Provides enterprise cybersecurity strategy, mitigates critical asset risks, secures Operational Technology assets, and collaborates with industry stakeholders;

Control 3 – Cybersecurity Services: Manages enterprise security technology, IAM, and the remediation of vulnerabilities across the enterprise;

Control 4 – Communications: Educates PG&E workforce on security threats, and promotes a culture of best security practices; and

Control 5 – Investigation and Insider Threats: Conducts internal and external investigations of criminal activities and employee misconduct.

b. Mitigations With RSE Scores

The forecast costs, RSEs and risk reduction scores for the planned mitigation work is shown in Tables 7, 8, and 9 below.

TABLE 7
FORECAST COSTS
2020-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Identify	JV	$380	$391	$403	$415	$428	$440	$454	$2,911
2	M2	Protect	JV	1,553	1,599	1,647	1,697	1,748	1,800	1,854	11,898
3	M3	Detect	JV	538	554	571	588	605	624	642	4,122
4	M4	Respond	JV	326	336	346	357	367	378	390	2,502
5		Total		$2,797	$2,881	$2,967	$3,056	$3,148	$3,243	$3,340	$21,432

TABLE 8
FORECAST COSTS
2020-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Identify	2F	$500	$515	$530	$546	$563	$580	$597	$3,831
2	M2	Protect	2F	18,013	18,553	19,110	19,683	20,273	20,881	21,508	138,020
3	M3	Detect	2F	3,708	3,819	3,934	4,052	4,173	4,299	4,428	28,412
4	M4	Respond	2F	175	180	185	191	197	202	209	1,338
5		Total		$22,395	$23,067	$23,759	$24,472	$25,206	$25,962	$26,741	$171,602

TABLE 9
RSE AND RISK REDUCTION: CYBER ATTACK- ALL MITIGATIONS

		Aggregated		Applied to RAMP Risk
Line No.	Applicable RAMP Risk	RSE[(a)]	Risk Reduction (NPV)[(b)]	Risk Reduction (Net Present Value (NPV))[(b)]
1	Mitigation: All Cyber Attack Mitigations	0.0002	0.02	–
2	Large Overpressure Event Downstream of M&C Facility	–	–	< 0.01
3	Large Uncontrolled Water Release (Dam Failure)	–	–	0.02
4	Loss of Containment on Gas Transmission Pipeline	–	–	< 0.01
5	Total	0.0002	0.02	0.02

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

(b) Information presented in terms of NPV to account for the discounting of benefits.

C. Emergency Preparedness and Response

1. Overview

The Emergency Preparedness and Response (EP&R) cross-cutting factor examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability and regulatory impacts.

EP&R advances PG&E’s response to emergencies by improving governance, strengthening coordination among the LOBs and improving collaboration with external partners such as the Federal Emergency Management Agency (FEMA) and California Governor’s Office of Emergency Services. EP&R requires integrated plans and the appropriate facilities, logistics, technology, and processes to respond to a catastrophic incident.

The EP&R organization works with PG&E’s LOBs to develop capabilities for responding to all emergencies such as: a clearly defined organizational structure for emergency response; scalable restoration plans and systems that assist responders with situational awareness; implementing technologies, such as resilient servers and enhanced basecamp communication systems; developing and disseminating emergency incident communications and situational awareness; training employees to respond to emergencies; testing capabilities through a number of exercises and developing and implementing enterprise-wide business continuity efforts; community outreach and customer support for coordinated interaction with Federal, State, County, City and Tribal Agencies. The EP&R organization also maintains PG&E's Emergency Operations Center (EOC) and alternate EOCs.

In the 2020 GRC, PG&E described several key initiatives that it would implement during the GRC period[11] such as expanding PG&E's weather forecasting, monitoring and modeling capabilities and engaging in activities to maintain and enhance PG&E's emergency preparedness. In the third quarter of 2019, PG&E moved EP&R out of the Community Wildfire Safety Program (CWSP) and created a new organization (EP&R) because EP&R addresses all hazard events. The expanded EP&R organization now consists of five teams each responsible for a unique EP&R scope of work.

EP&R Strategy and Execution: The Strategy and Execution team is responsible for a wide range of activities including: developing scalable plans and systems for responding to hazards; developing roles and responsibilities for emergency response efforts; working with internal and external stakeholders; leading business continuity efforts and external emergency preparedness events; maintaining the EOC and alternate emergency centers; and measuring and evaluating PG&E emergency response efforts. This team: publishes the annual Company Emergency Response Plan, (CERP) that provides guidance on managing emergencies of all kinds and works with the LOBs to develop CERP annexes; leads continuous improvement projects that improve emergency response functions; and tracks metrics on emergency readiness.

Meteorology: PG&E's meteorology department integrates weather data from numerous internal and external sources and uses these data streams to forecast wind and weather patterns to calculate fire risk levels across the service territory. The team also: provides daily weather forecasts and Storm Outage Prediction Project models; helps identify locations for new weather stations; and uses state of the art fire modeling to better understand fire patterns, movement, and behaviors. The Meteorology department plays

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[11] A.18-12-009, Exhibit (PG&E-4), Chapter 3.

a key role in the data presented for the decision process during a Public Safety Power Shutoff (PSPS)

EP&R Field Operations: Field Personnel and Public Safety Specialists (PSS) who support external and internal first responders and emergency managers. PSS personnel plan and train with external first responders to prepare for emergencies, wildfires and PSPS events. PSS teams also support CWSP open houses and workshops and provide first responder workshops about responding to gas and electric emergencies.

Public Safety Power Shutoff (PSPS): PG&E's PSPS Program proactively de-energizes select transmission and distribution circuit segments within Tier 2 and Tier 3 HFTD areas when elevated fire danger conditions occur. De energization is determined necessary to protect public safety when PG&E reasonably believes there is an imminent and significant risk of strong winds impacting PG&E assets, and a significant risk of a catastrophic wildfire should an ignition occur.

Wildfire Safety Operations Center (WSOC): The WSOC is a coordination and communications hub for wildfire activities. The WSOC monitors the service territory for wildfires and provides updates on any fires in PG&E's service area. The WSOC will also deploy PSS to fires to interface with the Incident Command organization. PG&E's Safety and Infrastructure Protection Teams are part of the WSOC and deployed via the WSOC to protect infrastructure during fires and other emergencies.

In this RAMP filing, the EP&R initiatives are divided into two categories:

1) Those initiatives supporting only Wildfire risk mitigation and aligned to the Wildfire RAMP risk;[12] and
2) Those initiatives supporting multiple risk mitigation efforts and therefore assigned in this RAMP filing as a cross-cutting factor.

Those risk mitigations and controls that are aligned to the Wildfire RAMP risk are described in Chapter 10 of this filing. The risk mitigations and controls applicable to multiple risks are described in Section C.5 below.

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12 More information about the EP&R Wildfire initiatives is included in PG&E's 2020 Wildfire Mitigation Plan Report, R.18-10-007, February 7, 2020.

2. **Modeling**

The EP&R cross-cutting factor impacts the consequence side of the bow-tie and is considered a consequence modifier. EP&R is relevant after a risk event occurs by defining how PG&E responds to a risk event. In modeling the effect EP&R has on a risk event, PG&E applied EP&R to risk events following which the EOC would be activated – catastrophic and severe events.

Because EP&R is an integral part of PG&E's operations, it is difficult to model the consequences of a risk event. Therefore, the model assumes that the safety, reliability and financial consequences of an event are reduced by a certain percentage when the EOC is activated.

3. **Impacts to the 2020 RAMP Risks**

Table 10 below maps the EP&R cross-cutting factor to the applicable RAMP risks.

TABLE 10
CROSS-CUTTING FACTOR SUMMARY: EP&R

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Failure of Electric Distribution Overhead Assets	Embedded	--	(a)
2	Failure of Electric Distribution Network Assets	Embedded	--	(a)
3	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Embedded	--	(a)
4	Large Uncontrolled Water Release (Dam Failure)	Embedded	--	(a)
5	Loss of Containment on Gas Distribution Main or Service	Embedded	--	(a)
6	Loss of Containment on Gas Transmission Pipeline	Embedded	--	(a)
7	Real Estate and Facilities Failure	Embedded	--	(a)
8	Wildfire	Embedded	--	(a)

(a) While this cross-cutting factor impacts the RAMP risk, it was not extracted from the data and considered or modeled separately.

EP&R controls and mitigations help to reduce the impact of a catastrophic or severe risk event. If a catastrophic or severe risk event occurs, PG&E activates its EOC and/or alternate emergency centers. PG&E would then initiate the EP&R controls to help mitigate the impact of these events such as: coordinated responses between the LOBs to re-energize electric lines and re-pressurize gas pipelines; deploying and staffing base camps to enhance restorations efforts for customers; coordinated customer outreach activities; and communications with third-party responder agencies.

4. Changes Since the 2017 RAMP

EP&R was not a 2017 RAMP risk.

5. Mitigations and Controls 2020-2026

EP&R is proposing 12 controls and nine mitigations.

a. Planned Work

<u>Controls</u>

C1 – Company Emergency Operations Plans and Standards for Response: Align PG&E emergency operations plans and standards with accepted emergency management industry practices and utility industry best practices. Standards that will be updated include: EMER-2001S: Company Emergency Operations Plan (CERP); EMER-1012M: Earthquake Playbook; EMER-3101M: Earthquake Annex, ERMER-3012M; Cybersecurity Annex, EMER-3102M: Fire Prevention Plan.

C2 – Emergency Response Technology: (1) LiveSafe application is a mobile two-way safety communications platform and risk mitigation tool to help employees stay safe in every day and high-risk scenarios. PG&E will enhance this tool based on employee and user feedback that will increase safety for PG&E staff; (2) Send Word Now (SWN) is a critical communications and alerting messaging tool to notify employees and external agencies of impacting events and incidents. PG&E is evaluating SWN to increase communications capabilities; (3) MutuaLink provides seamless operational communications sharing radio, voice, text, video, data files and telephone systems in a secure environment by use of the Interoperable Response and Preparedness Platform network that connects radios and satellite telephones. PG&E uses this technology to communicate internally and externally with first responders in local law enforcement, fire departments and with base camps and staging sites; and (4) Dynamic Automated Seismic Hazard (DASH) is an earthquake damage model that sends messages and graphics to subscribed users.[13]

C3 – EOC/Incident Command System (ICS) Training Program: Implement an annual credential program to train and enhance ICS skills and standards to coordinate an emergency response. Training programs will be built around emergency management industry best practices for accreditation and in collaboration with Cal-OES. The emergency training program is aligned with National Incident Management System, California Standardized Emergency Systems, and foundational ICS guidance provided by the FEMA's Emergency Management Institute and the California Specialized Training Institute (CSTI).

C4 – EOC Response: PG&E will train personnel to use the ICS as described in Control C3 above.

C5 – EOC Exercises: EOC exercises enhance emergency response coordination capabilities among EOC staff. They provide an opportunity to test the effectiveness of current EOC procedures and resources. Exercises include: Grid Restoration Table Top Exercise (TTX), Grid Restoration Functional, FEMA inspired exercises, Cyber Security TTX, Cyber Security/Electrical Grid Exercise IV Full-Scale, Earthquake Full-Scale, and Alternate Company Headquarters exercise.

C6 – Weekly Situational Awareness Calls (WSAC) and Enhancements: WSACs with Enterprise-Wide Coordination Group to identify operational issues that have enterprise-wide impacts. PG&E will enhance this control by changing the WSAC criteria to build metrics around the readiness of all the WSAC participants to respond to a catastrophic event.

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[13] DASH is described in the Seismic cross-cutting factor section below (Section G).

C7 – Early Earthquake Warning: PG&E is piloting a Shake Alert-based public-address system for earthquake notifications that includes: pre-event notification linked to ground movement sensors to warn of an impending quake; and links to mechanical systems (e.g., in a high-rise building elevators would be routed to the ground floor prior to shaking without any human intervention).

C8 – Debris Flow Modeling: Debris-flow modeling focuses on landslide-triggered debris flows in PG&E's service territory. PG&E uses pre and post wildfire geospatial data to model debris flow threat and probabilities. Burn areas are reviewed for proximity to PG&E infrastructure and for potential downstream impacts to communities. If modeling shows potential impacts to infrastructure or communities, plans are developed to eliminate or minimize potential damage.

C9 – Gas Systems Operations Temperature Forecasting: Provide temperature forecasts used to model forecasted gas demand and loads over a seven day forecast horizon. Gas demand forecasting is used to provide situational awareness and operational triggers for executing procedures such as gas curtailments.

C10 – Power Generation Hydro Management Forecasting: Provide temperature, precipitation, snow level forecasts and weekly briefings for multiple PG&E watersheds. This forecast data is used to help manage PG&E reservoirs and model inflow expected over the next week.

C11 – Short-Term Electric Supply Forecasting: Provide temperature and roof-top solar forecasting to help forecast electric demand and support procurement of energy in day-ahead markets.

C12 – Diablo Canyon Power Plant (DCPP) Emergency Response Organization Support: Provide emergency support for any emerging conditions at DCPP that may pose a risk to the public. Meteorological support is provided in the event of an emergency at DCPP including forecasting wind speed and direction and reporting of current conditions that support Protective Action Recommendations to San Luis Obispo County.

Mitigations

PG&E is proposing eight individual mitigations that are divided into three groups. The outputs from the risk model include only the two mitigation groups—EOC Enhancements and Mutual Aid (MA) Enhancements—and not the individual mitigation names.

TABLE 11
EP&R MITIGATIONS GROUPED BY MITIGATION TYPE

Line No.	Mitigation Group 1 – EOC Enhancements	Mitigation Group 2 – MA Enhancements	Foundational Mitigations
1	M1–Base Camp Project	M4–MA Tools and Equipment	M6–New Incident Specific Annexes
2	M2–Check In/ Check-Out with Salesforce	M5–Mutual Assistance Improvement	M8–Early Earthquake Warning Enhancements
3	M3–Secondary Emergency Roles, Enterprise-Wide		
4	M7–EOC/ICS Training Program Enhancements		

M1 – Base Camp Project: Improve personnel accountability and operations surrounding base camp activations, including check-in and check-out of employees. Implement IT controls and processes to account for personnel entering and exiting the base camp. Using technology for check-in and check-out will help PG&E account for all personnel entering and exiting the camp and will improve safety if a base camp needs to be evacuated by confirming that all personnel can be accounted for. Required equipment includes ruggedized devices that can be used at multiple entry/exit points.

M2 – EOC Check-In/Check-Out With Salesforce: Develop and implement processes and tools for the check-in and check-out function at the EOC.

M3 – Secondary Emergency Roles, Enterprise-Wide: Implement secondary emergency role in the event of an activated incident. PG&E will train personnel for multiple emergency response roles so that if one area gets hit by an emergency, staff from other areas are ready to assist. Using an all-hazards approach to training gives the staff the most versatility in managing incidents.

M4 – Mutual Aid Tools and Equipment: Develop a process for identifying, acquiring and dispersing of mutual assistance tools essential to emergency restoration for mutual assistance and internal crews.

M5 – Mutual Assistance Improvement: Develop guidance for acquiring and training mutual assistance resources. Improve mutual assistance program to onboard, process, track, demobilize and pay mutual assistance resources. Develop and implement mutual assistance and DCPP collaboration training program for DCPP employees and new MA Assistance employees.

M6 – New Incident-Specific Annexes: Develop new incident specific annexes (plans) to provide guidance to the LOBs to plan and document their responses to specific disruptions. Current annexes being developed are the Earthquake Emergency Restoration plan and the infectious disease annex. Other annexes will be developed based on current risk data. PG&E considers this to be a foundational mitigation.[14]

M7 – EOC/ICS Training Program Enhancements: As part of its foundational mitigation effort, PG&E established a 5-year training plan for personnel in leadership roles in the EOC. The training plan consists of four phases: (1) ICS Baseline Courses; (2) CSTI EOC Baseline Courses; (3) Advanced ICS for Select Personnel; and (4) Position-specific Training Workshops. Phase 3, ICS-300, is for all EOC supervisory personnel and advanced training (ICS-400) for all EOC Command and General staff.

M8 – Early Earthquake Warning Enhancements: The program will improve earthquake preparedness, resiliency, and response capability through the use of early warning technology. PG&E will plan, coordinate and execute: Public Address System upgrades in General Office (245 Market/77 Beale) (C7 above); Debris Flow Analysis (C8 above);

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[14] PG&E considers certain mitigations to be foundational mitigations because they support other controls and mitigations rather than directly mitigate risk and, as a result, PG&E is not assigning a risk score or calculating an RSE for these foundational mitigations.

and DASH Server Upgrade (C2 above). PG&E considers this to be a foundational mitigation.

b. Mitigations With RSE Scores

The forecast costs for the planned mitigations are shown in Tables 11 and 12, and the RSEs and risk reduction scores in Tables 13 and 14 below. PG&E did not calculate RSEs for Mitigation 6 or Mitigation 8 because they are considered foundational work.

TABLE 12
FORECAST COSTS
2020-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Base Camp Project	AB6	$1,000	$2,050	$1,051	$1,077	–	–	–	$5,178
2	M2	EOC Check-In, Check-Out with Salesforce	AB6	30	31	32	32	$33	$14	–	172
3	M3	Secondary Emergency Roles Enterprise-Wide	AB6	500	513	525	538	552	566	–	3,194
4	M7	EOC/ICS Training Enhancements[a]	AB6	980	980	980	980	980	980	$980	6,862
5		Subtotal EOC Enhancements		$2,510	$2,588	$2,688	$2,628	$1,565	$1,560	$980	$15,405
6	M4	MA Tools and Equipment	AB6	$40	–	–	–	–	–	–	$40
7	M5	Mutual Assistance Improvement	AB6	50	$51	$53	$54	–	–	–	208
8		Subtotal MA Enhancements		$90	$51	$53	$54	–	–	–	$248
9	M6	New Incident Specific Annexes	AB6	$250	$256	$263	$269	–	–	–	$1,038
10		Total		$2,850	$3,881	$2,903	$2,951	$1,565	$1,560	$980	$16,691

(a) The forecast costs for this mitigation exclude escalation. PG&E will escalate these costs in the 2023 GRC forecast using the 2023 GRC escalation rate.

TABLE 13
FORECAST COSTS
2020-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M8	Early Earthquake Warning Enhancements[(a)]	21	$255	$255	$255	$255	$255	$255	$255	$1,787
2		Total		$255	$255	$255	$255	$255	$255	$255	$1,787

(a) The forecast costs for this mitigation exclude escalation. PG&E will escalate these costs in the 2023 GRC forecast using the 2023 GRC escalation rate.

TABLE 14
RSE AND RISK REDUCTION: EP&R – EOC ENHANCEMENTS

			Aggregated		Applied to RAMP Risk
Line No.	Mit No.	Applicable RAMP Risk	RSE [(a)]	Risk Reduction (NPV)[(b)]	Risk Reduction (NPV)[(b)]
1	M1, M2, M3, M7	Mitigation: EOC Enhancements	440	2,667	–
2		Failure of Electric Distribution Network Assets	–	–	0
3		Failure of Electric Distribution Overhead Assets	–	–	37
4		Large Overpressure Event Downstream of Gas M&C Facility	–	–	2
5		Large Uncontrolled Water Release (Dam Failure)	–	–	7
6		Loss of Containment on Gas Distribution Main or Service	–	–	8
7		Loss of Containment on Gas Transmission Pipeline	–	–	16
8		Real Estate and Facilities Failure	–	–	20
9		Wildfire	–	–	2,576
10		Total	440	2,667	2,667

(a) See MWCs included in the source document modeling package for information used to calculate the RSE.

(b) Information presented in terms of NPV to account for the discounting of benefits.

TABLE 15
RSE AND RISK REDUCTION: EP&R – MA ENHANCEMENTS

			Aggregated		Applied to RAMP Risk
Line No.	Mit No.	Applicable RAMP Risk	RSE[(a)]	Risk Reduction (NPV)[(b)]	Risk Reduction (NPV)[(b)]
1	M4, M5	Mitigation: MA	14,918	654	–
2		Failure of Electric Distribution Network Assets	–	–	–
3		Failure of Electric Distribution Overhead Assets	–	–	10
4		Large Overpressure Event Downstream of Gas M&C Facility	–	–	1
5		Large Uncontrolled Water Release (Dam Failure)	–	–	2
6		Loss of Containment on Gas Distribution Main or Service	–	–	2
7		Loss of Containment on Gas Transmission Pipeline	–	–	4
8		Real Estate and Facilities Failure	–	–	5
9		Wildfire	–	–	630
10		Total	14,918	654	654

(a) See MWCs included in the source document modeling package for information used to calculate the RSE.

(b) Information presented in terms of NPV to account for the discounting of benefits.

D. IT Asset Failure

1. Overview

The IT Asset Failure risk is defined as failure of IT systems or infrastructure, resulting in outages, or system unavailability for mission critical assets impacting operations, or the ability to support public safety events.

IT has become increasingly engrained in PG&E operations. Across all LOBs, technology helps to improve safety and reliability, enhances the customer experience, and supports compliance. Technology enables and supports virtually all of PG&E's day-to-day activities, including work execution, grid control, customer support, emergency response, and asset management. The growing reliance on technology demonstrates PG&E's shift to what's known as a "digital business"—or more specifically, a "Digital Utility." As this shift continues, the reliability of IT assets and integrated systems becomes increasingly important for PG&E to function effectively.

To define the IT assets that could impact a RAMP risk, the 12 RAMP risk teams identified those IT software applications, infrastructure (hardware) and systems that, were they to fail, would significantly impact their RAMP risk event. The IT risk team started its analysis with the software applications and hardware components identified by the RAMP risk teams and used them to develop a more complete list of IT assets that could impact a RAMP risk.

To fully develop the potential impact to the RAMP risks, the IT risk team evaluated all of the software applications, systems, and hardware components that PG&E relies on to operate its business including asset management systems, collaboration tools, infrastructure technologies, operational management systems, work management systems, and others in order to more clearly understand and define the potential risks that could result from an IT asset failure. After completing this holistic analysis of potential IT asset failure risks, the IT risk team then applied the results of the analysis to the 12 RAMP risk events and determine if and how these potential IT asst risks applied to the software applications and hardware components relied on by the RAMP risk teams to mitigate risk. This IT analysis involved a review of foundational infrastructure systems (e.g., data centers, fiber optic backbone), hardware (e.g., servers, desktop and laptop computers), hosting environments (including compute, storage, and network technologies), communications systems (e.g., network routers, interconnect sites and switches, data collection units, radio base stations), and software applications (e.g., business applications, data management software, operating systems).

Because PG&E's IT systems are so complex and include so many individual elements, PG&E focused its risk analysis on Mission Critical (Tier 1) and Business Critical (Tier 2) systems for this 2020 RAMP. PG&E identified the IT assets that are included in the IT Asset Failure risk by reviewing approximately hundreds of IT assets, grouped by Level 1 Asset Category[15] and Level 2-3 Asset Category,[16] to determine the potential impact each asset would have on a RAMP risk event if that asset failed. This analysis assessed the interdependencies among the different IT assets and evaluated how a failure of one system, software application, or hardware component could impact other, inter-connected assets. PG&E did not identify each specific point where technology failure could impact the application or hardware component identified by the RAMP risk owner but focused instead on generic interdependencies. As the IT Asset Failure risk analysis matures, PG&E will move towards a more granular analysis of interdependencies.

The Level 1 and Level 2-3 Asset Categories that the IT risk team determined could potentially impact a RAMP risk were further analyzed to determine their potential impact on a risk event, a risk driver, or on the consequences of a risk event.

Direct Impact: Failure of an IT asset could directly cause a risk event or risk event driver to occur, could directly inhibit PG&E's ability to detect an

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15 The Level 1 Asset Category was the starting point for the detailed risk analysis, and it is segregated into foundational type technologies and systems such as: collaboration; infrastructure technologies; and management systems (i.e., asset management, customer management, IT management, operations management, etc.).

16 Level 2-3 Asset Category includes a more granular division of technology assets including: IT facilities; telephony; personal computing; document and filing sharing; application hosting; geographic information systems; outage management tools; and real-time monitoring tools.

occurrence of the risk event, or could directly inhibit PG&E's response to/recovery from a risk event; or

Indirect Impact: Failure of an IT asset/system could cause failure of an asset used directly to prevent, an event, or could, combined with other drivers, increase the likelihood of a risk event.

Consequence Multiplier: Failure of an IT asset could increase the impact of the risk event creating delays in the detection and response to an event.

For example, the Loss of Containment – Gas Transmission Pipeline risk owner determined that IT asset failures that led to the unavailability of the Gas SCADA and the Oasys applications could result in loss of visibility of the system and delayed response capability. Starting with this critical application, the IT risk team evaluated all the different IT assets that, should they fail, could impact the two critical applications. Through this analysis, the IT risk team identified nine different Level 1 Asset Category elements and 89 individual Level 2-3 Asset Category elements whose failure could impact the Gas Transmission risk event.

IT Asset Failure itself does not cause a risk event to occur. However, if a risk event and an IT Asset Failure occur at the same time, it is possible that the likelihood of the risk event occurring could increase or the outcome of the risk event could be more significant.

2. Modeling

IT Asset failure is included in the risk event bow ties as both impacting the likelihood of an event occurring and as a consequence multiplier.

As described above, modeling the risk of IT Asset Failure across the 12 RAMP risks involved a detailed analysis of hundreds of IT assets that can impact the RAMP risks in different ways and can result in minor to catastrophic impacts. Due to the complexities of the IT systems, the number of individual assets, and the compound relationships among the IT assets and the RAMP risks, it was difficult for the RAMP risk owners and IT risk team to determine exactly which IT assets would significantly impact a risk event if they failed. In addition to the individual IT assets, PG&E also struggled with how to account for the "foundational" IT assets (e.g., networks, communication systems, etc.) in frequency/impact quantification and mitigation effectiveness calculations.

Along with the difficulty identifying the critical IT assets (defined here as those that would impact a risk even if they failed), PG&E determined that it does not have sufficient internal data to support IT asset failure frequency, outage frequency, outage durations, the impacts those durations could have on the LOBs if a critical IT asset failed or sufficient internal data to evaluate the potential for IT asset to fail in the future. Finally, PG&E could not determine a defensible method for valuing the effectiveness of the planned mitigations.

PG&E is exploring ways to quantify and model IT Asset Failure and expects to calculate RSEs for IT Asset Failure in the 2023 GRC.

3. Impacts to the 2020 RAMP Risks

Table 16 and 17 below maps the IT Asset Failure cross-cutting factor to the applicable RAMP risks. IT Asset Failure is an added frequency for one RAMP risk and a consequence multiplier for three RAMP risks. PG&E is continuing to evaluate the impact that IT Asset Failure has on RAMP risks and expects to present IT Asset Failures as a cross-cutting factor, relative to additional RAMP risks in the 2023 GRC. [17]

TABLE 16
CROSS-CUTTING FACTOR DRIVER SUMMARY: IT ASSET FAILURE

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Large Uncontrolled Water Release (Dam Failure)	Added Frequency	6 percent (0.00001)	6 percent

[17] Information about how IT Asset Failure impacts the RAMP risks is included on WP 20-3.

TABLE 17
CROSS-CUTTING FACTOR CONSEQUENCE SUMMARY: IT ASSET FAILURE

Line No.	RAMP Risk	Outcome	Percent Frequency	Percent of Risk
1	Failure of Electric Distribution Overhead Asset	Asset Failure/Not Assoc. w/ Ignition/Coincident with IT Asset Failure	< 0.1 percent	0.3 percent
2	Large Overpressure Event Downstream of Gas Measurement and Control Facility	LOC and IT Asset Failure	0.1 percent	1.6 percent
3	Loss of Containment on Gas Transmission Pipeline	Rupture and IT Asset Failure	0.5 percent	1 percent
4	Loss of Containment on Gas Transmission Pipeline	Leak and IT Asset Failure	0.6 percent	<0.01 percent

IT Asset Failure impacts four RAMP risks:

Failure of Electric Distribution Overhead Assets

PG&E identified four IT assets or IT components that could multiply the consequences of a risk event if they failed at the same time a Failure of Electric Distribution Overhead Asset risk even occurred: (1) SCADA radio systems; (2) backhaul landline/microwave communication components; (3) ODN; and (4) the electric distribution management system.

Large Overpressure Event Downstream of Gas M&C Facility

IT Asset Failure could amplify the consequences of a risk event because IT asset failures could lead to the unavailability of Gas SCADA resulting on loss of visibility of the system and delayed response capability. IT Asset Failure is not likely to cause this risk event. The IT systems considered when analyzing IT Asset Failure risk are critical network components and mission critical communications systems supporting regulating, gas, meter and compression stations, electric plants, and valve lots.

Large Uncontrolled Water Release

IT Asset Failure coincident with a Large Uncontrolled Water Release failure (e.g., flood, seismic event, internal erosion or physical attack) will increase the likelihood of a risk event (dam failure). The IT systems considered when analyzing IT Asset Failure risk are critical network components and mission critical communications systems supporting hydroelectric plants.

Loss of Containment on Transmission Pipeline

IT Asset Failure is not likely to cause this risk event but could increase the consequence of an event if Gas SCADA is unavailable, causing loss of visibility into the gas transmission system and delayed response time. The IT systems considered when analyzing IT Asset Failure risk are critical network components and mission critical communications systems supporting regulating, gas, meter and compression stations, electric plants and valve lots.

4. Changes Since the 2017 RAMP

IT Asset Failure was not a 2017 RAMP risk.

5. Mitigations and Controls 2020-2026

a. Planned Work

PG&E has identified five IT Asset Failure risk mitigation programs:

M1 - Asset Management/Monitoring: Implement IT asset failure risk identification and/or failure detection and response capabilities;

M2 - Capacity/Coverage/Scalability: Add IT asset capacity, coverage and/or scalability to support increased demand;

M3 - Resiliency: Remove single points of failure, design IT asset(s) for continuity and resiliency;

M4 – Lifecycle: Replace end-of-life, at-risk, and/or high failure rate IT assets.

M5 - Multiple Risks Impact Mitigation: Risk mitigation projects or programs that combine one or more of the four IT Asset Failure mitigation programs (M1 through M4). For example, a single Multiple Risks Impact Mitigation may address both asset management and monitoring concerns as well as resiliency issues.

To develop the list of mitigation programs and assign them to the appropriate RAMP risks, PG&E evaluated more than 200 individual IT projects and mapped each one to: (1) one of the five RAMP mitigation programs; (2) a RAMP asset category; and (3) a RAMP risk.

For example, PG&E is planning nine third-party fiber replacement and repair projects. Because these projects are designed to replace end-of-life or at-risk assets, they were categorized as a part of the

Lifecycle Mitigation Program and IT Asset Failure Mitigation Program. Next, the IT risk team determined that the eight projects contribute to the asset category “Network – Transmission.” Finally, based on the initial mapping of IT assets to risks, the risk team knew that the Network-Transmission asset category applies to RAMP risks in Electric Operations, Gas Operations, and Power Generation.

The five IT Asset Failure mitigation programs often include multiple projects and/or programs. Because PG&E is continuing to build out its 2021-2026 project plan, it relied on its 2020 work plan as the basis for assigning the mitigation programs to the RAMP risks. A copy of the 2020 work plan aligned to mitigation programs is included in workpapers.[18]

The forecast costs for the planned mitigation programs are shown in Tables 18 and 19 below.

[18] See WP 20-4.

TABLE 18
FORECAST COSTS
2020-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Asset Management/Monitoring	JV	$230	$237	$244	$251	$259	$266	$274	$1,760
2	M2	Capacity/Coverage/Scalability	JV	86	88	91	94	96	99	102	656
3	M3	Resiliency	JV	77	79	82	84	87	89	92	589
4	M4	Lifecycle	JV	20,722	21,344	21,984	22,644	23,323	24,023	24,744	158,785
5	M5	Multiple Risks Impact Mitigation	JV	972	1,001	1,031	1,062	1,094	1,127	1,161	7,448
6		Total		$22,087	$22,749	$23,432	$24,135	$24,859	$25,605	$26,373	$169,239

TABLE 19
FORECAST COSTS, RSE, AND RISK REDUCTION
2020-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Asset Management/Monitoring	2F	$3,023	$3,113	$3,207	$3,303	$3,402	$3,504	$3,609	$23,162
2	M2	Capacity/Coverage/ Scalability	2F	10,818	11,142	11,477	11,821	12,175	12,541	12,917	82,891
3	M3	Resiliency	2F	3,501	3,606	3,714	3,825	3,940	4,058	4,180	26,825
4	M4	Lifecycle	2F	103,662	106,772	109,975	113,274	116,673	120,173	123,778	794,308
5	M5	Multiple Risks Impact Mitigation	2F	11,724	12,075	12,438	12,811	13,195	13,591	13,999	89,833
6		Total		$132,727	$136,709	$140,810	$145,035	$149,386	$153,867	$158,483	$1,017,018

b. Mitigations With RSE Scores

Given the complexities of evaluating the relationship between IT assets and RAMP risk events, the lack of internal data and difficulty determining mitigation effectiveness, PG&E was not able to calculate an RSE for IT Asset Failure.

PG&E is working through these issues and expects to present RSEs for IT Asset Failure mitigation programs in the 2023 GRC.

E. Physical Attack

1. Overview

Physical Attack is defined as an attack on PG&E physical assets or personnel, that could result in damage to property, business impacts, or injury/fatality. Physical attacks are increasing as evidenced by the increase in active shooter incidents in the U.S.

PG&E manages the Physical Attack risk in its Corporate Security organization. Activities include assessing and mitigating physical security risks related to employees, contractors, physical assets, facilities and infrastructure. The Corporate Security organization is responsible for emergency response, incident management and collaborating with local management on physical security vulnerability and mitigations.

2. Modeling

Physical Attack impacts the likelihood of a risk event and includes both attacks against a person and attacks on a PG&E facility or asset (vandalism).

To model this cross-cutting factor PG&E used a bottom-up approach, relying on both internal and proxy data. PG&E relied on internal data identifying each physical attack on a PG&E asset related to electric distribution overhead assets and gas distribution and transmission assets. To model physical attacks related to PG&E owned and managed facilities (real estate), electric distribution underground network assets, and hydroelectric facilities PG&E relied on proxy data and Subject Matter Expert (SME) insight.

3. Impacts to the 2020 RAMP Risks

Physical Attack impacts seven risks. PG&E is continuing to evaluate the impact that Physical Attack has on RAMP risks and expects to present Physical Attack as a cross-cutting factor relative to additional RAMP risks in the 2023 GRC.

Table 20 below maps the Physical Attack cross-cutting factor to the applicable RAMP risks.[19]

TABLE 20
CROSS-CUTTING FACTOR SUMMARY: PHYSICAL ATTACK

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Employee Safety Incident	Extracted from Existing	0.23 percent (1.4)	0.26 percent
2	Failure of Electric Distribution Overhead Assets	Extracted from Existing	0.1 percent (27)	0.1 percent
3	Failure of Electric Distribution Network Assets	Added Frequency	0.1 percent (0.01)	0.1 percent
4	Large Uncontrolled Water Release (Dam Failure)	Added Frequency	0.1 percent (0.00001)	0.2 percent
5	Loss of Containment on Gas Distribution Main or Service	Extracted from Existing	0.02 percent (7)	0.01 percent
6	Loss of Containment on Gas Transmission Pipeline	Extracted from Existing	0.4 percent (0.01)	0.5 percent
7	Real Estate and Facilities Failure	Added Frequency	27 percent (2.2)	0.2 percent

Employee Safety Incident

A physical attack is one of the drivers that can lead to the "Violence and other injuries by persons or animals" outcome of the risk event.

Failure of Electric Distribution Overhead Assets

Physical Attack can increase the likelihood of this risk event. It occurs when third parties tamper with Distribution Overhead assets resulting in outages.

Failure of Electric Distribution Network Assets

PG&E has not experienced a physical attack leading to asset failure in this part of the grid. There are controls that exist to make it very difficult for

[19] Information about how Physical Attack impacts the RAMP risks is included on WP 20-3.

unauthorized access to the vaults in which these assets are situated. In addition, the redundant nature of the system means that a single failure is unlikely to lead to any impact to the customer.

Large Uncontrolled Water Release

While a physical attack on a hydroelectric dam could potentially cause a risk event, there are no instances of this occurring in the U.S. Physical Attack is not a significant driver to the risk event.

Loss of Containment on Gas Distribution Main or Service

A physical attack could cause a loss of containment on Gas Distribution Main or Service event. Fewer than one percent of about 30,000 loss of containment events on gas distribution main or service that are expected to occur annually are attributed as physical attack or intentional damage.

Loss of Containment on Gas Transmission Pipeline

Physical Attack could cause the Loss of Containment on Gas Transmission Pipeline. Fewer than one percent of the loss of containment events on gas transmission pipeline that are expected to occur annually are attributed as physical attack or intentional damage.

Real Estate and Facilities Failure

Physical attacks could result in minor damage to a PG&E facility. The minor damage outcome is identified to have only financial consequences. Safety consequences related to a physical attack on a PG&E facility are accounted for in the Employee Safety Incident risk.

4. Changes Since the 2017 RAMP

Physical Attack was not a 2017 RAMP risk.

5. Mitigations and Controls 2020-2026

a. Planned Work

PG&E has developed its detailed Corporate Security project plan for 2020. These Corporate Security projects are designed to mitigate the Physical Attack risk. The projects are aligned to Prevent and Detect categories.

Prevent

Activities designed to reduce the likelihood of a physical attack. These activities limit the impact of security risk-based events, reducing both frequency and consequence.

In 2020, PG&E is planning 15 mitigation projects primarily aligned to this domain. One of the Protect projects PG&E is proposing is a Visitor Management System that will manage risks against an untrusted external visitor.

Detect

Activities designed to timely identify and respond to physical attack incidents.

In 2020, PG&E is planning 13 mitigation projects primarily aligned to this domain. One of the Detect projects PG&E is planning is the Strategic Gap Closure for Elevated Sites under which PG&E will close security gaps at elevated sites to match Security Defined Protection Level (SDPL) standards.

Between 2021 and 2026, PG&E will implement two mitigations: Prevent (Mitigation 1) and Detect (Mitigation 2). The individual projects aligned to these two domains will be developed.

In addition to the mitigations planned for 2020-2026, PG&E will also implement a series of controls to manage Physical Attack risk. These controls include:

Control 1 – Physical Security: Responsible for emergency response, incident management, and collaborating with local management on physical security vulnerabilities and incident management;

Control 2 – Security Asset and Technology: Design and implement technology solutions to mitigate physical security risks; and

Control 3 – Corporate Security Control Center: Monitor and respond to physical security alarms, and provide security office deployment, and physical access control management.

b. Mitigations With RSE Scores

The forecast costs, RSE and risk reduction scores for the planned mitigation work are shown in Tables 21, 22, and 23 below.

TABLE 21
FORECAST COSTS
2020-2026 EXPENSE
(THOUSAND OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Prevent	KZ	$710	$731	$753	$776	$799	$823	$847	$5,438
2	M2	Detect	KZ	474	488	502	518	533	549	565	3,629
3		Total		$1,183	$1,219	$1,255	$1,293	$1,332	$1,372	$1,413	$9,067

TABLE 22
FORECAST COSTS
2020-2026 CAPITAL
(THOUSAND OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M1	Prevent	3N	$9,500	$9,785	$10,079	$10,381	$10,692	$11,013	$11,343	$72,793
2	M2	Detect	3N	6,770	6,973	7,182	7,398	7,620	7,848	8,084	51,874
3		Total		$16,270	$16,758	$17,261	$17,779	$18,312	$18,861	$19,427	$124,667

TABLE 23
RSE AND RISK REDUCTION: PHYSICAL ATTACK – ALL MITIGATIONS

		Aggregated		Applied to RAMP Risk
Line No.	Applicable RAMP Risk	RSE[(a)]	Risk Reduction (NPV)[(b)]	Risk Reduction (NPV)[(b)]
1	Mitigation: All Physical Attack Mitigations	< 0.01	0.07	
2	Employee Safety Incident			0.02
3	Failure of Electric Distribution Network Assets			< 0.01
4	Failure of Electric Distribution Overhead Assets			0.03
5	Large Uncontrolled Water Release (Dam Failure)			< 0.01
6	Loss of Containment on Gas Distribution Main or Service			< 0.00
7	Loss of Containment on Gas Transmission Pipeline			0.01
8	Real Estate and Facilities Failure			0.01
9	Total	< 0.01	0.07	0.07

(a) See MWs included in the source document modeling package for information used to calculate the RSE.

(b) Information presented in terms of NPV to account for the discounting of benefits.

F. Records and Information Management

1. Overview

PG&E identified RIM as an enterprise risk because the risk of not having an effective RIM program may result in the failure to construct, operate and maintain a safe system and may lead to property damage and/or loss of life. Managing records and information inconsistently can lead to an operational incident or adverse business result if records that are needed cannot be located in a timely fashion.

PG&E manages this risk in its Enterprise Records and Information Management (ERIM) organization with significant input and support from the IT Organization. The ERIM program has become an integral part of PG&E's efforts to further strengthen its safety culture and to provide safe and reliable gas and electric service to its customers. PG&E endeavors to further reduce RIM risk by promoting more consistent records management across the LOBs, promoting consistent, LOB RIM compliance and improving operational efficiency.

PG&E organizes its mitigations and controls according to the ARMA International[20] principles for measuring program maturity. PG&E's ERIM Department structure is aligned with key functions needed to support PG&E's goal of reaching Information Governance Maturity Model (IGMM) Level 3 by 2022 and executing its supporting program roadmap. IGMM Level 3 is characterized by defined policies and procedures for meeting the Company's legal and regulatory requirements and is consistent with PG&E's renewed focus on compliance maturity.

2. Modeling

RIM impacts both the likelihood and consequence of a risk event.

RIM issues can impact the likelihood of a risk event if a record does not exist, is missing, is incorrect, or is not readily available. The risk model considers that there is a non-zero probability that records and information issues such as missing inspections records, incorrect construction documents, or asset information that is difficult to find, has the potential to increase the likelihood of a risk event occurring.

RIM issues can also impact the financial consequence of a risk event. To model the financial consequences, PG&E analyzed the potential financial consequences related to identifying and producing records after an event. To account for this financial consequence PG&E added a RIM multiplier that is adjusted according to the records maturity level of the LOB and that varies according to the financial consequences of the event itself (the model 22 assumes that it would cost more to identify and produce records after a larger event). Penalties and fines are excluded from the financial consequences in the risk model.

3. Impacts to the 2020 RAMP Risks

RIM impacts 10 RAMP risks. Table 24 below maps the RIM cross-cutting factor to the applicable RAMP risks.

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20 ARMA International was previously known as the "Association of Records Managers and Administrators (ARMA)." ARMA International is a membership association for information management and information governance professionals.

TABLE 24
CROSS-CUTTING FACTOR SUMMARY: RIM

Line No.	RAMP Risk	Taxonomy	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Employee Safety Incident	Consequence Impact/ Extracted from Existing	0.7 percent (4.2)	(a)
2	Failure of Electric Distribution Overhead Assets	Consequence Impact/ Extracted from Existing	0.02 percent (6)	(a)
3	Failure of Electric Distribution Network Assets	Consequence Impact/ Extracted from Existing	0.8 percent (0.01)	(a)
4	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Consequence Impact/ Extracted from Existing	3 percent (0.2)	(a)
5	Large Uncontrolled Water Release (Dam Failure)	Consequence Impact	--	(a)
6	Loss of Containment on Gas Distribution Main or Service	Consequence Impact/ Extracted from Existing	0.1 percent (35)	(a)
7	Loss of Containment on Gas Transmission Pipeline	Consequence Impact/ Extracted from Existing	0.1 percent (0.001)	(a)
8	Motor Vehicle Safety Incident	Consequence Impact	--	(a)
9	Real Estate and Facilities Failure	Consequence Impact	--	(a)
10	Wildfire	Consequence Impact	--	(a)

(a) Percent of Risk was not calculated when the cross-cutting factor impacts consequences of risk events.

4. Changes Since the 2017 RAMP

In the 2017 RAMP PG&E presented 13 mitigations and 4 controls it planned to implement during the 2017-2019 period. PG&E reported on the progress of the mitigations and controls in its 2020 GRC.[21]

Of the 13 mitigations PG&E proposed in its 2017 RAMP for the 2017-2019 period,[22] 3 mitigations were implemented during that period and have become ongoing controls. The mitigation numbers referred to herein are the numbers assigned in the 2017 RAMP.

- Accountability Related Mitigations (M1B);

21 A.18-12-009, Exhibit (PG&E-7), p. 7-10 to p. 7-17.

22 PG&E's 2017 RAMP Report, p. 20-20, Table 20-3.

- Protection Related Mitigations (M5B); and
- Enterprise Data Management System Migration (M8B)

Seven mitigations will continue to be implemented during the 2020-2022 period.

- M3B – Compliance Related Mitigations;
- M4B – Retention Related Mitigations;
- M6B – Availability Related Mitigations;
- M7B – Implement RIM Governance for Content in Unstructured Data Repositories;
- M10 – Disposition Related Mitigations;
- M11 – Integrity Related Mitigations; and
- M13A – Implement RIM Governance for Content in Structured Data Repositories.

The scope of work for the three remaining has been modified due to scope overlap with other projects and the mitigations as described in the 2017 RAMP are no longer being pursued.

- M9B – Electronic Records Cleanup;
- M12A – Preservation Strategy and Implementation; and
- M14A – Map Work Processes that Generate Records.

PG&E implemented the four controls as described in the 2017 RAMP to manage records and information risk.[23] The four controls, which are aligned to the framework of the IGMM, are: Accountability Related Controls; Transparency Related Controls; Compliance Related Controls; and Retention Related Controls.

5. Mitigations and Controls 2020-2026

PG&E is proposing seven individual RIM mitigations. These seven mitigations are combined in the risk model into a single RIM mitigation.

a. Planned Work

The RIM mitigations that PG&E will implement during the 2020 RAMP period are:

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[23] PG&E's 2017 RAMP Report, p. 20-14, Table 20-2.

M3C – Records Compliance Related Mitigations: These mitigations involve verification of compliance with applicable laws and other regulations issued by binding authorities, as well as with the ERIM program's policy and standards.

M4C – Records Retention Related Mitigations: These mitigations involve maintaining records and non-records for an appropriate time, accounting for legal, regulatory, fiscal, and operational requirements.

M6C – Records Availability Related Mitigations: These mitigations involve maintaining records and information in a manner that allows for timely, efficient, and accurate retrieval of records.

M7C (2020-2022) and M7D (2023-2026) – Implement RIM Governance for Content in Unstructured Data Repositories: Implementing metadata, retention controls and retention trigger events in applications such as e-mail, SharePoint, and file shares to support efficient and accurate retrieval of needed information and the application of automated retention and disposition of non-records.

M10C – Records Disposition Related Mitigations: This mitigation involves providing secure and appropriate disposition for records and non-records that have met retention and are not otherwise subject to an applicable legal hold.

M11C – Records Integrity Related Mitigations: These mitigations improve the integrity of records and information to support authenticity and reliability.

M13C (2020-2022) and M13D (2023-2026) – Implement RIM Governance for Content in Structured Data Repositories: This mitigation implements retention controls and identifies retention trigger events in database applications such as SAP, Customer Care and Billing, and other systems to dispose of records and information that are no longer needed.

PG&E will continue to use the four controls originally proposed in the 2017 RAMP to manage records and information risk during this RAMP period: C1 – Accountability Related Controls; C2 – Transparency Related Controls; C3 – Compliance Related Controls; and C4 – Retention Related Controls.

In addition, Records Protection Related Mitigations (formerly M5) will become a control (Control 5) in 2020.

b. Mitigations With RSE Scores

The forecast costs, RSE and risk reduction scores for the planned mitigation work are shown in Tables 25, 26, and 27 below.

TABLE 25
FORECAST COSTS
2020-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M3C	Records Compliance Related Mitigations	AB	$2	–	–	–	–	–	–	$2
2	M4C	Records Retention Related Mitigations	AB/JV	23	$889	$1,149	$383	$374	$384	$408	3,611
3	M6C	Records Availability Related Mitigations	AB/JV	1,321	646	660					2,627
4	M7C/ M7D	Implement RIM Governance for Content in Unstructured Data Repositories	AB/JV	3,350	5,657	5,633	5,557	2,296	2,474	1,376	26,343
5	M10C	Records Disposition Related Mitigations	AB/JV	421	860	610	650	500	250	–	3,291
6	M11C	Records Integrity Related Mitigations	AB/JV	1,190	863	897	1,072	802			4,823
7	M13C/ M13D	Implement RIM Governance for Content in Structured Data Repositories	AB/JV	220	1,767	2,507	2,572	2,227	1,979	2,097	13,370
8		Total		$6,527	$10,682	$11,456	$10,235	$6,199	$5,087	$3,881	$54,067

TABLE 26
FORECAST COSTS
2020-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mit. No.	Mitigation Name	MWC	2020	2021	2022	2023	2024	2025	2026	Total
1	M6C	Records Availability Related Mitigations	2F	$279	–	–	–	–	–	–	$279
2	M7C/ M7D	Implement RIM Governance for Content in Unstructured Data Repositories	2F	1,446	–	–	–	–	–	–	1,446
3	M13C/ M13D	Implement RIM Governance for Content in Structured Data Repositories	2F	–	$100	$1,000	$1,000	$1,000	$1,000	$1,000	5,100
4		Total		$1,725	$100	$1,000	$1,000	$1,000	$1,000	$1,000	$6,825

TABLE 27
RSE AND RISK REDUCTION: RIM- ALL MITIGATIONS

Line No.	Applicable RAMP Risk	Aggregated RSE[(a)]	Aggregated Risk Reduction (NPV)[(b)]	Applied to RAMP Risk Risk Reduction (NPV)[(b)]
1	Mitigation: All RIM Mitigations	6.3	139.3	–
2	Employee Safety Incident	–	–	0.1
3	Failure of Electric Distribution Network Assets	–	–	< 0.1
4	Failure of Electric Distribution Overhead Assets	–	–	1.0
5	Large Overpressure Event Downstream of Gas M&C Facility	–	–	< 0.1
6	Large Uncontrolled Water Release (Dam Failure)	–	–	< 0.1
7	Loss of Containment on Gas Distribution Main or Service	–	–	0.3
8	Loss of Containment on Gas Transmission Pipeline	–	–	0.2
9	Motor Vehicle Safety Incident	–	–	< 0.1
10	Real Estate and Facilities Failure	–	–	0.6
11	Wildfire	–	–	137.1
12	Total	6.3	139.3	139.3

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
(b) Information presented in terms of NPV to account for the discounting of benefits.

G. Seismic

1. Overview

Seismic events can be a significant driver of failure in LOB assets. Seismic events contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.

PG&E's service territory is in an active seismic zone and as such PG&E assets from all LOBs are subjected to potentially damaging ground shaking and related ground failure that ranges from minor to catastrophic from a single event. Damaging effects may occur without warning over a large geographic area and impact PG&E's ability to serve its customers and respond to the event. The greater San Francisco (SF) Bay Area is considered to have the highest seismic risk in PG&E's service territory due to the existence of many active faults located in highly-populated urban areas with dense PG&E infrastructure. Extensive damage to non-PG&E infrastructure and supporting business and suppliers will impact restoration efforts.

PG&E studies seismic hazard developments in its Geosciences Department (Geosciences). Geosciences is part of the Generation organization and provides services across PG&E's LOBs. Geosciences was developed as a department in the 1980s as part of the Long-Term Seismic Program (LTSP) focusing on geohazard issues at the DCPP. Currently Geosciences is involved in and supports geohazard risk assessments efforts across the enterprise and all the LOBs including:

- The DCPP LTSP;
- The Hydro Facility Safety Program;
- Evaluating seismic risk at all sites;
- The Gas Transmission Pipeline Geohazards Program;
- Electric transmission tower evaluations and support projects;
- Evaluating seismic risk in PG&E's facilities;
- The EP&R earthquake exercise, post-event reconnaissance and Dynamic Automated Seismic Hazard (DASH) program that functions as the company earthquake alert and initial response tool; and
- Earthquake science and learning from earthquakes ground motion model development and support including collaborations with the United States Geological Survey (USGS), national laboratories, industry working groups and many leading academic institutions advancing the seismic knowledge and implementation for risk reduction.

Focused seismic risk assessment and reduction activities are managed through the Geosciences Integrated Seismic Risk Management Program (ISRMP) that includes application of various tools to quantify seismic risk. The ISRMP enables progressive quantification of seismic hazard. Geosciences uses a tool called System Earthquake Risk Assessment (SERA) to analyze seismic risk. SERA is a commercial platform that has been modified for PG&E's applications to evaluate the geographically distributed electric and gas linear assets. SERA is used by utilities across the western U.S. and Canada, helping to standardize seismic hazard analyses.

The SERA platform includes fragility models for system components that have been developed from both California-specific and worldwide data from past earthquakes. The platform evaluates system performance from both ground shaking and ground failure (e.g., surface fault rupture, liquefaction, landslides) based on geohazard maps and earthquake scenarios. To test system performance PG&E models a number of plausible earthquake scenarios. Examples of earthquake scenarios include large earthquakes on numerous active faults which in the SF Bay Area region include the San Andreas, Hayward, and Rogers Creek faults.

Until 2019, SERA was used to analyze seismic performance of the electric system. At the end of 2019 Geosciences, with help and support from the Gas Organization, engaged the SERA vendor to incorporate PG&E's entire gas underground piping network (transmission and distribution) into the SERA platform. After this work is complete, Geosciences will incorporate the balance of the key above ground gas infrastructure into the model. The resulting integrated electric and gas system model covers the entire PG&E service territory and will permit evaluation of cross-cutting impacts to these LOBs.

The current focus of the ISRMP is to prioritize seismic risk assessment to assets in the greater SF Bay Area and then extend evaluations through the rest of PG&E's service territory. This strategy is informed by the USGS' findings that the seismic hazard and the consequential impact in the SF Bay Area is highest in this region and therefore represents the greatest seismic risk.

2. Modeling

The Seismic cross-cutting factor impacts both the likelihood of a risk event occurring and the consequences of a risk event. Seismic is a risk driver for the Large Uncontrolled Water Release (Dam Failure), Real Estate and Facilities Failure risks, Electric Operations risks, and Loss of Containment on Gas Transmission Pipeline and Distribution Main or Service risks.

As described above, PG&E modeled this cross-cutting factor using two tools: SERA and DASH. SERA is used to evaluate the geographically-distributed electric and gas linear assets. DASH is an earthquake response tool that evaluates and notifies the LOB about potential system impacts.

PG&E evaluated the likelihood of a seismic event occurring by modeling three plausible earthquake scenarios in the SF Bay Area. The consequence of a seismic event is evaluated in terms of how a seismic event would impact gas and electric assets.

Outputs from the modeling included frequency of an earthquake and the costs of asset failures due to the seismic event. PG&E also considered how much worse asset failure could be following an earthquake compared to a routine asset failure. The risk model applies a consequence multiplier to risk events to describe this more severe outcome.

3. Impacts to the 2020 RAMP Risks

Seismic hazard impacts seven RAMP risks. A seismic event can result in safety, reliability and financial consequences. Table 28 and 29 below maps the Seismic cross-cutting factor to the applicable RAMP risks.

TABLE 28
CROSS-CUTTING FACTOR DRIVERS SUMMARY: SEISMIC

Line No.	RAMP Risk	Taxonomy	Risk Frequency Percentage (Events/Year)	Percent of Risk
1	Failure of Electric Distribution Overhead Assets	Added Frequency	0.2 percent (41)	12 percent
2	Failure of Electric Distribution Network Assets	Added Frequency	0.8 percent (0.08)	1 percent
3	Large Uncontrolled Water Release (Dam Failure)	Added Frequency	10 percent (0.0014)	6 percent
4	Loss of Containment on Gas Distribution Main or Service	Added Frequency	0.3 percent (86)	39 percent
5	Loss of Containment on Gas Transmission Pipeline	Added Frequency	11 percent (0.2)	27 percent)
6	Real Estate and Facilities Failure	Added Frequency	62 percent (5)	99.8 percent
7	Wildfire	Added Frequency	<0.01 percent (0.01)	1 percent

TABLE 29
CROSS-CUTTING FACTOR OUTCOME SUMMARY: SEISMIC

Line No.	RAMP Risk	Outcome	Percent Frequency	Percent Risk
1	Failure of Electric Distribution Overhead Assets	Asset Failure/Seismic Scenario	0.2 percent	12 percent
2	Failure of Electric Distribution Network Assets	Asset Failure/Seismic Scenario	1 percent	1 percent
3	Loss of Containment on Gas Distribution Main or Service	Major – Seismic	<0.01 percent	38 percent
4	Loss of Containment on Gas Distribution Main or Service	Minor – Seismic	0.3 percent	0.3 percent
5	Loss of Containment on Gas Transmission Pipeline	Seismic-Rupture	9 percent	27 percent
6	Loss of Containment on Gas Transmission Pipeline	Seismic-Leak	1.6 percent	0.01 percent
7	Real Estate and Facilities Failure	Seismic-Minor	50 percent	22 percent
8	Real Estate and Facilities Failure	Seismic-Moderate	8 percent	28 percent
9	Real Estate and Facilities Failure	Seismic-Strong	2 percent	24 percent
10	Real Estate and Facilities Failure	Seismic-Severe	1 percent	25 percent
11	Wildfire	Seismic-RFW-Catastrophic Fire	<0.01 percent	0.7 percent
12	Wildfire	Seismic-Non-RFW-Catastrophic Fire	<0.01 percent	0.3 percent

Real Estate and Facilities Failure

Seismic risk accounts for 99.8 percent of the Real Estate and Facilities Failure risk and it is the key driver of this risk event. To model this risk PG&E conducted an initial sample study of 50 higher risk facilities primarily in the SF Bay Area, considering key facility parameters (e.g., age, type, occupancy, location, business functional criticality, etc.). Going forward, PG&E plans to conduct a more detailed assessment of the building portfolio in the SF Bay Area. PG&E will prioritize the facilities in the SF Bay Area due to high concentration of assets in this highly populated and seismically active zone.

Large Uncontrolled Water Release (Dam Failure)

Seismic is a risk driver of the Large Uncontrolled Water Release risk event and accounts for 6 percent of the total risk.

Loss of Containment on Gas Distribution Main or Service and Loss of Containment on Gas Transmission Pipeline

The seismic cross-cutting factor is considered a driver for these risk events. Seismic risk accounts for 27 percent of the Gas Transmission risk and 39 percent of the Gas Distribution risk.

Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Network Assets and Wildfire

Seismic is a cross-cutting factor for the failure of Electric Distribution Overhead and Network Assets risks and Wildfire risk. The seismic risk accounts for 12 percent of the Electric Distribution Overhead Assets risk,1 percent of the Electric Distribution Network Assets risk, and 1 percent of the Wildfire risk.

In addition to the RAMP risks, seismic risk is associated with other PG&E safety risks.[24] Seismic risk associated with the nuclear operation at DCPP was fully developed in a Seismic Probabilistic Risk Assessment (SPRA) under the rules mandated by the Nuclear Regulatory Commission (NRC). The SPRA was updated and submitted to the NRC in 2018, and incorporated hazard input from the LTSP which was vetted by a formal Senior Seismic Hazard Advisory Committee process. NRC has reviewed and accepted the SPRA as meeting their requirements as of January 2019. This SPRA is being maintained and managed under the LTSP Program. The seismic risk was determined to be approximately 32 percent of the total risk (Core Damage Frequency)

PG&E will continue conducting seismic risk evaluations for all RAMP assets and, as appropriate, will also conduct seismic risk evaluations for non-RAMP assets as well.

4. Changes Since the 2017 RAMP

Seismic was not a 2017 RAMP risk element.

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[24] Only PG&E's Top 12 safety risks are designated as RAMP risks in the 2020 RAMP filing. PG&E describes the additional safety risks in Chapter 19, "Other Safety Risks."

5. Mitigations and Controls 2020-2026

a. Planned Work

The ISRMP started in 2019 to more consistently assess the seismic hazard and seismic risk for all LOBs. As its first priority during this RAMP period, PG&E will focus its seismic risk mitigation efforts in the SF Bay Area for electric, gas, and real estate (facilities) assets. Going forward, the ISRMP will develop and maintain seismic risk quantifications by focusing on key elements such as:

- Seismic source characterization, regional geology;
- Site specific and distributed system ground motion models;
- Ground failures such as landslide, liquefaction and fault crossings;
- Asset health as an input to more accurately quantify seismic risk; and
- Logic modeling developments/enhancements.

This program is modeled after the LTSP that has been successfully used at the DCPP for more than 30 years. Seismic risk analysis for gas and electric assets includes three viable and severe scenarios: the Hayward Fault at the foot of the East Bay hills; the San Andreas Fault that extends through the SF Peninsula; and the Rogers Creek Fault that extends from the Bay through Santa Rosa. Future updates will expand to consider total hazard from other faults.

During the 2020 RAMP period Geosciences will work with LOB asset owners and risk managers to develop the means to consistently quantify seismic risk and to propose risk mitigations tailored to those LOB assets. To develop the seismic mitigations for the different asset types, Geosciences and the LOB teams will work together to analyze asset failure modes and asset-specific risks.

PG&E will also continue to update and refine information in SERA to address uncertainties in modeling results based on earthquake experience learnings, research, and collaborations with leading earthquake academia and government agencies, including the California Energy Commission. This continual improvement process will lead to more granular system performance modeling to better estimate damages from future earthquakes.

In addition to system damage assessment tools such as SERA, PG&E has also developed a proprietary earthquake response tool called DASH. The DASH tool collects seismic instrument records and ground shaking maps from the USGS to evaluate and notify of potential system impacts within a 15-30 minute timeframe after an earthquake. The DASH tool compares ground shaking maps against simplified damage models specific to each LOB and produces reports of potential damage that the business uses to inform and prioritize inspections and responses. The DASH tool also includes a continuous improvement element that includes annual updates of infrastructure inventories and tool maintenance/reliability improvements.

In the 2023 GRC PG&E will propose that the ISRMP and LTSP will be combined into a single program for the enterprise.

b. Mitigations with RSE Scores

Seismic risk assessment is a collaborative process between ISRMP and the LOBs. It is a foundational program that quantifies the potential seismic risk for operations assets. The LOBs develop the mitigations to address this risk.

While the ISRMP is not proposing seismic mitigations in the 2020 RAMP, PG&E will maintain its LTSP and ISRMP Program for assessing seismic risk.

H. Skilled and Qualified Workforce

1. Overview

PG&E's Human Resources (HR) Department develops and delivers technical, leadership and other training that helps to maintain a skilled, safe and qualified workforce. Failing to maintain a Skilled and Qualified Workforce (SQWF) is one of PG&E's top cross-cutting factor factors than can impact safety.

PG&E Academy develops and updates courses based on priorities established by the LOBs and to reflect new or changing regulations and business procedures. In 2019 PG&E Academy delivered more than 5,300 instructor-led training sessions. That translates to 69,570 student days of training (one student day equals one student in one day of training).

As a part of PG&E's Apprenticeship training programs, employees also are required to complete on-the-job training in areas such as electric operations, gas operations, safety and compliance, and leadership. PG&E Academy also offers web-based technical training courses to employees and contractors. These courses cover a wide range of disciplines, from beginner to advanced levels, across many technical specialties, including compliance, emergency response, systems O&M, and hazardous energy control. PG&E also offers 31 state-certified apprentice programs.

PG&E's goal is to ensure that training and qualifications for high consequence work is current and applied to the workforce in a systematic and repeatable way. High-risk work includes activities such as: excavation and trenching beyond 4 feet; heavy equipment operation; utility tree trimming, clearance work and vegetation management; general construction activities; welding and/or hot tapping of gas lines; and fault protection/grounding.[25]

PG&E uses the "human performance"[26] driver from the RAMP asset-based risks to establish the baseline for the SQWF risk because this driver captures incidents or events due to a person incorrectly performing a task. Recognizing that not all mistakes are due to a lack of skills or qualifications, PG&E used skills assessment data along with SME judgement to establish the proportion of incorrect operations likely attributable to an employee not having the necessary skills and qualifications.

2. Modeling

The SQWF cross-cutting factor impacts the frequency of a risk event such that a portion (expressed as a percentage in the model) can be attributed to a workforce that does not have the appropriate training for the work they are performing. SQWF is a sub-driver to the Human Performance and Incorrect Operations drivers in Electric Operations and Gas Operations respectively.

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25 See PG&E's Contractor Safety Program Risk Matrix that is aligned to the PG&E Utility Standard SAFE-3001S.

26 This driver is also referred to as Incorrect Operations.

To estimate the impact that a lack of training can have on a risk event, PG&E reviewed the results of the skills tests maintained by the HR organization for the Gas and Electric Organizations. Each failed skilled assessment is assumed to be an indicator of a risk event. For example, if there is a one percent failure rate on a Gas Organization skills assessment, the risk model applies that one percent to the increased likelihood that a Gas Operations risk event could occur due to Incorrect Operations.

3. Impacts to the 2020 RAMP Risks

SQWF impacts six RAMP risks. Table 30 below maps the SQWF cross-cutting factor to the applicable RAMP risks.

TABLE 30
CROSS-CUTTING FACTOR SUMMARY: SQWF

Line No.	RAMP Risk	Risk Modeling Taxonomy	Risk Frequency Percentage (Events/Year)	Percent of Risk
1	Employee Safety Incident	Extracted from Existing	3 percent (19)	3 percent
2	Failure of Electric Distribution Network Assets	Extracted from Existing	2 percent (0.2)	4 percent
3	Failure of Electric Distribution Overhead Assets	Extracted from Existing	0.1 percent (15)	0.1 percent
4	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Extracted from Existing	0.5 percent (0.03)	1 percent
5	Loss of Containment on Gas Distribution Main or Service	Extracted from Existing	<0.01 percent (2)	<0.01 percent
6	Loss of Containment on Gas Transmission Pipeline	Extracted from Existing	<0.01 percent (0.0001)	<0.01 percent

4. Changes Since the 2017 RAMP

In the 2017 RAMP PG&E proposed eight controls focused on rigorous training programs for new and existing employees, and ongoing assessments of specific skills and qualifications. Together, these controls help to reduce the chance that a worker will perform tasks for which they are not qualified. PG&E continues to implement these controls to mitigate the SQWF risk.

In the 2017 RAMP PG&E proposed 13 mitigations focused on qualifications and training needed to safely perform high consequence work. The mitigations were designed to identify which workers are expected to perform high consequence work through qualifications catalogs and training profiles in order to match the right workers with the right training. The proposed mitigations fell into three categories:

1) Foundational: Work that will improve PG&E's data and information in order to identify all high consequence work and refine risk model inputs related to consequences and frequencies. PG&E completed nine of the eleven foundational mitigations. One mitigation (M10 – Qualification and Tasks Loaded into HR Systems) was incorporated into Control 1 (Gas Operator Qualifications Program). One mitigation (M11 – IT Solution for Curriculum Management) was cancelled because PG&E has a process in place and did not need to pursue this additional work.
2) Technical Competence: Improving access to technical procedures, standards and job aids. PG&E proposed and completed one mitigation (M13 – Training Substation in Livermore) in 2018.
3) Qualification Verification: Increase the visibility into and use of qualifications when scheduling and assigning work. PG&E proposed and completed one mitigation (M12 – Applicant Installer On-Boarding Process) in 2019.

5. Mitigations and Controls 2020-2026

a. Planned Work

The SQWF mitigations and controls planned for the 2020 RAMP period are focused on Gas Operations and Electric Operations employees since the SQWF cross-cutting factor is a driver of gas and electric risks. The mitigations planned for this period were initially proposed in PG&E's 2017 RAMP.[27] PG&E completed two mitigations (M14A and M21)[28] proposed in the 2017 RAMP.

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27 PG&E's 2017 RAMP Report, p. 15-10, Table 15-2 (M1A – Safety Management System) and p. 21-24, Table 21-4 (all other mitigations).

28 PG&E's 2017 RAMP Report, p. 21-24, Table 21-4. Note, In the 2017 RAMP (I.17-11-003) this mitigation was referred to, in error, as both M20 (p. 21-23) and M21 (p. 21-24, Table 21-4).

PG&E is planning five mitigations:

M1B (Employee Safety Incident) – Enterprise Safety Management System (ESMS): PG&E will identify and implement a new enterprise tool in lieu of the "Expand Business Process Index" mitigation (M1B) proposed in the 2017 RAMP for the 2020-2022 period. The project will be led by the Enterprise Health and Safety organization. The ESMS is a series of capabilities (people, process, and technology systems) required to define, plan, implement, and continuously improve workforce safety. It includes an Enterprise Management of Change (EMOC) process to identify, understand, and evaluate the risks and hazards when changes are made to facilities, operations, or personnel to assure they are properly controlled. When a standard or procedure changes, or there is new equipment introduced in the field, the EMOC process will indicate that the associated training needs to be updated accordingly. The EMOC system database will provide support for tracking changes to other controls and mitigations.

M15 – Enhance Technical Information Library (TIL) and Guidance Document Library (GDL) (Technical Competence): The TIL and GDL are online repositories for PG&E's policies, standards, procedures, and guidance documents. PG&E's employees refer to these documents whenever they are completing a new or unfamiliar task or procedures. The planned enhancements include: improve ease of use through developing a standard, mobile friendly, format for new documents and reformatting of existing documents; improve search engine/function with key words and task names; and create the data and capability to link a specific task from the work scheduling system to the appropriate procedure or job aid.

M17 – Work Scheduling Integration with Qualifications (Qualification Verification): Automate the verification of qualifications by integrating PG&E's SAP HR system, where qualifications are tracked, with the work scheduling system. This will allow for matching work to specific employee qualifications. The Gas Operations organization is in the process of implementing a solution to integrate work scheduling and qualification verification. Electric Operations is evaluating the best way to move forward to improve their processes to management certifications and the scheduling of work.

M18 – Qualification Cards for Electric Employees: Qualification cards contain information about the qualification status for each employee and are scanned at the yard or job site, before work begins. Scanning the card before work begins reduces the risk that an employee will be assigned a task for which they are not qualified. PG&E has issued a request for proposal for a vendor to implement a new qualification card system that will include employees in the operating LOBs.

M19 –Electric Review and Update Expected Job Functions: This foundational mitigation enhances the details about the specific qualifications and skills required for Electric tasks, similar to the details tracked for Gas Operations and Nuclear Operations. This mitigation will improve the qualifications documentation for jobs classifications, specific positions and tasks performed.

PG&E will continue to perform Controls 1 through 8 as described in the 2017 RAMP.[29] They are:

- C1/C2 – Gas Operator Qualifications Program and Employee Knowledge and Skills Program;
- C3 – Job Profile, Job Description/Profiling Process;
- C4 – Technical Training Profiling/Governance;
- C5 – Standards and Procedures Review Process;
- C6 – Apprentice Training;
- C7 – Training Effectiveness Monitoring; and

[29] PG&E's 2017 RAMP Report, p. 21-9 to p. 21-12, and Table 21-2.

- C8 – Display Training in the Learning Management System.

PG&E completed work on two mitigations proposed in the 2017 RAMP and is transitioning those activities from mitigations to controls:

C9 (M20 in the 2017 RAMP[30]) – Improve, Collect, and Analyze Data Related to Skill Degradation: This control was proposed as a mitigation in the 2017 RAMP (M20) for the 2020-2022 period. This mitigation is complete for the Electric Organization. PG&E's Electric Operations organization used a third party to analyze skill degradation timeframes for various skills and tasks. This data was averaged to result in a 3-year re-assessment and re-training cycle for Electric Field employees. The majority of Gas Operations work is strictly regulated by the Department of Transportation and employees must re-qualify for specific tasks on regulatory intervals. Most tasks are requalified every three years though certain tasks are requalified more often (e.g., welders must be requalified every six months). If an employee fails a re-qualification, they are remediated, but if they fail a second time they are not allowed to do that type of work.

C10 (M14A in the 2020 RAMP) – On the Job Support – Mobile Technology for Foreman and Crew Leads: This control was proposed as a mitigation in the 2017 RAMP (M14A) for the 2020-2022 period. PG&E completed the work described in the 2017 RAMP. Going forward, this activity will consist of making improvements and enhancements to the mobile technology and available documentation.

b. Mitigations With RSE Scores

The ESMS mitigation is discussed in greater detail in the Employee Safety Incident risk chapter. The RSE and risk reduction scores are shown in Table 31 below.

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30 In PG&E's 2017 RAMP Report this mitigation was referred to, in error, as both M20 (p. 21-23) and M21 (p. 21-24, Table 21-4).

TABLE 31
RSE AND RISK REDUCTION: SQWF

			Aggregated		Applied to RAMP Risk
Line No.	Mit. No.	Applicable RAMP Risk	RSE[(a)]	Risk Reduction (NPV)[(b)]	Risk Reduction (NPV)[(b)]
1	M1B	Mitigation: ESMS	12.9	29.6	–
2		Employee Safety Incident	–	–	29.6
3		Total	12.97	29.6	29.6

(a) See MWs included in the source document modeling package for information used to calculate the RSE.
(b) Information presented in terms of NPV to account for the discounting of benefits.

PG&E is not estimating costs for the other four mitigations described above in this RAMP due to uncertainties around the scope work. Therefore, PG&E cannot provide RSEs for these programs. PG&E will continue to refine the scopes of the proposed mitigations and will provide cost forecasts in the 2023 GRC.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 21

RISK ASSESSMENT AND MITIGATION PHASE

STEADY STATE OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
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A. Introduction

1. 2020 General Rate Case Settlement Agreement: Principles for Asset Replacement

The 2020 General Rate Case (GRC) Settlement Agreement (Settlement Agreement)[1] includes the following provision (Settlement Agreement, Section 5.1):

> PG&E should strive for reasonable rates of steady state replacement, consistent with risk-informed decision making, for crucial operating equipment necessary to provide safe and reliable service. Such steady state replacement includes pro-active replacement of an asset prior to in-service failure when warranted based on risk and engineering analysis that considers vintage, material properties, environmental conditions, life-extension maintenance practices, and any other relevant parameters. PG&E should strive to reduce post-failure replacement for assets where failure can result in unreasonable safety or cost impacts. PG&E will evaluate and explain in its next Risk Assessment and Mitigation Phase (RAMP) Report how its existing capital asset maintenance and replacement activities, including both pro-active and post-failure replacement, and costs thereof, promote cost-effective and risk informed steady state replacement. In those instances where PG&E's proposals in its next RAMP Report do not follow the principle of steady state replacement, PG&E should explain the basis for PG&E's proposals.

In this chapter, Pacific Gas and Electric Company (PG&E or the Company) discusses its risk-informed approach to pro-active asset replacement for each of its operating lines of business: Gas Operations, Electric Operations, and Power Generation.

2. Definition

PG&E defines "steady state replacement," as described in the Settlement Agreement, to include ongoing replacements and pro-active

[1] The Settlement Agreement was filed by PG&E and Settling Parties on December 21, 2019 with the California Public Utilities Commission (CPUC or Commission) in Docket No. Application (A.) 18-12-009.

replacement of an asset prior to in-service failure when warranted based on risk and engineering analysis that considers vintage, material properties, environmental conditions, life-extension maintenance practices, and any other relevant parameters.

B. Gas Operations

1. Gas Operations Asset Management Strategy Overview

Gas Operations (GO) includes the asset families listed below as part of PG&E's Asset Management (AM) framework under the Publicly Available Specification 55/International Organization for Standardization 55001 standards. Each asset family has an AM plan that provides an assessment of the condition of the asset, risk mitigations, strategic objectives and asset maintenance for the lifecycle of the assets. The asset family structure allows PG&E to drive risk management strategies consistently within and among the GO asset families. The GO asset families are as follows:

a) Gas Storage
b) Compression and Processing (C&P)
c) Transmission Pipe
d) Measurement and Control (M&C)
e) Distribution Mains and Services (DMS)
f) Customer Connected Equipment
g) Liquefied Natural Gas/Compressed Natural Gas
h) Asset Data

The discussion below focuses on those GO asset families with ongoing, proactive replacement programs for aging and/or deteriorating assets in the field. These include Gas Storage; C&P; Transmission Pipe; Measurement and Control; and Distribution Mains and Services.

2. Gas Operations Asset Management Programs

GO plans, designs, installs, maintains, and replaces the physical assets of the gas transmission and distribution system so that each component operates in a safe and reliable manner. GO has proactive replacement programs for the following key assets:

- Gas Storage
  - Storage Wells

- Compression and Processing
  - Compressor Units
- Transmission Pipe
  - Transmission Pipeline
- Measurement and Control
  - Distribution Regulator Stations
  - High Pressure Regulator (HPR) Stations
- Distribution Mains and Services
  - Distribution Mains

PG&E also replaces other gas assets, such as valves, distribution services, Supervisory Control and Data Acquisition equipment, and regulator station components, as identified through maintenance programs.

Asset replacement is the most effective mitigation for certain risk drivers. For example, the Vintage Pipe Replacement Program for transmission pipe that replaces pipe with vintage fabrication and construction defects interacting with land movement, is a key mitigation for threats leading to Loss of Containment (LOC) and Loss of Service events. However, asset replacement is not the most effective mitigation for other risk drivers such as third party/mechanical damage since the asset is in the ground and a third party may dig into it. In such a case, other layers of controls are built around it such as the Public Awareness program to reduce dig-ins, and In-Line Inspection (ILI) to detect any latent damage.

This section includes a description of the key steady state replacement programs by asset family and further explains how the replacement programs are associated with the top Company risks.

a. Gas Storage

For the storage asset family, AM is focused on risk integrity management via assessment, rework, and refurbishments of wells within the storage fields. As part of the lifecycle management of the storage assets, wells are evaluated for their need and usefulness. If a well is determined to be no longer needed and useful, the well is plugged and abandoned (permanent removal of the asset from service), which includes closure of the wellbore, reclamation of the surface area and possible modifications to the remaining facilities and equipment removal.

1) Storage Well Refurbishments

The Storage Well Inspection Program is a key mitigation for the LOC at Natural Gas Storage Well or Reservoir risk and addresses several drivers including corrosion, erosion, incorrect operations, third party/ mechanical damage, and weather related/outside forces thereby reducing the likelihood of the risk event occurring due to these drivers.

The mitigation pace is generally determined by using the prioritized risk based ranking of wells for consideration for assessments and rework projects. The factors that are taken into consideration for the risk-based prioritization include condition, years in service, and component and well performance. Work execution schedule for remedial work also considers ability to effectively and efficiently conduct work, opportunity to minimize mobilization efforts as well as station outages.

Well entry work includes: integrity logging (inspections); pressure testing; and replacement and repair of wellheads, downhole safety valves, up-hole safety valves, compromised tubulars, and other associated well auxiliary equipment. The near and long term focus for Storage is as follows:

Near-term: PG&E is continuing with its plan to complete well integrity baseline assessments, repair or replace gravel pack and liner, and retrofit wells to tubing and packer to meet California Geologic Energy Management Division requirements to eliminate a single point of failure and well construction standard. This program will be completed by October 1, 2025. The sale or decommissioning of Pleasant Creek and Los Medanos potentially will eliminate the need to perform baseline assessment and eliminate a single point of failure as the facilities would no longer be classified as storage facilities and would only be used to recover any remaining working or base gas from the assets if decommissioned.

<u>Long-term</u>: The adopted Natural Gas Storage Strategy includes continued operations of McDonald Island and selling or decommissioning Los Medanos and Pleasant Creek storage fields. Although the outlook for natural gas in California predicts we will have a reduced demand for storage, the installation of tubing and packer will have an impact on the field deliverability at McDonald Island likely necessitating the construction and connection of new wells to continue to meet the storage needs.

b. Compression and Processing

C&P assets include compressor units and associated equipment installed at PG&E's nine gas transmission compressor stations and three underground storage facilities (McDonald Island, Los Medanos, and Pleasant Creek). The C&P Asset Family also includes the gas odorizers installed systemwide.

Approximately 65 percent of the units in PG&E's compressor fleet are at or over 40 years old. The AM strategy for compressor units focuses on life extension, with the overall objective of ensuring safe and reliable operation of the units. Elements of this strategy include: Routine maintenance programs including inspections, periodic overhauls of compressor units, targeted component replacements and compressor replacements. Compressor asset health is determined based on age, parts availability for critical asset components, vendor support, upgrades or replacements completed or in progress, and performance of critical asset components. Aging and obsolete equipment represents a key threat area for the C&P asset family. Equipment-related risks are managed by replacing aging and obsolete equipment or upgrading or retrofitting equipment to meet current industry and environmental regulations, or changing business needs. There are several programs for mitigating equipment-related risks in C&P family such as Compressor Replacements, Compressor Unit and Station Control Replacements, Emergency Shutdown System Upgrades, Electrical Upgrades at Hinkley and Topock Compressor Stations, and Routine Capital and Expense. There are also C&P programs aimed to address threats like incorrect operations, manufacturing-related and welding/fabrication defects, corrosion, and weather and outside force/third-party damage. These are common to both C&P and M&C assets and include programs such as: (1) Critical Documents, (2) Engineering Critical Assessments, (3) Station Strength Testing, (4) Facilities Integrity Management Program (FIMP) Risk Management and, (5) Physical Security Upgrades.

The key steady state replacement programs in the C&P Asset Family are: (1) the Compressor Replacements program and (2) the Compressor Units and Station Control Replacements program. These address the LOC at Gas M&C or C&P Facility risk and are described in more detail below.

1) Compressor Replacements

The Compressor Replacements program is a key mitigation for the risk of LOC at the transmission C&P facility. This program mitigates equipment-related threats and risks that can adversely impact gas system operations through the loss of service, loss of operating flexibility and reliability, and inability to meet evolving industry and environmental regulations. As part of its AM process, PG&E prioritizes compressor units and equipment for replacement. The Long-Term Compression Investment Plan is part of the C&P AM Plan[2], which enables long-term planning and forecasting investments associated with lifecycle management of compression assets, and provides an initial schedule for replacing the appropriate assets of PG&E's compressor units over a 30-year period (2016-2045). Together with the AM strategy, compression utilization or changes in markets are evaluated to ensure that investments are not placed in assets which do not align with long term projections.

2) Compressor Unit and Station Control Replacements

The Compressor Units and Station Control Replacements program mitigates the LOC risk at the transmission C&P facility. This program was established to systematically replace compressor unit and station controls that are becoming obsolete. Most

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[2] 2018 C&P Asset Management Plan presented in 2019 Gas Safety Plan Appendix C.

compressor units and stations are installed with a Programmable Logic Circuit (PLC) that monitors and controls the operation of the compressor unit, ensuring safe and reliable operation. The lifespan of compressor unit and station PLCs is 15-20 years on average. PG&E considers several factors like age, obsolescence, lack of ongoing vendor support and spare parts availability to determine the pace of station control and unit control replacements. This program addresses the threats of equipment-related issues that reduce station reliability, and equipment-related lack of service and spare parts availability along with technology obsolescence.

c. Transmission Pipe

For the Transmission Pipe asset family there are several programs that proactively either repair or replace pipe prior to in-service failure when warranted based on risk and engineering analysis, including ILI, Direct Assessment, Hydrostatic Testing, Shallow/Exposed Pipe, Earthquake Fault Crossings, Geo-Hazard Threat Identification and Mitigation, Valve Automation, Valve Safety and Reliability, Class Location Change, Vintage Pipe Replacement, and Other Pipeline Safety and Reliability Replacements. Transmission pipe replacements are driven by inspection/assessment findings and analysis of risk factors. The key steady state replacement program is the Transmission Pipe Replacement Program.[3] This program addresses pipe replacements specific to: (1) the Vintage Pipe Replacement Program; and (2) the Other Pipeline Safety and Reliability Pipe Replacement program. These programs address the LOC on Gas Transmission Pipeline RAMP risk.

[3] Refer to A.17-11-009, PG&E's 2019 Gas Transmission and Storage rate case application for further details on these programs.

1) Vintage Pipe Replacement Program

The Vintage Pipe Replacement Program addresses various drivers including fabrication and construction defects,[4] weather related and outside forces, external corrosion, internal corrosion, and stress corrosion cracking and thereby reduces the likelihood of the risk event occurring due to these risk drivers.

PG&E's plan for its Vintage Pipeline Replacement Program is to mitigate risk, by the end of 2027, for vintage pipe segments containing vintage fabrication and construction threats that are subject to a high risk of land movement and are in close proximity to population. PG&E continues to monitor for land movement risk changes for the remaining vintage fabrication and construction threats and may add those to this mitigation program should the land movement risk rise at these pipeline locations.

2) Other Pipeline Safety and Reliability Pipe Replacements

Safety and Reliability driven pipe replacements (other than vintage pipe replacements) are included in this program. The pipe replacement program addresses several risk drivers including external corrosion, internal corrosion, stress corrosion cracking, third-party/mechanical damage, manufacturing related defects and weather related outside forces. PG&E expects to continue to replace pipe due to leaks, dig-ins, corrosion integrity issues, overbuilds and encroachments, and other pipeline safety and reliability issues that arise.

d. Measurement and Control

The M&C asset family includes gas regulation equipment associated with transmission and distribution regulating stations, and gas

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[4] While age alone does not pose a threat to pipeline integrity, age does play a role because of the type of vintage manufacturing and construction practices that were acceptable at that time. PG&E considers "vintage pipe" to include pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today.

transmission terminals. In addition, this asset family includes, farm tap[5] regulator sets, large volume customer regulating and meter stations, selected large customer meter sets, and equipment for monitoring gas quality. The M&C AM strategy is determined based on the condition of the overall station and its individual components through an assessment based on age, obsolescence, physical condition, functional performance, and maintenance history. The population of M&C stations varies in terms of age and condition. The aging and obsolete equipment is a key threat for the M&C assets. There are several programs to address this threat in the M&C family, such as: (1) Regulator Station Rebuilds, (2) Regulator Station Component Replacements, (3) HPR Replacements, (4) Terminal Upgrades, and (5) Station Overpressure Protection Enhancements. There are also M&C programs aimed to address threats like incorrect operations, manufacturing-related and welding/fabrication defects, corrosion, and weather and outside force/third-party damage. These threats are common to C&P and M&C assets and include programs, such as: (1) Critical Documents, (2) Engineering Critical Assessments, (3) Station Strength Testing, (4) FIMP Risk Management, and (5) Physical Security Upgrades.

The key steady state replacement programs for the M&C Asset family are: (1) Regulator Station Rebuilds, and (2) Regulator Station Component Replacements.

1) Regulator Station Rebuilds

The gas transmission and distribution Regulator Station Rebuild program is a key mitigation for: (1) the risk of an Overpressure (OP) event leading to a LOC on downstream assets; and (2) the risk of LOC at the M&C facility. This program includes projects to completely rebuild the station (above and below ground) to replace old and obsolete equipment, valves and piping, upgrade configuration to meet current system needs, and address any

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[5] PG&E defines a farm tap as a facility connected to the high-pressure gas transmission pipeline system that includes regulation equipment to regulator pressure below 60 pounds per square inch gauge and that provides gas service to one or two services. Farm taps are typically installed with HPR-type regulators.

outstanding issues with station maintenance and operations. The criteria for determining the frequency and priority of station rebuilds include, station condition based on age, equipment obsolescence (product and parts no longer supported and available), operational issues identified for equipment and station configuration, maintenance status (high level of corrective maintenance); and modifications required to address changing operational requirements for the station.

2) Regulator Station Component Replacements

The gas transmission and distribution Regulator Station Component Replacements program is a key mitigation for: (1) the risk of an OP event leading to a LOC on downstream assets, and (2) the risk of LOC at the M&C facility. Regulator Station Component Replacement program includes mitigation activities for equipment-related threats related to age and obsolescence, maintenance difficulties, and impaired functional operation. This program includes routine expense and capital projects for gas transmission and distribution regulator stations that arise during normal operation of M&C facilities that must be performed to maintain current levels of service and reliability. Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation, inspection and testing of asset components, and needed modifications to address equipment safety or performance issues.

e. Distribution Mains and Services

For the DMS asset family, the key steady state replacement programs for the LOC on Gas Distribution Main or Service RAMP risk event are the Distribution Pipeline Replacement Programs. These programs include: (1) the Gas Pipeline Replacement Program; (2) the Plastic Pipe Replacement Program; and (3) the Reliability Main Replacement Program.

1) Distribution Pipeline Replacement Programs

These programs address risk drivers Corrosion, Material or Weld – Metallic and Plastic, and Natural Forces and thereby reduce the likelihood of the risk event occurring. Factors for prioritization include age, material type, leak history, cathodic protection, seismic impact, and proximity to the public. PG&E's annual pipeline replacement rate across all three programs has increased from 27 miles in 2010 to 126 miles in 2019. The long-term plan is reaching a deactivation rate for the approximately 26,000 miles of pre-1985 pipe that would limit asset age to 100 years[6] by:

- Continuing to replace high priority steel pipe;
- Increasing replacement rate of pre-1985 Aldyl-A and similar plastic year over year; and
- Completing all identified reliability main replacement for each given year.

3. How Gas Operations Uses Risk Prioritization to Identify Equipment for Replacement

GO mitigates and/or controls identified risks through the following methods:

- Operational changes and restrictions. For example, PG&E might temporarily lower the pressure within the pipeline after performing safety work such as ILI.
- Increased or modified maintenance, monitoring and surveillance. For example, PG&E performs additional leak surveys in areas where clusters of historical leaks have occurred on the gas system.
- Repair, refurbishment or replacement projects. For example, PG&E might replace equipment prior to obsolescence or replace various components within a regulator station.

The integrity management teams for each asset family assess the condition of assets using information from a variety of sources including SAP, preventive and corrective maintenance records, Corrective Action Program,

[6] Gas Distribution Mains and Service Asset Management Plan (GP-1102).

and process hazards analysis.[7] For assets in GO, age is one of many likelihood of failure factors related to asset condition that is considered in asset replacement decisions. Other asset condition factors considered may include corrosion, land movement, and third party damage, for example. Factors such as population density, system reliability, and cost effectiveness are also considered. GO takes a risk based approach to AM and as such the AM/risk framework includes understanding of the data associated with the asset around:

- Material property/physical characteristics of the asset (impacts the likelihood of risk event);
- Geospatial location of the asset (impacts the consequence of risk event); and
- Condition of the asset (impacts the likelihood of risk event).

All of PG&E's GO expense and capital projects/programs are evaluated using the Risk-Informed Budget Allocation (RIBA) prioritization methodology.[8] Each project/program is classified as Mandatory, Compliance, Commitment, Customer Generated (Work Requested by Others), Support, Interdependent, and None. Projects/programs are then assessed for impacts to safety, the environment, and reliability that could be mitigated by the project. The portfolio prioritization process incorporates the RIBA assessment as well as constraints information such as resources and system availability. The asset family owners use this information to make prioritization decisions.[9]

C. Electric Operations

1. Electric Operations Asset Management Strategy Overview

PG&E's Electric Operations (EO) AM vision is to attain the optimum balance of asset risk, performance, and cost. This vision is achieved

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7 A process hazard analysis is a structured approach to identify hazards, understand their consequences, and develop safeguards to prevent or mitigate their effects.

8 As discussed more fully in Chapter 2 (PG&E's Enterprise Risk Management Framework, Section C.4.h), the RIBA scoring methodology is being revised to use the outputs of the quantitative operational risk modeling developed in RAMP to enable consistent data driven, risk informed decision making.

9 See A.18-12-009, Exhibit (PG&E-3), for further information on this process.

through activities associated with the asset objectives created for each asset family. Asset families are groups of similar assets for the purposes of managing PG&E's electric system's physical assets and developing planned approaches to work management and prioritization through a risk-informed strategy. PG&E's EO has nine asset families:

1) Transmission Line Overhead;
2) Transmission Line Underground;
3) Substation;
4) Operational Assets and Systems;
5) Distribution Line Overhead;
6) Distribution Line Underground;
7) Distribution Network;
8) Asset Information; and
9) Streetlights.

AM develops 5-year plans for each asset family, containing plans to achieve asset objectives and include a risk-based approach for managing assets to reduce risk. The asset objectives are drafted based on current conditions and future uncertainties, and ongoing reviews are performed as part of continuous improvement. Where improvement activities impact the AM strategy, changes will be incorporated into strategic plans.

2. Electric Operations Asset Management Programs

PG&E has proactive replacement programs focused on aging or deteriorating distribution assets in the field with reliability impacts in the following asset families:

a) Distribution Line Overhead;
b) Substation;
c) Distribution Line Underground; and
d) Distribution Network.

The long-term vision for these asset families is to improve the overall safety and reliability of the assets through a combination of asset condition understanding, infrastructure improvements, and promotion of a culture that focuses on the long-term safety and reliability of the assets.

While EO strives to establish steady-state replacement strategies and programs, EO's overall AM strategy assesses EO's entire portfolio of risks to achieve risk reductions. As such, EO's AM approach considers several factors (maintenance requirements, replacement requirements, resources, competing priorities) when identifying work plans to manage its risks. For example, achieving risk reduction on EO's top risk, the wildfire risk, may impact ongoing replacement programs if both activities rely on the same resources. The following sections describe current considerations and strategies for key asset replacement programs.

a. Distribution Line Overhead

The Distribution Line Overhead asset family includes key components needed to operate a distribution overhead system, including pole/support structure, primary conductor, voltage regulating equipment, protection equipment, switching equipment, transformers, and secondary conductor.

Long term goals related to ongoing replacements for this asset family include leveraging prioritization models to support identifying priority asset replacements/programs, developing a smooth ramping of asset replacements to minimize spikes in replacements for asset age bubbles, and implementing asset resilience strategies (e.g., wildfire system hardening). Key proactive replacement programs in this asset family include pole replacements and conductor replacement.

1) Pole Replacements

PG&E has approximately 2.3 million poles providing distribution service, including approximately 25,000 non-wood poles. With fire resiliency improvement efforts, non-wood or wood poles wrapped in fire resistant coatings may increase in the future.

PG&E has an extensive condition monitoring program for wood poles in accordance with requirements of General Order 165. Annual patrols in urban areas and bi-annual patrols in rural areas are conducted, visually looking for damaged poles and other defects on the distribution overhead system. Detailed inspections, looking for external damage or deterioration, are performed on assets at varying intervals depending on their High Fire-Threat District (HFTD) designation: every five years for Tier 1/non-HFTD assets, every three years for Tier 2 HFTD facilities, and every year for Tier 3 HFTD facilities. Future inspection cycles may be adjusted to align with new information. Intrusive inspections are also performed approximately every 10 years to identify internal or below ground decay that may be present in the pole.

Historically, PG&E replaces an average of 21,000 wood poles per year for a variety of reasons, including damage or deterioration. Poles are also replaced for projects requiring larger conductor (capacity), installation of covered conductor as part of system hardening, and work at the request of others. During 2019, the number of pole replacements identified through inspections increased as a result of the Wildfire Safety Inspection Program-enhanced inspections. Additionally, poles in good condition, except for decay around the ground line, are identified for reinforcement. Installing a steel truss and banding it to these poles PG&E can restore the strength of the pole to 100 percent (commonly known as pole stubbing).

Ultimately, PG&E strives to minimize wood pole failures and associated outages and remediate degraded wood poles in a timely manner.

2) Overhead Conductor Replacement

PG&E has approximately 81,000 circuit miles of overhead conductor on its distribution system that operate between four kilovolt (kV) to 21 kV, including bare and covered conductors made from aluminum and copper. PG&E monitors the condition of overhead primary conductor through patrols and inspections consistent with General Order 165, and targeted infrared scans. Replacement plans are developed using failure rates obtained through wire down analysis and splice data from the infrared scans.

In 2018, a study was performed to better understand the condition and performance of distribution overhead conductors. The study helped establish a distribution of service life, near-term replacement rate, and long-term steady-state replacement rates. The modeling from the study indicated that a significant year-over-year increase of total replacement length is needed to maintain 2016 outage levels. The results of the study informed PG&E's decision to forecast replacing additional miles of overhead conductor. In the 2020 GRC, PG&E forecast replacing an average of 97.3 miles annually from 2020-2022, compared to approximately 47 miles of overhead conductor replaced in 2017. Future replacement rates will also leverage the study results.

PG&E's strategy for replacing overhead conductor targets primary conductor that poses a high risk of failure in non-HFTD areas. Planned replacements to maintain or improve reliability, however, may not be fully executed due to higher priority work, such as safety/emergency or compliance-related work. Additional proactive replacements will occur as part of PG&E's System Hardening program, where bare overhead primary conductor will be replaced with covered conductor to reduce wildfire risk in HFTDs areas.[10] System Hardening related replacements will currently focus on Tier 2 and Tier 3 HFTD areas. PG&E plans to replace approximately 1,000 circuit miles of overhead conductor, as part of System Hardening from 2020-2022. Some of the conductor replaced in Tier 2 and Tier 3 HFTD areas would have otherwise been identified for replacement as a result of annealing or deterioration. Ultimately, PG&E strives to replace deteriorated conductor, reduce conductor failures, and reduce the possibility of wildfire as a result of energized conductor falling to the ground.

b. Substation

The substation asset family consists of equipment forming the electric network that interconnects electric generation, transmission, and distribution systems throughout PG&E's territory. Equipment in this asset family includes substation facilities, transformers and voltage regulators, circuit breakers and switchgear, switches, batteries, reactive equipment, grounding systems, bus structures, and energy storage.

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10 More information about conductor replacement as it relates to the Wildfire risk can be found in Chapter 10.

Long term goals related to ongoing replacements for this asset family include initiatives to better understand asset failures and asset life expectancy.

Substation equipment may be replaced for a variety of reasons, including equipment failure, equipment reaching the end of its useful life, operational performance issues, not meeting current operational or cybersecurity standards, replacement parts becoming obsolete or unavailable, or excessive cost of maintenance. The majority of substation equipment replacement projects involve more than just the in-kind replacement of a single piece of equipment with a like-for-like piece of equipment. For instance, the newer equipment may be manufactured with different dimensions or operating specifications, requiring relocation of other existing equipment and installation or replacement of ancillary equipment. Additionally, when PG&E replaces equipment, it may make engineering and economic sense to upgrade or add other equipment to improve reliability, enhance public safety, or bring up to current standards. For example, PG&E may upgrade associated connectors, switches, and communication equipment, when replacing a substation circuit breaker or transformer. This approach of work bundling results in efficient execution of work, lowering the replacement cost of the associated assets.

PG&E's substation asset replacement program includes replacing various types of major and minor equipment within this asset family, including transformers, circuit breakers and switchgear.

PG&E has 760 distribution substations in its electric system. Substations are facilities containing assets and infrastructure used to transform voltage from one level to another. Other electric facilities exist that are used for switching purposes only, for power generation and/or third-party service. Transformers, circuit breakers switchgear, and other assets reside within substations.

Transformers convert higher voltages of electricity to distribution/utilization voltages for delivery to customers. PG&E maintains an inventory of approximately 2,200 distribution substation transformers throughout its service territory. PG&E identifies, prioritizes and replaces transformers that are near the end of their useful lives and are at high risk of failure. A condition-based assessment of substation equipment through monitoring, testing and inspection is used to prioritize replacements. In addition to proactive planned replacement based on asset health indices, PG&E replaces transformers to provide increased capacity, and performs emergency replacements based on actual or imminent in-service failures.

Circuit breakers automatically interrupt the flow of electricity in the event of a problem, such as a short circuit or circuit overload. Including substation switchgear breakers, PG&E has approximately 5,200 circuit breaking units. Circuit breaker replacements include a combination of proactive planned replacements and emergency replacements. Planned replacements are based on asset health indices, capacity additions or replacements included during bus upgrades. Circuit breakers can also be replaced as part of larger substation projects or on an emergency basis for in-service or imminent in-service failures. Substation circuit breakers are identified and prioritized by developing a health index for the distribution circuit breakers throughout the PG&E service area. Key factors included in the health index are: asset age, overstress (if any), failure, obsolete parts, oil analysis and maintenance and operating history.

c. Distribution Line Underground

The distribution line underground asset family consists of underground cables, line equipment, and transformers.

Long term goals related to ongoing replacements for this asset family include replacing all remaining primary Paper Insulated Lead Covered (PILC) cables, replacing all oil-filled switches with solid dielectric switches, and leveraging technological advances to develop condition-based replacement programs with appropriate replacement rates. Key proactive replacement programs in this asset family include: primary cable replacements and oil switch replacements.

1) Primary Cable Replacements

Excluding network cables, the distribution underground primary cable asset class is comprised of over 26,000 circuit miles of cable. Cables are categorized by the following insulation types, along with their typical deployment periods:

- PILC – Primarily installed for use in both San Francisco and Oakland network systems as early as the 1920s, up to the present, in certain circumstances where underground conduit constraints exist.
- High Molecular Weight Polyethylene (HMWPE) – Deployed from the early 1960s through the 1980s.
- Cross-Linked Polyethylene (XLP) – Installed from the early 1960s through the late 1990s.
- Ethylene Polypropylene Rubber (EPR) – Deployed from the late 1990s to the present.

The majority of these underground cables are installed in urban and suburban areas throughout the service territory. Most PILC cables in PG&E's system are located in PG&E's San Francisco and East Bay Divisions, while EPR cable is used for most new installations systemwide.

Cables are replaced by re-pulling new cable within the existing infrastructure, or by trenching or boring to install new underground facilities where replacement in-place is not feasible or cost effective. Cable replacement projects may also include upgrading switches, transformers, enclosures, and other associated equipment. In some cases, cable targeted for replacement is evaluated using cable testing or rejuvenation to determine whether a more cost-effective alternative would be effective for all or part of the project.

Cable replacements are prioritized based on age and type of cable, or a combination of these factors and other influences. When possible, PG&E's Reliability Related Cable Replacement Program leverages the results of diagnostic testing to further prioritize the replacement of poor performing primary cable sections. Cables tested with neutral deterioration are prioritized higher for replacement. PG&E's replacement strategy focuses on cable sections that are failing at higher rates (e.g., HMWPE). In the 2020 GRC, from 2020-2022, PG&E forecast replacing 24 miles of HMWPE cable, 21 miles of XLP and other cable, and 15 miles of PILC.

PG&E's strategy also includes reactive replacement for all failed cable. Mainline cables are primarily replaced under the Emergency Program, while local loop cables are typically replaced under the Critical Operating Equipment Cable Replacement Program. Underground cable is also replaced as part of Capacity program if there is an overload, or current exceeds the current rating, and in PG&E's Emergency and Maintenance programs. Ultimately, PG&E strives to proactively replace primary cables to maintain the current failure rate and overall system reliability.

2) Load Break Oil Rotary Switch Replacements

Line switches are used to interconnect, sectionalize, and transfer load between circuits. Load Break Oil Rotary (LBOR) switches are a type of switch that are manually operated and oil-filled that use solid blade mechanisms immersed in oil to break or make loads. There is no easy or efficient way to properly inspect the oil level and test the quality of the insulating oil for LBOR switches. As these switches age, the strength and quality of the insulating oil becomes suspect and can potentially be a safety hazard for PG&E personnel. PG&E has approximately 13,300 LBOR switches in its service territory.

In 2014, PG&E began replacing LBOR switches. PG&E's LBOR replacement program primarily focuses on switches manufactured prior to 1975 without oil inspection sight glasses. However, switches manufactured after 1975 may also be replaced when inspection and condition assessments indicate such work is necessary. In the 2020 GRC period, PG&E plans to replace 90 pre-1975 LBOR switches annually. Ultimately, PG&E strives to eliminate oil-filled switchgear from the distribution system.

d. Distribution Network

The distribution network asset family is composed of network transformers and network protectors serving customers in the San Francisco Financial District and downtown Oakland.

Long-term goals associated with ongoing replacement programs include maintaining or decreasing in-service failure rates and developing a smooth ramping up of asset replacements that minimizes spikes in replacements for asset age bubbles. Key proactive replacement programs in this asset family include: targeted replacements of network transformer and network protectors, and network cable replacement and switch installations.

1) Targeted Replacements of Network Transformer and Network Protectors

Network transformers are used to step primary voltages down to service voltages. Network protectors are designed to automatically isolate faults in order to prevent service interruptions on the network. PG&E has a total of 1,392 network transformers, including 94 transformers located in high-rise buildings, and a total of 1,385 network protectors.

Some transformers in high-rise buildings are oil-filled, posing a fire risk. In 2010, PG&E began replacing oil-filled transformers with dry-type transformers to minimize fire risks and increase safety. PG&E plans to replace all oil-filled network transformers in its service territory by the end of 2022. Network oil-filled transformer replacements are included in a mitigation to the Failure of Electric Distribution Network Assets risk.[11]

PG&E also makes condition-based replacements for equipment in this asset family. PG&E routinely monitors the condition of its network transformers and network protectors through inspections and oil sampling. Equipment found with deteriorated conditions are flagged for replacements. Condition-based replacement is a

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[11] See Chapter 12 for more information on the Failure of Electric Distribution Network Assets risk.

continuous effort to ensure safe and reliable operation of the equipment. Condition-based replacements are also included as a control to the Failure of Electric Distribution Network Assets risk.[12]

Ultimately, PG&E strives to minimize in-service failure, work towards fully deployed condition-based maintenance, and identify a reasonable life cycle plan for these assets.

2) Network Cable Replacement and Switch Installations

PG&E's networked distribution systems consist of 188 circuit miles of cable in 12 network groups, ten in San Francisco and two in Oakland. PG&E performs systematic replacement of network cable assets and installation of switches in downtown San Francisco and Oakland networks. Many of the existing network primary and secondary cables date from the 1920s to the 1960s and are nearing the end of their useful life. The network systems replacement program is an on-going program that started in 2011. The program work includes replacing primary and secondary cables, modifying network transformers to accept the new primary cables, and installing switches. PG&E is installing switches at the same time cables are replaced to meet operational requirements by providing a switching location outside the substation to establish feeder clearance points. PG&E plans to proactively replace additional network cable as part of a new mitigation.[13]

3. How Electric Operations Uses Risk Prioritization to Identify Equipment for Replacement

PG&E's EO Risk Management Program is consistent with PG&E's Integrated Planning process. PG&E develops an active list of risk profiles, quantifies risks, maps each risk driver, control, and consequence affecting the risk, develops mitigations to promote risk reductions, and establishes key performance indicators or metrics to monitor risk performance. In order

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[12] See Chapter 12 for more information on the Failure of Electric Distribution Network Assets risk.

[13] See Chapter 12 for more information on the Failure of Electric Distribution Network Assets risk.

to inform work prioritization, EO performs a RIBA analysis to characterize risks based on a number of factors and utilizes additional prioritization frameworks and tools to help prioritize its work.[14]

The RIBA process evaluates projects and programs from a safety, environmental, and reliability risk perspective to assess the degree of relative risk exposure and impact being addressed. Other factors are also incorporated into the evaluation to inform capital investment decisions, including, but not limited to, compliance requirements and project inter-dependencies. RIBA scores are assigned to approved projects or programs. The RIBA scores for the EO portfolio of work are used to support creation of or adjustments to the capital investment plan that meets the most critical demands of the electric distribution system, consistent with available resources and operational performance requirements.

Following the 2017 and 2018 wildfires, EO instituted an additional risk prioritization framework to prioritize fire ignition prevention work within the EO portfolio. The framework evaluates whether programs and projects prevent fire ignitions (highest priority), have strong links to safety (medium to high priority), or have a low safety risk (lowest priority). These inputs were used in conjunction with EO's newly-designed circuit-based approach, which was developed to prioritize work starting in 2020. The circuit-based approach applies to distribution line, transmission line and substation work and optimizes the work within EO portfolio by value, risk ranking, and resource availability to develop a work plan targeting the highest priority activities on the circuits with most risk.

PG&E continues to improve risk models for both distribution and transmission. This continuous improvement aims to model probability and consequence at the asset level, forecast risk and inform planned mitigations. This also enables the prioritization of work based on these forecasted risk reductions. As new data becomes available and the environment in which

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14 As discussed more fully in Chapter 2 (PG&E's Enterprise Risk Management Framework, Section C.4.h), the RIBA scoring methodology is being revised to use the outputs of the quantitative operational risk modeling developed in RAMP to enable consistent data driven, risk informed decision making.

PG&E operates continues to change, EO will continue to evolve its risk management and prioritization.

D. Generation

1. Generation Asset Management Strategy Overview

Generation's AM Program provides a systemwide look into the condition of the generation equipment and proposes projects and/or changes to operations and/or maintenance practices to ensure that Generation's long-term investment plan maintains or reduces risk and maintains or improves the safety and reliability of the generation portfolio.

2. Generation Asset Management Programs

a. Hydroelectric

PG&E has 105 hydroelectric generating units at 66 powerhouses with a generating capacity of 3,890.6 megawatts (MW). PG&E has a hydroelectric AM Program that includes most of the equipment used for hydroelectric generation.

Equipment and systems associated with water storage and conveyance and with the power train are considered key operating equipment in the hydroelectric AM program.

b. Fossil and Solar

PG&E has three fossil-fuel generating stations that are between ten and 11 years old. These three generating facilities have a combined maximum normal operating capacity of 1,400 MW. These units have an expected life of 30 years and the major components are currently covered by long-term service agreements with the original equipment manufacturer for the major components of the power train. PG&E is guided by the Commission's operations and maintenance (O&M) standards (General Order 167) and uses a high energy piping (HEP) standard to help assure the stations are safely maintained.

PG&E also has ten solar photovoltaic generating facilities. The majority of these sites are less than nine years old. PG&E has a program in place to repair or replace the inverters and to replace panels as they fail.

Major components necessary to provide safe and reliable service are proactively replaced, repaired or refurbished.

c. Nuclear

PG&E has one nuclear generating facility, the Diablo Canyon Power Plant (DCPP), located nine miles northwest of Avila Beach in San Luis Obispo County. DCPP consists of twin pressurized water reactors, Units 1 and 2, rated at a nominal 1,122 MW and 1,118 MW, respectively. DCPP Units 1 and 2 began commercial operation in May 1985 and March 1986, respectively, and are licensed by the Nuclear Regulatory Commission (NRC) to operate until November 2, 2024 and August 26, 2025. PG&E has a robust NRC-required maintenance (AM) program where major components necessary to provide safe and reliable service are monitored, tested, and proactively replaced or refurbished in accordance with NRC regulations. PG&E does not plan to operate DCPP past its current NRC license expiration dates.[15]

3. How Power Generation Uses Risk Prioritization to Identify Equipment for Replacement

PG&E takes a risk informed approach to AM for Generation. PG&E quantifies risks using the Enterprise Risk Management process, which includes enterprise risks such as a large uncontrolled water release or a nuclear core damaging event. Following that process, PG&E performs a RIBA analysis to characterize risks based on several factors. The RIBA process is used to evaluate projects and programs from a safety, environmental, and reliability perspective to assess the degree of relative risk exposure and impact being addressed.[16] The purpose of a RIBA score is to capture on a relative basis the safety, environmental and reliability risks that each project or program in Generation aims to prevent, based on the worst direct reasonable impact or event that the work activity mitigates. In

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[15] The Commission has approved a retirement plan for DCPP (Decision 18-01-022).

[16] As discussed more fully in Chapter 2 (PG&E's Enterprise Risk Management Framework, Section C.4.h), the RIBA scoring methodology is being revised to use the outputs of the quantitative operational risk modeling developed in RAMP to enable consistent data driven, risk informed decision making.

addition to safety, environmental and reliability risks, other factors including, but not limited to, the RIBA classification, justification and project inter-dependencies are incorporated into the evaluation to inform investment decisions.

All approved projects or programs have RIBA scores. The RIBA process is used to aggregate the individual project and program risk assessments to support creation of or adjustments to the investment plan. The following sections describe considerations and strategies for key asset replacement programs.

a. Hydroelectric Asset Management Practices and Programs

1) Hydroelectric Asset Management Practices

PG&E employs the following process to identify and ultimately mitigate the risks associated with PG&E's hydroelectric assets:

a) Asset Registry

PG&E uses equipment records in SAP Work Management to track the key characteristics and nameplate data for each hydro asset. These records provide the foundation for maintenance planning, AM and engineering.

b) Design and Performance Criteria

For each hydro asset type, PG&E develops technical documents which contain design and performance criteria. While design criteria are used primarily for new equipment, performance criteria are used to assess existing equipment, providing a technical threshold against which to measure assessment results.

c) Assessment Standards

For each hydro asset type, PG&E develops technical documents which contain assessment standards and procedures. Such standards and procedures (based on industry best-practices and regulations) explain how and when each asset type should be assessed.

d) Assessments

In line with its assessment standards and procedures, PG&E conducts tests and inspections across its fleet of hydro assets. For each asset type, there are often numerous types of tests and inspections, each with its own required frequency, as outlined by the assessment standard/procedure. Assessment results are analyzed and interpreted, and corresponding condition indicators are logged in SAP that is linked directly to each equipment record.[17]

e) Quantification of Asset Risk

Based on its assessment results and condition indicators, PG&E's AM team calculates risk scores for each key piece of hydro equipment. Risk scores consist of health scores (which are a proxy for the probability of failure) and consequence scores (which are a proxy for the consequence of failure). Taken together, PG&E can quantify the risk of its respective hydro assets. Risk scores are logged in Excel Workbooks on a secure SharePoint site.

f) Asset Risk Mitigation/Control

PG&E mitigates and/or controls identified risks through the following methods:

- Operational changes and restrictions. For example, where appropriate PG&E will temporarily lower the flow in a leaking canal or institute a no-run-zone on a hydro unit with vibration problems.
- Increased or modified maintenance, monitoring and surveillance. For example, where appropriate PG&E will install instrumentation near a penstock to monitor ground movement.
- Repair, refurbishment or replacement projects. For example, where appropriate PG&E will replace a

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17 SAP is used for the penstock program and powertrain programs. The dams and water conveyance program assessment results are tracked separately.

highly-deteriorated (due to cavitation or corrosion) turbine runner, or it might re-line a degraded section of canal.

2) Hydroelectric Asset Management Programs

a) Storage and Conveyance

The assets in this category have long service lives and are not routinely replaced. PG&E's focus regarding storage and conveyance assets is centered around on-going maintenance and mitigations to assure the assets are safe and reliable for employees and the public and meet all regulatory requirements.

PG&E's water storage and conveyance systems consist of dams, reservoirs, tunnels, canals, flumes, siphons, and penstocks, which enable PG&E to transport and store runoff and aquifer flows to the hydro powerhouses to allow for flexible generation. Additionally, the conveyance and storage systems meet critical water storage and delivery requirements, for purposes of water conservation, fish and wildlife habitat protection and enhancement, domestic water usage, recreational water requirements, irrigation district and agricultural water needs, and natural resource protection. The system collectively includes the following approximate number of, or miles of, support infrastructure: 98 reservoirs, 73 diversions, 170 dams (68 large dams[18] and 103 small dams), 173 miles of canals, 43 miles of flumes, 132 miles of tunnels, 65 miles of pipe (penstocks, siphons, and low head pipes), four miles of natural waterways, and approximately 140,000 acres of fee-owned land.

i) Dams

Dams are routinely maintained with mitigations to address any issues that develop, and not typically replaced.

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18 The Federal Energy Regulatory Commission (FERC) classifies large dams as those dams with a height of greater than 33 feet. Dams less than 33 feet high, but that are classified by FERC as high or significant hazard are treated as large dams and must comply with the Part 12 regulations. (18 Code of Federal Regulations (CFR) Part 12D).

PG&E's dams are associated with the Enterprise Risk, Large Uncontrolled Water Release. The dam safety program is regulated by the State of California Department of Water Resources, Division of Safety of Dams (DSOD) and the FERC. The following includes the AM approach to dams:

- Routine observations by trained Hydro O&M personnel;
- Regular inspections by qualified engineers in PG&E's Dam Safety Program;
- Regular regulatory inspections by the FERC and DSOD based on dam hazard classification;
- Five-year Independent Consultant Safety Inspections in accordance with 18 CFR Part 12D;
- Engineering evaluations of dam stability, seismicity, spillway design capacity, and other design and operational issues as conditions and engineering guidelines evolve; and
- Major repairs are infrequent, but can require high cost (~$20-$100 million) projects.

ii) Penstocks

Penstocks are typically repaired or refurbished, not replaced, based on condition and consequence of failure. PG&E utilizes a condition, risk and economic-based approach to AM. The following includes the AM approach to penstocks:

- Routine O&M patrols may yield emergent maintenance/repair performed as-needed;
- Detailed inspection by subject matter experts and non-destructive examination inspections;
- Inspection frequency is based on penstock risk; and
- Replacement is usually not cost effective.

iii) Water Conveyance

Water Conveyance assets are typically repaired or refurbished, not replaced, based on condition and consequence of failure. PG&E utilizes a condition, risk and economic-based approach to AM. The following includes the AM approach to water conveyance:

- Major repair project prioritization based on locational health and consequence of failure scores, determined through five-year AM condition assessments;
- Conveyance relining costs are decreasing as several high consequence sites have been addressed in recent years; and
- Routine maintenance is performed by O&M based on findings from monthly patrols.

b) Power Train

The assets in this category are replaced or refurbished based on condition, reliability requirements, and economics.

i) Turbines

PG&E utilizes a condition, reliability and economic-based approach to AM. The following includes the AM approach to turbines:

- Turbine replacement or refurbishment decisions are based on current condition of the equipment, safety and powerhouse economics;
- Typical inspections and tests are performed every five to eight years depending on previous condition assessments; and
- Weld repairs are performed periodically during annual outages for life extension.

ii) Generators and Rotors

PG&E utilizes a condition, reliability and economic-based approach to AM. The following includes the AM approach to generators and rotors:

- Generator performance testing and modeling every five years per Western Electricity Coordinating Council requirements;
- Physical inspection occurs during outages and stator insulation testing is performed annually; and
- Life extension through stator rewinds and rotor cleaning or refurbishment based on asset condition.

PG&E has plans to rewind several generator stators and the associated generator rotors will be cleaned or refurbished over the next few years.

iii) Transformers

PG&E utilizes a condition and risk-based approach to AM. The following includes the AM approach to transformers:

- Visual inspections and oil testing are conducted annually. Offline electrical testing is done every five years. More extensive assessments are conducted if warranted by the condition of the transformer.
- Replacement or refurbishment typically address deteriorating oil quality, paper insulation, or leaks in the transformer bank.
- PG&E has plans to replace or refurbish several transformers over the next few years.

b. Fossil Asset Management Practices and Programs

PG&E's fossil AM practices and programs are guided primarily by the Commission's O&M standards (General Order 167) and the PG&E fossil generation High Energy System Safety Program (HESSP) standard.

1) O&M Standard

General Order 167 sets forth standards that govern the O&M of power plants. The purpose of General Order 167 is:

> …to implement and enforce standards for the maintenance and operation of electric generating facilities and power plants so as to maintain and protect the public health and safety of California

> residents and businesses, to ensure that electric generating facilities are effectively and appropriately maintained and efficiently operated, and to ensure electrical service reliability and adequacy.[19]

The standards set forth in General Order 167 include operation standards, maintenance standards, and logbook standards. PG&E accomplishes compliance with General Order 167 through the use of various internal controls, and through audits by the CPUC. General Order 167 was set in place post energy crisis by the CPUC to enforce prudent practices in the availability of the fossil fleet for California.

2) Fossil Generation HESSP Standard

This standard provides the requirements for inspecting, conducting analysis, managing associated mitigation, and corrective actions for PG&E's fossil generation HESSP, which includes HEP and high energy fixed equipment. This program monitors HEP systems for integrity and safety while meeting the requirements of the American National Standards Institute/American Society of Mechanical Engineers B31.1, Power Piping, Appendix V Section V-6.0 and other codes for high energy fixed equipment.

HEP systems are normally considered to include the main steam, reheat (both hot and cold), bypasses, feedwater (high pressure and low pressure), blowdown lines, drain lines, vent lines, and extraction steam piping.

High energy fixed equipment includes heat recovery steam generators, boiler drums, blowdown tanks, economizers, evaporators, attemperator, condenser, deaerator, and other balance of plant pressurized equipment, such as air receivers, ammonia tanks, and gas filters.

c. Nuclear Asset Management Practices and Programs

Nuclear generation has classified the operating equipment at its nuclear generating station and applied testing, maintenance, and

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[19] CPUC, General Order 167, Section 1.0 Purpose.

replacement strategies reflective of a zero-tolerance for critical equipment failures.

1) Equipment Reliability Process

The nuclear generation equipment reliability process integrates a broad range of activities into one process. Using this process, personnel evaluate important plant equipment, develop and implement long-term equipment health plans, monitor equipment performance and condition, and adjust preventive maintenance tasks and frequencies based on equipment operating experience. This process includes activities such as:

- Reliability-centered maintenance—optimized maintenance plans that are established based on systematic evaluation of the safety and operational consequences of each failure and degradation mechanism that causes the failures;
- Preventive maintenance (PM), periodic, predictive (PdM), and planned—maintenance performed either periodically, or based on observed conditions, that ensures the equipment will continue to meet its design requirements without failure;
- Surveillance and post-maintenance testing—assures equipment that will be relied upon is capable of performing its design function;
- Lifecycle management planning—integrates aging management and economic planning for optimized operation, maintenance and service life of equipment to maintain acceptable performance and safety;
- Equipment performance and condition monitoring—performance monitoring over time that detects performance degradation and need for maintenance before a failure occurs;
- Internal and external operating experience assessment—formalized process of reviewing industry and station equipment experience to identify equipment reliability vulnerabilities and address them before a failure occurs; and
- Maintenance Rule evaluation—regulated process to ensure that reliability of equipment important to safety is maintained and

causes of unacceptable performance are investigated and corrected.

2) Equipment Reliability Classification

The equipment reliability classification (ERC) is established, using industry-standard criteria, to identify the equipment in one of the four following categories:

- Critical – failure can cause such results as a reactor trip, power transient greater than 20 percent, complete loss of nuclear heat removal, or complete loss of vital AC power;
- Important Non-Critical – failure can cause results such as an unplanned power reduction greater than 2 percent, a power transient of 2 percent to 20 percent, or loss of a redundant safety feature;
- Economic Non-Critical – failure can cause unplanned power reduction less than 2 percent, or is required to meet North American Electric Reliability Corporation, FERC or insurance requirements, emergency response equipment, or has been found to be more cost-effective to maintain than to allow failure;
- Run-to-Maintenance – equipment that does not fall into the above categories that can be run until corrective maintenance is required; and
- Exempt – equipment includes those that are operationally insignificant, highly reliable, or largely passive.

The equipment reliability for each objective guides the development of the reliability strategies for that component as shown in Table 21-1 below:

TABLE 21-1
NUCLEAR EQUIPMENT RELIABILITY CLASSIFICATION

Line No.	ERCs	Objectives	Strategies
1	Critical	Early detection of incipient failures. Failures are rare.	Level of PM/PdM ensures incipient failures are detected and all failures are prevented wherever practical. Inventory management (spare parts strategy). AM (develop long term strategy). Implement cost effective design changes to avoid single point functional failures. Maintenance strategies maximize reliability and availability, and minimize possible failures caused by infant mortality and human error. Plant resources are applied first to protecting these components from failure.
2	Important Non-Critical	Few failures are expected.	Level of PM/PdM ensures few failures and that all performance criteria are met. AM (develop long term strategy). The condition of these components is not allowed to degrade simply because there may be redundancy in design. Maintenance strategies and the level of resources applied ensure components meet required levels of performance.
3	Economic Non-Critical	Most component failures are prevented. PM strategies ensure that industry requirements are met. Prescribed strategies are more cost effective than an RTF strategy.	Simple and effective PM tasks performed to extend useful life.
4	Run-to-Maintenance	Failures can be tolerated.	PM or PdM not performed. Repair or replacement of these components on a corrective or elective basis is the most cost-effective maintenance strategy. Plant resources will not be expended to prevent failures.
5	Exempt	Failures are not expected. Exempt from analysis of consideration of preventive or predictive maintenance.	Exempting highly reliable or operationally insignificant components permits a more focused effort on components which merit most attention. Components may fall under plant programs other than PM.

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

RAMP ACRONYM LIST

RAMP ACRONYM LIST
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

A

ACSR	Aluminum Conductor Steel-Reinforced
AM	Asset Management
API	American Petroleum Institute
ARB	Air Resources Board **(see CARB)**
ARMA	Association of Records Managers and Administrators
ASME	American Society of Mechanical Engineers
ATWACC	After Tax Weighted Average Cost of Capital

B

BC Hydro	**BC Hydro and Power Authority** is a Canadian electric utility in the province of British Columbia, simply known as **BC Hydro**
BDB	Beyond Design Basis

C

49 CFR	Title 49 of the Code of Federal Regulations – Transportation
C&P	Compression & Processing **or** Compression and Processing
C/Mins	customer minutes
CalGEM	California Geologial Energy Management
CAP	Corrective Action Program
CARB	California Air Resources Board
CDL	commercial driver's license
CDLA	Class A Commercial Driver's License
CDSE	Chief Dam Safety Engineer
CE	Cause Evaluation
CEC	California Energy Commission
CEMA	Catastrophic Event Memorandum Account
CEO	Chief Executive Officer
CERP	Company Emergency Response Plan
CFR	Code of Federal Regulations
CMI	Customer Minutes of Interruption
CNG	Compressed Natural Gas (can be used as lowercase)
COE	Critical Operating Equipment
CoRe	Consequence of Risk Event
COVID-19	Coronavirus
CPUC or Commission	California Public Utilities Commission
CRESS	Corporate Real Estate Strategy and Services
CRO	Chief Risk Officer
CRR	Corporate Risk Register
CSF	Cybersecurity Framework
CSO	Customer Service Office

CSTI	California Specialized Training Institute
CUE	Coalition of Utility Employees
CVA	Climate Vulnerability Assessment
CWSP	Community Wildfire Safety Program

D

D.	Decision
D-Line	Distribution Line
DA	Direct Assessment
DART	Days Away, Restricted and Transferred
DASH	Daminfo Automated Seismic Hazard
DCD	Downed Wire Detection
DCPP **or** DCNPP	Diablo Canyon Power Plant **or** Diablo Canyon Nuclear Power Plant
DFA	Distribution Fault Anticipation
DIMP	Distribution Integrity Management Program
DMS	Distribution Mains and Services
DMV	Department of Motor Vehicle
DOCP	Distribution Overhead Conductor – Primary
DOH	Distribution Overhead
DOT	Department of Transportation **or** U.S. Department of Transportation
DSOD	Division of Safety of Dams
DSP	Dam Safety Program
DTS-FAST	Distribution Transmission Substation—Fire Action Scheme and Technology

E

E&R	Engineering and Risk
EAP	Emergency Action Plan
EAP	Employee Assistance Program
ECA	Engineering Critical Assessment
ECISSP	Electrically-Connected Isolated Steel Service Program
EF	Equivalent Fatalities
EHS	Environmental and Health and Safety
EIR	Electric Incident Report
EO	Electric Operations
EOC	Emergency Operations Center
EORM	Enterprise and Operational Risk Management
EP&R	Emergency Preparedness and Response
EPH	Enterprise Performance Huddle
EPR	Ethylene Polypropylene Rubber (can be used as lowercase)
ERC	equipment reliability classificiation
ERIM	Enterprise Records and Information Management

RAMP ACRONYM LIST
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

ERR	Enterprise Risk Register
ESMS	Enterprise Safety Management System
EVM	Enhanced Vegetation Management
EWT	Early Warning Technologies

F

FAA	Federal Aviation Administration
Fd	Force of water
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FFD	Fitness for Duty (can be used as lowercase)
FIA	Fire Index Area
FIMP	Facility Integrity Management Program
FMEA	Failure Modes and Effects Analysis
FPI	Fire Potential Index

G

GCC	Gas Control Center
GD-GIS	Gas Distribution Geographic Information System
GDL	Guidance Document Library
GMC	ground motion characterization
GO	Gas Operations
GO	General Office **or** General Order
GOES	Governance Oversight Execute Support
GPRP	Gas Pipeline Replacement Program
GPS	Global Positioning System **or** Geographic Positioning System
GRC	General Rate Case
GT	Gas Transmission (can be used as lowercase)
GT&S	Gas Transmission and Storage

H

HCA	High Consequence Area
HEP	High Energy Piping
HFTD	High Fire Threat District
HMWPE	High Molecular Weight Polyethylene **or** High Molecule Weight Polyethylene
HPR	High-Pressure Regulator (can be used as lowercase)
HR	Human Resources
HSSP	High Energy System Safety Program

I

IAM	Identity and Access Management

RAMP ACRONYM LIST
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

ICS	Incident Command System **or** Incident Command Structure
IGMM	Information Governance Maturity Model
ILI	In-Line Inspection
IMT	Incident Management Team
IOU	Investor-Owned Utility (can be used as lowercase)
ISN	ISNetworld
ISO	International Standards Organization
ISRMP	Integrated Seismic Risk Management Program

J

K

L

LFHC	low-frequency/high consequence
LiDAR **or** LIDAR	Light Detection and Ranging
LNG	Liquefied Natural Gas (can be used as lowercase)
LNT	linear no dose threshold
LOB	Line of Business (can be used as lowercase)
LOBs	Lines of Business (**do not define Lines of Business—use LOB above**)
LOC	loss of containment
LoRe	Likelihood of a Risk Event
LTIP	Long-Term Incentive Plan
LTSP	Long-Term Seismic Program **or** Long Term Seismic Program
LVCR	Large Volume Customer Regulator

M

M&C	Maintenance and Construction
M&C	Measurement & Control **or** Measurement and Control
MAOP	Maximum Allowable Operating Pressure
MARS	Multi-Attribute Risk Score (can be used as lowercase)
MAVF	Multi-Attribute Value Function (can be used as lowercase)
MOC	Management of Change
MPP	Meter Protection Program
MSD	Musculoskeletal Disorder (can be used as lowercase)
MVS	Motor Vehicle Safety
MVSI	Motor Vehicle Safety Incident
MW	megawatt
MW	Mitigation Effectiveness workpapers

N

NCL	Nurse Care Line

RAMP ACRONYM LIST
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

NERC	North American Electric Reliability Corporation
NESE 100	Near 100 year storm event
NIST	National Institute of Standards and Technology
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
NWS	National Weather Service

O

O&M	operations and maintenance (should be lowercase unless it is a Dept.)
ODN	Operational Data Network (can be used lowercase)
OIR	Order Instituting Rulemaking
OP	Over Pressure
OPP	Over Pressure Protection
OSA	Office of Safety Advocate
OSHA	Occupational Safety and Health Administration

P

PAR	Population at Risk
PdM	Predictive maintenance
PRA	Probabilistic Risk Assessment
PRC	Public Resource Code
PSPS	Public Safety Power Shutoff
PSPs	Public Safety Plans
PSS	Public Safety Specialists
PVMI	preventable motor vehicle incident

Q

R

R.	Rulemaking
RAMP	Risk Assessment and Mitigation Proceeding
RCC	Risk and Compliance Committee
REFCL	Rapid Earth Fault Current Limiter
REM	Roentgen Equivalent Man
RFW	Red Flag Warnings
RIBA	Risk Informed Budget Allocation **or** Risk-Informed Budget Allocation
RIM	Records and Information Management
RMC	Risk Management Community
RO	Regulated Output

RAMP ACRONYM LIST
GLOSSARY OF ACRONYMS AND ABBREVIATIONS

ROW	Right-of-Way (can be used as lowercase)
RP	Recommended Practice
RSE	Risk Spend Efficiency
RTU	Remote Terminal Unit

S

SAMA	Severe Accident Mitigation Alternative
SAP	Systems Applications and Products **(should <u>not be spelled out</u> unless we get an approval from the case manager)**
SCADA	System Control and Data Acquisition
SCC	Stress Corrosion Cracking
scfh	standard cubic feet per hour
SED	Safety and Enforcement Division
SERA	System Earthquak Risk Assessment
SGF	Sensitive Ground Fault
SHED	Safety, Health, ECAP, DOT
SIF	Serious Injury or Fatality **or** Serious Injuries or Fatalities **or** Serious Injury and Fatality
SIPT	Safety and Infrastructure Protection Teams
SLD	Safety Leadership Development
SLR	Sea level rise
S-MAP or SMAP	Safety Model Assessment Proceeding
SME	Subject Matter Expert (can be used as lowercase)
SMYS	Specified Minimum Yield Strength
SNO	Safety and Nuclear Operations **or** Safety and Nuclear Oversight
SOPP	Storm Outage Prediction Program **or** Storm Outage Prediction Project
SPRA	Seismic Probabilistic Risk Assessment (can be used as lowercase)
SQWF	Skilled and Qualified Workforce
SSC	seismic source characterization
STIP	Short-Term Incentive Plan
SWN	Send Word Now

T

TIL	Technical Information Library
TIMP	Transmission Integrity Management Program
TS	Transportation Services
TURN	The Utility Reform Network
TVMR	Transmission Vegetation Management Reliability

U

UAM	Underground Asset Management
UG	Underground
USGS	U.S. Geological Survey **or** United States Geological Survey

V

VP	Vice President
VST	Vehicle Safety Technology

W

WBT	web-based training
WELL	Well Integrity Management Plan
WHO	World Health Organization
WRO	Work Required by Others
WROF	Weather-Related Outside Force
WSAC	Weekly Situational Awareness Calls
WSD	Wildfire Safety Division
WSIP	Wildfire Safety Inspection Program
WSOC	Wildfire Safety Operations Center
Wt	warning time

X

XLP	cross-linked polyethylene

Y

Z