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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation Into the November 2017 Submission of Pacific Gas and Electricity Company's Risk Assessment and Mitigation Phase.	Investigation 17-11-003 (Filed November 9, 2017)

2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT
OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 M)

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Dated: November 30, 2017

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In compliance with California Public Utilities Commission (Commission or CPUC) Decisions (D.) 14-12-025 and 16-08-018, and the Commission's Rules of Practice and Procedure, Pacific Gas and Electric Company (PG&E or the Company) respectfully submits its 2017 Risk Assessment Mitigation Phase (RAMP) Report (Report). Consistent with the Commission's requirements set forth in the above decisions and related proceedings, PG&E's RAMP submission precedes PG&E's 2020 General Rate Case (GRC) Application and, among other things, provides initial quantitative, probabilistic views of the Company's top safety risks; identifies the costs associated with controlling these risks; and describes future mitigation plans based on an alternatives analysis and informed by the concept of risk-spend efficiency. PG&E also has included in its RAMP filing a specific discussion on the Company's safety culture, executive engagement, and compensation practices, risk evaluation of substations, and information on steady state asset replacement for Gas Operations, Electric Operations and Power Generation.

I. BACKGROUND AND PROCEDURAL HISTORY

In Decision 14-12-025, the Commission adopted a risk-based decision-making framework (Framework) into the Rate Case Plan (RCP) for the energy utilities' GRCs. The Framework was developed as a result of Senate Bill (SB) 705 (Statutes of 2011, Chapter 522), which stated in Public Utilities Code Section 963(b)(3):

> It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

Under Public Utilities Code Section 750, the Commission was directed to "develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation."

The Framework consists of the following, based on these directives:

> For the large energy utilities, this will take place through two new procedures, which feed into the GRC applications in which the utilities request funding for such safety-related activities. These two procedures are: (1) the filing of a Safety Model Assessment Proceeding (S-MAP) by each of the large energy utilities, which are to be consolidated; and (2) a subsequent Risk Assessment Mitigation Phase (RAMP) filing in an Order Instituting Investigation for the upcoming GRC wherein the large energy utility files its RAMP in the S-MAP reporting format describing how it plans to assess its risks, and to mitigate and minimize such risks. The RAMP submission, as clarified or modified in the RAMP proceeding, will then be incorporated into the large energy utility's GRC filing.[1/]

In D.16-08-018, the Commission adjudicated the consolidated S-MAP applications and the format of the RAMP submissions. In that decision, the Commission adopted guidelines for what the RAMP submissions should include, as well as an evaluation method for RAMP submissions. In addition, the Commission held that PG&E's November 30, 2017 RAMP filing shall include the Gas Transmission and Storage system.[2/]

On September 1, 2017, PG&E submitted a letter requesting an Order Initiating Investigation (OII). OII 17-11-003 was filed by the Commission on November 9, 2017.

II. RISK ASSESSMENT MITIGATION PHASE REPORT

PG&E's Report is organized in chapters, as follows:

1/ D.14-12-025 at 2-3.

2/ D.16-08-018, pp. 154-5.

CHAPTER	TITLE
A	Introduction
B	Risk Model Overview
C	Safety Culture
D	Compensation Policies Related To Safety
Attachment A	2016 and 2017 PG&E STIP Scorecards
1	Transmission Pipeline Rupture With Ignition
2	Failure To Maintain Capacity For System Demands
3	Measurement And Control Failure – Release Of Gas With Ignition Downstream
4	Measurement And Control Failure – Release Of Gas With Ignition At Measurement And Control Facility
5	Release Of Gas With Ignition On Distribution Facilities – Cross Bore
6	Compression And Processing Failure – Release Of Gas With Ignition At Manned Processing Facility
7	Release Of Gas With Ignition On Distribution Facilities – Non-Cross Bore
8	Natural Gas Storage Well Failure – Loss Of Containment With Ignition At Storage Facility
9	Distribution Overhead Conductor Primary
10	Transmission Overhead Conductor (TOHC)
11	Wildfire
12	Nuclear Core Damaging
13	Hydro System Safety – Dams
14	Contractor Safety
15	Employee Safety
16	Motor Vehicle Safety
17	Lack Of Fitness For Duty Program Awareness
18	Cyber Attack
19	Insider Threat
20	Records And Information Management
21	Skilled And Qualified Workforce

CHAPTER	TITLE
22	Climate Resilience
Appendix 1	Risk Assessment For Substations
Appendix 2	Steady State Operations

PG&E has also provided supporting Workpapers to this Report.

III. CONCLUSION

The models presented in this RAMP filing are first generation probabilistic operational risk models intended to represent progress and a step forward on PG&E's path to data-driven, risk-informed decision making. PG&E has made significant progress and has evolved its approach to risk management during the development of this RAMP filing. PG&E is committed to building on the progress made through the RAMP process by incorporating lessons learned, and additional regulatory comments and insights, with the goal of minimizing risk and maximizing the safety of PG&E's customers and the communities PG&E serves.

Respectfully submitted,

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Dated: November 30, 2017

Investigation: 17-11-003
(U 39 G)
Exhibit No.: ______________________
Date: November 30, 2017
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

TABLE OF CONTENTS

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE REPORT

TABLE OF CONTENTS

(CONTINUED)

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER A
INTRODUCTION

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER A
INTRODUCTION

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully submits its first Risk Assessment and Mitigation Phase (RAMP) filing. The RAMP filing is a requirement of the California Public Utilities Commission (CPUC or Commission) General Rate Case (GRC) process, applicable to all large investor-owned utilities in the state, and is intended to provide the Commission and other stakeholders with an early indication of each utility's risk priorities and mitigation plans that have been informed by the development and application of probabilistic risk models.

This RAMP precedes PG&E's 2020 GRC Application and provides initial quantitative, probabilistic views of the Company's top 22 safety risks; identifies the costs associated with controlling these risks; and describes future mitigation plans based on an alternatives analysis and informed by the concept of risk-spend efficiency.

PG&E also has included in its RAMP filing a specific discussion on the Company's safety culture, executive engagement, and compensation practices; risk evaluation of substations; and information on steady state asset replacement for Gas Operations, Electric Operations and Power Generation.

It is important to note that the analysis and identified risks presented in this RAMP filing reflect PG&E data and modeling efforts as of November 2017. This filing evaluates the risks using best currently available data and assumptions as necessary; analyzing mitigation alternatives by understanding the potential risk reduction effectiveness of each and the associated costs—two fundamental pieces of the Risk Spend Efficiency (RSE) calculation; and making decisions about how to effectively manage the risk that will be included in the Company's 2020 GRC application.

As shown in the Gas Operations risk chapters within this filing, following the San Bruno gas pipeline explosion, extensive analysis was completed internally and by third-party experts to identify long-term actions to enhance the management of gas assets and to reduce risk. The modeling of specific risk events included in RAMP confirmed that the Company is taking the right actions and new actions are not yet needed. In Electric Operations, new insights have been gained. For example, the data used for the RAMP analysis shows that the safety consequence associated with Distribution Overhead Conductor is more often a result of people coming in contact with intact conductor, rather than resulting from wire down events. As a result, mitigations chosen in that chapter include a focus on getting the message out to populations of people most likely to be working at heights around energized overhead conductor. PG&E believes there is value in further developing operational risk modeling techniques and using them in management-led risk and compliance committees and within the senior management-led integrated planning process to help drive better decision making and clearly demonstrate line of sight between risks, drivers, alternative mitigations and anticipated risk reduction.

PG&E continues to learn and adapt to a changing environment by refining its approach to quantitative risk assessment, applying additional sources of data, and gathering more information about the interrelationship between risks. As a result, risk models presented in this filing will improve over time and actions taken to manage risks may change.

B. Background

Managing risk is a continually evolving process, and while there are inherent risks in delivering gas and electricity to 16 million Californians, PG&E's top priority is always the safety of its customers, employees and the public. While it may not be possible to eliminate all risks such as those associated with natural disasters, wildfires and earthquakes, PG&E's goal is to proactively prepare and enhance its infrastructure to deliver safe and reliable energy every day. By systematically and comprehensively identifying, analyzing, evaluating, mitigating, and monitoring risks that could potentially prevent PG&E from achieving its goal, PG&E's Enterprise and Operational Risk Management (EORM) program enables PG&E to reduce this inherent risk.

Since 2011, when PG&E first established its EORM Program, the Company has:

- Developed and refined a comprehensive, prioritized risk register;
- Implemented a strong central governance function to provide risk management guidance and insights into the progress being made;
- Incorporated risk into the Integrated Planning process;
- Set annual goals year-over-year to improve risk quantification and improve the Company's ability to measure risk reduction; and
- Enabled visibility of risk management progress through discussion at Line of Business (LOB) Risk and Compliance Committee meetings and executive-led risk governance committees, and regular presentations to committees of the Boards of Directors of PG&E Corporation and PG&E. In these different forums, PG&E continues to evaluate any new information and determine whether or not a change in course of action is required to respond to immediate or short-term crises outside of the RAMP/GRC process and adjust as necessary. PG&E expects an explanation of measures taken to mitigate risk will occur annually in accordance with accountability reporting, once

requirements are established through the S-MAP process. This report will also contain a description of any changes to previously stated mitigation plans.

In the interests of providing safe and reliable energy to all our customers and communities, PG&E continues to evolve its risk management process to better understand the sources of risk and identify the best possible opportunities for further reducing them. This has involved developing probabilistic operational risk models that enable the Company to: (1) describe risks as events with a distribution of outcomes, rather than a point estimate, (2) quantitatively evaluate alternative mitigation strategies and estimate risk reduction, (3) choose implementable risk mitigations informed by RSE, and (4) better monitor top risks.

C. PG&E's Approach

In its approach to the RAMP and in the filing itself, PG&E has taken great care to be transparent, accountable and inclusive. In doing so, parties have been able to see how PG&E has modeled each of its top safety risks and offer ideas and feedback on how its approach may be refined or improved.

The Company has demonstrated transparency by documenting its modeling assumptions and rationale for decisions in a manner that the Company believes is repeatable, straightforward and understandable.

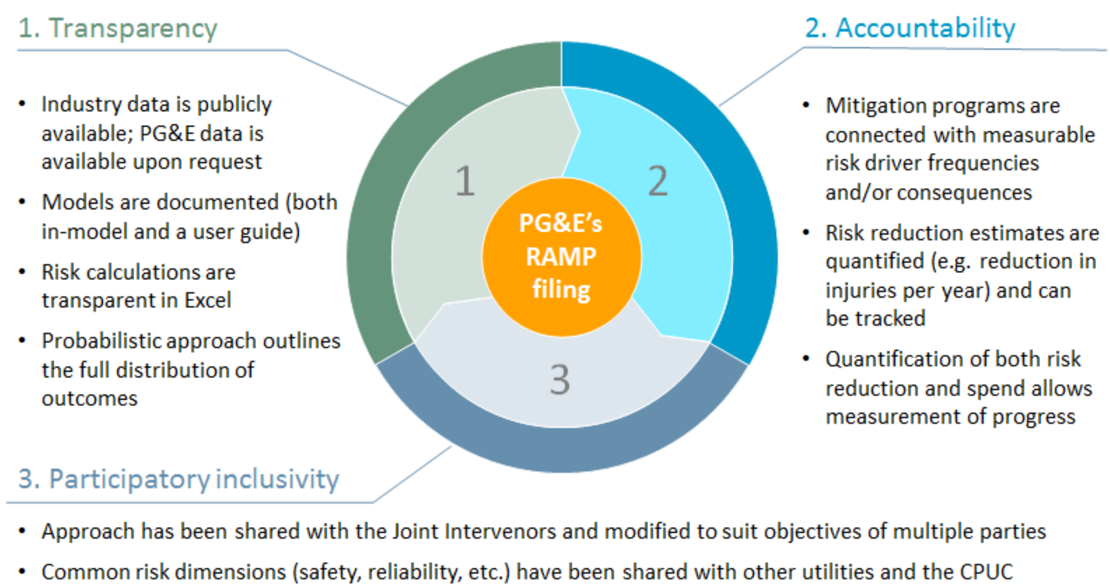
Risk chapters and supporting workpapers include data that will provide the basis for accountability reporting such as risk driver frequencies and metrics. This can help PG&E demonstrate where the Company has met its risk reduction goals, and provide a basis to explain any variance from forecast.

In the spirit of participatory inclusivity, PG&E has reached out and met with interested parties, sharing assumptions, modeling approaches, and lessons learned with the goal of delivering a RAMP filing that reflects comments and feedback provided throughout the process. Beginning in November 2016, PG&E has met with various stakeholders including the CPUC SED, CPUC Office of Ratepayer Advocates (ORA), CPUC Office of Safety Advocates (OSA), Coalition of California Utility Employees (CUE), The Utility Reform Network (TURN) and Indicated Shippers (IS) among other to share how PG&E is preparing for RAMP, the assumptions the Company is making, and what is being learned. PG&E has shared the list of top safety risks and the methodology used to identify them; the general modelling and approach assumptions being considered and used; how the probabilistic operational risk models were being constructed; the approach to identifying and using data sources; any identified limitations; and next steps.

All parties asked questions and provided feedback that was incorporated as appropriate.

Figure A-1 provides some specific takeaways from the efforts undertaken over the past year to deliver on the objectives of RAMP.

Figure A-1: PG&E's RAMP Filing Approach



In addition to being transparent, accountable, and inclusive, PG&E's RAMP approach is also based on achieving seven main objectives:

1. **Focus on Safety**

   This RAMP filing includes a probabilistic assessment of the Company's top safety risks including a description of the controls currently in place, mitigations underway, and plans for improving the mitigation of each risk, including two alternatives. It also includes chapters dedicated to describing PG&E's safety culture, executive engagement and compensation policies.

2. **Move Towards Probabilistic Calculations as Much as Possible**

   PG&E developed individual and comparable risk models for each of the identified top safety risks. The risk models are meant to help PG&E LOBs understand, from a quantitative perspective, the frequencies associated with risk drivers and the range of consequences associated with each risk event. The RAMP operational risk models produce full risk distributions (where a tail average, expected value, or any point on the curve can be measured) based on PG&E-specific data whenever feasible, industry data where applicable, calibrated subject matter expertise, and combinations thereof. A description of the data sources used to assess each risk is discussed in the individual risk chapters of this filing and in associated workpapers.

3. Present Two Alternative Mitigation Plans for Each Risk

All the risks included in PG&E's RAMP filing are presented in their own chapter, in the same manner, using the same framework that, in each chapter, culminates in an alternatives analysis showing the proposed mitigation plan and two alternative plans. The information included in each risk-specific chapter addresses the first eight of the ten steps in the Cycla 10-step Risk-informed Resource Allocation Process with the final two steps to be addressed later.[1] Each risk chapter includes the following:

- An executive summary that includes the risk name, scope of the risk, the data sources used, and a brief discussion of PG&E's experience in managing the risk;
- A risk assessment based on a bow tie assessment framework, including a data-driven evaluation of the risk exposure, risk drivers and frequencies, and the range of consequences associated with the risk resulting in a Multi-Attribute Risk Score (MARS)[2] [Cycla Step 1: Identify Threats; Cycla Step 2: Characterize Sources of Risk];
- Current controls and mitigations underway through 2019;[3]
- A proposed plan to mitigate the risk, which identifies a mitigation strategy informed by an early stage RSE calculation to be included, or adjusted as necessary, in the 2020 GRC and an alternatives analysis [Cycla Step 3: Mitigation Identification; Cycla Step 4: Evaluate the Anticipated Risk Reduction; Cycla Step 5: Determine Resource Requirements; Cycla Step 6: Mitigation Selection; Cycla Step 7: Identify

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1 The RAMP filing addresses the first eight of the 10 Cycla Steps for Risk-informed Resource Allocation. The two steps this process does not address Step 9: Adjusting mitigations following CPUC decision on allowed resources and Step 10: Monitoring the effectiveness of risk mitigations will be addressed after receiving the GRC decision and in the submission of the Accountability Report, respectively.

2 Reference Section 1.9 – Multi-Attribute Risk Score (MARS) in Chapter B for explanation of the MARS calculation and methodology.

3 Controls are limited to work completed and in place in 2016. Mitigations are listed in this filing in two sections: (1) work to be completed in the 2017-2019 timeframe; and (2) work to be completed in the 2020-2022 timeframe. The first section of mitigations was reflected in the 2017 GRC (unless otherwise stated) and the second section of mitigations will be included in the 2020 GRC (again, unless otherwise stated).

Total Cost; and Cycla Step 8: Adjust Mitigations Considering Resource Constraints];

- Proposed metrics for evaluating risk reduction effectiveness; and
- A summary of next steps.

4. Present an Early State "Risk Mitigated to Cost Ratio" or Related "Risk Reduction Per Dollar Spent"

The outputs of the risk assessments, i.e., the baseline MARS evaluation and RSE calculations for each mitigation, are presented to show the potential for comparing risks and proposed mitigations.

It is important to note that given this is PG&E's first attempt at developing probabilistic risk models for its top safety risks (beyond what is done under the purview of the Nuclear Regulatory Commission for PG&E's Diablo Canyon Power Plant (DCPP) operations)[4] improvements in the quality and availability of data and a deeper understanding of risk tolerance are needed before risks and the effectiveness of mitigations truly can be compared. However, using the RSE metric based on a consistently calculated MARS is a first step towards comparability across risks and mitigations.

5. Describe the Company's Safety Culture, Executive Engagement, and Compensation Policies

The safety culture chapter describes PG&E's plan to improve safety culture over time and includes descriptions about executive engagement in the process. Included in a separate chapter,[5] PG&E has described how its compensation policies align with promoting safety as a key objective of the Company.

6. Identify Lessons Learned

PG&E describes lessons learned and next steps throughout this filing. In addition to programmatic lessons learned about quantitative operational risk modeling[6] and alternatives analysis that are included in next steps, each

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4 PG&E's DCPP Nuclear Operations team has an established Probabilistic Risk Assessment (PRA) model developed and refined over the past two plus decades. The DCPP PRA model is regularly used by the plant for decision-making.

5 Chapter D, Compensation Policies Relating to Safety.

6 For example, as described in Chapter B, PG&E has found that the trust attribute—which is difficult to obtain meaningful data for – may have limited value in assessing safety-related risks.

individual risk chapter includes a similar discussion about how to improve the models that have been developed.

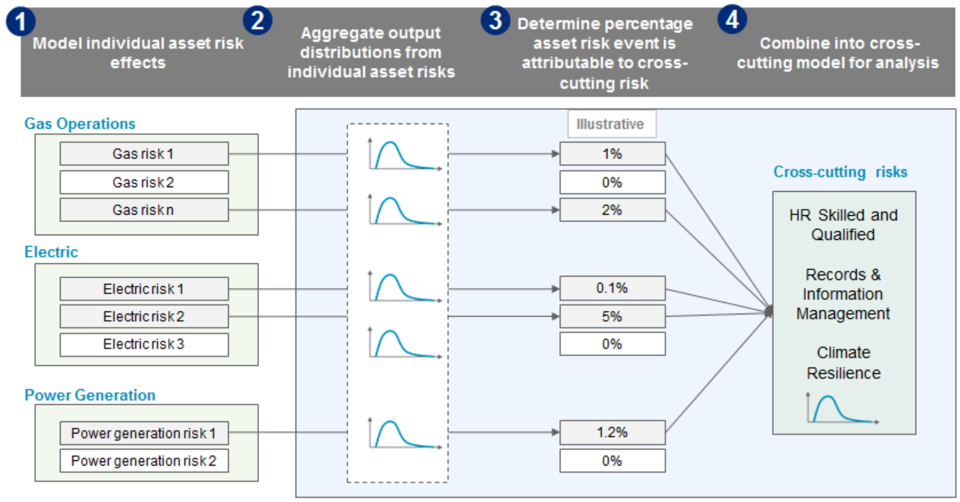
One of the main lessons learned in this process is with respect to cross cutting risks. Three of PG&E's top safety risks presented in this filing—Records and Information Management, Skilled and Qualified Workforce, and Climate Resilience—are interrelated and can be considered sub drivers of other risks. For example, the Skilled and Qualified Workforce risk, i.e., not having a skilled and qualified workforce to correctly perform work, could have significant safety consequences and is considered by PG&E a risk in and of itself. Additionally, the lack of a skilled and qualified workforce also can cause "incorrect work operations" which is an identified risk driver for a number of risks such as the Gas Transmission Pipeline Failure with Ignition risk.

To address this, PG&E developed a cross-cutting model that is dependent on the outputs from other asset or stand-alone risk models. These models are not specific risk events; instead, they are an aggregation of the associated stand-alone or asset risks.

The three cross-cutting risk models are Records and Information Management, Skilled and Qualified Workforce, and Climate Resilience. Records and Information Management and Skilled and Qualified Workforce evaluate each of the stand-alone risks and estimate what portion of the risk could be attributed to a records issue or a skilled and qualified workforce issue, respectively. The portion attributed to these two cross-cutting risks is an input to the appropriate cross-cutting model. A slightly different approach is taken for Climate Resilience. The Climate Resilience model anticipates that climate change may increase some of the stand-alone risks. For example, stronger and more frequent storms could lead to additional Distribution Overhead Conductor Primary risk as more wires may be downed as a result. These inputs are anticipated in the output of the Climate Resilience model.

Figure A-2 shows a graphical representation of the approach taken to model cross-cutting risks.

Figure A-2: Cross-Cutting Risk Model Methodology



7. Prepare for Annual Accountability Reports

This filing includes information that may be used in future accountability reports, including metrics and forecasted risk reduction. PG&E expects more work will be done with the SED-sponsored Metrics Working Committee to solidify what accountability reporting will ultimately include and will participate in that process.

D. Choosing the Top Safety Risks for Inclusion in RAMP

PG&E started the RAMP process with the Company's Risk Register that contains over 200 risks. To populate this risk register with the most important risks to the Company, LOBs hold workshops and brainstorming sessions to identify "worst case probable events" (loosely described as "P95" events) that could prevent PG&E from achieving its objective of providing safe, reliable, affordable and clean energy to our customers every day. These risk events are evaluated using a standard risk evaluation tool (RET) and rank ordered on a relative basis based on a risk score. This list of risks becomes the Company Risk Register.

The RET is a 7x7 matrix consisting of seven consequence levels that range from negligible to catastrophic across six weighted attribute areas and seven frequency levels that range from once every 100+ years to >10 times/year.

When assessing identified risks, LOBs choose the appropriate consequence level (1-7) for each of the six weighted consequence attributes based on how the risk is described and then assign the frequency level (1-7) by which those consequences might occur.

Next, an algorithm is applied using consequence and frequency “inputs” to establish the risk score (“output”).

The weighting of the consequence attributes in the algorithm is designed such that safety risks score higher than financial or reliability risks. Also, the consequences are weighted more heavily than frequency in the overall score. As a result, this approach tends to prioritize high consequence, low frequency safety risks.

The top risks are then flagged for senior management attention and oversight and are prioritized for assessing additional risk reduction options. In addition, any risk that is assessed as having a potentially catastrophic impact, regardless of frequency, is designated as an Enterprise Risk and is currently overseen by PG&E’s Board of Directors.

PG&E evaluated several options for determining which risks to include in its RAMP filing and reviewed these options with internal and external stakeholders.[7] Based on stakeholder feedback, PG&E included the highest scoring risks that had a potential safety consequence of causing permanent or serious injuries or illnesses to employees, the public or to contractors. This captured the 22 top risks noted in Table A-1 below.

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7 External stakeholders included Sempra, CPUC SED, ORA, OSA, TURN, IS and Energy Producers and Users Coalition, and CUE.

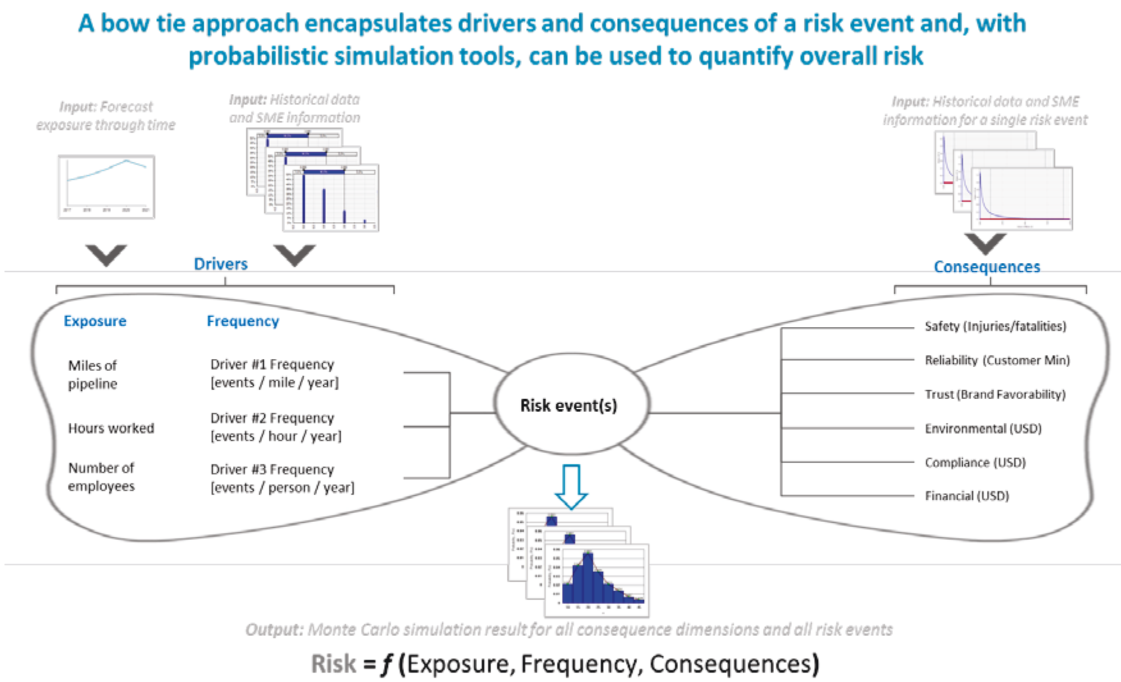
Table A-1: PG&E RAMP Risks

Chapter	Name	LOB
1	Transmission Pipeline Failure – Rupture with Ignition	Gas Operations
2	Failure to Maintain Capacity for System Demands	Gas Operations
3	Measurement and Control Failure – Release of Gas with Ignition Downstream	Gas Operations
4	Measurement and Control Failure – Release of Gas with Ignition at M&C Facility	Gas Operations
5	Release of Gas with Ignition on Distribution Facilities – Cross Bore	Gas Operations
6	Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility	Gas Operations
7	Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore	Gas Operations
8	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility	Gas Operations
9	Distribution Overhead Conductor – Primary	Electric Operations
10	Transmission Overhead Conductor	Electric Operations
11	Wildfire	Electric Operations
12	Nuclear Operations and Safety – Core Damaging Event	Generation
13	Hydro System Safety – Dams	Generation
14	Contractor Safety	Safety and Health
15	Employee Safety	Safety and Health
16	Motor Vehicle Safety	Safety and Health
17	Lack of Fitness for Duty Awareness	Safety and Health
18	Cyber Attack	Information Technology
19	Insider Threat	Information Technology
20	Records and Information Management	Enterprise Records and Information Management
21	Skilled and Qualified Workforce	Human Resources
22	Climate Resilience	Strategy and Policy

E. **Risk Assessment and Model Overview**

Through the RAMP process, PG&E has developed 22 first generation probabilistic operational risk models based on the bow tie analysis framework illustrated in Figure A-3 below.

Figure A-3: Illustrative Bow Tie Analysis Framework



A bow tie analysis is constructed using four basic components:

1. **The Risk Event:** The center of the bow tie. The risk is an event or events that PG&E seeks to avoid and could impact PG&E's ability to deliver on its objective of providing safe, reliable, affordable, and clean energy.
2. **The Exposure:** The far left side of the bow tie. Exposure is the measure that fundamentally determines the physical materiality of the risk, e.g., miles of transmission pipeline, number of employees, miles of overhead distribution lines, etc. Exposure is important for defining the scope, context and granularity of the risk, i.e., is the risk associated with the entire system, or focused on one piece of it?
3. **The Risk Drivers:** To the immediate left of the center of the bow tie. Risk drivers are the factors that could cause one or more risk events to occur. The bow tie uses actual data (PG&E data, industry data, or calibrated subject matter expertise, or some combination thereof), to measure the frequencies associated with each risk driver. These frequencies are reported as number of risk events caused by that risk driver, per unit of exposure, per unit of time, e.g., number of pipeline transmission failures with ignition events/miles of transmission pipeline/year caused by external corrosion. This level of

detail enables PG&E to focus attention on the most important risk drivers. Risk driver frequency data, combined with exposure, enables PG&E to compare its performance against industry performance to begin to understand what may be driving any differences.

4. **The Consequences:** The right side of the bow tie. Consequences are the range of outcomes associated with the risk occurrence. In PG&E's risk framework, consequences are measured across six attributes: (1) Safety-separated into injuries and fatalities; (2) Environmental; (3) Compliance; (4) Reliability; (5) Trust; and (6) Financial (excluding below the line, shareholder costs). Continuing with the Gas Transmission Pipeline Failure with Ignition example, the consequences depend largely on where the event occurs. If the risk occurs in a heavily populated area, the consequences are more likely to be severe than consequences resulting from the same event occurring in a remote area. The consequence data is then used in Monte Carlo simulations to develop a full distribution of risk consequences to understand the probability associated with each consequence attribute.

A more detailed description of PG&E's approach to probabilistic risk modeling, for stand-alone and cross-cutting risk models is included in Chapter B – Risk Model Overview.

F. Expected Value and Tail Average

PG&E's EORM Program considers the possibility of low frequency, high consequence events, even if they have never occurred in the Company's history. As such, in modeling our top safety risks, PG&E has included the Tail Average (TA), i.e., the average of the worst 10 percent of simulated outcomes, to ensure that PG&E considers these low frequency/high consequence events and that the Company maintains the level of visibility and oversight needed to appropriately manage these types of risks.

The Expected Value (EV), or the "average" event, also is a useful measure for ensuring the Company is focused on choosing mitigations and targeting controls in the most efficient manner possible, i.e., mitigations that reduce risk across the distribution of possible outcomes, not just the TA.

By measuring both EV and TA, PG&E examines the potential impact of mitigations across the distribution of risk and can focus on mitigations that affect "extreme" events (TA) and "everyday" (EV) events.

G. Controls, Mitigations, and Risk Spend Efficiency

Control is defined as:

> *"A currently established measure that is modifying risk";*

and mitigation is defined as:

> *"A measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of an event."*

PG&E has identified existing controls and mitigations for each top safety risk to understand the current level of risk and use this understanding to inform the 2020-2022 mitigation plans. The frequencies of the risk drivers and the distributions of the associated consequence attributes reflect available data through 2016. For purposes of RSE calculations, PG&E focused on mitigations (rather than controls) due to the forward looking nature of its program and the desire to understand the potential risk reduction associated with new mitigation investments. In some cases, mitigations included in the RAMP risk chapters are new items and in other cases, mitigations represent a strengthening of existing controls.

Mitigations proposed in each chapter are designed either to reduce one or more of the risk driver frequencies or 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 table format within each risk specific chapter.

PG&E did not estimate RSE for controls and existing mitigations that end prior to 2020. Controls already funded through the regulatory process are often associated with work necessary for compliance and have been subject to regulatory review in prior rate cases. PG&E instead focused on calculating RSEs for all proposed mitigations for items to be included in the 2020 GRC over the years 2020-2022.

In this filing, individual mitigations are "bundled" together to create mitigation plans. Each mitigation plan may include both mitigations (risk reducing activities) and "foundational" activities. Foundational activities can be thought of as initial work needed to implement future mitigations, e.g., investments in Information Technology (IT) infrastructure or data gathering. Foundational activities generally do not result in risk reduction and therefore do not have associated RSE calculations. RSEs for the entire mitigation plan are calculated as follows:

$$RSE_{Mitigation\ Plan} = \frac{Risk\ Reduction_{Mitigation\ 1} + \dots + Risk\ Reduction_{Mitigation\ n}}{Total\ Cost\ of\ All\ Mitigations\ in\ the\ Plan}$$

The RSEs presented in the alternatives analysis section of each chapter are based on costs and risk reduction forecasted over the 2017-2022 timeframe. This methodology was shared during stakeholder meetings and there was general agreement that it was unrealistic to use first generation models, populated with first generation data, to predict the risk reduction achieved in the 2017 GRC period (2017-2019), then re-baseline and predict again what risk reduction would be achieved over the 2020 GRC period (2020-2022).

PG&E approached the concept of RSE as a way to evaluate risk mitigation plans as one of many inputs into the overall decision making process; however, it does not always dictate a particular result. In some cases, work that has low or no RSE will be selected above mitigations with high RSE. These cases generally fall into four categories:

1. **Some risks may require foundational work before risk reducing work can begin.** IT infrastructure is a good example of this type of risk. The investment in IT infrastructure (e.g., servers, operating systems, databases, etc.) may not directly reduce risk and would naturally receive a "0" RSE score. But without that investment, PG&E may not be able to efficiently manage risk in the future.
2. **Some risks may have little or no associated data.** Data may not be readily available; it may be insufficient or not collected at all. Risk reduction from given activities may not be measurable or observable. Cyber Attack and Insider Threat are two such risks where lack of event data has made performing RSE calculations infeasible at this time.
3. **Risks where the long term benefit of the project outweighs the shorter term costs.** PG&E's probabilistic risk model is a 6-year model that spans 2017-2022. Risk benefits that extend beyond the 2020 GRC time horizon are not captured; therefore, some capital projects where costs tend to be higher will receive a lower RSE (higher cost and equal or less risk reduction) than operations and maintenance-type expense projects because the benefits are truncated at the six year mark. Over the longer term, these capital cost intensive mitigations may prove to have better RSEs than their expense alternatives.
4. **Other constraints.** In some cases, the best RSE mitigation may not be executable for any number of reasons including feasibility, qualified workforce availability, materials availability, permitting constraints, etc.

Additionally, because RSE is a ratio, high cost mitigations with large associated risk reduction may have the same RSE as low cost mitigations with small associated risk reduction and the current risk level may warrant greater spend to achieve greater risk reduction.

Due to all of these factors, each of the risk mitigation plans includes a justification for the chosen alternative and additional justification is provided when the decision is not based on RSE alone.

H. Estimating Costs

In this filing, PG&E has presented both capital and expense recorded costs associated with risk controls and mitigations for 2016. PG&E also identifies mitigations for 2017-2019 and mitigations anticipated to be requested in the 2020 GRC, the 2019 Gas Transmission and Storage (GT&S) Rate Case, and future Transmission Owner rate cases under Federal Energy Regulatory Commission jurisdiction.

PG&E made a number of assumptions in estimating costs as follows:

1. Costs are reported in ranges due to the uncertainty associated with predicting future mitigation needs. Gas Operations provided point estimates for alignment with the 2019 GT&S Rate Case forecast. PG&E has used the best available information when calculating and estimating the costs associated with each mitigation. Because PG&E's GRC forecasting process is still in the early stages, however, the mitigation cost forecasts included in the 2020 GRC application may be significantly different from the estimates included in this filing.
2. Some risks are mitigated using labor not typically associated with planning orders or major work categories. PG&E has estimated costs based on the number of associated Full Time Equivalent hours multiplied by the standard employee rate for the specific job function.
3. Some mitigations have a risk reduction benefit across multiple risks. PG&E has made a best effort to estimate cost allocations between risks where feasible. Where this allocation cannot be reasonably estimated, PG&E will apply the full cost of the mitigation to each applicable risk. PG&E will not "double count" these costs in its GRC application or in any other rate case.
4. Some Below the Line (BTL) costs may be difficult to predict. PG&E removed cost types defined in its BTL Standard when analyzing financial consequences associated with risk events included in this filing.

II. Lessons Learned and Next Steps for PG&E

A. Risk Assessment

1. **Quantitative Operational Risk Modeling.** Since early 2017, PG&E began transitioning from its historical qualitative approach to a more probabilistic and quantitative approach, consistent with the expectations for this filing. Parallel to the development of its RAMP filing, PG&E has participated in Commission-led Safety Model Assessment Proceeding (S-MAP) workshops whereby intervenors and the large California IOUs shared risk assessment methodologies and explored ways to improve utility risk modeling approaches. PG&E has adopted much of what was learned during these workshops to inform the probabilistic models presented in this RAMP.

As PG&E implements this more sophisticated approach to risk assessment, data quality and availability is improved across all risks, and risk reducing activities are implemented, PG&E expects risk scores and priorities to change over time.

The Company sees value in the potential of probabilistic operational risk modeling, not only for deepening its understanding of risks but for enabling data-driven, risk-informed decision making. This quantitative approach can also support to transparent discussions about risk, mitigation strategies, and levels of risk.

This transition will involve the development of new skills, techniques and data sources. It will take time and resources to complete this transition; however, PG&E believes it can make meaningful progress toward achieving its stated goal of quantifying its top risks by 2020, while continuing to improve and evolve the operational risk models developed as part of the RAMP process.

2. **Governance, Oversight, and Evolution.** RAMP has accelerated PG&E's progress in its risk management journey towards quantifying its top risks. Today, the Company has 22 probabilistic risk models for its top safety risks and defined plans for evolving and improving these models so that even better decision making capabilities can be developed. As mentioned above, PG&E needs to better understand longer term risk reduction potential beyond the 6-year time horizon and refine its operational risk models to accommodate this type of analysis.

   PG&E has started creating a governance structure for the management and development of these and other risk models and data so they can increasingly be used in decision making. PG&E is also working on warehousing inputs and outputs; model validation and acceptance; and the development of additional analytical tools for making decisions within programs to further enhance its ability to identify, model and manage risk.

3. **Risk Tolerance.** Providing gas and electric service is an inherently risky endeavor and risk cannot be completely eliminated. Greater measurement and transparency allows the Company to discuss current levels of risk and contemplate new mitigations. Understanding risks at a more detailed level provides opportunities for the Company and its stakeholders to attempt to define a risk tolerance that can further guide investments in risk mitigation.

4. **Interrelationships between risks.** As PG&E continues to refine its approach to risk modeling, improvements will be made in identifying and understanding 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.

B. Tracking of Associated Financials

Previously, PG&E's accounting system (SAP) was set up to track costs by major work category, work orders and planning orders, but not necessarily in the context of how those activities relate to risks on the risk register. The company has made adjustments to SAP to incorporate RAMP related IDs to track mitigation costs for use in future accountability reporting.

C. Limitations

The completeness and availability of relevant data is a challenge. To compensate for lack of data, additional assumptions, subject matter expertise and proxy data were used and referenced in work papers. Therefore, the inputs and outputs of the models may not completely mirror PG&E's experience.

PG&E does not currently optimize investments across risks. The data is not robust enough, nor are the risks comparable enough to do this effectively. Additionally, optimization is best done in the context of risk tolerance, which has yet to be defined.

III. Conclusion

The models presented in this RAMP filing are first generation probabilistic operational risk models intended to represent progress and a step forward on PG&E's path to data-driven, risk-informed decision making.

The bow tie analysis foundational to PG&E's risk assessment approach allows the Company to better see the connections between risk drivers, controls and mitigations. By using this analysis to predict the impact mitigations may have in reducing risk and understanding the effectiveness of existing controls, PG&E is able to communicate what the Company is doing to manage safety risks inherent in the business.

PG&E has made significant progress and has evolved its approach to EORM during the development of this RAMP filing. PG&E is committed to building on the progress made through the RAMP process by incorporating lessons learned, and additional regulatory comments and insights, with the goal of minimizing risk and maximizing the safety of our customers and the communities we serve.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER B
RISK MODEL OVERVIEW

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER B
RISK MODEL OVERVIEW

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Introduction

As discussed in Chapter A, this Risk Assessment and Mitigation Phase (RAMP) filing includes first generation, high level models, that provide strategic insights for upcoming General Rate Case (GRC) applications. The objective of this section is to explain the methodology employed in developing the 22 models used to probabilistically assess the consequence of various risks reported in Pacific Gas and Electric Company's (PG&E or the Company) 2017 RAMP filing.

In the development of these models the following objectives were achieved:

- "[M]ov[ing] toward probabilistic calculations as much as possible"[1];
- Developing a consistent approach for quantitative modeling for different types of risk;
- Comparing risks across Lines of Business (LOB);
- Presenting an early stage "'risk mitigated to cost ratio' or related 'risk reduction per dollar spent'"[2] – using quantitative risk assessment methods;
- Outlining all assumptions and inputs used in each model – using a consistent approach and record of the analyses and assumptions; and
- Modeling risks through the GRC period – emphasizing quantitative analytics as compared to subjective judgement when addressing risk drivers.

A. Risk Quantification

When less is known about various future events, and potential outcomes, decision makers tend to rely on experience, rules-of-thumb, and "gut feel." Understanding and measuring those components of risk has been a central research topic and decision makers continue to grapple with it.

Understanding risks requires that uncertainties be measured in a consistent and robust manner, including what can cause an event occurrence, the likelihood of that occurrence, the options to mitigate the event, and the relative costs and impacts of those mitigations. This is a significant challenge since risks are characterized by multiple dimensions such as expected outcome, worst possible outcome, or a range of likely outcomes. This challenge is compounded by the nature of PG&E's business, operating diverse assets in a dynamic environment. PG&E embarked on a path to use more detailed and consistent measures of risk,

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1 California Public Utilities Commission (CPUC or Commission) Decision (D.) 16-08-018, p. 151.

2 *Id.*

and to support those analyses with objective data, in order to better inform critical business decisions.

B. Probabilistic Models

For the RAMP filing, PG&E developed Monte Carlo or Excel-based stochastic models using @Risk, software developed by Palisade Corporation (an add-in to Microsoft Excel).[3]

As described on the @Risk website:[4]

> @RISK (pronounced "at risk") performs risk analysis using Monte Carlo simulation to show you many possible outcomes in your spreadsheet model—and tells you how likely they are to occur. It mathematically and objectively computes and tracks many different possible future scenarios, then tells you the probabilities and risks associated with each different one.

The following is a description of the Monte Carlo simulations used by @RISK:[5]

> Monte Carlo simulation is a computerized mathematical technique that allows people to account for risk in quantitative analysis and decision making. The technique is used by professionals in such widely disparate fields as finance, project management, energy, manufacturing, engineering, research and development, insurance, oil & gas, transportation, and the environment.
>
> During a Monte Carlo simulation, values are sampled at random from the input probability distributions. Each set of samples is called an iteration, and the resulting outcome from that sample is recorded. Monte Carlo simulation does this hundreds or thousands of times, and the result is a probability distribution of possible outcomes. In this way, Monte Carlo simulation provides a much more comprehensive view of what may happen. It tells you not only what could happen, but how likely it is to happen.
>
> By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis.

When the program is launched, an additional ribbon is created in Excel with functions to efficiently run Monte Carlo simulations. The general process to create a Monte Carlo model is to: (1) define output attributes, such as its probability distributions, the parameters of such distributions, and the mapping between input and outputs; (2) identify the number of iterations to be simulated; (3) run the simulation; and finally (4) review the results (in the form of probability distributions). Input distributions can be defined by fitting raw data or fitting to subject matter expertise expectations. Output distributions are then

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3 For additional information on the models, see the Risk Model Guide, provided as WP B-1.

4 http://www.palisade.com/risk/.

5 http://www.palisade.com/risk/monte_carlo_simulation.asp.

derived from input distributions using Excel formulas. All @Risk functions use the prefix "Risk" to distinguish @Risk functions from other Excel functions.

PG&E recognizes that there may be alternative solutions for developing probabilistic models and does not advocate the use of only this tool for probabilistic analysis.

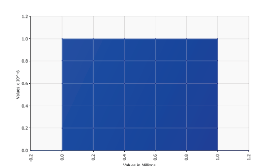
1. Common Distributions

A fundamental objective of RAMP is to move to probabilistic calculations and away from individual scenario based scoring to a range of possible outcomes. This is facilitated by using statistical distributions to model potential inputs. Depending on the nature of the risk driver and the type of data available, PG&E relied on a variety of distributions to describe the ranges and subject matter based judgements were made on which distributions to use for each model input. The selection of which distribution to use is not a science and outcomes can change with any adjustment to input distributions.

There are two main types of distributions: discrete and continuous. Discrete distributions take on distinct or separate values while continuous distributions can take on any value. Below are common continuous and discrete distributions used in the risk models:

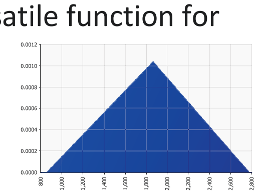
- Uniform (continuous distribution)

  The RiskUniform function creates a simple distribution where all continuous values between a minimum and maximum are equally possible. This is typically used when there is only information on a minimum and maximum value and nothing else is known about the uncertain event (random variable). A uniform distribution with a maximum of 10,000 and minimum of 0 has equal probability for all random samples between the 10,000 and 0.



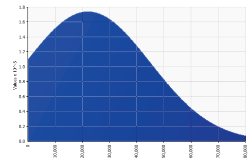
- Triangular (continuous distribution)

  The RiskTriang function creates a simple and versatile function for modeling a continuous distribution when we only have data for the minimum, maximum, and most likely (mode) values of the uncertain event (random variable). The probability density function of such distribution has a triangle shape: increasing from the minimum value to a peak at the most likely value and then decreasing to the maximum value.



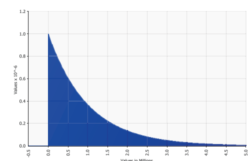
- Normal (continuous distribution)

  The RiskNormal function creates the symmetrical bell-shaped distribution which is defined by the average or mean and standard deviation. The standard deviation indicates the spread of the distribution where a smaller standard deviation indicates a narrower bell-shaped curve. Many large set of losses roughly follows a normal distribution such as the number of customers affected during an outage. The minimum and maximum values of a normal distribution are negative infinity and positive infinity, respectively. However, these distributions can be truncated if, for example, only non-negative values are reasonable outcomes.



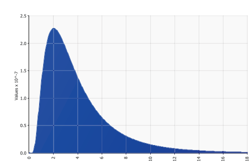
- Exponential Decay (continuous distribution)

  The RiskExpon function creates a continuous non-negative distribution, of which the probability density function decreases at a rate proportional to its current value. This distribution has a single scale parameter, its mean. The density function of such distributions always decreases from a modal value at 0. That is, the most likely values are always small values. This function is typically used when a loss happens significantly more often around zero, has fewer mid-range losses, and has a tail of significantly larger losses. If the mean is known, then the RiskExpon function can be used.



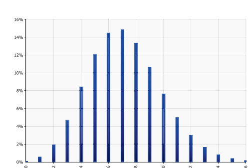
- Log normal (continuous distribution)

  Similar to the normal distribution, the RiskLognorm function creates a distribution with a given mean and standard deviation. However, unlike the normal distribution the log normal distribution has only positive values. This characteristic is similar to an exponential decaying distribution, however, the log normal distribution does not have a modal value of 0, but has a modal value of non-negative value.



- Poisson (discrete distribution)

  The RiskPoisson function generates a distribution with non-negative integer values. This distribution is often used to describe the number of "events" in some amount of time



such as the number of equipment failures in a year. It has a single parameter, usually denoted by the Greek λ (lambda), which is the mean and variance of the distribution. This parameter can be interpreted as a rate.

If the equipment failures of a risk event is $\lambda = 125$ failures events per year, on average, the RiskPoisson function can be used to create a discrete distribution with mean 125. It is important to note that a discrete distribution should be used when a failure is binary (i.e., a failure occurs or it does not occur).

- Binomial and Bernoulli (discrete distributions)

  The RiskBinomial function is used to create a distribution of the number of "successes" in a sequence of *n* independent trials when the probability of success, *p*, remains constant from trial to trial.

  A situation where you would use this function is to model the outcomes of flipping 10 fair coins where heads is a "success". There are 10 flips or 10 independent trials ($n=10$), with a probability, *p*, of obtaining a successful head outcome 50 percent of the time.

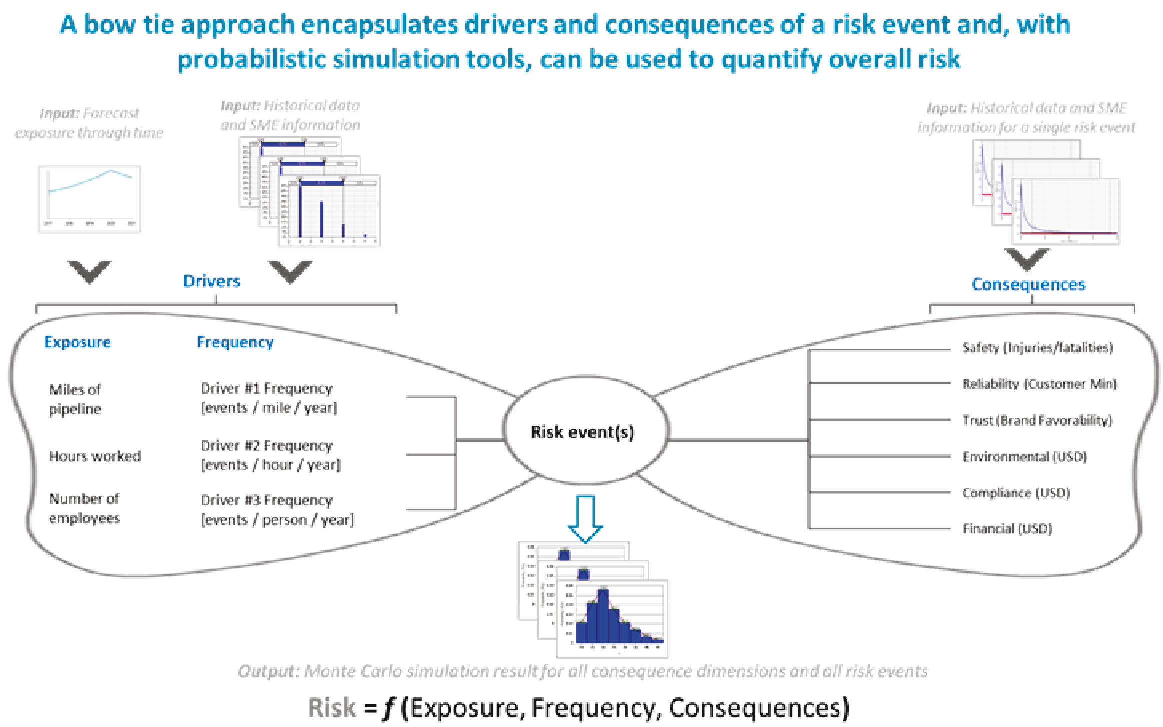
  The RiskBernoulli function is a specific form of the RiskBinomial function with $n=1$.

There are many distributions that can be used to describe events and data. Judgments on which input distributions to use were made with the knowledge of common distributions, understanding the available data, and probabilistic modeling expertise through internal resources supported by consultants.

C. Bow Tie Methodology

The scope of each risk has been defined with a bow tie methodology, (see Figure B-1) and precedes the risk modeling quantification effort. Using the bow tie methodology allows for consistency across all RAMP risk models. Using a bow tie methodology enables the risks to be decomposed into risk drivers and consequence attributes.

Figure B-1: Bow tie Methodology Overview



In the center of the bow tie is the risk event, which is a single, measurable event caused by the drivers on the left-hand side, which brings about the consequences on the right-hand side.

Careful definition of the risk event is critical for understanding the overall risk. Only the defined risk event will have been quantified in the risk models. For example, in the case of the "Gas Transmission Pipeline Rupture with Ignition" risk, the risk event excludes "gas transmission pipeline rupture *without* ignition" events.

Principles for defining risk events:

1. Risks should be characterized by a *single* risk event, which drivers independently contribute to, in order for automatic allocation (through the VBA code) of mitigation risk reduction to function appropriately in the models. If multiple risk events are tabulated or particular drivers lead to different sets of consequences, then allocation of risk reduction must be performed manually.
2. Risk consequences should be defined to be mutually exclusive of other risks, such that risk events and consequences are not double-counted. For example, a wildfire could be seen as a consequence of an electric distribution overhead conductor or electric transmission overhead conductor wire-down event. For RAMP, the risk event definitions of electric

distribution overhead conductor and electric transmission overhead conductor risks have explicitly *excluded* wildfire consequences, which are evaluated in the Wildfire Risk bow tie.

Drivers on the left-hand side of the bow tie are the causes for the risk event. The list of drivers should be exhaustive and encapsulate all possible causes for the risk event. Drivers should also be measureable, with an associated frequency that can be informed by industry and/or PG&E data. Drivers can be broken down into an exposure and a frequency in units of counts per exposure per given time period, to further decompose the left-hand side. See Exposure and Frequency section below for further detail.

On the right hand side of the bow tie are the consequences—what could possibly happen after a *single* risk event has occurred. See the Consequence Severity section below for further details on consequences.

PG&E endeavored to adhere to these principles; however, due to variations in defining risk scope among LOBs and differences in how data is recorded for different purposes, there are deviations. For example, the electric distribution risk is quantifying the risk of electrocution through contact either with intact energized wires or with energized wires as a result of wires down events. Most wires down events result in the wire being de-energized thus not impacting safety consequences, but is a major contributor to reliability consequences. These different events result in different consequences and an adjusted risk bow tie and a modified model was created to accommodate. Similarly, the Insider Threat and Cyber Attack risks consist of disparate risk events aggregated into one model.

Next Step: Regarding risk event definitions, learnings from the modeling work will lead to future modifications of the risk scope to continuously improve consistency among the organizations. Regarding mutual exclusiveness, the current assumption is that any remaining overlap between risks is small due to the rare nature of these risks as well as the disparate nature of the risk events. For example, possible overlaps would result in an employee or contractor that was injured or killed in another risk but is also accounted for in the Employee and Contractor Safety risk.

D. Timeframe

All 2017 RAMP models cover a period of six years, between 2017 and 2022. The 6-year view allows calculations of Risk Spend Efficiencies (RSE) across the GRC time period which is critical as the RAMP is a precursor to the 2020 GRC. However, due to the near-term time horizon of the modeling, long-term benefits of mitigations and their expected risk reduction impacts (i.e., asset replacement, new capacity projects, etc.) will be underestimated. Although, building a model that details calculations for a longer time period (>6 years) can be performed, the optimal timeframe is unclear (i.e., 10 years or 40 years, etc.) as well as longer periods also require many more inputs and assumptions.

Next Step: PG&E will consider future model developments that allow a longer time horizon over which to calculate costs and benefits and more accurately capture RSEs.

E. Exposure and Frequency

Defining the Exposure, Frequency and Consequences of a risk will determine the baseline or current residual risk profile. After a baseline is calculated, mitigation effects are defined and the estimated residual risk can be simulated.

Exposure is the measurement of the asset or activity. The choice of an exposure measure is driven by the granularity of the risk scope. For example, for the "Gas Transmission Pipeline Failure with Ignition" risk the exposure is measured as miles of Gas Transmission pipeline. Exposure is a time dependent scalar value that can vary from year to year. For example, in the motor vehicle safety risk, the exposure is vehicle miles driven and these values increase over the years of the model from 2017-2022.

Often, frequency is represented as a number of events per unit of time. Although this definition of frequency is used in the PG&E risk models, it is first decomposed into an exposure value and a frequency per exposure value. Frequency is the number of events per *exposure* unit per time and is defined for each high-level driver for each risk. The frequency distributions are time independent, that is, there is one distribution defined for each year of the model.

Next the consequence distributions of the risk were determined to complete the current view of the risk or baseline modeling of current residual risk.

F. Consequence Severity

Utilities have many objectives including providing safe, reliable and affordable energy to customers. To thoroughly represent the objectives of PG&E, a multi-attribute approach is taken to assess the range of consequences associated with a risk.

To enable comparisons among risks, the same consequence attributes and natural units have been used for each risk. A list of the seven consequence attributes used in the risk models, which is based on PG&E's consequences in the Risk Evaluation Tool (RET),[6] is presented in Table B-1.

Table B-1: Consequence Attributes and Units

Consequence	Natural Units
Safety – Injuries	Injuries
Safety – Fatalities	Fatalities
Reliability	Customer outage minutes
Trust	Percentage change in brand favorability
Environmental	U.S. Dollars (USD) ($)
Compliance	USD ($)
Financial	USD ($)

Note that not all of the consequence attributes are applicable to all risk models. For example, the motor vehicle safety risk does not include an environmental impact, since none is anticipated as a result of this risk. Further details for each consequence are presented in the following sub-sections.

Through the Safety Model and Assessment Proceeding (S-MAP) process, that determines the requirements of RAMP, PG&E is ordered to "remove shareholders' financial interests from consideration in…risk models." To satisfy this requirement, PG&E has removed shareholder dollars from the risk models consequence attributes. PG&E used the Company's Below-the-Line (BTL) Accounting Standard[7] to determine which costs should be excluded.

1. Safety Consequence Attribute

The safety consequence attribute includes both injuries and fatalities as a result of risk events. Because injuries can vary in severity, a consistent definition of what constitutes as an injury is important in risk quantification. For the quantification models, the federal Occupational Safety and Health Administration (OSHA) definition of injuries has been used in the RAMP risk models. The OSHA definition is as follows:

> You must consider an injury or illness to meet the general recording criteria, and therefore to be recordable, if it results in any of the following: death, days away from work, restricted work or transfer to another job, medical treatment beyond first aid, or loss of consciousness. You must also consider a case to meet the general recording criteria if it involves a significant injury or illness diagnosed by a physician or other licensed health care professional, even if it does not result in death, days

6 RET is described in PG&E S-MAP Prepared Testimony, May 1, 2015.

7 Utility Procedure: FIN-3901S Below-the-Line Accounting Standard, Publication Date: December 21, 2016, Rev 8.

away from work, restricted work or job transfer, medical treatment beyond first aid, or loss of consciousness. [from https://www.osha.gov/pls/oshaweb/]

When OSHA data is not available, it is assumed other public sources of information such as data reported to the CPUC or Pipeline and Hazardous Materials Safety Administration (PHMSA) are comparable to the OSHA definition.Environmental Consequence Attribute

The natural unit used for the environmental consequence attribute is USD ($). The value in this consequence input section captures remediation and clean-up costs, and excludes environmentally related fines. For some risk models (e.g., Electric Distribution Overhead Conductor Primary and Transmission Overhead Conductor Primary) the environmental consequence attribute are left blank as the consequences are covered in another risk model, or they are determined to be not applicable.

2. **Reliability Consequence Attribute**

The natural unit used for the reliability consequence attribute is outage time measured in customer-minutes. A simplifying assumption in the risk models is that an electric customer minute lost is equivalent to a gas customer minute lost.

Next step: Revisit this natural unit to ensure the equivalence is accurate and that the metric covers the most important aspects of reliability (i.e., worst performing circuits) and update model as necessary.

3. **Trust Consequence Attribute**

The purpose of the trust consequence attribute is to ensure that every action to maximize safety and reduce risk is made with the customer in mind. PG&E views customer trust as an extremely important consideration in delivering safe, reliable, affordable, and clean energy, and how PG&E models the risks. In evaluating its models, PG&E found the trust attribute to be the least quantifiable measure. Through the S-MAP, PG&E has come to realize the other large California Investor-Owned Utilities (IOUs) are not using the trust attribute. As PG&E works to achieve greater uniformity among the risk management methodologies used by the IOUs, PG&E looks forward to further collaboration with the Commission and S-MAP participants on whether to continue to include the trust attribute and—if so—how to quantify it.

With respect to past and current modeling, and to better understand how customers view the Company and its operations, PG&E uses customer surveys[8] to measure the trust attribute. In PG&E's initial assessment of how risk events could impact the way customers view the Company, PG&E applied customer survey results for the years 2009-2016.

The trust consequence for each iteration is drawn from one of three uniform distributions, which can be adjusted. The default settings are:

- High Severity = 12 to 20 percent impact
- Severe = 5 to 12 percent impact
- Low = 0 to 5 percent impact

Depending on whether an incident has an impact to life safety, the distribution will range from low, severe, to high severity. When there is no impact to life safety, there is no measureable effect.

4. Compliance Consequence Attribute

Compliance consequences reflect the cost of additional investment or effort to attain and maintain compliance with all applicable regulations after the risk event occurs. The natural unit used for this attribute is USD ($).

In line with RAMP filing requirements, costs that are considered BTL have been excluded from the models. For example, penalties or notice of violations due to failure to comply with federal or state regulations are excluded from consideration in these models.

5. Financial Consequence Attribute

The natural unit for the financial consequence attribute is USD ($) and excludes costs that are considered BTL. This attribute encompasses financial outcomes that are not included in the compliance or environmental category such as costs related to repairing property or equipment, compensatory claims, and/or other restoration costs.

G. Baseline and Mitigations

With the above inputs for exposure, frequency and consequence the current state of the risk event can be simulated to provide a current residual risk value – that is, the state of the risk with the information we have at a moment in time. This current state view or baseline is a starting point to determine any additional

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8 The term "Brand Favorability" is used to describe PG&E customer surveys used to measure the trust attribute.

activities or mitigations that can be performed to reduce the risk outcomes further.

A mitigation is defined as a measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of an event. Mitigation adequacy and effectiveness is judged based on how much of the exposure is affected, the change to specific driver frequencies (and how those frequencies may change over time), the change to specific consequence attributes, and the associated cost. In the current RAMP risk models, these changes alter the mean of the input distributions and the estimated residual risk distribution can be simulated.

H. Stand Alone vs. Cross-cutting Risk Modeling

There are two types of risk models: stand-alone models and cross-cutting models.

A stand-alone model is used to represent asset related risks, such as the Gas Transmission Pipeline Rupture with Ignition Risk.

Some risks on PG&E's list of top safety risks can be considered sub-drivers to many other risks. To address this, PG&E developed a cross-cutting model. The cross-cutting model is dependent on the outputs from other asset or stand-alone models. These models are not specific risk events and instead are portions of the associated stand-alone or asset risks.

In PG&E's 2017 RAMP filing there are three cross-cutting models: Enterprise Records and Information Management (ERIM), Skilled and Qualified Workforce (SQWF), and Climate Resilience (CR). The process by which these cross-cutting risks are compiled to produce an output is described in Figure B-2 and in the text below:

- Step 1: Individual asset or stand-alone models are completed.
- Step 2: Outputs from all associated risk models are collected into the cross-cutting model.
- Step 3: The cross-cutting risk owners worked with asset risk owners to determine the percentage of the asset risk event attributable to the cross-cutting risk.
- Step 4: The product of these percentages and the asset modeled distributions then become the cross-cutting risk distributions.

This cross-cutting modeling approach allows PG&E to pivot disparate risks into a view of specific sub driver effects and to focus on mitigation strategies that are programmatic in nature, prioritized by the areas of the business where the largest percentages of cross-cutting risk are attributed. For example, the ERIM risk is focused on strengthening the key tenets of ERIM maturity and applying those first in Gas Operations, where among all top safety risks, ERIM is most attributed.

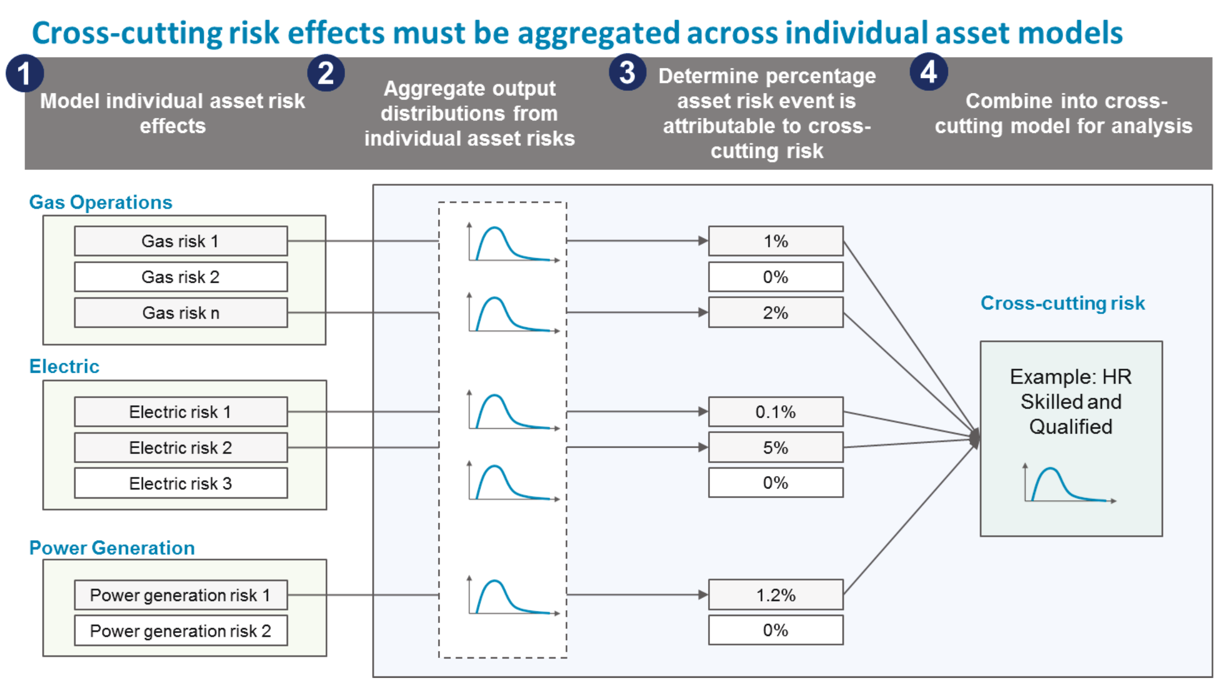
The drawback of using this cross-cutting approach is the dependence on the outputs of the stand-alone models. Also because these cross-cutting risks are an alternative view of the associated risks, double counting will occur and the cross-cutting risks will be more susceptible to change when additional risks are modeled and when existing stand-alone models are updated or modified, making risk reduction difficult to measure.

The consequences of all risks are limited to first order impacts, i.e., what may happen directly after and explicitly attributable to an event, except for the ERIM and CR risks.

ERIM risk may increase the financial outcomes of many risks if after a risk event additional work is required to support discovery efforts.

The CR risk also incorporates estimates of additional risk event frequencies due to specific climate change events. This estimating is represented by multiplier distributions that are applied to the contribution of each driver to the CR risk (see Climate Resilience, Chapter 22 for additional details).

Figure B-2: Cross-cutting Model Diagram



I. Multi-Attribute Risk Score

After all models are simulated, PG&E combined the various consequence attribute outcomes into a single value for risk reduction calculations. This is required in order to compare risks with each other (i.e., the "worth" of a gas risk relative to an electric risk). To enable comparisons across risks, each risk score is converted into a Multi-Attribute Risk Score (MARS). This is done by using a scaling approach to convert each consequence attribute from its natural unit to a point along a common scale.

While beginning the process for PG&E-wide risk scoring comparisons, PG&E is also concurrently participating in the S-MAP Joint Intervenor Approach (JIA) and Joint Utility Approach (JUA) processes to establish common attributes and approach to weightings among utilities, with the goal of consistency and comparability across the largest IOUs. PG&E currently has the following attributes in common with the JIA and JUA process: safety, reliability, and financial with similar natural units for safety and financial. PG&E will continue to work with the CPUC and other stakeholders as a decision is reached on this and future risk management proceedings.

Through the JIA process, PG&E acknowledged the importance of first setting the natural units and ranges of each attribute before discussion of how each attribute is weighted relative to each other. The natural units of each consequence attribute are listed in Table B-2 with the reasoning in Table B-3.

For the RAMP filing, the weights from the RET tool are used as a placeholder and discussion point for initial MARS calculations (Table B-2) that will spur further refinement with PG&E leadership, the Commission, and other utilities and parties. PG&E's approach to calculating MARS in this RAMP filing is to scale the risk outcome values by a range for each consequence attribute, multiply by weights, and aggregate into a unitless MARS.

It is possible to calculate apparent equivalence among the consequence attributes using the placeholder amounts for weights and range found in Table B-2. But such calculations should only be performed to understand the relationship between the consequences based on PG&E's proposed MARS approach in this RAMP filing. Because they are based on placeholder amounts that need more refinement, if calculations of consequence attribute equivalence are performed, the resulting equivalences themselves are not meaningful.

Table B-2: RAMP Ranges and Weighting Approach

Consequence Attribute	Units/Year	Range	Weights (RET)[a]
Safety	Fatalities and Injuries		30 percent
Safety – Injuries	Injuries	0-1,000	3 percent
Safety – Fatalities	Fatalities	0-100	27 percent
Environmental	USD	$0-$5B	5 percent
Reliability	Customer minutes	0-1B	25 percent
Compliance	USD	$0-$5B	5 percent
Trust	percent change in brand favorability	0-100 percent	5 percent
Financial	USD	$0-$5B	30 percent

(a) Rounded to the nearest percent.

Table B-3: RAMP Ranges and Weights Notes

Attribute	Range Notes	Weight Notes
Safety1_Injury	Based on historical annual OSHA reportable injury values and JIA bounds for serious injuries.	Total safety weight set to RET weight. Weights between injury and fatalities set to 1:100 through S-MAP JUA[a] process.
Safety1_Fatality	Based on historical annual fatalities and JIA bounds.	Total safety weight set to RET weight. Weights between injury and fatalities set to 1:100 through S-MAP JUA process.
Environmental	Range set to $0-$5billion range in-line with RET financial bounds as this is also a USD metric.	Weight set to RET weight.
Reliability	Range set to 0-1billion customer min range based on historical electrical outages. (4million customers for 4 hours≈1billion)	Weight set to RET weight.
Compliance	Range set to $0-$5billion range in-line with RET financial bounds as this is also a USD metric.	Weight set to RET weight.
Trust	This metric is a change in brand favorability and the natural range is 0-100 percent change.	Weight set to RET weight.
Financial	Range set to $0-$5billion range in-line with RET financial bounds.	Weight set to RET weight.

(a) "Updated Summary Report on the Joint Utilities Approach Safety Attribute Test Driver Results" S MAP JUA process September 8, 2017.

The outcome measurement or probability metric for each attribute is calculated for each risk. The probability metric used in the RAMP is the calculation of the

90-100 percent Tail Average (i.e., the average of the worst 10 percent of all outcomes).

Although the use of the mean or expected value outcome distribution is also available and is shown in the filing as an additional data point for comparison, it is only somewhat responsive to small changes in extreme outcomes and is heavily focused on average events that are largely managed through regular operations and maintenance work.

The selection of the 90-100 percent tail average measurement is influenced by PG&E's past experience of catastrophic risks (not an average occurrence). In 2010, PG&E experienced a tragic gas pipeline rupture with ignition event in San Bruno, California where there were several fatalities, many injuries, and significant property damage. From this tragic event came a strong focus on the identification, evaluation and reduction of high consequence risk outcomes. It is therefore reasonable to look closely at a tail percentile or tail average metric for a risk program. Tail percentile measures (such as the P95 value or the 95^{th} percentile) are easily understood, but are insensitive to small changes in the extreme outcomes. Tail averages (such as the average of the worst 10 percent of all outcomes) are stable measures, responsive to subtle changes, and can be readily understood.

After the outcome measurement, weights, and ranges are established, the below formula is used to calculate each consequence attribute score.

$$Consequence\ attribute\ score = \frac{Outcome\ measurement}{Range}\ x\ Weight\ x\ Scalar$$

The scalar used in the 2017 RAMP has the value of 10,000. The use of the scalar provides more intuitive scoring values from 0-10,000 instead of small decimal values between 0-1.

The Consequence attribute scores are summed into a MARS.

$$\text{MARS} = \sum \text{Consequence attribute score}$$

For the RAMP the overall MARS is the average across all six years modeled.

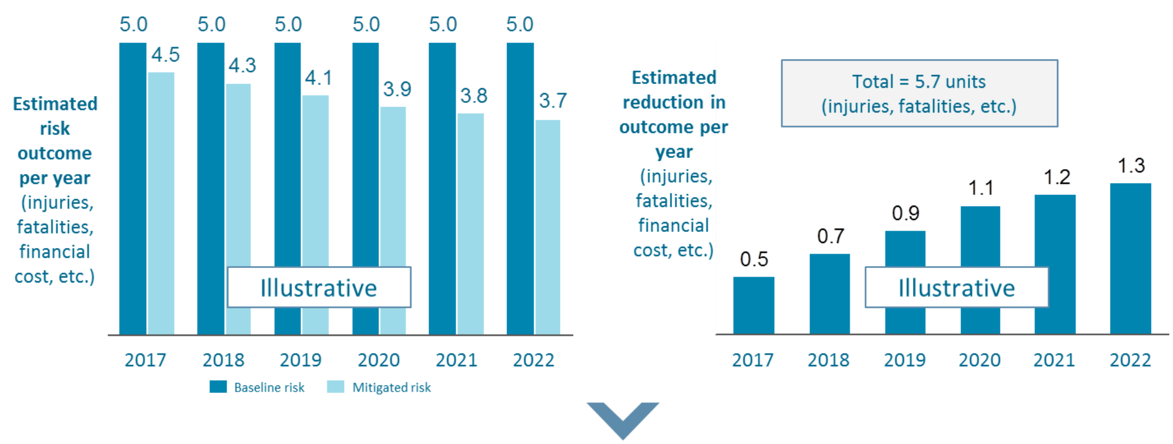
J. Risk Spend Efficiency

A requirement for the RAMP filing is to "present an early stage risk mitigated to cost ratio…"[9] PG&E is using the RSE to present this ratio. RSE reflects the mitigation benefits, measured in risk reduction value, relative to its cost.

Figure B-3 is an illustrative output from a model. For each model with mitigations, the current residual risk, or baseline risk, and estimated residual risk output (based on the assumption that the mitigations will achieve the expected risk reduction) can be compared. In the figure, the current residual risk is in dark blue and the estimated residual risk is in light blue. The difference between these values is the risk reduction achieved through implementing the mitigation or mitigation program (a group of mitigations).

The sum of all years of risk reduction is then divided by the cost of the associated mitigation program(s) to calculate the RSE. A ranked list of PG&E's 2017 RAMP (based on Tail Average RSE) is provided as a workpaper B-60 supporting this chapter.

Figure B-3: Illustrative Risk Outcome for a Consequence Outcome vs. Time (left) and the Associated Risk Reductions (right)



$$RSE = \frac{\sum Risk\ reduction}{\sum Cost} = \frac{5.7}{\$100} = 0.057$$

Risk common currency (injuries, fatalities, etc.) per USD

K. List of Risks and Model Types

There are currently 22 top safety risks quantified as part of RAMP. There are two main types of models: asset or stand-alone models and cross-cutting

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9 D.16-08-018, p. 151.

models. Cross-cutting models are informed by the results from asset or stand-alone models.

Each risk also has a prefix that is used when naming variables that allow for structured aggregation of risk model data into results tables. Prefixes and the @Risk variable naming conventions (documented in-model) should be followed when modifying risk models.

Table B-4: Asset or Stand-alone Models

#	Line of Business	Model Prefix	RAMP Risk Name
1	Gas Operations	GAS	Transmission Pipeline Failure – Rupture with Ignition
2	Gas Operations	GSO	Failure to Maintain Capacity for System Demands
3	Gas Operations	MCDS	Measurement and Control (M&C) Failure – Release of Gas with Ignition Downstream
4	Gas Operations	MCFAC	M&C Failure – Release of Gas with Ignition at M&C Facility
5	Gas Operations	DMSCB	Release of Gas with Ignition on Distribution Facilities – Distribution Cross-bore
6	Gas Operations	CPFAC	Compression and Processing Failure – Release of Gas with Ignition at Manned Processing Facility
7	Gas Operations	DMS	Release of Gas with Ignition on Distribution Facilities – Non-Cross-bore
8	Gas Operations	STO	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility
9	Electric Operations	DIST	Distribution Overhead Conductor Primary
10	Electric Operations	TRANS	Transmission Overhead Conductor
11	Electric Operations	WILD	Wildfire
12	Generation	NUC	Nuclear Operations and Safety – Core Damaging Event
13	Generation	HYD	Hydro System Safety – Dams
14	Safety and Health	CONSAFE	Contractor Safety
15	Safety and Health	EMPSAFE	Employee Safety
16	Safety and Health	MVS	Motor Vehicle Safety
17	Safety and Health	FFD	Lack of Fitness for Duty Program Awareness
18	Information Technology	CYB	Cyber Attack
19	Information Technology	INSIDER	Insider Threat

Table B-5: Cross-cutting Models

#	Line of Business	Model Prefix	RAMP Risk Name
20	Enterprise Records and Information Management	ERIM	Records and Information Management
21	Human Resources	SQWF	Skilled and Qualified Workforce
22	Strategy and Policy	CR	Climate Resilience

L. Preview of Bow Tie and Consequence Tables

Figure B-4 and Figure B-5 are previews of the risk bow ties and consequence tables that will be shown in the risk specific chapters. As stated in Section C, a bow tie methodology is used, where the left-hand side of the bow tie represents the drivers of the risks. Drivers can be broken down into an exposure and a frequency in units of counts per exposure per time to further decompose the left-hand side.

On the right-hand side of the bowtie are the consequences—what could possibly happen after a *single* risk event has occurred.

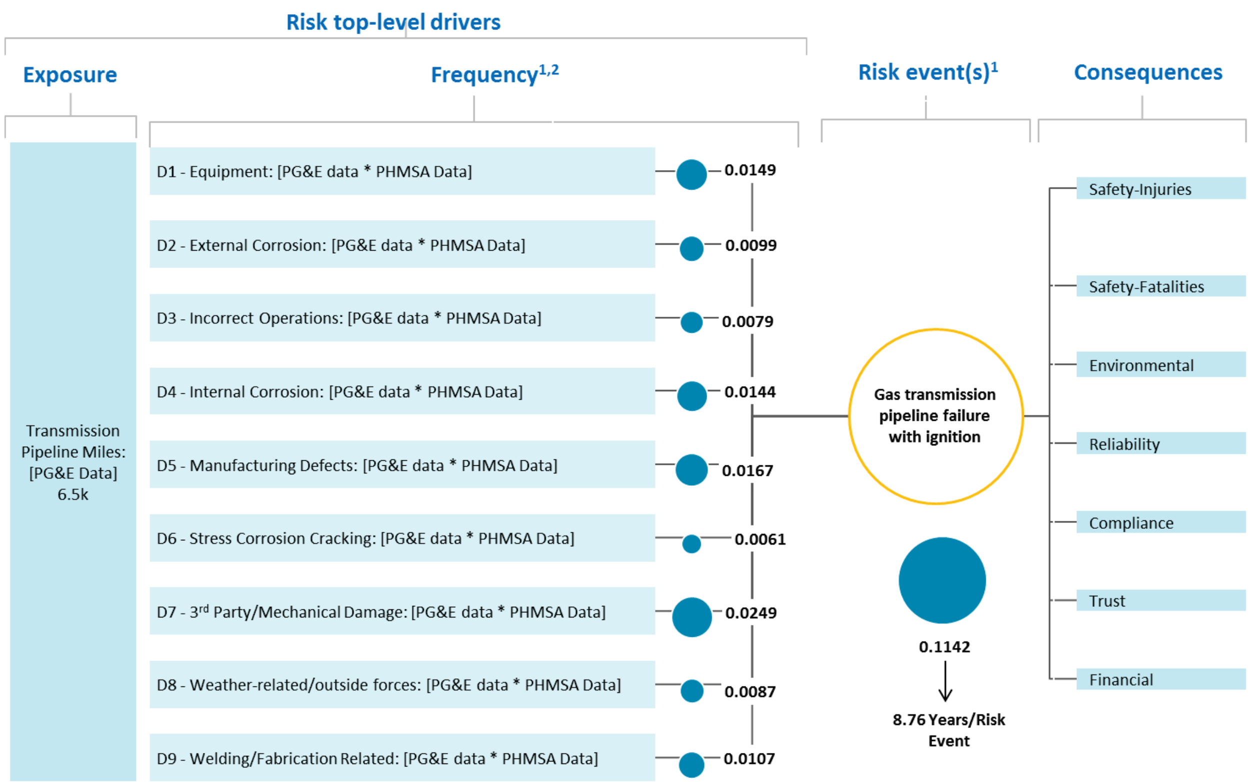
Figure B-4 shows the bow tie for the Gas Transmission Pipeline Failure with Ignition risk. The risk event is the center of the bow tie with the text defining the risk: "Gas Transmission Pipeline Failure with Ignition." The risk event value shown is the expected value of the number of risk events per year and has a value of 0.1142 per year or 8.76 years/risk event. This 0.1142 value is a summation of the driver frequencies as stated in the bow tie footnote:

Equipment	0.0149
External Corrosion	0.0099
Incorrect Operations	0.0079
Internal Corrosion	0.0144
Manufacturing Defects	0.0167
Stress Corrosion Cracking	0.0061
3rd Party/Mechanical Damage	0.0249
Weather-related/outside forces	0.0087
Welding/Fabrication Related	0.0107
Risk Event	0.1142

There are nine drivers associated with this risk event labeled D1-D9: Equipment, External Corrosion, Incorrect Operations, Internal Corrosion, etc. Each driver has an associated distribution of events that lead to the center risk event. For example, using PG&E data and PHMSA data, the Equipment driver has an average of 0.0149 events that have led to a gas transmission pipeline failure with ignition event. This 0.0149 is modeled using a Poisson distribution; also stated within the footnote of the bow tie. All drivers are listed in the order as they appear in their respective models (unless otherwise stated) and at this point are assumed to be mutually exclusive.

The exposure of the risk is stated on the far left-hand column and in this case extends the length of the driver list, representing that the exposure is applicable to all drivers.

Figure B-4: Gas Transmission Pipeline Failure With Ignition Risk – Year 1 – Bow Tie



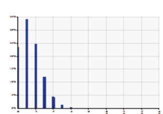
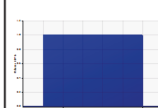
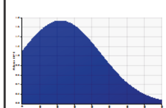
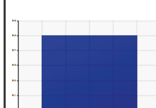
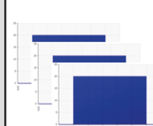
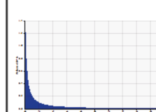
[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.

The right-hand side of the bow tie quantifies the impact if/when a risk event occurs. However, when a risk event occurs, the consequence outcomes for each risk event are different from one event to another. For example, when a gas transmission pipeline failure with ignition event occurs, there may be three injuries reported associated with that event or there may be 10 injuries or zero injures, etc. Consequence input distributions are used to quantify the possible outcomes resulting from each risk event.

Figure B-5 is the associated risk consequence table that accompanies the bow tie from Figure B-4. Input data and distributions used to calculate output distributions are show in the seven consequences columns within the table. For example, when a gas transmission pipeline failure with ignition event is simulated within the model, the Safety-Injuries outcome is calculated using the input percent of 13.3 percent of the risk events will result in an injury (based on PHMSA data). If an injury is calculated to occur, a distribution of the number of injuries is sampled (i.e., will there be 1 injury, 2 injuries, 3 injuries, etc.). The injury distribution used for this risk is a Poisson distribution with a mean value of 7.2. A similar consequence outcome calculation is performed for each associated attribute.

After all calculations are completed, the model produces outcome distributions for each modeled attribute for each year modeled. From the outcome distributions the tail average and MARS can be calculated using the methodology from Section 1.9. The consequence table includes the outcome tail average value in natural units with the same value converted to a MARS calculation in the last two rows. Finally, the MARS for the overall risk is displayed in the bottom right cell. In this instance, MARS is calculated to be 37.62.

Figure B-5: Gas Transmission Pipeline Failure With Ignition Risk – Consequence Table

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PG&E Data	PG&E Data	NA	PG&E Data	PHMSA
Consequence Distributions	Percent of onshore, ignited incidents with injury or fatality=13.3% Mean=7.2 (Poisson) 	Percent of onshore, ignited incidents with injury or fatality=13.3% Mean=1.5 (Poisson) 	Min=$0 Max=$1M (Uniform) 	System likelihood of customer outage =12% x Customers (Normal): Ave=22k Std Dev=23k  x Customer minutes (Uniform): Min=0 days *24*60 Max=2 days *24*60 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Ave=$8.6M Std Dev=$61.2M (Lognormal) 
Outcome-TA-NU[1]	1.06	0.22	$ 565,851	6,299,387		2.0%	$ 9,685,119
Outcome-TA-MARS[2]	0.29	5.94	0.06	15.75		9.78	5.81
						MARS Total	**37.62**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

Similar figures will accompany each risk in individual risk chapters to follow.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER C
SAFETY CULTURE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER C
SAFETY CULTURE

TABLE OF CONTENTS

LIST OF FIGURES

I. Introduction

The focus of this chapter is on Safety Culture, a central and overarching component of Pacific Gas and Electric Company's (PG&E or Company) overall safety approach. PG&E has an unwavering commitment to safety and continues to work to improve its safety culture, creating a consistent, well-communicated, and consolidated approach. As part of that commitment, PG&E's Safety and Health department has aligned under the Chief Operating Officer (COO) to improve accountability and governance. Opportunities for improvement were also identified in communication. In addition, PG&E is focusing on strengthening its safety culture as part of the One PG&E Occupational Health and Safety Plan, and to ensure that it is prevalent throughout the Company, fundamental in all operations, and consistent with PG&E's Mission, Vision, and Culture.

Our Mission

To safely and reliably deliver affordable and clean energy to our customers and communities every single day, while building the energy network of tomorrow.

Our Vision

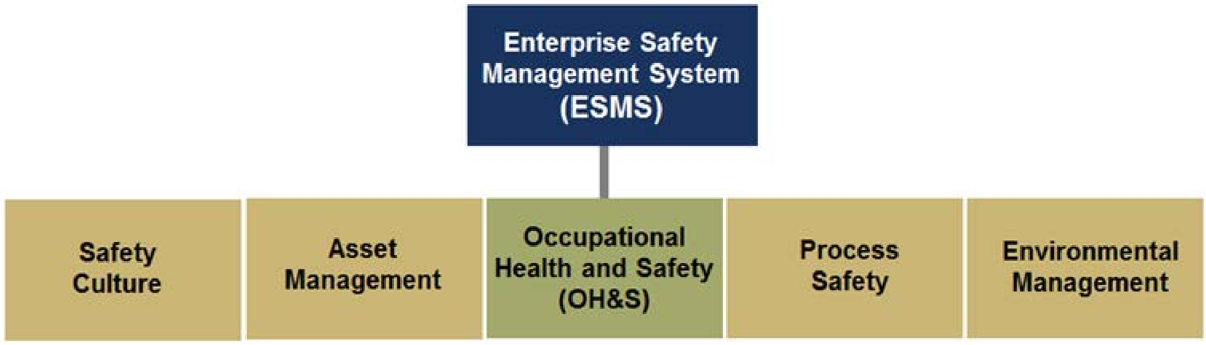
With a sustainable energy future as our North Star, we will meet the challenge of climate change while providing affordable energy for all customers.

Our Culture

- ***We put safety first.***
- ***We are accountable. We act with integrity, transparency and humility.***
- ***We are here to serve our customers.***
- ***We embrace change, innovation and continuous improvement.***
- ***We value diversity and inclusion. We speak up, listen up and follow up.***
- ***We succeed through collaboration and partnership. We are one team.***

To achieve these goals and drive consistency, PG&E is developing a comprehensive Enterprise Safety Management System (ESMS) covering public, employee and contractor safety. This change will enable systematic identification of hazards, reduction of risks and promote an effective safety culture to reduce incidents and injuries. "Management System" in this context refers to a systematic approach to managing a business process, including the necessary governance structures, policies and procedures that support continuous improvement. PG&E implemented a Safety Management System (SMS) in Gas Operations known as PG&E's Gas Safety Excellence Program. This comprehensive approach improved the safety performance and culture of Gas Operations and has contributed to the development of enterprise-wide system to be applied more broadly across PG&E.

Figure C-1: Enterprise Safety Management System Framework



In 2016, PG&E issued its ESMS Policy (the Policy) applicable to all Lines of Business (LOBs) and then engaged Lloyd's Register, an independent third-party auditor, to perform a gap analysis to assess the line of business programs with respect to the Policy. PG&E also performed a review of the major nationally and internationally recognized safety-related management systems and determined that a broader framework was required to reflect the diversity and complexity of PG&E's business.

Moving to an ESMS will help PG&E manage assets and processes to reduce the safety risks, foster continuous learning and improvement, and connect the behavior of employees and contractors to the desired safety culture.

As a part of the implementation of the ESMS, PG&E is developing the One PG&E Occupational Health and Safety Plan, a comprehensive plan to prevent injuries to employees and contractors. The remainder of this chapter will describe how PG&E's One PG&E Safety & Health (S&H) plan will further enhance PG&E's Safety Culture. The plan will be implemented in two phases:

1. The first phase, (a five-year planning cycle) which has been completed, included identifying the risk drivers and developing a mitigation plan for those risks, setting long-term goals and establishing the strategies to meet them.
2. The second phase is a rolling two-year tactical plan which describes how those strategies will be applied within each individual line of business and will incorporate many of the recommendations from the report on PG&E's safety culture that was submitted to the California Public Utilities Commission in May 2017.

A. PG&E's Safety Context

In the last seven years, PG&E has made progress across the enterprise in integrating safety into how it plans, executes and measures work. PG&E's current safety culture and practices are in large part based on the feedback from internal assessments, third-party investigations, benchmarking, and regulatory proceedings.

PG&E has incorporated this feedback in its development and implementation of a number of important new programs designed to strengthen PG&E's overall safety profile. Examples of these programs include safety initiatives in each of the three operational LOBs such as the Gas Safety Excellence Program; the Speak Up program; the Corrective Action Program (CAP); and the 24/7 Nurse Report Line.

In addition to these new programs, PG&E has also accelerated improvements in existing programs, standards, and procedures. For example, PG&E has accelerated improvements in the Contractor Safety Program. These have helped PG&E make significant progress, particularly in public safety—measured by improvements in key performance indicators such as reductions in emergency response times and reductions in gas-system "dig-in" rates. Although this chapter focuses on safety culture, PG&E continues to implement numerous other initiatives and programs in the areas of asset management, process safety and to improve public safety.

Since 2010, there has been moderate progress in reducing rates of employee and contractor injuries and motor vehicle incidents, but PG&E's goals in these areas have not yet been met. The culture, while improved, needed more cohesive vision and coordinated organization required to move forward. The "One PG&E Occupational Health and Safety Plan" is intended to accelerate progress in meeting these goals throughout the Company.

B. PG&E's Focus on Safety Culture

Safety culture is a broad, organization-wide approach to safety management informed by the effectiveness of the systems and processes that are put into place. Safety culture includes the accountability and communication at all levels with established metrics that ensure clear visibility into what is getting done. Safety culture is also the outcome of the systems and process that are implemented. At PG&E, the safety culture is the end result of combined individual and group efforts toward values, attitudes and goals. In creating the One PG&E Occupational Health and Safety Plan, the safety culture will evolve and will be exhibited and driven by a deep concern for employee safety and well-being, and be reflected in all areas and levels within the enterprise. PG&E is working to enhance its safety culture by focusing on instilling safety knowledge, policies and behaviors throughout the organization. Building this strong safety culture requires the framework of the ESMS and the organizational vision of the Five-Year Plan. To drive engagement across the Company, PG&E has focused on empowering employees and promoting open communication in the following ways:

1. PG&E's front-line employees actively participate in the development and implementation of safety mitigations to develop a sense of ownership and accountability needed for successful implementation. PG&E has begun using a process referred to as "learning teams." These teams, facilitated by corporate safety, are comprised of employees who perform the work to improve work processes. The improvements cover areas such as procedures, tooling and pre-job safety briefs. This type of early involvement helps ensure that employees are fully committed to the solutions that are ultimately implemented.
2. PG&E continues to promote a culture where people can raise issues and take actions to improve safety in the field. PG&E has created an environment where employees who openly raise safety issues and near hits are supported for doing so. Furthermore, PG&E employees are authorized and expected to take any actions necessary to protect the safety of the public, their fellow employees and PG&E contractors.
3. A healthy safety culture comes from employees' willingness to speak up about the deficiencies they see, share information, and have crucial conversations with each other. Several initiatives are designed to empower the workforce and encourage these behaviors such as:
   - The Corrective Action Program:

     CAP gives all employees a voice by providing the tools for the identification of safety issues and opportunities for improvement, as well as accountability for follow-up in instances where investigation and corrective actions are necessary.

   - "Speak Up for Safety":

     This communication campaign, implemented in 2016, is designed to encourage the workforce to better communicate around safety without fear of reprisal, allowing for early identification and remediation of potential safety issues.

   - Biennial Employee Survey and quarterly 'pulse' Survey:

     Both surveys are tools to inform progress on safety culture, and identify areas where improvement is needed.

   - Supervisory Leadership Development Program:

     This program provides procedures, guidelines, workshops and coaching for leaders to engage with their employees and each other about safety risks and their mitigation.

- Leadership:

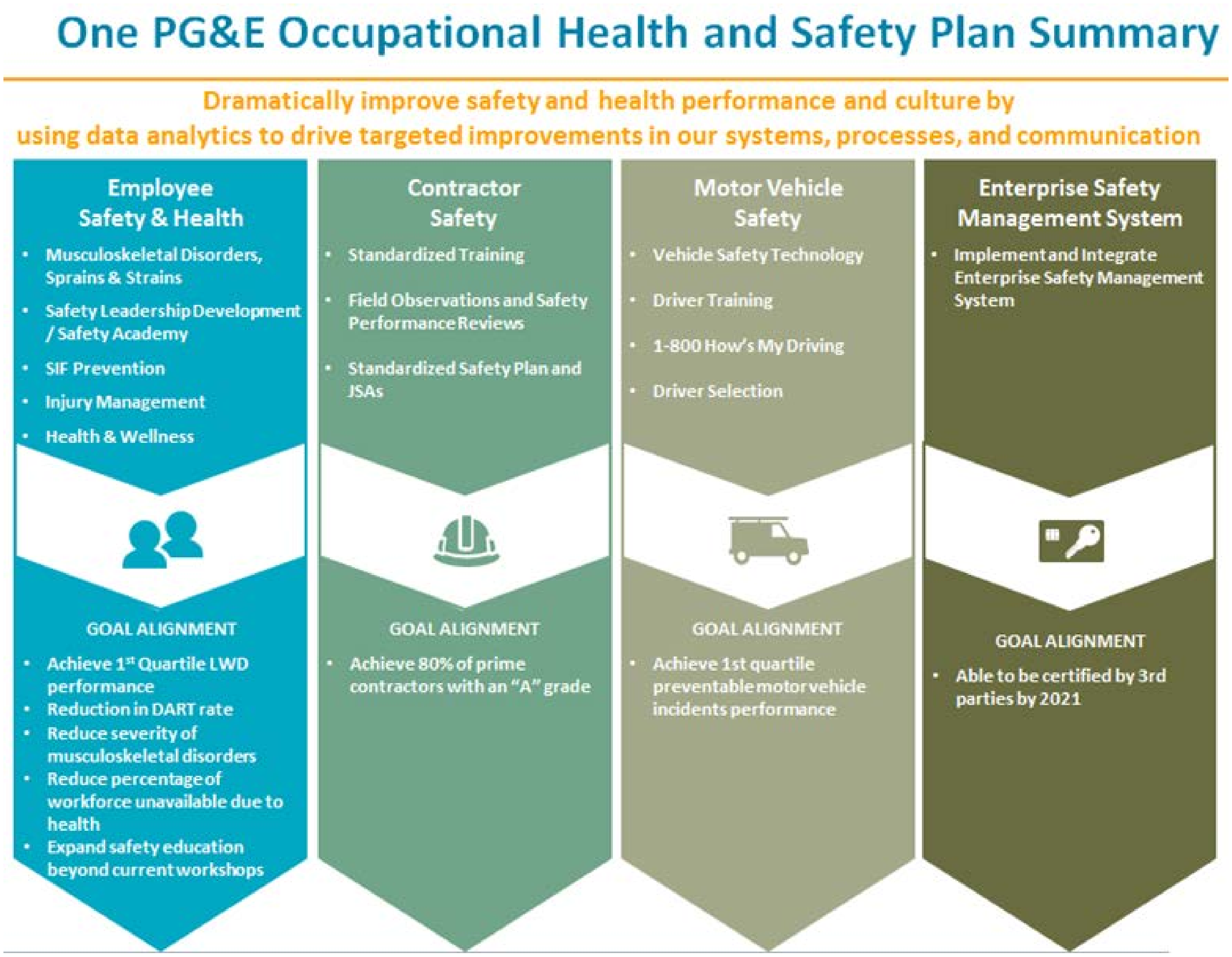
  Leaders are personally accountable for creating a safety culture by demonstrating that PG&E's safety values hold true at every level of the enterprise. Their actions set the tone, clarify expectations, and demonstrate that nothing comes before safety - not deadlines, productivity, or profit.

C. Implementing PG&E's One PG&E Occupational Health and Safety Plan

The plan will include the following components to achieve the outlined vision of safety performance:

1. Define the One PG&E Occupational Health and Safety Plan, by conducting benchmarking studies and leveraging data to drive better decision making. By defining the plan, PG&E is also defining the communication, setting metrics and establishing enterprise alignment (see Employee Safety Chapter for more detail).
2. PG&E has implemented programs that will be enhanced into 2018 and will be maintained as mitigations for the Employee Safety risk. PG&E's vision for continuously improving safety performance is grounded in a structured behavior model, the Plan-Do-Check-Act, for describing specific strategies to achieve these goals across the four focus areas.
   - The "Plan" step includes identifying drivers and tactics;
   - The "Do" step describes the high-level implementation for the tactics;
   - The "Check" step describes how progress will be measured; and
   - The "Act" step describes the process for continuous improvement.
3. Implementation of the ESMS Governance process to support the safety plan. This Governance builds on the existing policies and procedures by introducing frequent audits and observations to analyze risks and exposures and determine whether the mitigations are correctly implemented and effective.

Figure C-2: One PG&E Occupational Health and Safety Plan



II. Methodology for Developing the One PG&E Occupational Health and Safety Plan

The One PG&E Occupational Health and Safety Plan, which is being developed in 2017, provides the overall enterprise strategy and approach to employee and contractor occupational safety and health covering the next five years. It encompasses the four categories of employee safety and health, contractor safety, motor vehicle safety, and SMS.

This plan will help to drive a robust safety culture as it relates to achieving safety and health improvement goals for employees and contractors. The plan includes an integrated approach to drive shared accountability with Corporate Safety and the LOBs. The procedures followed in developing the foundation of the plan includes:

1. Conducting benchmarking studies:

   This benchmark analysis, e.g., serious injuries and fatalities, informed the development of Safety Improvement Plans for the three operational LOBs and improved safety practices.

2. Leveraging data, e.g., incident type and location, to drive decision making, including data analytics to target improvements throughout systems, processes and communication.

3. Developing dashboards to provide a strategic view of loss drivers:

   Dashboards (such as the "Safety and Health Dashboard") were created to provide a strategic view of losses across the enterprise and for each line of business across the strategic focus areas of safety.

4. Defining and implementing appropriate metrics, such as Business Plan Review:

   By utilizing appropriate metrics, PG&E is able to better target its efforts, monitor progress, and hold company leadership accountable for executing its plans.

5. Aligning communications across the LOBs to improve transparency and visibility:

   An aligned communication plan helps the workforce to feel that PG&E creates a supportive, comfortable environment that fosters open communication about safety, compliance and ethics, and other specific topics.

A. Conducting Benchmarking Studies

PG&E's safety plans have been shaped by the feedback from internal evaluations, third-party assessments, benchmarking, and regulators. This feedback informed the development of Safety Improvement Plans for the three operational LOBs, which were reviewed at the enterprise level as part of PG&E's Integrated Planning Process (IPP).

The Company has undertaken benchmarks in the two following main areas:

- The Bureau of Labor Statistics (incidents, illnesses and fatalities by industry); and
- Peer company benchmarking (workforce health conditions, contractor safety, motor vehicle safety, and serious injuries and fatalities).

In addition to these benchmarks, the Company holds:

- A once a year roundtable for California utilities to share utility insights in terms of best practices to decrease the number of incidents; and
- A twice a year peer industry group of outside safety professionals to focus on the prevention of serious injuries and fatalities.

B. Leveraging Data to Drive Decision Making

PG&E has conducted analyses of the safety incidents that have occurred within PG&E to get a holistic view of not only where the incidents were occurring but also the type of incidents.

This analysis informed PG&E how it compared to similar utilities and best in class organizations and provides a means to focus PG&E's resources to have the greatest impact on preventing injuries and illnesses for employees and contractors of PG&E.

In the first phase of plan development, PG&E applied data analytics to drive targeted improvements throughout systems, processes and communication. The identified five-year goals for occupational safety and health are:

- Achieve 1st quartile Lost Work Day (LWD) performance
- Achieve 35 percent reduction in Days Away, Restrictions and Transfers rate
- Target exposures that drive musculoskeletal disorders (MSD)
- Reduce percentage of workforce unavailable due to health by 8 percent
- Expand safety education beyond current workshops
- Achieve 80 percent of prime contractors with "A" grade
- Achieve 1st quartile preventable motor vehicle incidents performance
- Achieve conformance with an independent occupational safety and health standard such as ANSI Z10

These goals cover the five years of the One PG&E Occupational Health and Safety Plan and were defined considering the following eight focus areas:

- Musculoskeletal Disorder, Sprains and Strains
- Serious Injury and Fatality Prevention
- Workforce Unavailable Due to Health
- Safety Leadership
- Injury Management
- Motor Vehicle Safety
- Contractor Safety
- Safety Management System

C. Developing Dashboards to Provide a Strategic View of Loss Drivers

In order to provide visibility to the line of business, owners' dashboards were created to provide a strategic view of losses across the enterprise and for each line of business across the strategic focus areas of people safety. A separate dashboard exists for contractor safety. In 2018, PG&E will bring this information together onto one platform with additional detail to improve decision making by leaders.

D. Defining and Implementing Appropriate Metrics

PG&E has started tracking a more extensive set of safety metrics. These metrics allow PG&E to better target its efforts, monitor progress, and hold company leadership accountable for executing its plans. These measures are primarily tracked through the Business Plan Review process, a monthly, data driven conversation in which senior leadership reviews the Company's performance against its two-year goal. Scorecards are developed for each review to ensure clarity and accountability for results.

Since 2012, PG&E's safety metrics expanded to include contractor safety as well as public and employee safety measures and have evolved to include more leading indicators. The Company now tracks 27 safety metrics as part of its safety dashboard, including:

- 14 employee safety measures
- 3 contractor safety measures
- 10 public safety measures

PG&E's use of public, employee and contractor safety performance metrics has matured in recent years and PG&E is now employing more leading indicators such as:

- Near hit reporting, which allows employees to participate in a program designed to avoid repeat incidents;
- Evaluation of the quality and timeliness of corrective actions (known as the "corrective action index") to mitigate the potential for repeat incidents;
- Use of in-vehicle monitoring technology to provide data around hard braking, hard acceleration and potential incidents of speeding.

These indicators measure the behaviors we are trying to encourage, and we expect that positive results with these leading indicators will drive positive safety results.

E. Aligning Communications to Improve Transparency and Visibility

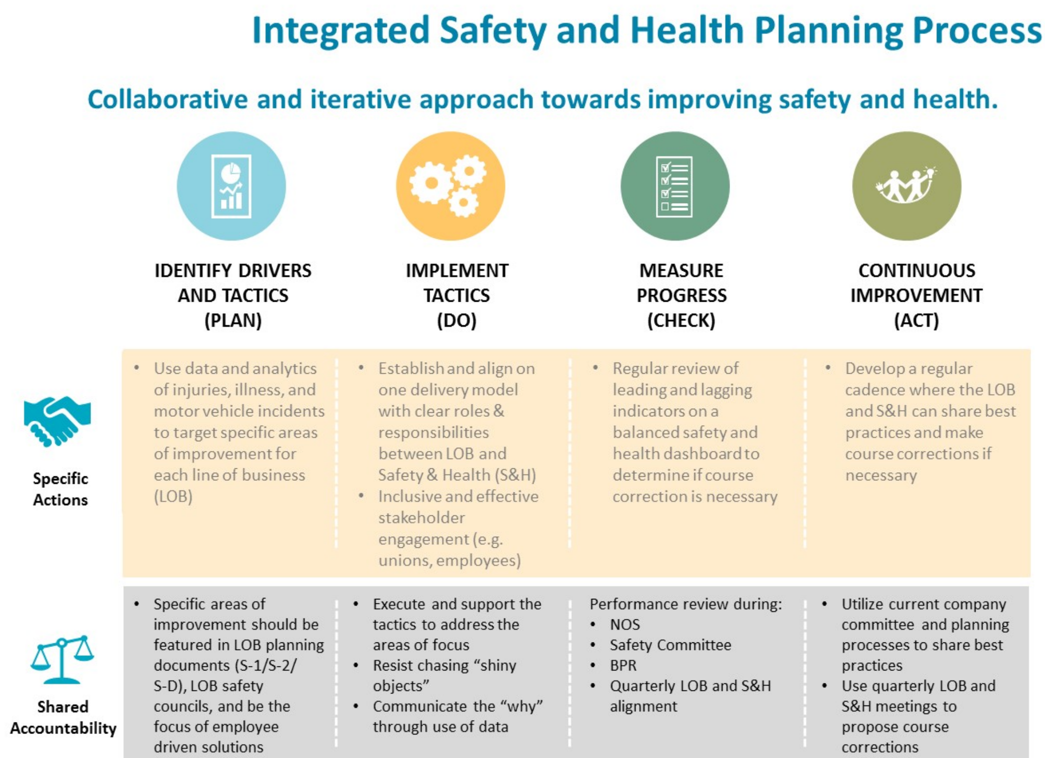
S&H has developed a communication strategy that is focused on creating awareness, engagement and appreciation of our programs. The strategy—developed by a cross-section of communication professionals and line-of-business safety leaders—positions S&H as an organization that employees can rely on for timely information and safety expertise. PG&E seeks to encourage a supportive environment that fosters open communication about safety, compliance and ethics, and other topics. This aids in all aspects of reporting, behavior change, engagement, and safety performance.

PG&E is establishing new communication processes to provide transparency on lessons learned from prior events and regular communications on specific required actions. This includes:

- Daily communications through the Daily Digest (an email bulletin pushed to all employees) on related Safety and Health topics.
- Monthly leader packets that target a specific area of focus for the month such as preventing strains and sprains. The leader packets provide the right information to the right level at the right time to target specific behaviors that are impacting loss.
- Enhanced communications by reporting, training and support to improve timely reporting through the 24/7 Nurse Report Line "timeliness of reporting injuries" metric, which PG&E began tracking in 2014, as a company-wide Short-Term Incentive Plan metric for 2016. This reaffirmed PG&E's emphasis on encouraging employees to "speak up" to get care faster for work-related injuries and discomfort. Timely reporting of injuries, a leading indicator, was added to PG&E's safety dashboard to help set goals and track progress in this area.
- PG&E also began to leverage work done in 2014 to improve PG&E's communications about safety in response to feedback from employees across the Company. In 2014, an analytical consulting firm Monitor 360 completed analysis of survey comments from the 2012 and 2014 Premier surveys to identify "narratives" that indicate strategic opportunities to support continuous improvement of PG&E's safety culture. This report began to inform PG&E's safety communications in 2015 and was later utilized in 2016 to develop a safety communication campaign called "Speak Up for Safety."

Prior to Session 1 of our IPP, a meeting was held individually with each member of the Executive Management team as well as a presentation to the Board of Directors to socialize with them the One PG&E Occupational Health and Safety Plan. Alignment for the plan was approved at the end of the Session 1 meetings in July.

Figure C-3: Planning Process



III. The Key Initiatives of the Occupational Health and Safety Plan

As discussed above, to support the development of the One PG&E Occupational Health and Safety Plan, PG&E utilized historical data, industry benchmarking and its IPP to align the enterprise on the Plan.

The resulting One PG&E Occupational Health and Safety Plan reflects the collaboration and engagement across all aspects of PG&E's business and provides the basis for 2018-2019 tactical plans. The 2018-2019 tactical plans are being developed now as part of Session 2 and will be completed in 2017.

PG&E promotes the enterprise's governance through the eight following focus areas:

- Musculoskeletal Disorder, Sprains and Strains
- Serious Injury and Fatality Prevention
- Workforce Unavailable Due to Health
- Safety Leadership
- Injury Management
- Motor Vehicle Safety
- Contractor Safety

- Safety Management System

A. Musculoskeletal Disorder, Sprains and Strains: Musculoskeletal Disorders

MSDs, Sprains and Strains make up 64 percent of all injuries. Focus on this area is essential to reduce LWDs, restricted time due to health and severity of MSDs.

MSDs are caused by repetitive over use or exertion on the body. The result can be long term injuries.

To address this risk, PG&E's plan focuses on the enhancement of the Ergonomic Assessments, Industrial Athlete Program and Early Symptom Intervention activities as defined by the work areas with most injuries. PG&E will use Learning Teams[1] to develop approaches and solutions to this risk, and will ensure each LOB is accountable for implementing the Learning Teams' recommendations.

To measure progress in addressing this risk, PG&E will look at percentage of participation in the Industrial Athlete program, the number of ergonomic assessments and the extent that that the LOBs have implemented solutions to ergonomic risks.

PG&E will quarterly review the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and to determine whether there is adequate cross functional alignment among LOBs.

B. Serious Injury and Fatality Prevention

A SIF (Serious Injury and Fatality) is any incident that results, or could potentially result, in any of the following to employees or directly supervised contractors resulting from work performed for PG&E:

1) Work-related fatal injury or illness;
2) Work-related injury or illness that required immediate life-preserving rescue action, and if not applied immediately would likely have resulted in the death of that person; and
3) Work-related injury or illness that resulted in a permanent and significant loss of a major body part or organ function.

PG&E's SIF Prevention program focuses on the specific exposures which have led to serious injuries at PG&E in the recent past. Initial analysis of SIF data found

1 Learning Teams are small teams of 5-7 front-line employees led by a credible facilitator, who has respect of both of 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.

22 such exposure factors, many of which are common across LOBs. The SIF Prevention Field Guide and the Observation Program leverage the exposure factors to ensure SIF is in the forefront for field workers. Rigorous processes identifying incidents with SIF potential focus investigative resources on understanding these situations and developing the appropriate corrective actions to prevent and reduce the likelihood of recurrence. This same process is applied to actual SIF events.

The SIF Prevention Field Guide explains the exposure factors and the prevention measures and behaviors that reduce SIF potential. PG&E is currently enhancing its Observation Program through better tools, governance, oversight, and reporting. By recording specific aspects of an observation (e.g., at-risk behaviors observed, SIF exposure factors identified), the opportunity to learn from observations is multiplied through visibility to the data.

Through review of all injuries and near hits, PG&E identifies incidents with SIF potential for an in-depth cause evaluation. The results of these investigations and the identified corrective actions are monitored through **the CAP** to ensure timely completion and effectiveness. The CAP encourages employees to speak up for safety and identify issues related to assets, records, or processes that, when addressed, reduce public safety risks. It gives all employees a voice by providing the tools for the evaluation of all safety issues as well as accountability in instances where investigation and corrective actions are necessary. As of July 2017, all employees have access to CAP.

PG&E will continue to enhance its causal evaluation standards and expand the use of Learning Teams to increase learning and SIF prevention. PG&E will review, annually at minimum, the results of these programs to evaluate the effectiveness of the programs, and to determine whether there is adequate cross functional alignment among LOBs.

C. Workforce Unavailable Due to Health

A key driver for the risk of an unavailable workforce due to health is the fact that 5 percent of the population accounts for 55 percent of medical spend, 50 percent of PG&E's working population has at least one chronic condition, and individuals with at least one chronic condition are up to three times more likely to be injured on the job.

To address this risk, PG&E plans to expand from 5 percent to 20 percent of this highest-risk population by end of 2017 a program which provides targeted healthcare decision-support for medical care, treatment and medications. PG&E will encourage employee participation in annual health screenings, increase health coaching to support healthy habits and changes, and increase use of clinics and telemedicine kiosks for immediate care.

PG&E will regularly review the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and to determine whether there is adequate cross functional alignment among programs. Additionally, PG&E will review employee utilization of clinics, participation in health screenings, and utilization of health coaching.

D. Safety Leadership

Leadership in safety is essential to an effective safety culture. Leaders drive culture, culture change and accountability.

To enhance safety leadership, PG&E will accelerate and enhance the Crew Leader Training, enhance its coaching and observations program, use observations to target areas where follow-up is necessary, and establish the use of Learning Teams. Continued integration of the skills and language from **the Safety Leadership Development (SLD) Program** into the new and improved programs described earlier will reinforce PG&E's desired safety culture. This program began in 2014 and targeted supervisors, managers, and superintendents overseeing employees with the highest potential for hazards. This program provides procedures, guidelines, workshops and coaching for leaders to engage with their employees and each other about safety risks and their mitigation. Classroom training is supplemented by in-field coaching, observations, metrics and annual Officer and Director Safety Summits. Efforts are underway to refine the program to accelerate and improve the quality based on lessons learned from the first year of delivery to crew leaders. To measure progress, PG&E will monitor the percent of participants who have received coaching and feedback after participating in SLD training. Metrics are also being developed to assess the quality of the observations of SLD participants completed by safety coaches that are experts in the SLD curriculum.

PG&E will review annually at minimum the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and determine whether there is adequate maturity of these capabilities and cross functional alignment among LOBs. Safety leadership will also be an integrated element of the ESMS described earlier.

E. Injury Management

Injury management is essential to employee safety. Injury management is important because it shows employees that their leaders are concerned with their well-being; promotes healing and early return to work; and ensures quality and appropriate medical care for the employee. Early injury reporting and early return to work is essential to Injury Management.

To address the risk of prolonged injury due to lack of proper early care and/or lack of adequate reporting processes, PG&E is instituting Injury Management programs. PG&E has established a job task bank available to all LOBs. The job task bank allows PG&E employees to return to work while accommodating any medical restrictions associated with an injury. In addition, PG&E will enhance its overall management of an employee's journey from initial notification of an injury to his/her return to work.

Ways to measure the effectiveness of PG&E's Injury Management program include a review of the number of lost time cases, the number of cases where an accommodation was not made, and whether injuries were reported in a timely fashion. PG&E will review at least annually the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and to determine whether there is adequate cross-functional alignment among LOBs.

F. Motor Vehicle Safety

The primary driver for the Motor Vehicle Safety risk is the fact that 94 percent of Motor Vehicle Incidents are due to driver behaviors (including distracted driving, risky driving behaviors and fatigue).

To address this risk, PG&E is enhancing its DriverCheck coaching program, as well as its LOB accountability for driver safety (see Motor Vehicle chapter). PG&E is also focused on delivering consistent, timely and targeted Driver Training, adopting and implementing Vehicle Safety Technology, and introducing a Driver Selection process that uses all data points to create a driver risk profile.

PG&E expects to measure effectiveness of these activities through analysis of the DriverCheck rate, training completion and vehicle technology data, e.g., hard brake rate, hard acceleration rate, and over 80 miles per hour rate. These metrics are leading indicators of potential motor vehicle incidents and provide a method for targeting interventions to improve driver behaviors.

PG&E will review annually at minimum the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and to determine whether there is adequate cross functional alignment among LOBs.

G. Contractor Safety

The Corporate Contractor Safety Program was fully implemented as of December 31, 2016 and includes measures to effectuate the requirements in the Kern Settlement Agreement (Kern OII). PG&E seeks to implement additional program initiatives to improve contractor safety performance and to ensure compliance is maintained with the program requirements throughout the enterprise with the goal of reaching 1st quartile contractor safety performance over the next several years. (See Contractor Safety chapter). There are four primary components to the program:

- Pre- Qualification – Ensure that all prime contractors and subcontractors sourced for medium- and high-risk work at PG&E meet minimum safety qualifications prior to contract execution and commencement of work activities.
- Safety Planning – Ensure that all medium- and high-risk work activities have safety factored into the job plan from start to finish.
- Oversight – Ensure that all medium- and high-risk work activities are governed by qualified PG&E oversight and that all work follows the safety plan designed for the job.
- Evaluate – Conduct post-job evaluations to capture contractor safety performance, including lessons learned, to enhance continuous improvement and to identify quality or problematic contractors.

Enhancements are planned in all aspects of this program, including quarterly Contractor Safety Program compliance assessments, integrating contractor field safety observations as part of PG&E's observation program and implementing a contractor badging system to track training and qualifications in the field.

To measure the effectiveness of these enhancements, PG&E will review the number of assessments completed, whether the corrective actions were completed on time, and whether contractors complied with their training requirements.

PG&E will regularly review the results of these programs through injury data analysis to evaluate the effectiveness of the programs, and to determine whether there is adequate cross functional alignment among LOBs.

H. Safety Management System

The SMS is a component of the ESMS and provides a uniform approach to the management of Corporate Safety, ensuring governance, process consistency, and rigor. PG&E is implementing an SMS that will include controls and governance for all safety and health-related processes, and will focus not only on public safety, but on employee and contractor safety as well. The SMS is expected to be fully implemented by 2021.

IV. Internal Governance Framework: Board Engagement

The PG&E Corporation and Utility Boards of Directors are ultimately responsible for oversight of safety at the companies, and have recently clarified the oversight roles for safety generally, as well as expanded the oversight roles into governance of the corporate safety function.[2]

Both Boards of Directors have established a Safety and Nuclear Oversight Committee (SNO Committee) that has a basic responsibility to specifically oversee and review policies, practices, standards, goals, issues, risk, and compliance relating to safety. Corporate Safety plays a role in every SNO meeting by providing updates on safety plans (like the five-year plan) and relevant topics (outcomes of investigations). There is ample time for the board to ask questions and in each meeting they have asked if Corporate Safety requires additional support. Among other things, the SNO Committees review and discuss:

- Significant safety issues and legal developments;
- How to improve safety performance at the companies;
- Instillation of strong safety culture at the companies;
- Appropriate safety goals to be included in company executive compensation programs; and
- The adequacy and direction of each company's corporate safety function (including oversight for the Chief Safety Officers and for the budget and staffing for the function).

The Boards hold regularly scheduled meetings, and the SNO Committees must meet at least six times per year. Members of PG&E management regularly attend Board and Committee meetings. The SNO Committees' charters specifically require that the Chief Safety Officer provide regular reports regarding:

- Status of safety policies, practices, standards, goals, issues, risk and compliance; and
- Activities relating to establishment and performance on safety metrics.

The SNO Committee meetings include extensive discussion and engagement with Board members and management regarding safety. Each company's Board of Directors also receives reports regarding matters reviewed—including safety matters—and discussed at SNO Committees, and may request presentations regarding specific safety topics.

As of Q1, 2017, Safety now reports to the Chief Operating Officer and as a result, all LOBs leads and Corporate Safety reporting to the same person. This elevates Safety to an enterprise perspective and provides Safety with the authority and direction to

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[2] For information regarding PG&E's compensation policies related to safety, see Chapter D.

address issues that impact the enterprise. This also ensures a clean line of communication regarding any gaps in programs or performance and also ensures if there are things not getting support they have the reporting structure to report it up and then it can come down to the LOB's through that process. Further, Corporate Safety also has a dual reporting structure to the SNO Board. This ensures safety can elevate issues to the highest level if needed to bring visibility and garner support to drive the intended outcomes.

V. Conclusion

PG&E has made moderate progress in reducing rates of employee and contractor injuries and motor vehicle incidents, but has not yet achieved it goals. PG&E is moving towards adopting an enterprise-wide SMS over the next five years. Within the adoption of the ESMS, PG&E will focus on improving the employee and contractor safety program by adopting a "One PG&E Occupational Health and Safety Plan" for the entire enterprise. The "One PG&E Occupational Health and Safety Plan" is intended to accelerate PG&E's progress in this important area on an enterprise-wide basis.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER D
COMPENSATION POLICIES RELATED TO SAFETY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER D
COMPENSATION POLICIES RELATED TO SAFETY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

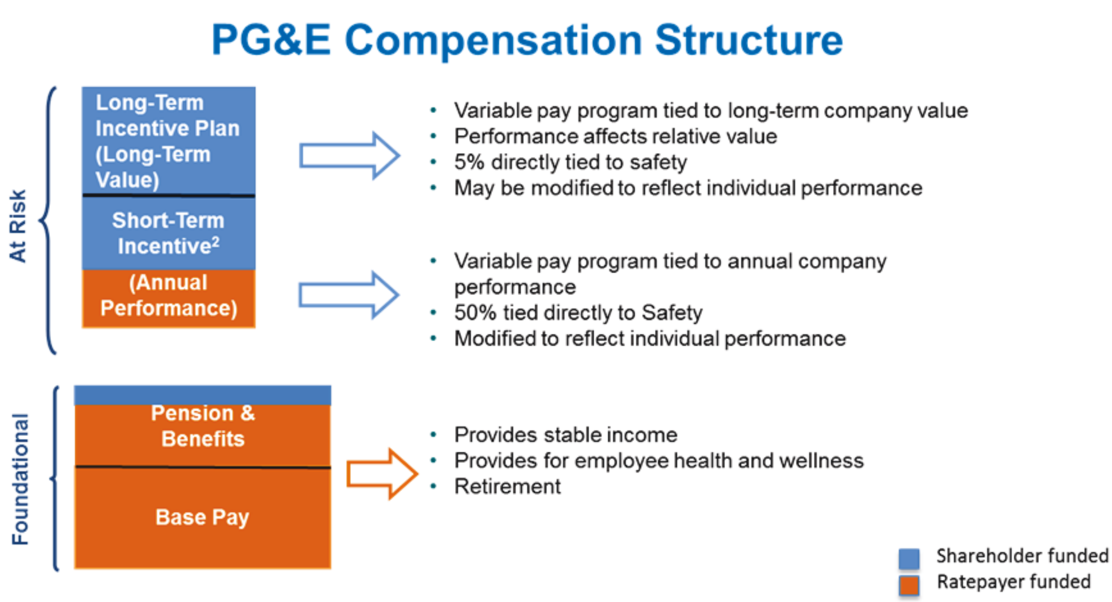
I. Introduction

One of the ways that Pacific Gas and Electric Company (PG&E or Company) is focusing on strengthening its culture of safety is by incorporating safety into its compensation policies and has made safety a significant component of employees' at-risk compensation.[1] This chapter will describe: (i) the structure of compensation for PG&E's employees, including the role that safety plays in PG&E's at-risk compensation, and (ii) how safety metrics included in that compensation are established and evaluated.

II. Overview of Compensation

A general overview of the structure of PG&E employee's compensation can be found in Figure D-1 below.

Figure D-1: PG&E Compensation Structure



Generally, PG&E employee compensation consists of two distinct categories—"foundational" and "at-risk" compensation, with the proportion of at-risk pay, and the overall proportion funded by shareholders increasing as you move up the organizational structure.

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1 This chapter is included in PG&E's Risk Assessment and Mitigation Phase filing as required in Decision 16-08-018 at 152.

A. Foundational Compensation

As defined by PG&E, foundational compensation includes an employee's base pay, as well as pension and benefits. This is the portion of an employee's compensation designed to provide a stable income, as well as health, wellness and retirement benefits. Foundation pay, by design, is not meant to be at-risk. For executive employees, the foundational piece constitutes about 40 percent of their overall compensation, whereas for the majority of PG&E's represented employees it represents 100 percent of their overall compensation.

1. How Safety factors into Foundational Compensation

PG&E's non-represented employees, from the Chief Executive Officer (CEO) to front line employees, as well as those salaried employees represented by the International Brotherhood of Electrical Workers, Local 1284 (IBEW) and the Engineers and Scientists of California, Local 20 (ESC) are evaluated each year on individual performance goals and how well they demonstrate a defined set of competencies. Performance goals will frequently include safety related objectives, specific to the employees job function. The first competency is "Puts Safety First," PG&E's safety competency. The following are some of the ways that employees are expected to demonstrate their commitment to safety for themselves and their team:

- Openly acknowledges safe behavior and encourages employees to report safety issues;
- Provides appropriate training, resources and support to foster a safety-first culture;
- Identifies and takes action to mitigate safety risks;
- Shows by actions and words that public and employee safety come first;
- Acts to improve safety practices for self and team;
- Stops unsafe behavior and raises safety concerns regardless of "chain of command"; and
- Safeguards physical and electronic/digital assets.

Each participating employee is assigned a performance rating that measures how well they did in achieving their individual goals and how well they demonstrated PG&E's defined competencies, including "Puts Safety First." This performance rating is then considered when determining an employee's annual base pay or "merit" increase and, therefore, the amount of the employee's base pay for the following year.

While the majority of PG&E's represented employees do not participate in this annual evaluation, the leaders who establish work priorities and are personally accountable for instilling the safety culture in their employees, do participate. In this way, they are responsible for creating an environment where all employees understand that Safety is PG&E's first and foremost priority.

B. At-Risk Compensation

As defined by PG&E, at-risk 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. There are two main at-risk components of compensation—the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). All salaried employees, those hourly paid employees who are not represented by a labor agreement, and salaried employees represented by the IBEW and the ESC participate in PG&E's STIP.

Participation in PG&E's LTIP program is more restricted, with only a portion of PG&E's management employees and all executive level employees participating.

1. STIP

STIP is PG&E's variable pay program tied to annual company performance. PG&E has one STIP program for all employees, while participation rates vary with level, metrics and weighting applied to those metrics do not vary by level or organization. Table D-1 below shows the target STIP participation rates for employee level.

Table D-1: Target STIP Participation Rates

Job Level	Target Participation Rate (% of Base Pay)
All Support Levels	6%
Professional Levels: Associate, Career, Senior and Expert	10%
Leadership Level: Supervisor	12%
Professional Level: Principal Leadership Levels: Manager and Senior Manager	15%
Professional Level: Chief Leadership Level: Director	20%
Leadership Level: Senior Director	30%
Executives	Approved by Compensation Committee or Board of Directors (in 2017 the participation rate ranges from 40% to 125%)

STIP is comprised of Safety Financial, Customer, and metrics, with the safety metrics currently constituting 50 percent of the total STIP program. The 2017 STIP program consists of the following nine public and employee safety measures:

- Diablo Canyon Power Plant Reliability and Safety Indicator for Unit 1 and Unit 2;
- Electric Overhead Conductor Index (composed of the circuit miles of electric distribution infrared inspections completed, the circuit miles of distribution electric conductor upgraded/replaced, and the number of trees trimmed/removed as part of the vegetation management program);
- 911 Emergency Response;
- Gas In-Line Inspection (ILI) and Upgrade Index (composed of two equally weighted components: ILIs and In-Line Upgrades);
- Gas Dig-ins Reduction;
- Gas Emergency Response;
- Serious Injuries and Fatalities (SIF) Corrective Action Index (composed of the percentage of SIF corrective actions completed on time, and the quality of corrective actions as measured against an externally-derived framework);
- Serious Preventable Motor Vehicle Incident Rate; and
- Timely Reporting of Injuries.

The remaining 50 percent of PG&E's STIP is made up of customer measures that comprise 25 percent, and a financial metric that constitutes 25 percent of the total program.

a) How STIP Safety Metrics Are Established and Evaluated

STIP metrics are established each calendar year (Plan Year) by the Compensation Committee of the PG&E Corporation Board of Directors (Compensation Committee).

The process begins with PG&E's Integrated Planning process, through which lines of business identify the key safety risks and other issues, along with potential metrics. The Company sets specific goals for the metrics, which are based on historical performance, benchmarking data, and other relevant information.

Typically, the Company's senior leadership makes recommendations on the metrics to be included in the following year STIP in the fourth quarter of each year. (Many metrics beyond those ultimately included in the STIP become part of the Business Plan Review process and are monitored by the Company's senior leadership on a monthly basis.) The STIP metric recommendations move along parallel tracks to the Safety and Nuclear Oversight (SNO) Committee and to the Compensation Committee of the PG&E Corporation Board. The SNO Committee reviews the metrics and provides feedback to the Compensation Committee about the metrics that should be included in the STIP. Ultimately, the Compensation Committee makes final decisions about which metrics will be included in the STIP for all employees.

The Company evaluates its performance against the goals each month, and the annual result is used as the basis for the STIP payout. Goals for the following year are established using the same process described above. PG&E has provided its 2016 and 2017 STIP Scorecards as Attachment A to this exhibit. Each Scorecard provides key pieces of information about the metrics that make up the program for the year, including the weighting of each metric; the threshold, target and maximum payout target performance goals; the results (i.e., PG&E's actual performance for the metric); and the overall STIP score for the year.

b) How Safety Affects STIP Payout

With respect to safety, both an executive and non-executive employee's STIP payout is affected by the Company's STIP score (i.e., Company performance against established metrics). The Company's final STIP performance score is determined by evaluating achievement of business performance measures based on the rating scales and standards established at the beginning of each Plan Year. The STIP Score can range from 0 percent to 200 percent of target each year. Before the final STIP score is finalized, the Compensation Committee reviews and approves the results. Notwithstanding the Company performance score, the Compensation Committee has ultimate discretion when approving STIP each year for all employees, other than those holding a president or CEO position (which requires approval by the full board). The Compensation Committee has exercised this discretion in the past—some examples include the reduction in 2015 of the score on the Lost Work Day Case Rate to zero for all employees, to reflect the seriousness of Employee Safety, due to the death of an employee and a contractor. And, in 2011, the

Compensation Committee of the Board exercised its discretion and reduced executives' 2010 STIP payout to 0 percent, and the appropriate full Boards exercised the same discretion and reduced the 2010 payout to 0 percent for the President and CEO as a result of the San Bruno accident.

Additionally, both an executive and non-executive employee's STIP payout is impacted by the individual employee's performance on competencies and individual goals. The STIP payout can be impacted In addition to employee's annual base pay or "merit" increase as described above.

2. LTIP

LTIP is PG&E's long-term variable pay program. LTIP consists of two components—Performance-based shares (Performance Shares) and Restricted Stock Units (RSU). Performance Shares pay out in a range from zero to 200 percent based predominantly on how well PG&E's stock performs compared to a comparator group over a 3-year period. While LTIP performance is tied primarily to long-term company value, it also includes a 5 percent safety metric. In 2017 that safety metric is SIF: Effectiveness of Corrective Actions.

While the safety metric accounts for 5 percent of LTIP, long-term company value, the primary driver of LTIP performance, can also be significantly impacted by safety issues. For example, following the San Bruno accident, for the respective 3-year periods corresponding to 2012-2014 payouts, PG&E's stock underperformed the comparator group, resulting in a zero payout of Performance Shares for three years. Performance Shares paid out at 35 percent and 50 percent respectively in 2015 and 2016—significantly below target.

RSUs pay out each year notwithstanding the Company's performance against the Performance Comparator Group. However, the value of those shares is also affected by the performance of the Company's stock.

C. Reward and Recognition

When an employee goes above and beyond their regularly assigned job duties, supervisors can recognize that performance through PG&E's Reward and Recognition program. The Reward and Recognition program supports PG&E's efforts to strengthen the safety culture by providing a means to recognize employees who contribute over and above their normal job duties. Examples of safety specific performance recognized in 2017 include, developing new procedures to address specific operational issues, providing after hours or emergency support, or performing safety related work beyond assigned job duties.

III. Conclusion

PG&E's compensation policy strengthens the culture of safety by appropriately incorporating safety performance into both base pay and at risk compensation. From the front line supervisor to the chief executive officer, safety behaviors and results impact annual and long-term compensation. When safety performance has fallen short, the PG&E Corporation board of directors has taken action to reduce at-risk pay in response. As PG&E's safety culture changes and matures the specific safety metrics and how safety impacts employee compensation will continue to evolve so that safety remains in the forefront.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER D

ATTACHMENT A

2016 SHORT-TERM INCENTIVE PLAN (STIP)

YEAR-END RESULTS

2016 Short-term Incentive Plan (STIP) Year-end Results

These performance measures and targets have been approved by the Compensation Committee of the PG&E Corporation Board of Directors, which retains complete discretion to determine and pay all STIP awards to officers and non-officer employees.

2016 Year-End STIP Update

Key Points

We were successful in hitting our year-end targets for **seven of our thirteen** Short-term Incentive Plan (STIP) measures. As a result of our performance, the overall PG&E 2016 STIP score is 0.936[1]. A detailed interpretation of the STIP 2016 Scorecard follows along with an explanation of our final results.

STIP 2016 Scorecard

2016 STIP Measures	Weight	STIP Performance Targets (1)			Results			
		Threshold 0.5	Target 1.0	Maximum 2.0	Results	Quartile	Unweighted Score	Weighted Score
Safety	**50%**							**0.423**
DCPP Reliability and Safety Indicator – Unit 1	4%	94.2	98.7	100.0	100.0	1st	*2.000*	**0.080**
DCPP Reliability and Safety Indicator – Unit 2	4%	94.2	98.7	100.0	90.0	3rd	*0.000*	**0.000**
Transmission & Distribution (T&D) Wires Down	5%	3,000	2,572	2,400	3299	2nd	*0.000*	**0.000**
911 Emergency Response	5%	95.0%	97.5%	98.5%	98.3%	1st	*1.800*	**0.090**
Gas In-Line Inspection (ILI) and Upgrade Index	6%	0.500	1.000	2.000	0.88	- -	*0.880*	**0.053**
Gas Dig-ins Reduction	5%	2.18	2.03	1.96	2.02	2nd	*1.143*	**0.057**
Gas Emergency Response	5%	21.5	21.0	20.0	20.0	1st	*2.000*	**0.100**
Lost Workday Case Rate	6%	0.353	0.320	0.275	0.402	3rd	*0.000*	**0.000**
Serious Preventable Motor Vehicle Incident (SPMVI) Rate	6%	0.252	0.239	0.226	0.280	- -	*0.000*	**0.000**
Timely Reporting of Injuries	4%	64.0%	67.1%	70.2%	67.3%	- -	*1.065*	**0.043**
Customer	**25%**							**0.250**
Customer Satisfaction Score	15%	75.5	75.7	76.3	76.1	3rd	*1.667*	**0.250**
System Average Interruption Duration Index (SAIDI)	10%	101.1	96.3	93.9	109.0	2nd	*0.000*	**0.000**
Financial	**25%**							**0.263**
Earnings from Operations ($M) (2)	25%					- -	*1.053*	**0.263**
Overall YTD 2016 STIP Score	**100.00%**							**0.936**

Our EFO target is not publicly reported. Unbudgeted items impacting comparability (such as changes in accounting methods) will be excluded.

The Compensation Committee of the PG&E Corporation Board of Directors has complete discretion to determine and pay all STIP awards to officers and non-officer employees. This includes discretion to reduce the final score on any and all measures downward to zero.

1 To reinforce the importance of leadership accountability for safety, the Compensation Committee reduced the 2016 score for PG&E's senior officers to 0.900 due to the tragic deaths last year of employee Dave Spurgeon and contractor Nash Mayer.

Detailed Interpretation of STIP 2016 Scorecard

Safety – 50 percent of total STIP score

Public Safety

Nuclear Operations - (8 percent weighting). As measured by:

- *Diablo Canyon Power Plant Performance Indicator:* The year-end score as reported to Institute of Nuclear Power Operations (INPO) for PG&E's Diablo Canyon Power Plant Units 1 and 2 is based on twelve performance indicators for nuclear power generation, including unit capability, radiation exposure and safety accident rate.

  Performance: Unit 1 **Exceeded** year-end stretch goal. Unit 2 **Did not meet** the threshold goal, experiencing a 10 point loss due to a redundant safety system valve that required manual operation to perform its safety function.

Gas Operations - (16 percent weighting). As measured by:

- *In-Line Inspection (ILI) and Upgrade Index – (6 percent weighting):* PG&E's ability to complete planned in-line inspections and pipeline retrofit projects. Includes two equally weighted components: In-Line Inspections and In-Line Upgrades.

  Performance: **Did not meet** year-end target. Performance driven by inspecting 259 miles (vs. 336 miles target) and upgrading 107 miles (vs. 111 miles target). Inspection mileage target was not achieved due to damaged in-line "pigs," poor performance with Rosen's tools, and projects deferred awaiting new tool development. Upgrade mileage target was not achieved, as projects were deferred to align with future bundle efforts and the re-scoping to non-traditional design.

- *Gas Dig-Ins Reduction - (5 percent weighting):* The total number of third-party dig-ins to PG&E gas assets per 1,000 Underground Service Alert (USA) tickets. A dig-in refers to any damage (impact or exposure) that result in a repair or replacement of an underground facility as a result of an excavation.

  Performance: **Exceeded** year-end target. Year-end performance attributed to Gas Operations Compliance Programs focusing on educating contractors, patrolling excavation sites, meeting with companies that had damaged PG&E facilities, visiting supply stores and equipment rental companies, and inviting contractors to safe digging workshops.

- *Gas Emergency Response - (5 percent weighting):* The average response time that a Gas Service Representative (GSR) or qualified first responder takes to respond to the site of an immediate response gas emergency order.

  Performance: **Met** year-end stretch goal. Gas Service Representatives (GSRs) now respond to all gas odor calls as Priority 0, Immediate Response.

Electric Operations - (10 percent weighting). As measured by two equally weighted metrics:

- *Transmission and Distribution (T&D) Wires Down - (5 percent weighting):* The number of wires-down events with resulting sustained unplanned outages.

  Performance*:* **Did not meet** year-end target due to unfavorable weather and tree failures due, in part, to the impact of the extended drought. Despite missing the target, significant work was performed in 2016 to reduce incidents, including replacing overhead conductors and circuits, clearing vegetation, infrared inspections, and improving the corrective action process.

- *911 Emergency Response - (5 percent weighting):* The percentage of time that PG&E staff relieve first responders at the site of a potential PG&E electric hazard within 60 minutes.

  Performance: **Exceeded** target and nearly met year-end stretch goal. Continued process improvements in resource dispatching, pre-storm damage estimating, and other areas to improve metric performance.

<u>Employee Safety</u> - (16 percent weighting). As measured by:

- *Lost Workday (LWD) Case Rate - (8 percent weighting)*: The number of LWD cases incurred per 200,000 hours worked, or for approximately every 100 employees. An LWD case is a current-year OSHA recordable incident that has resulted in at least one lost workday.

  Performance: **Did not meet** year-end target. The result is mainly driven by sprain and strain and musculoskeletal injuries, which account for 67 percent of the total LWD cases in 2016.

- *Serious Preventable Motor Vehicle Incident (SPMVI) Rate - (8 percent weighting):* The total number of *serious* preventable motor vehicle incidents that the driver could have reasonably avoided, per one million miles driven.

  Performance: **Did not meet** year-end target. Result is mainly due to rear-ending and striking a third-party, which account for 48 percent of total SPMVIs in 2016.

Customer – 25 percent of total STIP score

- *Customer Satisfaction Score (CSS) - (15 percent weighting):* The overall satisfaction of customers with the products and services offered by PG&E, as measured through an ongoing quarterly survey.

  Performance*:* **Exceeded** year-end target. Satisfaction increased among residential and business customers in 2016. Reliability, plus community outreach, offset negative media associated with the criminal trial.

- *System Average Interruption Duration Index (SAIDI) - (10 percent weighting):* The total time the average customer is without electric power during a given time period (measured in number of minutes). Includes all planned and unplanned sustained outages.

  Performance: **Did not meet** year-end threshold goal. Performance was impacted by unfavorable weather and below target equipment and vegetation-related performance. 2016 was the second best system reliability ever recorded.

Financial – 25 percent of total STIP score

- *Earnings from Operations (EFO) - (25 percent weighting):* Net income excluding items impacting comparability, which represent income or expenses associated with events or circumstances considered unusual and not part of ongoing core operations. The measurement is non-GAAP.
  - Performance*:* The 2016 earnings from operations target is not publicly reported.

The Compensation Committee of the PG&E Corporation Board of Directors has complete discretion to determine and pay all STIP awards to officers and non-officer employees. This includes discretion to reduce the final score on any and all measures downward to zero.

2017 Short Term Incentive Plan (STIP) Performance Measures & Targets

These performance measures and targets have been approved by the Compensation Committee of the PG&E Corporation Board of Directors, which retains complete discretion to determine and pay all STIP awards to officers and non-officer employees.

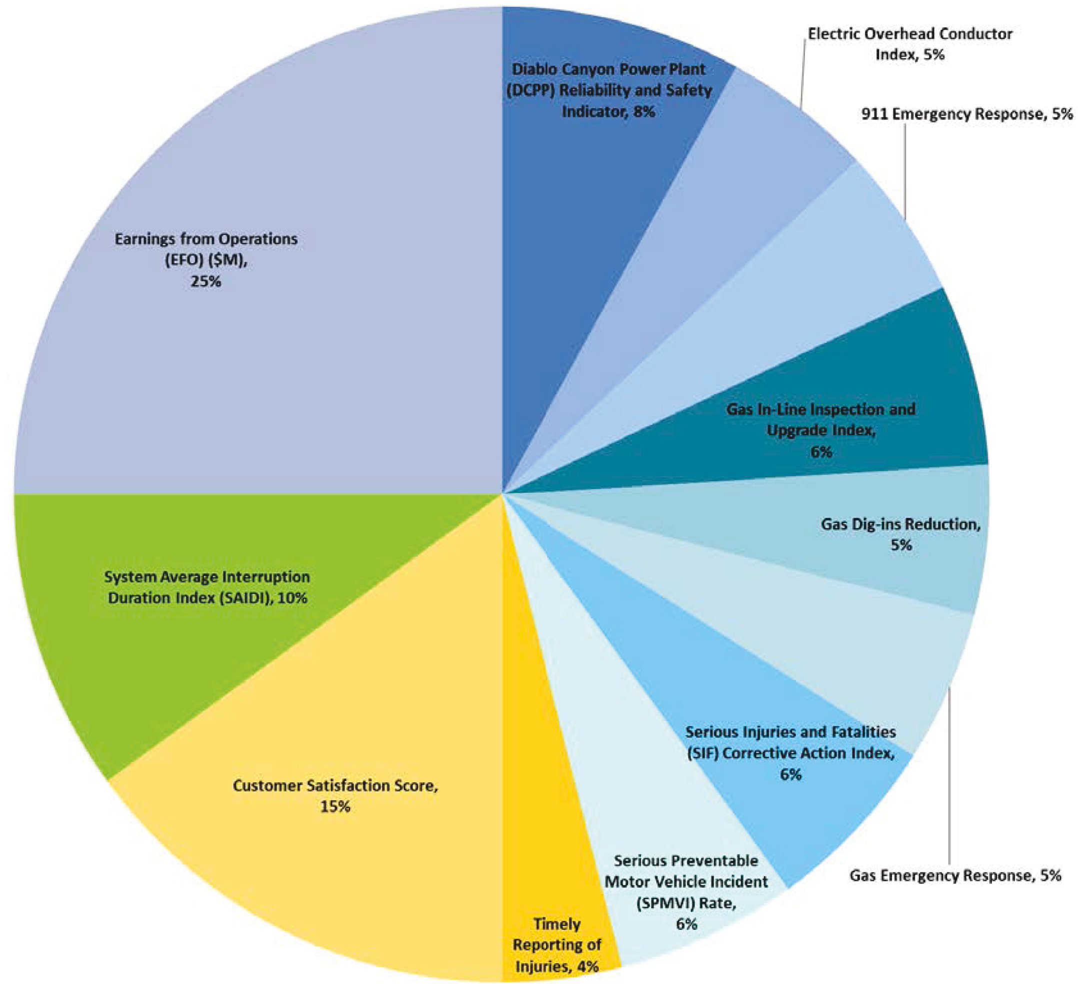
Pacific Gas and Electric Company

2017 STIP Overview

2017 STIP Structure

STIP is designed to incent and reward eligible employees for their performance in core areas that drive our business: public and employee safety, reliability, customer satisfaction and earnings.

- Category weighting:
  - ✓ Safety - 50 percent
    - Public
    - Employee
  - ✓ Customer - 25 percent
    - Customer Satisfaction
    - Electric Reliability
  - ✓ Financial - 25 percent
- STIP is an at-risk component of our pay that rewards us annually for company and individual performance
- Contact your leader or HR Business Partner with questions



Pacific Gas and Electric Company

2017 STIP Performance Targets

Weight	2017 STIP Measure	2017 STIP Performance Targets		
		Threshold 0.5	Target 1.0	Maximum 2.0
50%	**Safety**			
	Public Safety			
	Nuclear Operations			
	Diablo Canyon Power Plant Reliability and Safety Indicator			
4%	DCPP Unit 1 Score	85.3	90.5	95.8
4%	DCPP Unit 2 Score	85.3	87.6	90.0
	Electric Operations			
5%	Electric Overhead Conductor Index *New for 2017*	0.500	1.000	2.000
5%	911 Emergency Response	95.0%	97.5%	98.5%
	Gas Operations			
6%	Gas In-Line Inspection and Upgrade Index	0.500	1.000	2.000
5%	Gas Dig-ins Reduction	2.02	1.92	1.82
5%	Gas Emergency Response	22.0	21.0	20.0
	Employee Safety			
6%	Serious Injuries and Fatalities (SIF) Corrective Action Index *New for 2017*	0.500	1.000	2.000
6%	Serious Preventable Motor Vehicle Incident (SPMVI) Rate	0.252	0.239	0.224
4%	Timely Reporting of Injuries	67.3%	71.3%	75.3%
25%	**Customer**			
15%	Customer Satisfaction Score	75.9	76.4	77.9
10%	System Average Interruption Duration Index (SAIDI)	110.2	107.0	104.7
25%	**Financial**			
25%	Earnings from Operations (EFO) ($M)	- -	- -	- -

(1) Scores are evenly distributed (linear) between the points on the scales above, except EFO which utilizes the performance scale
(2) Our EFO target is not publicly reported but is consistent with the guidance range for 2016 EPS from operations. Unbudgeted items impacting comparability (such as changes in accounting methods) will be excluded.

STIP Category – Safety (50% Weighting)

Measures both the public and employee safety of our operations and demonstrates our commitment to serving our communities. PG&E's overall safety performance will be measured primarily by our achievement of the metrics defined below. The Compensation Committee of the PG&E Corporation Board of Directors, which is ultimately responsible for reviewing and approving our year-end STIP score, will also take into consideration the overall impact our business operations had on public and employee safety.

		2017 STIP Measures	Weight	Definition	What's New in 2017
Public Safety	Nuclear	Diablo Canyon Power Plant (DCPP) Reliability and Safety Indicator Units 1 & 2	8%	The year-end score is based on a composite of 11 nuclear industry performance indicators for nuclear power generation, including unit capability, radiation exposure, and safety accident rate.	Indicator shifting to revised industry 2020 goals
	Electric	Electric Overhead Conductor Index New measure for 2017	5%	The Electric Overhead Conductor Index tracks the successful completion of three key work activities : (1) circuit miles of electric distribution infrared inspections completed, (2) circuit miles of distribution electric conductor upgraded/replaced, and (3) number of trees trimmed/removed as part of the vegetation management program. This public and employee safety metric supports the prevention of distribution conductor failures resulting in wires down.	New measure and definition for 2017
		911 Emergency Response	5%	The percentage of time that PG&E personnel respond to a 911 call (electric) within 60 minutes.	Same measure and definition as 2016
	Gas	Gas In-Line Inspection and Upgrade Index	6%	PG&E's ability to complete planned in-line inspections and pipeline retrofit projects. Includes two equally weighted components: In-Line Inspections and In-Line Upgrades.	Same measure and definition for 2016
		Gas Dig-ins Reduction	5%	The total number of third-party dig-ins to PG&E's gas assets per 1,000 Underground Service Alert (USA) tickets. A dig-in refers to any damage (impact or exposure) that result in a repair or replacement of an underground facility as a result of an excavation.	Same measure and definition for 2016
		Gas Emergency Response	5%	The average response time that a Gas Service Representative or a qualified first responder (e.g., Gas Crew, Leak Surveyor) takes to respond to the site of an immediate response gas emergency order.	Same measure and definition for 2016
Employee Safety		Serious Injuries and Fatalities (SIF) Corrective Action Index New measure for 2017	6%	The Serious Injuries and Fatalities ("SIF") Corrective Action Index tracks PG&E's response to SIF eventsby measuring: (1) percentage of SIF corrective actions completed on time, and (2) quality of corrective actions as measured against an externally-derived framework.	New measure and definition for 2017
		Serious Preventable Motor Vehicle Incident (SPMVI) Rate	6%	The total number of SPMVIs that the PG&E driver could have reasonably avoided, per 1 million miles driven. SPMVIs involve significant human error or misconduct, or vehicle damage. Minimum vehicle damage limit is $5,000.	Same measure and definition for 2016
		Timely Reporting of Injuries	4%	Percentage of work-related injuries reported to the 24/7 Nurse Report Line within one day of the incident.	Same measure and definition for 2016

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STIP Category – Customer (25% Weighting)

Measures customer satisfaction with our services and the reliability of our gas and electric operations.

	2017 STIP Measures	Weight	Definition	What's New in 2017
Customer	Customer Satisfaction Score	15%	The overall satisfaction of customers with the products and services offered by PG&E, as measured through an ongoing quarterly survey.	Same measure and definition for 2016
	System Average Interruption Duration Index (SAIDI)	10%	The total time that the average customer is without electric power during a given time period (measured in number of minutes). Includes all planned and unplanned sustained outages.	Same measure and definition for 2016

Pacific Gas and Electric Company

STIP Category – Financial (25% Weighting)

Measures the financial performance of our ongoing core operations.

	2017 STIP Measures	Weight	Definition	What's New in 2017
Financial	Earnings from Operations (EFO) ($M)	25%	Net income excluding items impacting comparability, which represent income or expenses associated with events or circumstances considered unusual and not part of ongoing core operations. The measurement is non-GAAP.	Same measure and definition for 2016

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 1
TRANSMISSION PIPELINE RUPTURE WITH IGNITION

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 1
TRANSMISSION PIPELINE RUPTURE WITH IGNITION

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Transmission Pipeline Rupture with Ignition.
IN SCOPE	Rupture of a transmission pipeline with ignition which may result in loss of containment and/or severe consequences.
OUT OF SCOPE	Transmission pipeline rupture without ignition.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, Pipeline and Hazardous Materials Safety Administration (PHMSA) data, and subject matter expertise.

Pacific Gas and Electric Company (PG&E) owns and operates approximately 6,585 miles of gas transmission pipeline and associated major equipment (including transmission valves) through which PG&E transports natural gas to distribution centers, storage facilities and large volume customers. The risk analyzed in this chapter is the rupture of a transmission pipeline resulting in loss of containment and/or uncontrolled gas flow leading to ignition. Potential consequences associated with this event include: injuries and fatalities, prolonged outages, property damage, and/or significant environmental damage. There are nine risk drivers that can lead to this event as outlined by the American Society of Mechanical Engineers[1] (ASME) B31.8S standard. These drivers[2] include external corrosion, internal corrosion, stress corrosion cracking, manufacturing-related defects, welding/fabrication related, equipment related, third-party/mechanical damage, incorrect operations, and weather-related/ outside force.

Transmission pipeline ruptures with ignition do not happen frequently. Between 2010 and 2016, the natural gas transmission industry experienced a total of 83 rupture with ignition reported events with 11 having safety impacts,[3] the largest of which was the PG&E incident in San Bruno.

Transmission Pipeline Rupture with Ignition Risk has been on PG&E's risk register since 2013. It is also an Enterprise Risk overseen by the Nuclear, Operations, and Safety Committee of PG&E's Board of Directors. Transmission Pipeline Rupture with Ignition

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1 See ASME standard B31.8S-2004 "Managing System Integrity of Gas Pipelines." This ASME code is incorporated by reference in 49 Code of Federal Regulations (CFR) Part 192.7.c.5.

2 The risk drivers are referred to as "threats" in the ASME B31.8S standard and these two terms are used interchangeably throughout this document.

3 Data source: Pipeline and Hazardous Materials Safety Administration (PHMSA) Major Incident Data, 2010-2016.

can result in very high consequences or result in very few consequences, largely depending on where and when the event occurs. Although there is a low probability of a high consequence event, PG&E manages the risk at the highest levels of the company.

PG&E is actively addressing this risk through a variety of controls and mitigations. The mitigation programs proactively target risk reduction on specific risk drivers. These include programs such as (1) Valve Automation, (2) In-Line Inspection (ILI), (3) Hydrostatic Testing, and (4) pipe replacement programs that address threats arising from vintage pipeline construction methods or shallow and exposed pipeline.

The risk assessment undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process showed that 13 percent of events could result in serious safety consequences in the form of fatality or injury. By implementing the proposed mitigation plan outlined in this chapter, PG&E forecasts a potential 7 percent in overall multi-attribute risk score (MARS) between 2017 and 2022.

Going forward, PG&E plans to collect and analyze more data, when available, to improve the model inputs and continue the move towards more quantitative, data driven risk models. For the Transmission pipeline rupture with ignition risk described in this chapter, one of the key next steps is to identify the data needed to quantify the compliance category. A detailed list of next steps is included in Section VIII below.

II. Risk Assessment

A. Background

The risk assessed is the rupture of a transmission pipeline with ignition resulting in loss of containment and/or uncontrolled gas flow leading to potential public and employee safety issues, prolonged outages, property damage, and/or significant environmental damage. While this is generally a low probability risk, the consequences can be very high. Much of PG&E’s gas transmission backbone is located in rural areas; however, a significant portion of PG&E’s local transmission system is located in densely populated areas. PG&E’s natural gas transmission pipe represents approximately 7 percent of the nation’s High Consequence Areas (HCA).[4]

The risk bow tie, in Figure 1-1 below, shows the exposure and frequency drivers for this risk as well as the probability of a risk event. The risk event, at the center of the bow tie, is defined as a rupture of a transmission pipeline with ignition.

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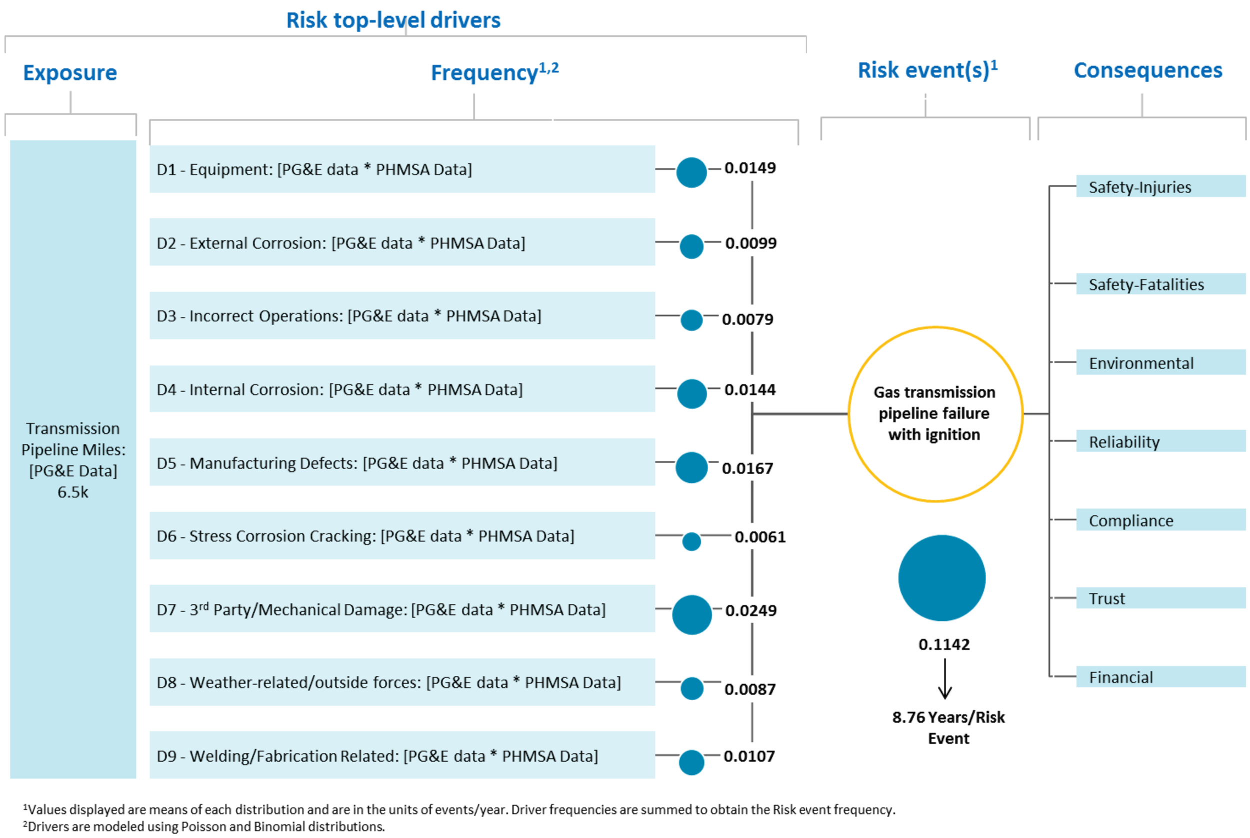
4 As of March 2017, PG&E reported in the 2016 PHMSA annual report, a total of 1,512 HCA miles. In the same period, the rest of the nation’s transmission and gathering pipelines reported 20,352 HCA miles (including PG&E miles).

Based on the model inputs for frequency, this risk event is expected to occur approximately every nine years on average.

Figure 1-1: Risk Bow Tie



B. Exposure

PG&E measured the risk exposure as the number of miles of transmission pipeline owned and operated by PG&E. As a result, the total exposure used in the model equates to 6,585 miles[5] of transmission pipeline for 2017-2022. PG&E assumes that the exposure stays constant over the 2017-2022 time period and makes no distinctions between the different pipe segments within the model.

5 The miles include 55.3 miles of StanPac and 14 miles that are within PG&E's storage facilities. The data is as of 2016 as reported in the PHMSA 7100.2 report.

C. Drivers and Associated Frequency

PG&E identified nine risk drivers[6] associated with the Transmission Pipeline Rupture with Ignition risk, which are described in detail below. PG&E is identifying all nine drivers as causes that have the potential to lead to the risk event even though PG&E has not historically experienced incidents from some of these risk drivers. PG&E used two datasets for the frequency calculation including: (1) PHMSA annual report (7100.2-1 report);[7] and (2) PHMSA Major Incident Reporting data.[8] The data sets were filtered to include only natural gas and blanks (gas carriers).

In order to calculate the estimated number of leaks that lead to rupture causing ignition, PG&E performed the following steps:

1. The PHMSA annual report (7100.2-1) was used to tabulate the number of leaks experienced at PG&E.
2. The number of leaks was multiplied by the percent of leaks that led to rupture in the entire industry. Given the small sample of ruptures at PG&E, the likelihood of ruptures given leak was estimated using the entire population of leaks in the industry. This calculation was performed for each of the nine drivers.
3. The PHMSA Major Incident Reporting Data was used to estimate the fraction of ruptures that led to ignition in the industry. PG&E-specific data was not used for this calculation due to the small sample set of ruptures leading to ignition experienced by PG&E. This calculation was performed for each of the nine drivers.
4. The outputs from the previous two steps were multiplied to estimate the number of leaks that lead to a rupture with ignition.
5. For example, to calculate the probability of rupture with ignition for the equipment related risk driver: 48 leaks per year, multiplied by the 0.47 percent probability of rupture given leak and multiplied by the 6.54 percent probability of ignition given rupture leading to 0.0149 rupture with ignition events/year.

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6 The risk drivers are referred to as "threats" in the ASME B31.8S standard, ASME standard B31.8S-2004 "Managing System Integrity of Gas Pipelines." This ASME code is incorporated by reference in federal code 49 CFR Part 192.7.c.5.

7 The PHMSA 7100 annual leak report is filtered for PG&E to get the PG&E historical leak data. The time period used is 2010-2016. Since this dataset does not include a filter for commodity types, the report was filtered for natural gas carriers and blanks to include all gas carriers.

8 PHMSA Major Incident report includes a collection of all major incidents in the United States. The time period is 2010-2016. Since this dataset does not include a filter for commodity types, the report was filtered for natural gas carriers and blanks to include all gas carriers.

The drivers are:

- **D1 – Equipment:** Equipment failures can lead to over-pressure excursions and leaks. Based on the probability distribution used in the model, the average number of rupture with ignition events due to equipment failures is 0.0149 per year. This can be interpreted as one event every 67 years.
- **D2 – External Corrosion:** External corrosion is the deterioration of the outside of the pipe that results from reaction with the outside environment (i.e., soil and water). Over time, this can reduce the wall thickness of the pipe, making the pipe weaker and more susceptible to other threats. Based on the probability distribution used in the model, the average number of rupture with ignition events due to external corrosion is 0.0099 per year. This can be interpreted as one event approximately every 101 years.
- **D3 – Incorrect Operations**: Damage can occur as a result of incorrect operation of the pipeline or associated equipment. Incorrect Operations is defined as any activity, or omission of an activity, by company personnel, which could adversely affect the safety or reliability of the pipeline. Failures due to incorrect operations occur as a result of work procedure errors or human performance factors. Based on the probability distribution used in the model, the average number of rupture with ignition events due to incorrect operations is 0.0079 per year. This can be interpreted as one event approximately every 127 years.
- **D4 – Internal Corrosion:** Corrosion of the internal wall of transmission pipelines occur following exposure to water and/or contaminants in the gas. The extent of the corrosion damage that may occur and the threat this creates will depend on the operating conditions of the pipeline as well as the particular combinations of these various corrosive constituents within the pipe. Based on the probability distribution used in the model, the average number of rupture with ignition events due to internal corrosion is 0.0144 per year. This can be interpreted as one event approximately every 69 years.
- **D5 – Manufacturing Defects:** Manufacturing defects include longitudinal seam defects caused by flaws in the welding of the pipe seam and pipe body defects caused by various steel impurities. Based on the probability distribution used in the model, the average number of rupture with ignition events due to manufacturing defects is 0.0167 per year. This can be interpreted as one event approximately every 60 years.
- **D6 – Stress Corrosion Cracking (SCC):** SCC is cracking from the combined influence of tensile stress and a corrosive environment. Based on the probability distribution used in the model, the average number of rupture with ignition events due to SCC is 0.0061. This can be interpreted as one event approximately every 164 years.

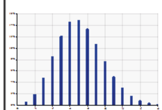
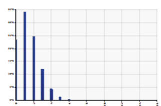
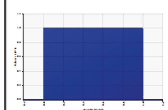
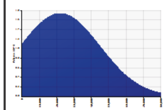
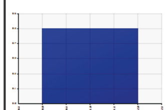
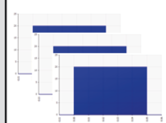
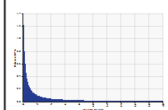
- **D7 – Third Party/Mechanical Damage:** Excavation damage happens when the pipeline is inadvertently ruptured or dented through digging. Based on the probability distribution used in the model, the average number of leaks with ignition due to third party/mechanical damage is 0.0249 per year. This can be interpreted as one event approximately every 40 years.
- **D8 – Weather Related Outside Forces (WROF):** WROF may be caused by a wide range of factors including water crossings, unstable soil/erosion, heavy rains/floods and seismic activity. Some of these events occur suddenly (i.e., earthquakes and floods) or can occur slowly (e.g., soil creep). Based on the probability distribution used in the model, the average number of leaks with ignition due to WROF is 0.0087 per year. This can be interpreted as one event approximately every 115 years.
- **D9 – Welding/Fabrication Defects:** Welding/fabrication defects where a segment of pipe connects to neighboring segments or components are another driver. Based on the probability distribution used in the model, the average number of leaks with ignition due to welding/fabrication defects is 0.0107 per year. This can be interpreted as one event approximately every 93 years.

D. Consequences

The range of consequences and the attributes that help describe the tail average risks and the associated MARS are shown in Figure 1-2 below. In the figure, there is an explanation of the data sources used for each of the consequence attributes and the resultant tail average outcomes and MARS values. Based on the tail average[9] results, trust and reliability outcomes contribute the most to the overall baseline MARS.

[9] See Chapter B, Risk Model Overview, for the definition of tail average and other risk model terminology.

Figure 1-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PG&E Data	PG&E Data	NA	PG&E Data	PHMSA
Consequence Distributions	Percent of onshore, ignited incidents with injury or fatality=13.3% Mean=7.2 (Poisson) 	Percent of onshore, ignited incidents with injury or fatality=13.3% Mean=1.5 (Poisson) 	Min=$0 Max=$1M (Uniform) 	System likelihood of customer outage =12% x Customers (Normal): Ave=22k Std Dev=23k  x Customer minutes (Uniform): Min=0 days *24*60 Max=2 days *24*60 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Ave=$8.6M Std Dev=$61.2M (Lognormal) 
Outcome-TA-NU[1]	1.06	0.22	$ 565,851	6,299,387		2.0%	$ 9,685,119
Outcome-TA-MARS[2]	0.29	5.94	0.06	15.75		9.78	5.81
						MARS Total	37.62

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** The PHMSA major incident data set was used to quantify the conditional probability that a major incident results in injuries. Based on this data, the percentage of ignition incidents with injury is 13 percent.[10] Seventy-nine injuries were reported for the 11 major incidents with ignition leading to an average number of injuries of 7.2 per event. Based on the tail average model results across the 2017-2022 time period, the average worst case number of injuries per year is 1.06.
- **Safety – Fatalities (SF):** The PHMSA major incident data set was used to quantify the conditional probability that a major incident results in fatalities. Based on this data, the percentage of ignition incidents with fatalities is 13 percent.[11] Sixteen fatalities were reported for the 11 major incidents with ignition leading to an average number of fatalities of 1.5 per event. Based on the tail average model results across the 2017-2022 time period, the average worst case number of fatalities per year is 0.22. This can be interpreted as one fatality every five years.

10 The 13 percent represents the total incidents with fatalities and injuries within the industry.

11 *Ibid*.

- **Environmental (E):** Assumed zero to a maximum of $1 million impact based on PG&E's historical environmental remediation costs.[12] Based on the tail average model results across the 2017-2022 time period, the average worst case environmental related costs would be $565,851.
- **Reliability (R):** The most significant outages are expected to occur on radial feed[13] pipelines of which about 900 miles exist in PG&E's gas transmission system. The following were used to estimate the reliability impact: the ratio of radial miles in the system, the likelihood of a radial feed outage, duration of an outage, and the average number of customers in the radial feed segments. Based on tail average model results across the 2017-2022 time periods, the average worst case reliability impact is 6,299,387 customer minutes or approximately 105,000 customer hours.
- **Compliance (C):** Gas Operations excluded this consequence category given the lack of data needed to model it. Additional research is needed to determine compliance impacts stemming from new regulations and is identified as a next step in Section VIII.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all Gas Operation risks.[14] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is 2 percent.
- **Financial (F):** The PHMSA major incident data set was used to determine the average cost of a major incident or risk event. The average cost for the 83 major incidents with ignition is used to estimate the average financial impact of $8.6 million. Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case financial impact is approximately $10 million. This outcome is lower than anticipated and PG&E plans to perform additional data analysis in the future to better evaluate the financial impact.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls described in this section addresses one or more drivers of the Transmission Pipeline Risk. Table 1 below summarizes the controls, mitigations and 2016 recorded costs associated with each. The controls identified below are

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12 This is PG&E's internal data for the cost of environmental remediation work.

13 Radial feed is a single supply line to a downstream market. It is also known as single feed and is a commonly used term for any utility supply.

14 Refer to Chapter B, RAMP Risk Model Overview, for the trust consequence calculation details.

representative programs and not a comprehensive list of all the work that Gas Operations does to address the transmission pipeline rupture risk.[15]

C1 – Corrosion Control: All 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) eliminate the elements that led to corrosion; or (2) prevent the natural corrosion process with 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 Stress Corrosion Cracking drivers. Corrosion Control is also a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, M&C Failure – Release of Gas with Ignition at M&C Facility risk and the Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility risk. The total cost for this program is not allocated among the risks.

C2 – Direct Assessments: Direct Assessment (DA) is a method of conducting assessments of pipeline integrity, as outlined in 49 CFR Part 192 Subpart O. DA is used to proactively address time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking and prevent anomalies from growing to a size that affects the structural integrity of the pipeline. The assessment techniques are called: (1) External Corrosion Direct Assessment to identify and assess locations likely to have external corrosion; (2) Internal Corrosion Direct Assessment to identify and assess locations likely to have internal corrosion; and (3) Stress Corrosion Cracking Direct Assessment 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 Stress Corrosion Cracking drivers. This program is also a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk. The total cost for this program is not allocated among the risks.

C3 – Transmission Integrity Management Program (TIMP) Pressure Tests: TIMP Pressure Tests are a method of conducting assessments of pipeline integrity, 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

15 Refer to the 2019 Gas Transmission and Storage (GT&S), Chapter 3, Summary of Request, for details on the complete portfolio of work.

Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related Defects, Welding/Fabrication Related, and Third Party/Mechanical Damage drivers.

C4 – Leak Survey: PG&E conducts leak surveys on the Gas Transmission pipeline system to meet 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.

a. Foot Survey: Foot surveys are the most common method to conduct leak surveys and require personnel to carry a portable gas leak detector in close proximity to the pipeline route.
b. Aerial Survey: 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.
c. Mobile Survey: Ground-based mobile technology is a portable gas detector transported on all-terrain vehicles (or possibly cars or trucks) along the pipeline right-of-way.

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 of the risk drivers. This program is also a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, and Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore risk. The total cost for this program is not allocated among the risks.

C5 – Locate and Mark: PG&E's Damage Prevention Program includes the Locate and Mark Program to prevent excavation damage to unmarked PG&E transmission pipeline assets. This program includes responding to notifications in a timely manner, physically locating PG&E transmission pipelines near the proposed excavations, and marking transmission assets and returning to the site when excavation activities are occurring near or over transmission assets. This control addresses the Third Party/Mechanical Damage driver. This program is also a control for the Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore risk. The total cost for this program is not allocated between the risks.

C6 – Patrols: Pipeline patrol is an activity required by the CFRs 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" (49 CFR Part 192.705). A secondary purpose of patrolling is to report observations of new construction that may impact a pipeline's Class Location or classification as a HCA (49 CFR Part 192.613). This control addresses the Third Party/Mechanical 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 overall goal of the Public Awareness Program, which is part of the Damage Prevention Program, is to enhance public safety, emergency preparedness and environmental protection through increased public awareness and knowledge. This control addresses the Third Party/Mechanical Damage driver. This program is also identified as a control for the Storage and Distribution risks. This program is also a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk and Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore risk. The total cost for this program is not allocated among the risks.

C8 – In-Line Inspections – 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 learn about 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. It 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. The repair activity and associated costs are also part of the overall program. ILI can be 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.[16]

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[16] Details on the factors that determine whether a pipeline is included the "Traditional" or "Non-Traditional" ILI programs are explained in the 2019 GT&S Rate Case.

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 conducting 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.[17] 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. For the purposes of the RAMP filing, 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 several drivers including External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related Defects, Welding/ Fabrication Related, Weather-Related and Outside Forces, and Third Party/ Mechanical Damage.

C9 – 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 several risk drivers including External Corrosion, Internal Corrosion, Stress Corrosion cracking, Third Party/Mechanical Damage, Manufacturing Related Defects and WROFs.

C10 – Earthquake Fault Crossings Program: The Earthquake Fault Crossings program addresses the specific threat of damage to a pipeline from land movement strains at known earthquake faults due to seismic events. California law requires natural gas operators to prepare for and minimize damage to pipelines from earthquakes as part of its integrity management program. 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

[17] PG&E states in Chapter 5 of its 2019 GT&S Testimony, "Integrity Management principles, as articulated in Title 49 of the Code of Federal Regulations – Transportation (49 CFR) Part O, require a baseline assessment be conducted on all pipeline miles within an HCA by the end of 2012 with periodic re-assessments of pipeline integrity within an HCA no later than seven years following the baseline assessment. As discussed later in this testimony, it has become a gas industry best practice to use ILI to conduct the baseline assessments as well as the re-assessments."

on how to manage the integrity of these segments of pipe. This control addresses the WROF driver.

C11 – Other Operations and Maintenance (O&M): Gas Transmission operations and maintenance activities are the actions planned, tracked and managed to ensure regulatory compliance and increase the useful lives of the Gas Transmission assets. Gas Transmission operations and maintenance expense includes costs to perform compliance, preventive and corrective tasks. This control addresses all drivers. This program is identified as a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, and Compression & Processing failure – Loss of Containment with Ignition at Manned Processing Facility risk. The total cost for this program is not allocated between the risks.

In addition to the controls listed above, there are mitigations identified for this risk. These mitigations are long term programs that started prior to 2016, were in place in 2016, and will be continuing on through the 2020-2022 time period and beyond. These mitigations address the various risk drivers and are described in detail below:

M1A – In-Line Inspection (ILI, Upgrades and First Time Inspections): This mitigation enhances the ILIs – Re-inspections control. As described in the control section above, the upgrades and first time inspections are defined as mitigation for this risk given PG&E's goal of making approximately 65 percent of the transmission system piggable by Traditional ILI methods by 2026. This is also in alignment with the 12-year pace of the program as approved in the 2015 Gas Transmission and Storage (GT&S) Rate Case.

At the end of 2016, 27 percent of the transmission system was capable of being inspected by ILI tools. The ILI program addresses several drivers including External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related Defects, Welding/ Fabrication Related, Weather-Related and Outside Forces, and Third Party/Mechanical Damage.

M2A – Hydrostatic Testing: PG&E hydrostatically tests pipe for several reasons, including to establish Maximum Allowable Operating Pressure (MAOP) as a part of original construction or when there is a Class Location change, as an integrity assessment to meet requirements of 49 CFR Part 192, Subpart O, to meet the requirements of California Public Utilities Commission (CPUC) Decision (D.) 11-06-017 and to fulfill PG&E's obligation to the National Transportation Safety Board (NTSB) Safety Recommendation P-10-4.

PG&E's Hydrostatic Testing program addresses several drivers including External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related Defects, Welding/Fabrication Related, and Third Party/Mechanical Damage.

M3A – Vintage Pipe Replacement: Approximately 47 percent of PG&E's gas transmission pipelines were designed, manufactured, constructed and installed before the advent of California pipeline safety laws in 1961. 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.

PG&E's vision for its Vintage Pipeline Replacement program is to replace, by the end of 2027, all of 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 (approximately 50 miles of pipeline).

The Vintage Pipe Replacement program addresses several drivers including Manufacturing Defects, External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing Related, and Third-Party/ Mechanical Damage.

M4A – 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 may reduce property damage, the danger to emergency personnel, and the public in the event of a pipeline rupture.

Valve Automation program may not have an impact on the likelihood of the risk event occurring but if the risk event was to occur, it does partially mitigate the consequence impacts. Automated valves make it easier to shut off the valves following a risk event, thereby aiding emergency response. The program impacts all consequence categories including Safety – fatality, Safety – injuries, Environmental, Reliability, Compliance, Trust and Financial. Since the program installs automated valves in place of manual valves, it does impact the Equipment Related driver.

M5A – Shallow and Exposed Pipe: The Shallow and Exposed Pipe Program was established to address the risks posed by shallow and exposed pipe on both land and locations of water and levee crossings. This program enhances public safety and improves system reliability by prioritizing, through a risk based engineering analysis that considers the pipeline specifications, manufacturing details and operating and maintenance history, to determine re-burial or replacement of shallow and exposed pipe. This program addresses the External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Third Party/Mechanical Damage, WROF and Welding and Fabrication Related drivers.

Table 1-1: Risk Controls and Mitigations 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000s)	2016 Recorded Capital ($000s)
C1	Corrosion	D2, D4, D6	GT&S	35,030	35,409
C2	Direct Assessments	D2, D4, D6	GT&S	39,368	–
C3	TIMP Pressure Tests	D2, D4, D5, D6, D7, D9	GT&S	53,163	–
C4	Leak Survey	All Drivers	GT&S	3,550	–
C5	Locate & Mark	D7	GT&S	10,598	–
C6	Patrols	D7, D8	GT&S	6,726	–
C7	Public Awareness	D7	GT&S	3,084	–
C8	ILI – Re-Inspections	D2, D4, D5, D6, D7, D8, D9	GT&S	10,309	–
C9	Pipe Replacement Program	D2, D4, D5, D6, D7, D8, D9	GT&S	20,414	14,879
C10	Earthquake Fault Crossings	D8	GT&S	1,410	1,663
C11	Other O&M	All Drivers	GT&S	30,953	–
M1A	ILI	D2, D4, D5, D6, D7, D8, D9	GT&S	89,036	134,211
M2A	Hydrostatic Testing	D2, D4, D5, D6, D7, D8, D9	GT&S	132,166	40,421
M3A	Vintage Pipe Replacement	D2, D4, D5, D6, D7, D8, D9	GT&S	–	93,383
M4A	Valve Automation	D1, SI, SF, E, R, C, T, F	GT&S	–	33,278
M5A	Shallow and Exposed Pipe	D2, D4, D5, D6, D7, D8, D9	GT&S	1,997	8,613
TOTAL Expense and. Capital				**437,804**	**361,857**

IV. Current Mitigation Plan (2017-2019)

The mitigation programs described in section III above continue through the 2017-2019 time period. The scope for these mitigations is described below.

M1B – ILI: First time inspection[18] of 93 miles in 2017, 218 miles in 2018, and 362 miles in 2019. In addition, within this mitigation, the pipeline upgrade proposed plan maintains the 12-year pace to make pipeline capable of accepting an ILI tool approved in CPUC D.16-06-056 concerning PG&E's 2015 GT&S Rate Case. The pipeline upgrades are in addition to the first time inspection mileage.

M2B – Hydrostatic Testing: Hydrostatically test 264 miles in 2017, 284 miles in 2018, and 37 miles in 2019. PG&E identified specific segments of pipeline that require a pressure test. PG&E is completing a high volume of mileage in 2017 and 2018 in order to meet the mandated mileage from the CPUC D.16-06-056.

M3B – Vintage Pipe Replacement: Replace 20 miles in 2017, 23 miles in 2018 and 3 miles in 2019. This proposed plan is partially based on assessment of site specific land movement information collected through PG&E's Geohazard Threat Identification program. Additionally, PG&E is mandated to replace 20 miles in 2018. The drop in cost

18 Includes both first time Traditional ILI and first time Non-Traditional ILI.

from 2018-2019 in this mitigation program is related to addressing fewer miles in 2019 than in 2018.

M4B – Valve Automation: Automate 35 valves in 2017, 46 valves in 2018, and 27 valves in 2019. This is equivalent to addressing 82 miles of transmission pipe in 2017, 95 miles in 2018 and 52 miles in 2019. Given that the exposure defined in the model is in miles, the equivalent miles addressed by the number of valves automations each year was calculated by analyzing the sections of pipeline which will be influenced by the valves.

M5B – Shallow and Exposed Pipe: Replace 2.5 miles in 2017, 1.5 miles in 2018 and 1.4 miles in 2019. The overall goal 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.

Table 1-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Forecast ($000)	2018 Forecast ($000)	2019 Forecast ($000)
M1B	In-Line Inspection	2000	2027	D2, D4, D5, D6, D7, D8, D9	80,000 (C) 61,117 (E)	90,619 (C) 49,079 (E)	213,526 (C) 53,816 (E)
M2B	Hydrostatic Testing	2011	2026	D2, D4, D5, D6, D7, D8, D9	200 (C) 127,273 (E)	955 (C) 154,766 (E)	34,517 (C) 115,997 (E)
M3B	Vintage Pipe Replacement	2015	2027	D2, D4, D5, D6, D7, D8, D9	107,400 (C)	346,682 (C)	40,557 (C)
M4B	Valve Automation	2011	2023	D1, SI, SF, E, R, C, T, F	43,014 (C)	39,922 (C)	29,541 (C)
M5B	Shallow and Exposed Pipe	2015	TBD[19]	D2, D4, D5, D6, D7, D8, D9	17,562 (C)	46,902 (C)	21,838 (C)
TOTAL Expense and Capital by Year					**248,176 (C) 188,390 (E)**	**525,080 (C) 203,845 (E)**	**339,979 (C) 169,813 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E has been executing against this portfolio of mitigation programs for the last several years. The selection of these mitigation programs was based on benchmarking, industry best practice, regulatory requirements, and Subject Matter Expert (SME) judgment regarding the risk profile of PG&E's gas transmission system. PG&E continues to believe these mitigation programs are the right activities to continue to reduce risk on the transmission system. This proposed set of mitigations also produce the highest risk spend efficiency out of the alternatives considered.

19 End date for this program is undetermined because PG&E is continuing to ascertain the program scope. This program is identified as a mitigation because it actively reduces risk and the program end date may be identified pending further analysis from TIMP.

The mitigations identified in Section IV above are multi-year programs that continue into the 2020-2022 time period. These mitigations are described in detail in Section III and include In-line Inspection, Hydrostatic Testing, Vintage Pipe Replacement, Valve Automation and Shallow and Exposed Pipe.

The proposed plan for 2020-2022 includes:

M1C – ILI: First time inspection of 351 miles in 2020, 408 miles in 2021, and 285 miles in 2022. In addition, within this mitigation, the pipeline upgrade proposed plan maintains the 12-year pace to make pipeline capable of accepting an inline inspection tool approved in CPUC D.16-06-056. The pipeline upgrades are in addition to the first time inspection mileage.

M2C – Hydrostatic Testing: Hydrostatic Testing 37.1 miles per year in 2020-2021, and 33.7 miles in 2022. This pace will help PG&E meet its Pipeline Safety Enhancement Plan commitments outlined in CPUC D.11-06-017 and NTSB Safety Recommendation objectives.

M3C – Vintage Pipe Replacement: Replace 3.11 miles in 2020 and 2.84 miles in 2021, and 3.88 miles in 2022. This proposed plan is based on assessment of site specific land movement information collected through PG&E's Geo-Hazard Threat Identification program. This recommended plan is to mitigate risk for vintage pipe program locations that are in high land movement areas and are in close proximity to people by the end of 2027 (within the next three rate case periods).

M4C – Valve Automation: This will include automating 27 valves in 2020, 26 valves in 2021, and 25 valves in 2022. This is equivalent to addressing 84 miles in 2020, 70 miles in 2021 and 37 miles in 2022. Given that the exposure defined in the model is in miles, the equivalent miles addressed by automating the number of valves each year was calculated by analyzing the sections of pipeline which will be influenced by the valves to be automated.

M5C – Shallow and Exposed Pipe: Replace an average of 1.4 miles per year in 2020-2022. This proposed plan helps mitigate the risk posed by currently identified locations of shallow and exposed pipe by replacing the pipe in locations that have high likelihood of failure and are in HCAs. The overall goal is to replace the highest risk locations in three rate case periods and continue to monitor the remainder.

Table 1-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	In-Line Inspection	0.0049	0.0005	2000	2025	D2, D4, D5, D6, D7, D8, D9	220,235 (C) 64,437 (E)	226,708 (C) 64,947 (E)	226,708 (C) 47,028 (E)
M2C	Hydrostatic Testing	0.0052	0.0006	2011	2026	D2, D4, D5, D6, D7, D8, D9	35,601 (C) 115,997 (E)	36,648 (C) 115,997 (E)	36,648 (C) 115,997 (E)
M3C	Vintage Pipe Replacement	0.0012	0.0001	2015	2027	D2, D4, D5, D6, D7, D8, D9	44,240 (C)	35,046 (C)	35,046 (C)
M4C	Valve Automation	0.0152	0.0009	2011	2023	D1, SI, SF, E, R, C, T, F	33,552 (C)	30,118 (C)	30,118 (C)
M5C	Shallow and Exposed Pipe	0.0008	0.0001	2015	TBD	D2, D4, D5, D6, D7, D8, D9	22,524 (C)	23,186 (C)	23,186 (C)
Proposed Mitigation Plan TA RSE: 0.0048 **TOTAL Expense and Capital by Year**							**356,152 (C)** **180,434 (E)**	**351,706 (C)** **180,944 (E)**	**351,706 (C)** **163,025 (E)**

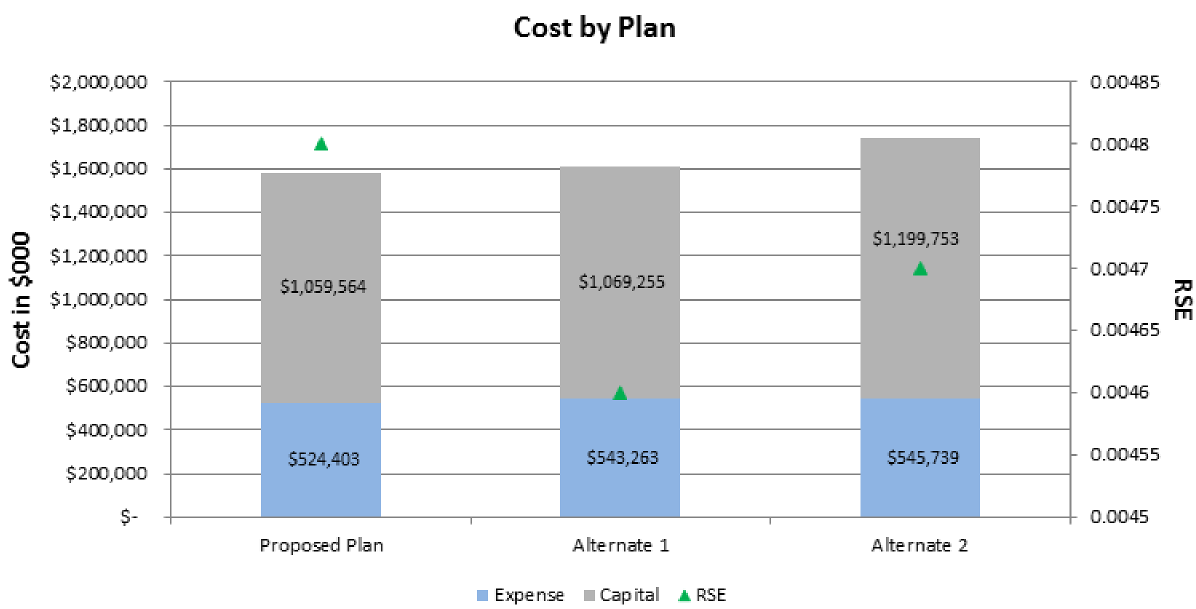
VI. Alternatives Analysis

While assessing all of the mitigations, Gas Operations identified two alternative options for the various mitigation program options. The alternatives were based on identifying mitigation efforts that allow PG&E to meet its compliance requirements with differing pace across multiple rate case periods while considering cost effectiveness and execution risks. The alternatives identified are based on SME judgment in terms of which mitigation programs will have the most impact to risk while considering cost effectiveness. Both plans are shown below in Tables 1-5 and 1-6.

Table 1-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	In-Line Inspection	0.0049	0.0005	x	x		WP 1-2
M1D	In-Line Inspection	0.0060	0.0007			x	WP 1-2
M2C	Hydrostatic Testing	0.0052	0.0006	x			WP 1-8
M2D	Hydrostatic Testing	0.0049	0.0005		x	x	WP 1-8
M3C	Vintage Pipe Replacement	0.0012	0.0001	x	x		WP 1-13
M3D	Vintage Pipe Replacement	0.0009	0.0001			x	WP 1-13
M4C	Valve Automation	0.0152	0.0009	x	x		WP 1-18
M4D	Valve Automation	0.0110	0.0006			x	WP 1-18
M5C	Shallow and Exposed Pipe	0.0008	0.0001	x			WP 1-23
M5D	Shallow and Exposed Pipe	0.0008	0.0001		x	x	WP 1-23

Figure 1-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

The mitigation programs described in detail in Section IV above are also the mitigations for this alternative proposal. In this alternative, the pace of hydrostatic tests is increased in 2022 and more miles of shallow and exposed pipeline are replaced in the 2020-2022 period. This alternative was not selected based on SME evaluation of current controls and mitigations required to lower risk with considerations for cost. The scope of the mitigations considered for this alternative and the justification for why this option is not selected is listed below:

M1C – ILI: This alternative maintains the same scope and pace as the proposed case and includes first time inspection of 347 miles in 2020, 417 miles in 2021, and 227 miles in 2022. The scope and pace stay the same because it is meeting CPUC D.16-06-056 to meet a 12-year pace.

M2D – Hydrostatic Testing: The alternative entails hydrostatically testing more miles in 2020-2022 than the proposed case to complete all the NTSB recommended miles by 2021. For 2022, given that the NTSB recommended miles are completed by 2021, this alternative proposes completing other non-HCA miles. It includes hydrostatically testing 98.3 miles in 2022 compared to 33.7 miles in the proposed case. While this approach more aggressively completes the NTSB pipe objectives, the costs would be significantly higher with minimal consequential risk reductions given that the sections of pipe included in 2022 are not near people.

Even though more miles are hydrostatically tested in 2022 compared to 2021, the costs in 2022 are lower because pipes being tested are in non-HCA areas and they are longer segments of pipe and have less set up costs.

M3C – Vintage Pipe Replacement: This alternative maintains the same scope and cost as the proposed case and includes replacing 3.1 miles in 2020, 2.8 miles in 2021, and 3.8 miles in 2022.

M4C – Valve Automation: This alternative maintains the same scope and cost as the proposed case and includes automating 27 valves in 2020, 26 valves in 2021 and 25 valves in 2022. This is equivalent to addressing 84 miles in 2020, 70 miles in 2021 and 37 miles in 2022.

M5D – Shallow and Exposed Pipe: This alternative entails replacing more miles, specifically, 2 miles of shallow and exposed pipe in 2020-2022 as compared to 1.4 miles in the proposed case for these years to address more high risk pipes sooner. This alternative was not selected because the cost forecast would have been 35 percent higher with minimal risk reduction as discussed in the 2019 GT&S rate case testimony.

Table 1-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	In-Line Inspection	0.0049	0.0005	2000	2027	D2, D4, D5, D6, D7, D8, D9	220,235 (C) 64,437 (E)	226,708 (C) 64,947 (E)	226,708 (C) 47,028 (E)
M2D	Hydrostatic Testing	0.0049	0.0005	2011	2026	D2, D4, D5, D6, D7, D8, D9	42,322 (C) 142,770 (E)	43,565 (C) 146,234 (E)	77,847 (E)
M3C	Vintage Pipe Replacement	0.0012	0.0001	2015	2027	D2, D4, D5, D6, D7, D8, D9	44,240 (C)	35,046 (C)	35,046 (C)
MC	Valve Automation	0.0152	0.0009	2011	2023	D1, SI, SF, E, R, C, T, F	33,552 (C)	30,118 (C)	30,118 (C)
M5D	Shallow and Exposed Pipe	0.0008	0.0001	2015	TBD	D2, D4, D5, D6, D7, D8, D9	33,215 (C)	34,191 (C)	34,191 (C)
TOTAL Alternative Plan 1 RSE: 0.0046 TOTAL Expense and Capital by Year							**373,564 (C) 207,207 (E)**	**369,628 (C) 211,181 (E)**	**326,063 (C) 124,875 (E)**

B. Alternative Plan 2

The mitigation programs described in detail in Section IV above are also the mitigations for this alternative proposal. This alternative, in 2020 and 2021, accelerates the pace of ILI runs, increases the miles of vintage pipeline replacement, and automates more valves. This alternative was not selected based on SME evaluation of current controls and mitigations required to lower risk with considerations for cost. The scope of the mitigations considered for this alternative and the justification for why this option is not selected is listed below:

M1D – ILI: This alternative includes inspecting more miles in 2021 and 2022. The option is to inspect 322 miles in 2020, 506 miles in 2021 and 276 miles in 2022. This alternative was based on changes in the criteria to determine pipelines to be included in Traditional ILI versus Non-Traditional ILI (i.e., this alternative keeps the pipelines that are between 1-2 miles in the Traditional ILI program as opposed to the recommended case where pipelines greater than one mile are excluded from the traditional program). This initiative was not selected because it increased annual cost and added low risk sections of pipe to the program.

M2D – Hydrostatic Testing: This alternative maintains the same scope and pace of the program as the first alternative case and includes completing all NTSB recommended miles by 2021 and additional non HCA miles to be done in 2022.

M3D – Vintage Pipe Replacement: Replace 7.3 miles in 2020 and 7.6 miles in 2021. This is a higher cost alternative that included addressing all of the elevated risk pipelines by 2024 versus by 2027 in the proposed case. The alternative was not selected because the additional mileage for this alternative is in a non-HCA or less populated location.

M4D – Valve Automation: Automate approximately 37 valves per year in 2020 and 2021 to end the program in 2021. This is equivalent to addressing 96.3 miles in 2020 and 68.4 miles in 2021. This alternative is not selected because it addresses lower risks for a higher cost alternative than the proposed plan. PG&E believes that the proposed plan achieves an appropriate balance between reducing system risk and affordability. As such, the additional dollars could be used for programs that address more risk.

M5D – Shallow and Exposed Pipe: This alternative maintains the same scope and pace of the program as the first alternative and includes replacing 2 miles of shallow and exposed pipe in 2020-2022.

Table 1-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	In-Line Inspection	0.0060	0.0007	2000	2025	D2, D4, D5, D6, D7, D8, D9	240,117 (C) 47,648 (E)	247,175 (C) 58,613 (E)	247,175 (C) 72,627 (E)
M2C	Hydrostatic Testing	0.0049	0.0005	2011	2026	D2, D4, D5, D6, D7, D8, D9	42,322 (C) 142,770 (E)	43,565 (C) 146,234 (E)	77,847 (E)
M3C	Vintage Pipe Replacement	0.0009	0.0001	2015	2027	D2, D4, D5, D6, D7, D8, D9	97,130 (C)	88,623 (C)	–
M4C	Valve Automation	0.0110	0.0006	2011	2023	D1, SI, SF, E, R, C, T, F	44,824 (C)	47,225 (C)	–
M5C	Shallow and Exposed Pipe	0.0008	0.0001	2015	TBD	D2, D4, D5, D6, D7, D8, D9	33,215 (C)	34,191 (C)	34,191 (C)
TOTAL Alternative Plan 2 RSE: 0.0047 TOTAL Expense and Capital by Year							**457,608 (C) 190,418 (E)**	**460,779 (C) 204,847 (E)**	**281,366 (C) 150,474 (E)**

VII. Metrics

The primary metric that Gas Operations is proposing to track risk reduction for this risk is the number of open leaks by risk driver. Gas Operations currently tracks the number of open leaks. This data was used as the input to the operational risk model. Using leaks as a means to understand risk reduction allows us to tie back directly to the basis of the risk model and compare actual versus forecasted risk reduction year over year.

Metrics associated with the mitigation programs are designed to measure if each program is progressing at the desired pace to achieve risk reduction objectives. The targets for these metrics will be established based on rate case outcomes through PG&E's Integrated Planning process. Table 7 below shows the proposed risk reduction and execution metrics:

Table 1-7: Metrics

Risk/Mitigation	Associated Driver and Consequence	Proposed Metric	Targets
Risk Reduction Metric			
Transmission Pipeline Rupture with Ignition	All Drivers	# of open leaks/ risk driver	TBD
Execution Metric			
ILI	D2, D4, D5, D6, D7, D8, D9	ILI index: Index includes upgrades vs. planned and inspections vs. planned.	TBD
Hydrostatic Testing	D2, D4, D5, D6, D7, D8, D9	Number of miles of hydrostatically tested versus planned	TBD
Vintage Pipe Replacement	D2, D4, D5, D6, D7, D8, D9	Number of miles of vintage pipe miles replaced versus planned	TBD
Valve Automation	D1, SI, SF, E, R, C, T, F	Number of valves automated versus planned	TBD
Shallow and Exposed Pipe	D2, D4, D5, D6, D7, D8, D9	Number of miles of shallow and exposed pipe miles replaced versus planned	TBD

VIII. Next Steps

For the Transmission Pipeline Rupture with Ignition risk discussed in this chapter, PG&E plans to continue to mature the risk quantification efforts in the following ways:

- Use PG&E data instead of industry data, when we can, to improve conclusions from risk quantification. The risk model for this risk was updated with PG&E historical leak data. However, given the small sample size of pipeline ruptures at PG&E, industry data was used to determine rupture and ignition likelihoods. This presents the opportunity to advance risk quantification in order to account for segment level data unique to PG&E.
- Refine model inputs for reliability, environmental, and compliance impacts. The modeling effort was primarily focused on safety. Given the lack of data to estimate the reliability and environmental impacts, the team made assumptions on the customer outage and environmental costs. Reliability impacts also need to be further analyzed and calibrated, and additional research is needed to determine compliance impacts stemming from new regulations. These model inputs are being assessed and, where possible, PG&E will update these inputs in the future.
- Refine model inputs for the financial impact. Industry data was used to determine financial impact for this model; however, the regulatory and business environment

in California may be different. Therefore, this consequence category needs to be further understood and updated.

- Consider how PG&E can align risk models with work plan and forecast development. For example, the Valve Automation program is forecasted in terms of number of valves automated. However, the quantification model for this risk is in terms of number of miles addressed by each mitigation program.
- Review new industry data reporting a significant increase to equipment-related defects. Both PG&E and the industry have seen a higher number of reported leaks due to equipment-related defects that may be the result of the change in PHMSA reporting thresholds rather than an actual increase in equipment-related defects.
- Perform further sensitivity analysis and calibration of model outputs. For example, given the design of the models, the Valve Automation program has the highest RSE among the mitigations selected for this risk. This is unexpected since valve automation, unlike other mitigations, does not prevent the event from occurring. Valve automation helps to reduce post-event consequences. For gas pipelines, which are under pressure, a valve closure does not stop the energy of the escaping gas right away, and, therefore, the consequential risk reduction for fatalities and injuries is minimal, with the maximum risk benefit being gained in reduction of additional injuries by allowing rescue personnel quicker access to the scene to protect life and property. In contrast, the ILI program, a program that prevents the occurrence of an incident, PG&E assumed the model outputs would yield more far reaching safety benefits.

PACIFIC GAS AND ELECTRIC COMPANY

2017 RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 2

FAILURE TO MAINTAIN CAPACITY FOR SYSTEM DEMANDS

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 2
FAILURE TO MAINTAIN CAPACITY FOR SYSTEM DEMANDS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Failure to Meet Capacity for System Demands.
IN SCOPE	Operating restrictions caused by gas transmission safety projects (e.g., in-line inspections (ILI) and hydrotests.
OUT OF SCOPE	Operating restrictions and associated consequences caused by risk drivers other than gas transmission safety projects(e.g., abnormal temperatures creating system constraints and causing customer outages, human operating errors while conducting manual operations, loss of gas control center due to a significant seismic event).
DATA QUANTIFICATION SOURCES	Assessment informed by Pacific Gas and Electric Company (PG&E) data, Pipeline and Hazardous Materials Safety Administration data, and subject matter expertise.

The chapter is focused on the failure to maintain capacity risk, resulting from gas transmission safety projects (e.g., ILIs and hydrotests) that lead to operating restrictions that reduce system capacity during winter months (November through March), when core customer gas load demands are high. Operating restrictions can occur if the safety work identifies issues that require immediate pressure reductions or sections of the system to be removed from service, both of which significantly reduce system capacity. For simplicity, the remainder of this chapter will refer to these operating restriction scenarios as "pressure reductions." This risk event can cause customer outages (controlled or uncontrolled) which could lead to consequent gas surge-backs into homes or the use of unsafe heating and cooking devices which presents a risk of fire or carbon monoxide (CO) poisoning, potentially resulting in serious injury or fatality.

The Failure to Meet Capacity for System Demands risk has been on PG&E's risk register since 2015. It is also an Enterprise-level risk overseen by the Nuclear, Operations and Safety Committee of PG&E's Board of Directors. PG&E does not believe any risk event of this nature has occurred in the industry. Although the occurrence of this event and associated consequences is unlikely, PG&E believes this risk should be managed at the highest level because of the potentially high safety and reliability consequences if this event were to occur. PG&E is actively addressing this risk through capacity and restoration projects as well as several improvements in the work execution planning process.

The sole driver for this risk event is pipeline safety projects. By implementing the mitigation strategy outlined in this chapter, PG&E forecasts a potential 38 percent reduction to the overall multi-attribute risk score (MARS) for the 2017-2022 time period.

Data relating to this risk event is scarce due to the rarity of the event's occurrence. Continuous improvement is necessary to develop quantitative methods for managing uncertainty related to lack of data. Overall, PG&E believes that there is a need to perform more data collection and analysis to improve the inputs to the model including mitigation effectiveness to make sure the quantification is supported by data and less reliant on Subject Matter Expert (SME) judgement.

Risk Assessment and Mitigation Phase (RAMP) provided a platform to accelerate PG&E's transition from a qualitative risk assessment to probabilistic risk modeling. Going forward, PG&E plans to collect and analyze more data to improve the model inputs and continue the move towards more quantitative, data driven risk models. For the Failure to Meet Capacity for System Demands described in this chapter, one of the key next steps is to attempt to quantify consequence scenarios that are possible due to the risk event including gas surge back into homes and hypothermia. A detailed list of next steps is included in Section VIII below.

II. Risk Assessment

A. Background

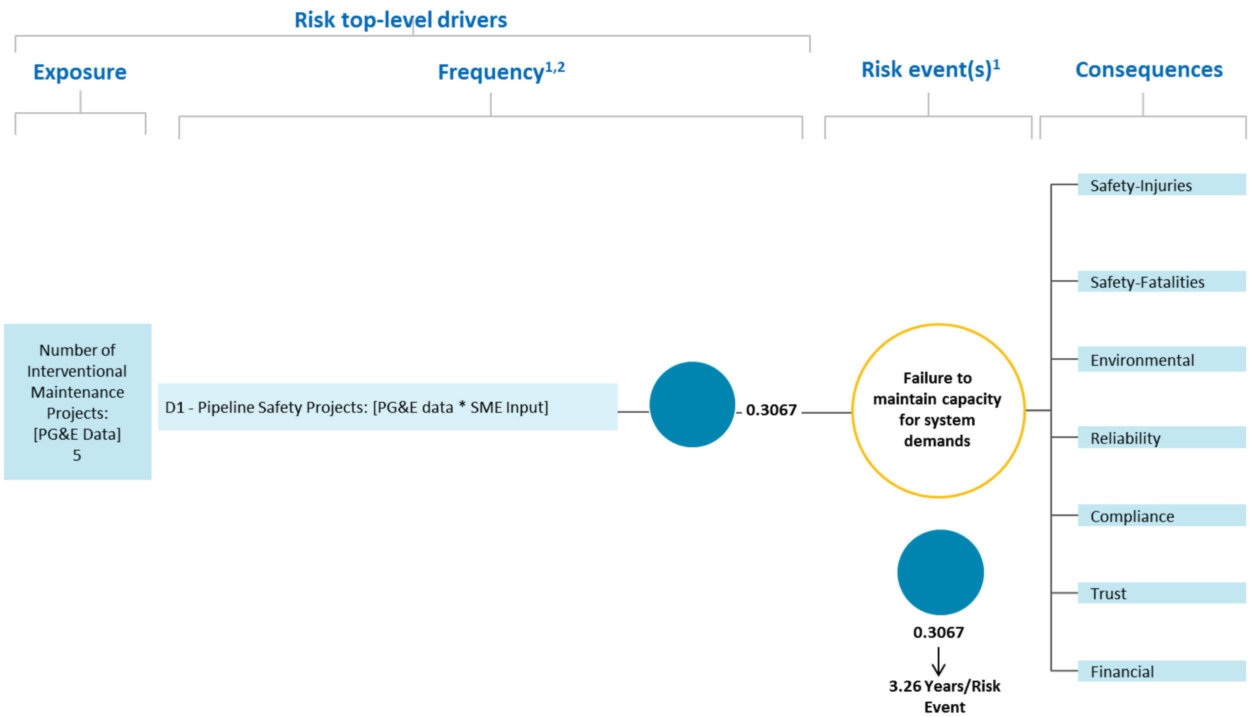
This risk has become one of the top risks for PG&E in the last two years because PG&E has substantially increased the number of safety projects performed to mitigate risks on transmission pipelines. The large number of safety projects per year has increased the likelihood of project delays, due to various reasons, into the winter months. Since capacity is a function of pressure—the lower the pressure, the lesser the capacity—a mandatory pressure reduction could reduce capacity below customer winter demand, at the time maximum capacity is needed most.

In addition to the high level bow tie-based operational risk models, PG&E has developed and currently utilizes a probabilistic model that pre-dates the development of the RAMP model (herein referred to as "PG&E probabilistic model"). The PG&E probabilistic model was designed to help quantify the likelihood that any given safety project delayed into the winter may result in pressure reductions that reduce capacity and create a risk of not meeting winter demands. This model informed the inputs into the RAMP model to estimate risk of customer outages. The RAMP model then extends the risk estimate by considering safety and reliability impacts once a customer outage occurs.

The bow tie in Figure 2-1 shows the exposure and frequency driver for the risk, as well as the probability of a risk event related to the risk driver. The risk event at the center of the bow tie is defined as the failure to meet capacity for system demands and the only driver identified for quantification purposes is the pipeline safety projects that are delayed into the winter months when demand in high.

Based on the model inputs for frequency, this risk event is likely to occur approximately every three years.

Figure 2-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Driver is modeled using a Binomial distribution.

B. Exposure

Exposure for this risk is defined as the number of pipeline safety projects (e.g., ILIs and hydrotests) scheduled for the beginning of or just before the winter season when system demand is high. The number of projects for 2017 was estimated using a historical average from the 2015-2016 and 2016-2017 winter seasons. As a result of improving work execution and planning practices as the years progress, PG&E expects the exposure (i.e., the annual number of safety projects executed in the winter) to decrease over the 2017-2022 time period. Table 2-1 below identifies the forecast number of safety projects delayed into the fall or winter which may result in pressure reductions that reduce capacity that PG&E estimates:

Table 2-1: Forecast Number of Delayed Safety Projects

Year	Number of Projects
2017	5
2018	4
2019	4
2020	3
2021	2
2022	2

C. Drivers and Associated Frequency

The driver for failure to maintain capacity for system demands analyzed in this chapter is as follows:

- **D1 – pipeline safety projects being delayed into or near the winter:** This can result in a pressure reduction if safety issues are discovered, which reduces capacity. Such a reduction in capacity would be an unintended consequence of performing the safety work. Based on the probability distributions used in the model, the average number of risk events due to this driver is 0.3067 per year. This can be interpreted as an event approximately every three years.

D. Consequences

PG&E considers three consequence scenarios associated with this risk. For purposes of RAMP, PG&E used one scenario to quantify the consequences: gas customers resort to unsafe heating or cooking methods during an extended gas outage, such as bringing outdoor barbecues, camp stoves, or propane heaters indoors, which present a risk of fire or CO poisoning. PG&E chose this scenario because it is the most probable among the three.

The second scenario is gas pressure surges back into homes due to older or failed appliance safety devices shortly after the pressure drops and extinguishes the pilot lights. The third scenario is hypothermia. With the loss of gas, the primary heating source, certain individuals may experience hypothermia at temperatures as warm as 46 degrees Fahrenheit.[1] While these were not included in this analysis, they may be incorporated into the model in the future as data becomes available.

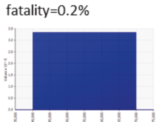
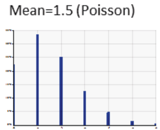
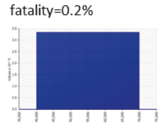
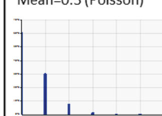
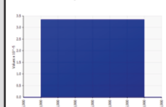
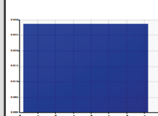
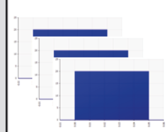
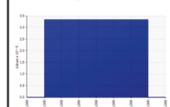
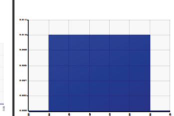
PG&E used SME input, informed by data regarding natural gas pilot light product recalls from the U.S. Consumer Products Safety Commission (CPSC), to estimate the percent of customers who may use unsafe heating or cooking equipment

1 During Hurricane Sandy, which hit the northeastern United States in 2012, it was reported that individuals experienced hypothermia at temperatures as warm as 46 degrees Fahrenheit.

during prolonged system outage. SMEs also identified the probabilities that customers using unsafe heating or cooking equipment would result in fires, poisoning, and subsequent injury or fatality.

Figure 2-2 below shows the range of consequences and the attributes that help describe the tail average risks and the associated MARS. The figure identifies the data sources used for each of the consequence attributes. Based on the tail average results, reliability contributes the most to the overall baseline MARS calculation. The reliability score for this risk is high because the model assumes that 40,000-70,000 customers are impacted due to this risk event. This assumption is based on an outage that requires the safe orderly shutdown and relight of 1 to 5 emergency shutdown zones.

Figure 2-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	U.S. CPSC data[3] and SME input	U.S. CPSC data[3] and SME input	NA	PG&E Data and SME Input	NA	PG&E Data	PG&E Data and SME Input
Consequence Distributions	Number of customers (Uniform): Min=40k, Max=70k x Percentage of customers using unsafe heating or cooking equipment during prolonged system outage=0.2% x Likelihood of ignition and subsequent injury or fatality=0.2%  Mean=1.5 (Poisson) 	Number of customers (Uniform): Min=40k, Max=70k x Percentage of customers using unsafe heating or cooking equipment during prolonged system outage=0.2% x Likelihood of ignition and subsequent injury or fatality=0.2%  Mean=0.5 (Poisson) 		Number of customers (Uniform): Min=40k, Max=70k  x Duration of customer hours (Uniform): Min =1 hour*60 Max=36 hours*60 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Number of customers (Uniform): Min=40k, Max=70k  Min=$200 Max=$300 (Uniform) 
Outcome-TA-NU[1]	0.73	0.25		114,149,807		3.76%	$23,446,648
Outcome-TA-MARS[2]	0.20	6.88		285.37		18.81	14.07
						MARS Total	325.34

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]U.S. Consumer Products Safety Commission data

- **Safety – Injuries & Fatalities:** CPSC data and SME input was used to quantify the average number of injuries and fatalities per household resulting from fires or CO poisoning. To estimate the percentage of risk incidents with injury and fatality, three values are multiplied together:

    1) The estimated number of customers that will be impacted by this risk events (40,000-70,000 customers);

2) The percentage of customers that use unsafe heating or cooking equipment during a prolonged gas service outage (0.2 percent) based on SME review of CPSC data; and

3) The likelihood of ignition and subsequent injury or fatality for those using unsafe heating or cooking equipment (0.2 percent), based on CPSC data and SME input.

The percentage of risk incidents with injury and fatality is then used to calculate distribution of likelihood of an incident resulting in an injury or fatality. The number of injuries and fatalities is based on SME input that any safety equipment built into the appliances will fail.[2] The average number of injuries is 1.5 per household and the average number of fatalities is 0.5 per household. Based on the tail average model results across the 2017-2022 time period, the calculated average worst case number of injuries per year is 0.73 and the average worst case number of fatalities per year is 0.25. This can be interpreted as one injury every 1.4 years or one fatality every four years.

- **Environmental:** PG&E excluded this consequence category as any anticipated environmental impacts will be negligible. Fires and/or explosions caused by gas surging back into a home or the use of unsafe heating devices are relatively localized events and will have minimal impact.
- **Reliability:** To quantify the reliability consequence, PG&E used: (1) the 40,000-70,000 customer range expected to be impacted during an event; and (2) the duration of a gas service outage for an individual customer (1-36 hours). Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case reliability impact is 114,149,807 customer minutes or approximately two million customer hours.
- **Compliance:** PG&E excluded this consequence category as the anticipated consequences are fines and penalties associated with investigations and these costs are excluded for the purposes of this model as they are below the line, shareholder costs.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all Gas Operation risks.[3] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is approximately 4 percent.
- **Financial:** Financial impact is based on PG&E's range of costs for relighting customer appliances and the range of customers that may experience a gas service outage due

2 Safety equipment refers to thermocouples designed to stop the flow of gas if the pilot flame is extinguished.

3 Refer to the Risk Model Overview chapter for the trust consequence calculation details.

to an event. PG&E's cost range for relighting a customer appliance is $200-$300. Based on the tail average model results across the 2017-2022 time periods, the average worst case calculated financial impact is approximately $23 million.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Hydraulic analysis by the Gas System Planning organization to help schedule safety projects to avoid delays into or near the winter and to understand customer outage risks is the one control in place in 2016. Table 2-2 below summarizes the risk control and 2016 recorded costs associated with the control.

C1 – Hydraulic Analysis[4] to Mitigate Customer Outage Risk: This control involves Gas System Planning performing hydraulic analysis to identify which safety projects, if pressure reductions are required, would create the risk of customer outages during the winter. Whenever possible, these projects are scheduled earlier in the year to minimize the risk that project delays will shift work into or near winter. If a project is delayed into or near the winter, hydraulic analysis is used to develop contingency operations to minimize the negative impact pressure reductions has on capacity. Probabilities of customer outages are also developed so PG&E can make an informed decision to either proceed or defer a project outside the winter. If a project proceeds, the known risks are used to develop appropriate contingency and emergency repair plans to quickly repair pipe so pressure can be restored, thereby minimizing the duration of exposure to customer outage risks.

In addition to the control listed above, there are existing mitigations for this risk. The mitigations include the focused pressure restoration projects, completion of capacity projects, and the three-year plan to improve work execution. Only the first two mitigations are included in the RAMP model for risk spend efficiency calculations because the three-year plan is essentially a work process improvement that staff within PG&E are performing and it does not result in a level of expenditure that can be quantified.

M1A – Pressure Restoration Projects: Pressure restoration projects restore pressure in a pipeline whose Maximum Allowable Operating Pressure (MAOP) has been reduced on an interim basis for safety or compliance reasons. The goal of the restoration project is to return pressure to its original MAOP or a value approaching it. Pressure restoration projects are targeted for systems that have a higher likelihood of safety work delays into or near the winter and where the pressure restoration is known to help minimize the impact of a potential safety work induced pressure reduction. An example is PG&E's

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4 Refer to the 2019 Gas Transmission and Storage Rate Case, Chapter 10, Gas System Operations, for details.

focus to restore pressure on Line 147 on the Peninsula where extensive safety work has resulted in safety projects being delayed into and near the winter each of the past three winter seasons.

M2A – Transmission Capacity Projects: Capacity projects install gas transmission facilities to meet general demand growth in an area. Examples of capacity projects include constructing new gas pipelines (including parallel pipelines), replacing pipelines with larger diameter pipelines, increasing regulating station capacity, and adding new regulating stations. A capacity project is undertaken when hydraulic modeling indicates that demand growth may constrain a local transmission system such that it may fail to meet Average Peak Day or Cold Winter Day service standards unless it is reinforced.

The primary purpose of capacity projects is to allow PG&E to expand the gas system to meet customer demands due to changes in the population and customer usage. These projects may also improve the ability for PG&E to maintain adequate capacity when safety projects result in pressure reductions, especially in the winter months, because adding capacity makes the system less sensitive to capacity reductions from safety projects. A major capacity project that is now operative is Line 407 in the Sacramento area.[5]

M3A – Three Year Plan: The three-year plan (3YP) is a process improvement mitigation to improve the work execution planning process within PG&E. This improvement plan began in 2016 and is expected to be completed in 2018. The 3YP is designed to provide high–level visibility across all work types to be executed within the upcoming three years. Advanced planning enables PG&E to more effectively acquire materials and permits, and schedule crews, which results in executing projects in a timely and efficient manner. With this type of planning, PG&E expects to have a reduced number of projects postponed into the winter months. This process improvement is a mitigation that would reduce the likelihood of this risk materializing. This effort started in 2016 so benefits will increase as more progress is made in 2017 and 2018. The 3YP was not included in the model since the mitigation is an internal process improvement initiative to streamline project execution and requires no additional resources nor are there incremental costs associated with it.

5 Line 407 became operative in October 2017.

Table 2-2: Summary of Risk Controls and Mitigations With 2016 Recorded Costs

#	Control	Associated Driver # and Consequence	Funding Source	2016 Recorded Expense ($000s)	2016 Recorded Capital ($000s)
C1	Hydraulic Analysis to Mitigate Customer Outage Risk	D1	GT&S	9,545	
M1A	Pressure Restoration Projects	D1	GT&S	1,300[6]	
M2A	Capacity Projects	D1	GT&S		79,118
TOTAL Expense and Capital				**10,845**	**79,118**

IV. Current Mitigation Plan (2017-2019)

The mitigation programs described in section III above continue through the 2017-2019 time period. The proposed plan for 2017-2019 includes:

M1B – Pressure Restoration Projects: As of mid-August 2017, all necessary physical work on Line 147 on the Peninsula needed to restore pressure has been completed. A required public hearing has been completed. PG&E is awaiting final approval from the California Public Utilities Commission. Other pressure restoration projects to be identified are based on safety work that may extend into winter months or other changes to the gas system. The cost forecast for this mitigation is estimated and uses the assumption that there are, on average, 1-2 pressure reductions per year that are triggered by ILI immediate indications which will cause hydraulic constraints. In addition, average dig and repair costs are assumed based on historical data to develop the average cost forecast per year.

M2B – Transmission Capacity Projects: Five transmission capacity projects are expected to be operational in 2017, three projects in 2018, and one project in 2019. In addition, because projects span multiple years, there are an average of 10-15 projects in engineering or beginning construction at any time.

> **M2B.i – Line 407:** As of October 2017, construction of Line 407 is operative. There may be minor post-construction costs in the years following 2017.

M3B – Three Year Plan: As the 3YP progresses, integrated work execution plans are expected to continuously improve scheduling and reduce the likelihood of safety project delays into the winter.

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6 Costs for Restoration Projects are not tracked separately. Instead, they are part of the projects such as ILI. This 2016 cost is based on three pressure reductions that occurred during the 2016/2017 winter season and the associated costs for the digs.

Table 2-3: Risk Controls and 2016 Recorded Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Forecast ($000s)	2018 Forecast ($000s)	2019 Forecast ($000s)
M1B	Pressure Restoration Projects	2017	2019	D1	n/a (C) 1,480 (E)	n/a (C) 1,480 (E)	n/a (C) 1,480 (E)
M2B	Transmission Capacity Projects	2017	2019	D1	36,500 (C) n/a (E)	72,430 (C) n/a (E)	54,696 (C) n/a (E)
M2B.i	Line 407	2017	2019	D1	105,000 (C) n/a (E)	8,623 (C) n/a (E)	522 (C) n/a (E)
TOTAL Expense and Capital by Year					**141,500 (C) 1,480 (E)**	**81,053 (C) 1,480 (E)**	**55,218 (C) 1,480 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the driver for Failure to Meeting Capacity for System Demands Risk. The mitigation programs for this risk in years 2020-2022 are pressure restoration projects[7] and transmission capacity projects. The mitigations identified for this risk are designed to enable adequate pipeline capacity to minimize the likelihood of a supply loss event due to inadequate capacity. This plan was selected because it will reduce the likelihood that ILI and hydrotest work will occur too close to or during the winter months, thereby increasing the reliability of service to PG&E customers.

The proposed plan includes the following scope:

M1C – Pressure Restoration Projects: Estimate 2 projects per year for 2020-2022.

M2C – Transmission Capacity Projects: Estimate 4 projects per year for 2020-2022.

The capacity portion of the proposed mitigation plan was determined to be the appropriate level and pace of work given the resource demands of PG&E's programs to mitigate other gas risks, the multi-year nature of capacity projects, and the need for capacity projects to be responsive to specifically located growth over which PG&E has no control. PG&E believes the proposed pace of work is appropriate to meet customer demand based on in depth analysis developed to project load growth.

The pressure restoration mitigation is also a response-oriented effort, and PG&E's forecast of the level of effort required reflects its recent experience.

Table 4 below shows the scoped mitigations, associated drivers, risk spend efficiency, and associated forecasted costs for each year from 2020-2022.

7 Cost forecast methodology for pressure restoration projects is described in Section IV.

Table 2-4: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Drivers	2020 Forecast ($000s)	2021 Forecast ($000s)	2022 Forecast ($000s)
M1C	Pressure Restoration Projects	56.1240	7.5365	2020	2022	D1	1,480 (E)	1,480 (E)	1,480 (E)
M2C	Capacity Projects	0.5522	0.0741	2020	2022	D1	55,486 (C)	59,016 (C)	59,016 (C)
Proposed Mitigation Plan TA RSE: 1.6246 **TOTAL Expense and Capital by Year**							**55,486 (C)** **1,480 (E)**	**59,016 (C)** **1,480 (E)**	**59,016 (C)** **1,480 (E)**

VI. Alternatives Analysis

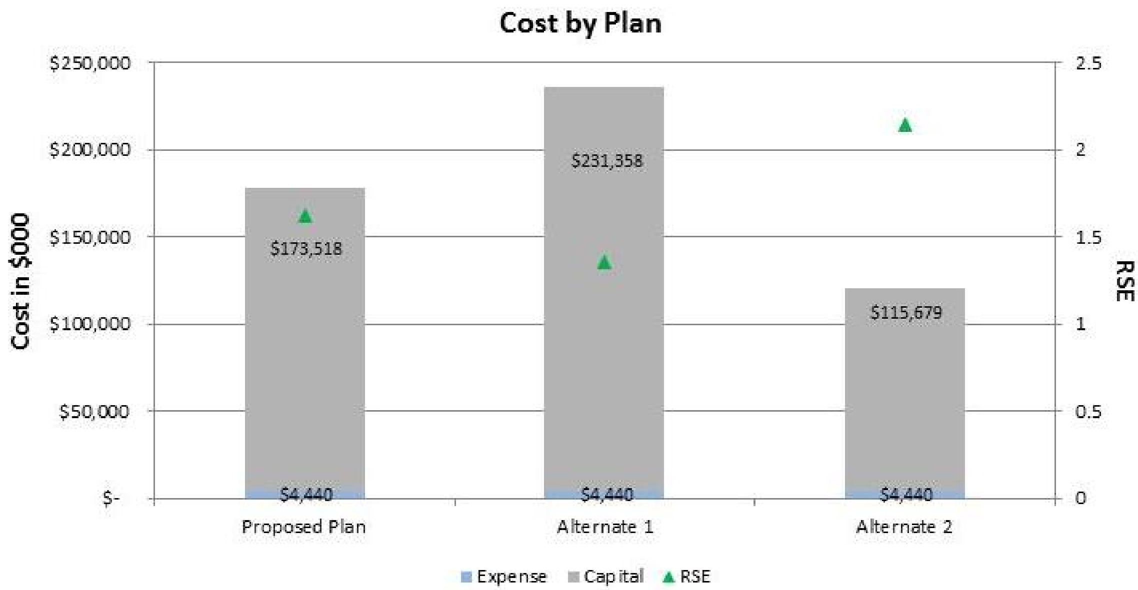
While assessing all of the mitigations, PG&E developed two alternative plans to the proposed mitigation plan. The alternatives were based on identifying mitigation efforts that may allow PG&E to meet system demand in winter months with differing pace across the specified period while considering cost and execution risks. Pace of work was considered for alternatives since the list of capacity projects is dynamic and is dependent on the outcomes of the hydraulic modeling analysis. Both plans are shown below in Tables 2-6 and 2-7.

Table 2-5: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Pressure Restoration Projects	56.1240	7.5365	X	X	X	WP 2-2
M2C	Capacity Projects	0.5522	0.0741	X			WP 2-6
M2D	Capacity Projects	0.5522	0.0741		X		WP 2-6
M2E	Capacity Projects	0.5522	0.0741			X	WP 2-6

Figure 2-3 below shows the breakdown of the proposed plan, alternative 1 plan, and alternative 2 plan based on cost and RSE.

Figure 2-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

Alternative Plan 1 modifies the scope of the capacity mitigation by increasing the expenditure and pace of transmission capacity projects by 25 percent. This alternative plan includes the following scope:

M1C Pressure Restoration Projects: The alternative proposal does not alter the number of pressure restoration projects from the recommended proposal, since such projects restore pipeline pressures rather than add new capacity.

M2D Transmission Capacity Project: Approximately 5 projects per year for 2020-2022.

This alternative plan is not recommended because it adds unneeded gas transmission capacity to meet customer demand within the 2020-2022 RAMP timeframe and would result in higher costs with minimal consequential risk reductions. Also, an increased pace of capacity project execution would require resources that would limit other work that addresses higher risks in the system and as such this option was not selected.

Table 2-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Drivers	2020 Forecast ($000s)	2021 Forecast ($000s)	2022 Forecast ($000s)
M1C	Pressure Restoration Projects	56.1240	7.5365	2020	2022	D1	1,480 (E)	1,480 (E)	1,480 (E)
M2D	Transmission Capacity Projects	0.5522	0.0741	2020	2022	D1	73,982 (C)	78,688 (C)	78,688 (C)
TOTAL Alternative Plan 1 RSE: 1.3604 **TOTAL Expense and Capital by Year**							**73,982 (C)** **1,480 (E)**	**78,688 (C)** **1,480 (E)**	**78,688 (C)** **1,480 (E)**

B. Alternative Plan 2

Alternative Plan 2 modifies the pace of the capacity project mitigation in the proposal described in Section V. The modification is a reduction in the expenditure and pace of transmission capacity projects by 25 percent. This alternative plan includes the following scope:

M1C– Restoration Projects: The alternative proposal does not alter the number of pressure restoration projects from the recommended proposal, since such projects restore pipeline pressures rather than add new capacity.

M2E – Transmission Capacity Projects: Approximately 3 projects per year for 2020-2022.

This alternative plan was not chosen because the determination of specific locations where additional capacity is required is based on empirical analysis. Even though the risk spend efficiency is the highest for this option, the reduced pace of work will not allow PG&E to meet customer demand. In addition, several key capacity projects would remain uncompleted, leaving tens of thousands of customers at risk for outages under peak conditions, or possibly warmer than peak conditions. Also, a reduced pace of capacity project execution would unduly protract reaching the policy goal of systematically eliminating manual operations as a substitute for capacity.

Table 2-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Drivers	2020 Forecast ($000s)	2021 Forecast ($000s)	2022 Forecast ($000s)
M1C	Restoration Projects	56.1240	7.5365	2020	2022	D1	1,480 (E)	1,480 (E)	1,480 (E)
M2E	Capacity Projects	0.5522	0.0741	2020	2022	D1	36,991 (C)	39,344 (C)	39,344 (C)
TOTAL Alternative Plan 2 RSE: 2.1454 **TOTAL Expense and Capital by Year**							**36,991 (C)** **1,480 (E)**	**39,344 (C)** **1,480 (E)**	**39,344 (C)** **1,480 (E)**

VII. Metrics

The primary metric that PG&E is proposing to track risk reduction for this risk is percent probability of one or more system failures to meet customer demand due to safety work encroaching on cold-weather season. This metric is a direct measure of the driver associated with this risk and therefore will allow PG&E to determine risk reduction.

Table 2-8: Metrics

Risk	Associated Driver #	Proposed Metric	Targets
Failure to meet capacity for system demands	D1	% probability of one or more system failures to meet customer demand due to safety work encroaching on cold-weather season	<2%[8]

The execution metrics to track progress on the Capacity Projects mitigation are currently being developed and is identified as a next step in Section VIII below.

There are no metrics associated with the restoration projects mitigation as the pressure restoration is conducted to return the pipeline to its previous operating pressure.

VIII. Next Steps

For the Failure to Maintain Demand for System Capacity risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Attempt to quantify consequence scenarios including gas surge back into homes and hypothermia;
- Refine inputs to the model particularly on the consequence categories including safety and reliability. In addition, consider inputs to the financial consequence category to include home owner property damage in addition to relight costs; and
- Evaluate and define appropriate execution metrics for mitigation programs to measure the progress of each program towards risk reduction objectives.

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8 Target as identified during PG&E's 2017 risk refresh/Session D process.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 3
MEASUREMENT AND CONTROL FAILURE – RELEASE OF GAS WITH IGNITION DOWNSTREAM

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 3
MEASUREMENT AND CONTROL FAILURE – RELEASE OF GAS WITH IGNITION DOWNSTREAM

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Measurement and Control (M&C) Failure – Release of Gas with Ignition Downstream
IN SCOPE	Loss of containment with ignition downstream of an M&C facility caused by an equipment-related or incorrect operations driver
OUT OF SCOPE	Events resulting in ignition at an M&C Facility
DATA QUANTIFICATION SOURCES	Assessment informed by Pacific Gas and Electric Company (PG&E) Overpressure[1] event data for 4/2012-12/2016, Pipeline and Hazardous Materials Safety Administration (PHMSA) data for transmission and distribution for 2010-2016, Intercontinental Exchange (ICE) data, and Subject Matter Expert (SME) judgement

A failure downstream of a Measurement and Control (M&C) facility resulting in loss of containment with ignition is a risk event with significant impacts related to injuries and fatalities, loss of service and/or equipment damage. This risk has been on PG&E's risk register since 2013. It is also an Enterprise level risk overseen by the Nuclear, Operations and Safety Committee of PG&E's Board of Directors. This risk event would be produced by failure of the pressure regulation system at an M&C station caused by equipment failure or incorrect operation.

While PG&E has experienced overpressure events and even loss of containment,[2] PG&E has never experienced this specific risk scenario with catastrophic consequences at any of the M&C stations. Industry data indicates that there have been a total of five overpressure (OP) events during the 2010-2016 time period which resulted in a loss of containment with ignition.[3] Of these five events, two were transmission-related and three were distribution-related.

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1 A large overpressure event is defined as an excursion that is 10 percent above Maximum Allowable Operating Pressure (MAOP), or 25 pounds per square inch gauge (psig) > MAOP for systems with MAOP of 250 psig or greater. A value of 15 inches of water column is for low pressure station locations.

2 On July 16, 2016, a 4" plastic gas line ruptured in Los Banos. The event resulted in: an unplanned gas release and service interruption for the Kagome Food Plant; damage to the Kagome Food Plant facility; damage to PG&E's infrastructure; and a reportable California Public Utilities Commission incident.

3 Based on 2010-2016 PHMSA overpressure event data file.

The drivers for this risk event take different forms based on the type of station (distribution versus transmission), the type of equipment installed, as well as the operational characteristics. However, the outcome is similar in that an overpressure event can occur with the potential for damage to downstream assets resulting in a loss of containment with ignition and subsequent consequences on people, equipment and structures. PG&E is actively addressing this risk through a variety of controls and mitigations. Since emphasis is placed on station reliability and integrity, PG&E focuses on continuous maintenance and inspection which positively contributes to safety. The risk assessment undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process showed that approximately 12 percent of events could result in serious safety consequences in the form of fatality and approximately 7 percent could lead to injury. By implementing the proposed mitigation plan outlined in this chapter, PG&E forecast a potential 15 percent reduction in overall multi-attribute risk score (MARS) between 2017 and 2022.

Going forward, PG&E plans to collect and analyze more data to improve the model inputs and continue the move towards more quantitative, data driven risk models. For the M&C risk described in this chapter, one of the key next steps will be to consider aligning risk models with work plan and forecast development. A detailed list of next steps is included in Section VIII below.

II. Risk Assessment

A. Background

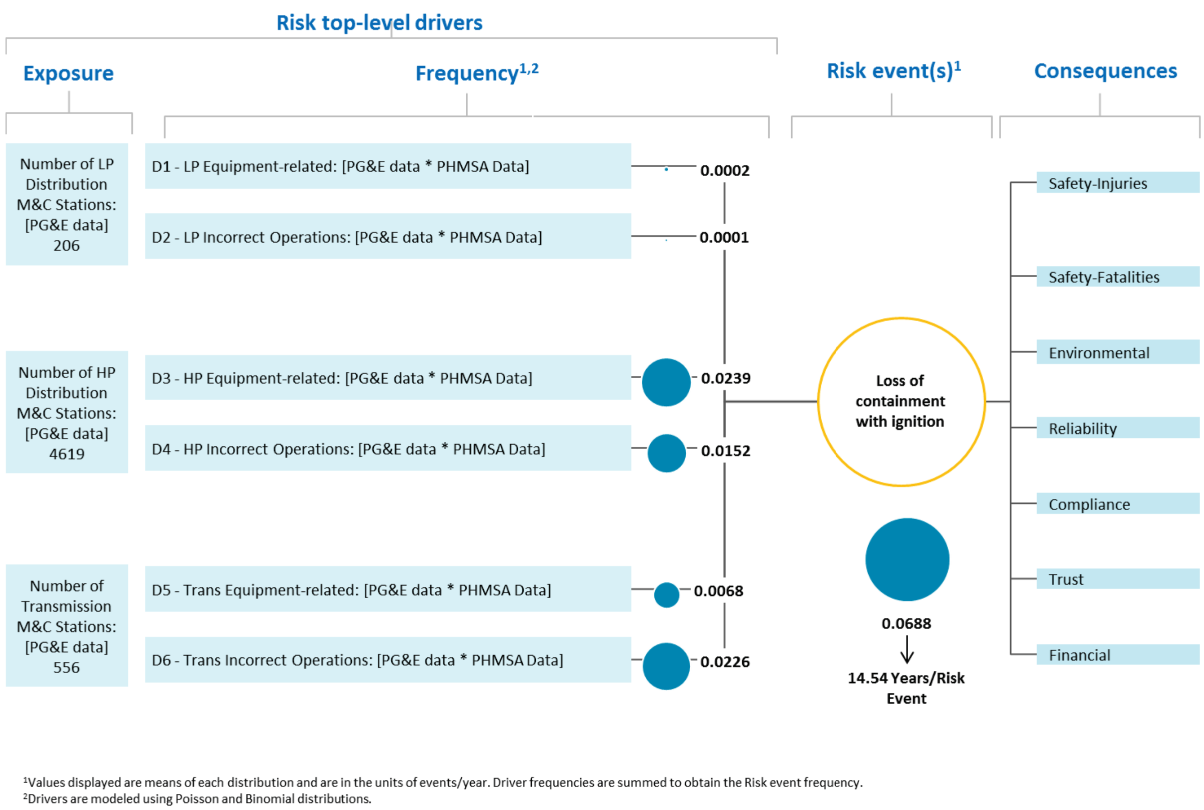
PG&E has approximately 556 gas transmission stations[4] and 4,825 distribution stations that serve a M&C function across its service territory. The risk of an overpressure event occurring at an M&C station, resulting in a rupture with ignition downstream, has the potential of leading to serious safety impacts. Although PG&E has never experienced an OP event resulting in a loss of containment with ignition with injuries or fatalities, PG&E has experienced 34 large OP events in 2011-2016.[5] Of those 34 large OP events, only one resulted in a loss of containment and none of the events resulted in a loss of containment with ignition.

4 The terms “station” and “facility” are used interchangeably throughout this document. All transmission stations are facilities. However, not all transmission facilities are classified as stations. Similarly, not all Distribution facilities are stations, and those not so classified are not subject to the same inspections and maintenance requirements.

5 Data is based on PG&E’s 2011-2016 Maximum Operating Pressure Excursion data file.

The risk bow tie, in Figure 3-1 below, focuses on drivers related to equipment and incorrect operations as the remaining drivers included in the American Society of Mechanical Engineers (ASME) B31.8S[6] are unlikely to cause an overpressure event. The risk bow tie shows the exposure and frequency drivers for the risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie, is defined as a loss of containment with ignition downstream of an M&C facility. Based on the model inputs for frequency this risk event has the potential to occur approximately every 15 years, on average.

Figure 3-1: Risk Bow Tie



B. Exposure

PG&E has categorized its 5,381 M&C stations into three main types based on their function and operational characteristics; these characteristics influence the likelihood of the risk event's occurrence as reflected in historical event data. The categorization also reflects variance in environmental and financial impacts that

6 See ASME standard B31.8S-2004 "Managing System Integrity of Gas Pipelines." This ASME code is incorporated by reference in the Title 49 of the Code of Federal Regulations – Transportation Part 192.7.c.5.

would result if the risk event were to occur, which in turn impacts the effectiveness of particular mitigations. The categorization and a detailed description of each station type can be found below:

- Low Pressure (LP) Stations: Stations that feed systems with pressures measured in inches of water column (typically 10.5 inches water column).
- High Pressure (HP) Stations: Stations are associated with outlet pressures of 60 pounds per square inch gauge (psig) or less.
- Transmission Stations: Stations are associated with outlet pressures of greater than 60 psig.

Table 3-1 below specifies the category counts for each of the station types that were used in PG&E's model. While there may be a very small change in the number of stations over time as stations are decommissioned, removed, or added, the exposure in the RAMP model is assumed constant between 2017 and 2022.

Table 3-1: M&C Station Count by Type

Station Type	Distribution		Transmission
	Low Pressure (LP) Stations	High Pressure (HP) Stations	
Count	206	4,619	556

C. Drivers and Associated Frequency

In reference to industry data, there have been a total of five OP events during the 2010-2016 time period which resulted in a loss of containment with ignition due to an OP event. Of these, two were transmission related and three were distribution related. As PG&E has not experienced an event of this nature, the model uses data available from PHMSA to quantify conditional probabilities of an OP event: Starting with the number of PG&E OP events in a year, a conditional probability is applied to determine the potential loss of containment resulting in ignition. The model incorporates minimum and maximum bound likelihood rates as a proxy to determine loss of containment resulting in ignition for transmission and distribution, respectively.[7]

Although, no injury or fatality has occurred as a result of the OP events that PG&E has experienced, the model employs the PG&E number of large OP events as a factor in evaluating the likelihood of the risk event as this data is specific to

[7] The minimum rate consists of 83 of 702 (12 percent) events leading to a loss of containment with ignition for transmission; the maximum rate consists of 467 of 754 (62 percent) events that lead to loss of containment with ignition for distribution.

PG&E. The use of industry data is an assumption made by PG&E that the frequency of ignition and safety events (failure rates) that PG&E might experience are those reflected by the industry.

For this risk, the associated drivers based on the bow tie are outlined below:

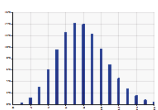
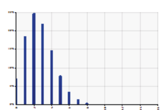
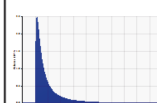
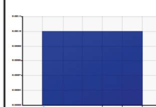
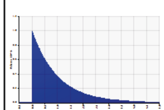
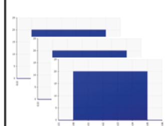
- **D1 – LP Equipment-Related:** Degradation of station components resulting from aging and wear, impacts of liquids and debris on equipment, or system operations impacts (e.g., low flow conditions) at a LP station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a LP equipment failure is 0.0002 per year. This can be interpreted as one event approximately every 5,000 years.
- **D2 – LP Incorrect Operations:** Failure of M&C station Overpressure Protection (OPP) associated with maintenance and operating tasks that place a facility in a non-standard mode at a LP station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a LP incorrect operation failure is 0.0001 per year. This can be interpreted as one event approximately every 10,000 years.
- **D3 – HP Equipment-Related:** Degradation of station components resulting from aging and wear, impacts of liquids and debris on equipment, or system operations impacts (e.g., low flow conditions) at a HP station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a HP equipment failure is 0.0239 per year. This can be interpreted as one event approximately every 42 years.
- **D4 – HP Incorrect Operations:** Failure of M&C station OPP associated with maintenance and operating tasks that place a facility in a non-standard mode at a HP station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a HP incorrect operation failure is 0.0152 per year. This can be interpreted as one event approximately every 66 years.
- **D5 – Transmission Equipment-Related:** Degradation of station components resulting from aging and wear, impacts of liquids and debris on equipment, or system operations impacts (e.g., low flow conditions) at a transmission station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a transmission equipment failure is 0.0068 per year. This can be interpreted as one event approximately every 147 years.
- **D6 – Transmission Incorrect Operations:** Failure of M&C station OPP associated with maintenance and operating tasks that place a facility in a non-standard mode at a transmission station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to a transmission incorrect

operation failure is 0.0226 per year. This can be interpreted as one event approximately every 44 years.

D. Consequences

Figure 3-2 below shows the range of consequences and the attributes that help describe the tail average risk and the associated MARS. In the figure, there is an explanation of the data sources for each of the consequence attributes. Based on the tail average results, trust and safety—fatality outcomes contribute the most to the overall baseline MARS calculation.

Figure 3-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PHMSA and ICE	SME Input	SME Input	PG&E Data	SME Input
Consequence Distributions	Percent of ignition events with injury=12% Mean=7.9 (Poisson) 	Percent of ignition events with fatality=7.2% Mean=2.7 (Poisson) 	Ave=5,822MCF Std Dev=10,744MCF Ave cost of Carbon[3]=$13 /tonne CO2 (Lognormal) 	Customer hours affected= Min=0 hours*60 Max=1,000 hours*60 (Uniform) 	Ave=$1M (Exponential) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Different for each type of station (Uniform) Distribution=$1M to $2M Transmission_simple=$3M to $15M Transmission_complex=$15M to $40M 
Outcome-TA-NU[1]	0.66	0.16	$2,725	20,677	$695,708	1.27%	$1,905,503
Outcome-TA-MARS[2]	0.18	4.29	0.00	0.05	0.07	6.34	1.14
						MARS Total	**12.07**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]To convert MCF to tonne multiply by ~52/1000

- **Safety – Injuries (SI):** PG&E used the PHMSA major incident data set[8] for transmission events with ignition and injury. Based on this data, the percentage of ignition incidents with injury is 12 percent and the average number of injuries per event is 7.9. Based on the tail average model results across the 2017-2022 time period, the average worst case number of injuries per year is 0.66. This average worst case scenario can be interpreted as 1 injury approximately every 2 years. This outcome is higher than anticipated since industry data on over-pressure events that

8 Data retrieved on January 3, 2017, https://phmsa.dot.gov/pipeline/library/data-stats/distribution-transmission-and-gathering-lng-and-liquid-accident-and-incident-data; Data from PHMSA incident reports (2010-2016).

lead to injuries is very limited and PHMSA data for all pipeline and station events was used in the analysis. Therefore, additional data analysis in the future may be able to better identify this risk consequence.

- **Safety – Fatalities (SF):** PG&E used the PHMSA Data Set[9] for transmission events with ignition and fatality. Based on this data, the percentage of ignition incidents with fatalities is 7.2 percent and the average number of fatalities per event is 2.7. Based on the tail average model results across the 2017-2022 time period, the average worst case number of fatalities per year is 0.16. This can also be interpreted as one fatality approximately every 6 years. Similar to the injury results, this outcome is higher than anticipated since industry data on over-pressure events that lead to fatalities is very limited and PHMSA data for all pipeline and station events was used in the analysis. Therefore, additional data analysis in the future may be able to better identify this risk consequence.
- **Environmental (E):** The PHMSA Data Set for both transmission and distribution related releases of gas with ignition were used to compute a weighted average from the 83 transmission and 467 distribution ignition incidents, which resulted in an average gas release volume of 5,822 millions cubic feet.[10] Based on the tail average model results across the 2017-2022 time period, the average worst case environmental related cost is $2,725 per year. This is equivalent to approximately 210 tonnee of CO_2. These results show that environmental impacts play a relatively small role in this risk.
- **Reliability (R):** PG&E leveraged SME judgment to determine the reliability impact of this risk. PG&E assumes zero to a maximum impact of 1,000 customer hours based on an individual station being out of service and the redundancy in PG&E's gas system. Based on the tail average model results across the 2017-2022 time period, the average worst case reliability impact would be of 20,677 customer minutes or approximately 344 customer hours. These results show that reliability has a relatively small role in this risk.
- **Compliance (C):** PG&E leveraged SME judgment to determine the compliance impact of this risk. PG&E assumes the primary cost of compliance after a major incident with ignition would be associated with additional inspection stemming from new regulations, the cost of which was estimated to be $1,000,000 on average. Based on the tail average

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9 Data retrieved on January 3, 2017, https://phmsa.dot.gov/pipeline/library/data-stats/distribution-transmission-and-gathering-lng-and-liquid-accident-and-incident-data; Data from PHMSA incident reports (2010-2016).

10 The average cost of carbon was taken from the ICE end of day close for California Carbon Allowance Futures as of day close March 29, 2017, which was $13 per tonne of carbon dioxide (CO_2).

model results, the average worst case compliance related impact is $695,708. Impacts in this category are relatively low in comparison to other risk consequence outcomes.

- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all GO risks. Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is 1.27 percent a year.[11] This consequence category has the largest impact on the baseline MARS since it is correlated to the safety consequences.
- **Financial (F):** PG&E leveraged SME judgment to determine the financial impact of this risk by using facility replacement costs as the basis for the model since estimates of downstream damage costs are different for each event. The financial impact was based on estimating lower and upper bound ranges for facility replacement costs with respect to distribution stations, transmission simple stations, and transmission complex stations. The distribution station count includes both LP and HP stations – totaling 4,825 stations. Transmission stations were broken out into those that were considered simple (428) and those that were considered complex (128). Replacement cost by station type is outlined in the table below:

Table 3-2: Station Replacement Costs

Station Type	Lower Bound	Upper Bound
Distribution Station	$1,000,000	$2,000,000
Transmission Simple Station	$3,000,000	$15,000,000
Transmission Complex Station	$15,000,000	$40,000,000

Based on the tail average model results across the 2017-2022 time period, the average worst case replacement costs amount to $1,905,503 a year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls and mitigations described in this section manages one or more drivers of the M&C Failure – Rupture with Ignition Downstream Risk. The controls and mitigations address reliability and integrity management of the stations to effectively control and monitor the gas system. Since emphasis is placed on station reliability and integrity, PG&E focuses on continuous maintenance and inspection which positively contributes to safety. Moreover, the M&C asset family has a robust set of reliability and integrity controls. The controls include on-going maintenance and inspection activities,

11 Refer to the Risk Model Overview chapter for the trust consequence calculation details.

on-going capital work to manage obsolescence and operational requirements, gas quality control and monitoring, and various other integrity management activities related to material condition. Table 3-3 included below summarizes the controls and associated 2016 recorded costs.

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 inspections. This control addresses the LP Equipment-related and HP Equipment-related drivers. This program is identified as a control for the M&C Failure – Release of Gas with Ignition at M&C Facility risk and the Release of Gas with Ignition on Distribution Facilities- Non-Cross Bore risk. The total cost for this program is not allocated between the risks.

C2 – Gas Quality Assessment: This program incorporates industry best practices and monitors the quality of gas entering the PG&E system. It is important to assess the quality of the gas in the pipeline to ensure that no debris or water flows through the pipeline which could impact the regulation function. This control manages the risk of gas quality issues of system to reduce the risk of equipment failure, and also reduces the risk of internal corrosion. This control addresses the Transmission Equipment-related driver. This program is identified as a control for the M&C Failure – Release of Gas with Ignition at M&C Facility risk and the Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility risk. The total cost for this program is not allocated between the risks.

C3 – Preventative Maintenance: Preventative Maintenance includes maintenance and inspection of station equipment to ensure station equipment remains in working order. Preventative maintenance also includes work that may be required to comply with pipeline safety regulations, and addresses the LP Equipment-related and HP Equipment-related drivers. This program is identified as a control for the M&C Facility risk and the Release of Gas with Ignition on Distribution Facilities- Non-Cross Bore risk. The total cost for this program is not allocated between the risks.

C4 – Regulator Station Component Replacement: This program is intended to replace equipment within a regulator station that has exceeded its useful life or is experiencing performance problems. This control ensures the equipment and components are operating properly and reduce the risk of a failure by managing equipment obsolescence and failure. This control addresses the LP Equipment-related and HP Equipment-related drivers. This program is identified as a control for the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The total cost for this program is not allocated between the risks.

C5 – Regulator Station Replacement: This program includes the complete or partial rebuild of transmission and distribution stations (above or below ground) to replace old and obsolete equipment and piping, to upgrade configuration 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. PG&E has concerns regarding employee safety related to vault access or vaults being located near traffic areas, i.e., conditions that put employees at risk during routine maintenance. This control addresses the LP Equipment-related, LP Incorrect Operations, HP Incorrect Operations, and HP Equipment-related drivers. This program also manages the risk of equipment obsolescence and failure. This program is identified as a control for the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The total cost for this program is not allocated between the risks.

In addition to controls, PG&E uses a series of mitigations to address equipment-related and incorrect operations threats to asset integrity. The selected set of mitigation activities is aimed at reducing the risks associated with the integrity of the facilities. Three mitigations began in 2016 and are continuing work through 2021 and 2022. Below is a description of these mitigations including the 2016 recorded costs in Table 3-3.

The mitigations selected for this risk are based on providing additional assurance to minimize the likelihood of an event. Along with the on-going controls to maintain and replace equipment, these mitigations provide additional safeguards against the threats of equipment-related failure and incorrect operations. The upgrade of documents ensures improved operation of the system; replacement of High Pressure Regulators (HPR) address aging stations and obsolescence; installation of SCADA provides system visibility to identify potential threats and to quickly mitigate these threats; and secondary OPP provides another line of defense to prevent overpressure events.

M1A – 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 Transmission Incorrect Operations driver as it reduces the chance of communication error between operator and control room along with the Compliance, Trust, and Financial consequence categories. This program is also identified as a mitigation for M&C Failure - Release of Gas with Ignition at M&C Facility risk and C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The cost for this program was allocated among all three risks with a 65 percent allocation to the two M&C risks and 35 percent to the C&P risk. Both the M&C show the total 65 percent allocation (i.e., the costs that were allocated to the two M&C risks were not separated).

M2A –HPR Replacement: This program is intended to replace distribution system HPR stations that have exceeded their useful life or are experiencing performance problems. This mitigation ensures the equipment and components are operating properly and reduces the risk of a failure by addressing the likelihood of equipment obsolescence and failure. Also, this mitigation reduces the likelihood of incorrect operations due to the ease of operations on newly replaced HPRs. This mitigation addresses the HP Incorrect Operations and HP Equipment-related drivers.

M3A – Supervisory Control and Data Acquisition (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. Typically, these locations are at regulator stations, where supply enters the downstream and pressure is highest, and at the historic or modeled points of lowest pressure. Due to their importance in operating the system, regulator stations may have multiple SCADA devices, one immediately upstream of, downstream of, and inside the station. SCADA devices provide the required visibility to GCC personnel. If the devices detect conditions that are out of the normal range, they send an alarm to the GCC. Operators then investigate and take necessary measures. This mitigation addresses the HP Equipment-Related, HP Incorrect Operations, Transmission Equipment-Related, and Transmission Incorrect Operations drivers along with all consequence categories (Safety-Injury, Safety-Fatality, Environmental, Reliability, Compliance, Trust, and Financial). This program is also identified as a mitigation for M&C Failure - Release of Gas with Ignition at M&C Facility risk. The total cost for this program is not allocated between the two M&C risks.

Table 3-3: Risk Controls and Mitigations and 2016 Recorded Costs

#	Control	Associated Driver # and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Corrective Maintenance	D1, D3	GRC	74,164	–
C2	Gas Quality Assessment	D5	GT&S	290	–
C3	Preventative Maintenance	D1, D3	GRC	9,007	–
C4	Regulator Station Component Replacement	D1, D3	GRC	–	13,064
C5	Regulator Station Replacement	D1, D2, D3, D4	GRC	–	18,543
M1A	Critical Documents Program	D6, C, T, F	GT&S	5,650	–
M2A	HPR Replacement	D3, D4	GRC	–	27,529
M3A	SCADA Visibility - T	D5, D6, SI, SF, E, R, C, T, F	GT&S	–	266
	SCADA Visibility - D	D3, D4, SI, SF, E, R, C, T, F	GRC	–	27,616
TOTAL Expense and Capital				**89,111**	**87,018**

IV. Current Mitigation Plan (2017-2019)

The mitigation programs described in the section above are also the mitigations for the 2017-2019 time period. As mentioned in the previous section, these programs are aimed to further address the integrity management of M&C facilities. The proposed plan includes the following scope:

M1B – Critical Documents Program: Continue update of station documentation. This includes work at the following representative numbers of stations: 66 stations in 2017, 88 stations in 2018, and 109 stations in 2019. The exposure in terms of number of stations for a particular year is estimated from the program forecast cost.[12]

M2B – HPR Replacement: Continue to replace HPRs at identified stations. This includes 375 stations in 2017, 405 stations in 2018, and 440 stations in 2019.

M3B – SCADA Visibility: Continue SCADA installations at identified distribution and transmission stations to provide visibility into the performance of the system. This includes 237 distribution and 3 transmission stations in 2017, 144 distribution and 13 transmission stations in 2018, and 149 distribution and 8 transmission stations in 2019.

In addition to the mitigations previously discussed in Section III, the program listed below will begin in 2018.

M4A – Station OPP Enhancements: This program is intended to improve performance of the transmission and distribution stations in the event of over pressurization. During the past two years, PG&E performed root cause investigations to determine the cause and to define actions to prevent recurrence. The scope of this program is currently being developed but is expected to include some of the following activities: (1) conducting benchmarking studies to determine best practices; and (2) installing secondary overpressure protection. System reviews may be performed to determine the most appropriate means of secondary overpressure protection; for example, stations with pilot-operated regulators and monitors could benefit from the installation of secondary OPP (e.g., slam-shut valves, working monitors, and relief valves). These purpose of these enhancements is to reduce the frequency of all threats through improved design and processes.

This program is intended to improve performance of the transmission and distribution stations in the event of over pressurization. The proposed plan includes addressing 80 transmission stations in both 2018 and 2019. The portion of the program that addresses the distribution stations is currently in preliminary development. While it is

12 The Critical Documents Program forecast includes costs associated with three main tasks: field visit preparation, on-site field verification, and document modernization. The representative number of stations has been determined as a fraction of the total number of stations to be addressed by the program, multiplied by the fraction that the forecast dollars for a given year represent out of the total program dollars.

not being included as a mitigation in this RAMP filing, a forecast will be provided as part of the 2020 General Rate Case.

Table 3-4: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Forecast ($000)	2018 Forecast ($000)	2019 Forecast ($000)
M1B	Critical Documents Program	2015	2021	D6, C, T, F	– (C) 5,842 (E)	– (C) 7,636 (E)	– (C) 9,593 (E)
M2B	HPR Replacement	2011	2023	D3, D4	53,180 (C) – (E)	46,474 (C) – (E)	55,993 (C) – (E)
M3B	SCADA Visibility	2015	2025	D5, D6, SI, SF, E, R, C, T, F	1,696 (C) – (E)	4,151 (C) – (E)	2,740 (C) – (E)
	SCADA Visibility	2014	2025	D3, D4, SI, SF, E, R, C, T, F	26,300 (C) – (E)	26,353 (C) – (E)	27,259 (C) – (E)
M4A	Station OPP Enhancements	2018	2023	D1-D6	– (C) – (E)	4,000 (C) 1,531 (E)	6,166 (C) 1,567 (E)
TOTAL Expense and Capital					**81,176 (C) 5,842 (E)**	**80,978 (C) 9,167 (E)**	**92,158 (C) 11,160 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for M&C Failure – Release of Gas with Ignition Downstream Risk. The mitigations described in Section IV above are ongoing and are also a part of the 2020-2022 mitigations. The proposed plan is expected to show a 14.9 percent reduction in the overall MARS score and includes the following scope:

M1C – Critical Documents Program: Continue update of station documentation, for 109 representative stations in 2020 and 88 in 2021. The proposed plan was determined by assessing resource constraints, system impacts and pace of risk mitigation for the threat of incorrect operations.

M2C – HPR Replacement: Continue to replace HPRs at identified stations at a rate of 440 a year throughout 2020-2022. This proposed scope aligns with PG&E's goal to address aging stations, obsolescence, and employee safety concerns.

M3C – SCADA Visibility: Continue SCADA installations at identified distribution and transmission stations to provide visibility into the performance of the system. This includes 149 distribution and 13 transmission stations in 2020, 150 distribution and 8 transmission stations in 2021, and 123 distribution and 8 transmission stations in 2022.

M4B – Station OPP Enhancements: Continue stations upgrades at selected stations during 2020-2022 with technology applications to upgrade regulation equipment and station performance at an annual rate of 80 stations. This was selected as the proposed case since PG&E aims to proactively and systematically address equipment-related failures in order to prevent additional OP events from occurring.

Table 3-5: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0163	0.0016	2015	2021	D6, C, T, F	–(C) 9,593 (E)	–(C) 9,593 (E)	–(C) – (E)
M2C	HPR Replacement	0.0154	0.0015	2011	2023	D3, D4	53,193–58,792 (C) – (E)	53,193–58,792 (C) – (E)	53,193–58,792 (C) – (E)
M3C	SCADA Visibility	0.0156	0.0016	2015	2025	D5, D6, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility			2014	2025	D3, D4, SI, SF, E, R, C, T, F	25,897–28,622 (C) – (E)	25,916–28,643 (C) – (E)	25,795–28,510 (C) – (E)
M4B	Station OPP Enhancements	0.0624	0.0062	2018	2023	D1-D6	6,188 (C) 1,567 (E)	6,176 (C) 1,567 (E)	6,176 (C) 1,567 (E)
TOTAL PROPOSED PLAN RSE: 0.0185 **TOTAL Expense and Capital by Year**							**89,563–97,887(C)** **11,160 (E)**	**88,412–96,738 (C)** **11,160 (E)**	**88,291–96,605(C)** **1,567 (E)**

VI. Alternatives Analysis

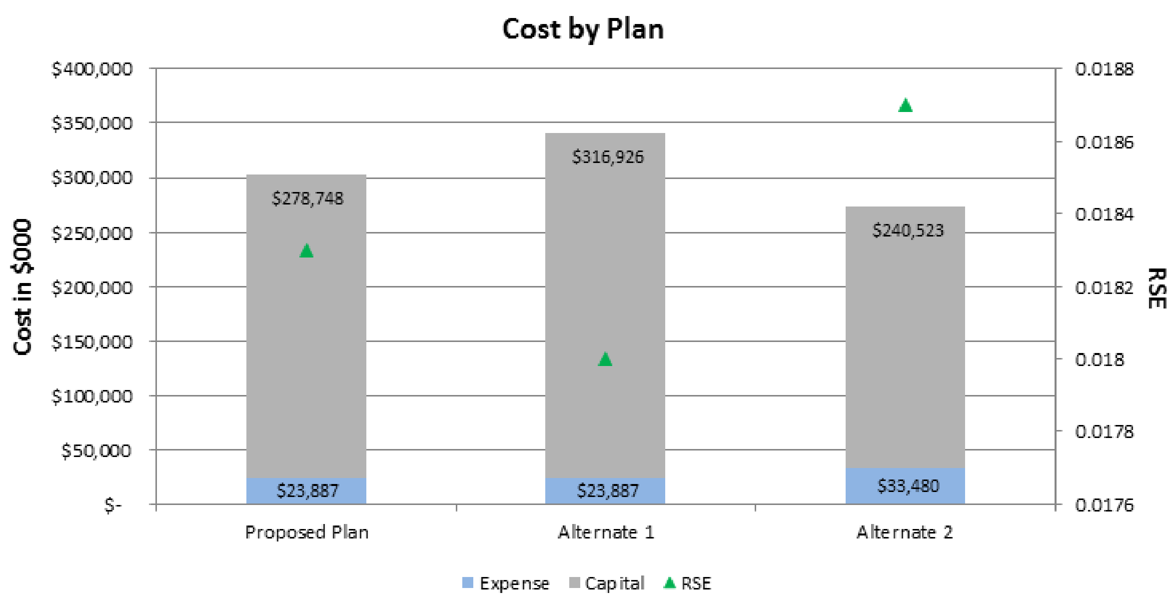
PG&E considered alternatives to the pace of replacement of HPRs in the system as this mitigation plays a key role in reducing the risk of an OP event affecting downstream assets. Both an accelerated and decelerated pace were analyzed and were ultimately not chosen for the proposed case based on the feasibility of execution of mitigations and overall affordability of the portfolio of mitigations. Table 3-6 below lists all mitigations along with their respective Risk Spend Efficiency (RSE) score.

Table 3-6: Mitigation List

#	Mitigation	Tail Average Risk Spend Efficiency Score (Units/1$M)	Expected Value Risk Spend Efficiency Score (Units/1$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Critical Documents Program	0.0163	0.0016	X	X	X	WP 3-2
M2C	HPR Replacement	0.0154	0.0015	X			WP 3-5
M3C	SCADA Visibility	0.0156	0.0016	X	X	X	WP 3-9
M4B	Station OPP Enhancements	0.0624	0.0062	X	X	X	WP 3-13
M2D	HPR Replacement	0.0154	0.0015		X		WP 3-5
M2E	HPR Replacement	0.0154	0.0015			X	WP 3-5

Figure 3-3 below shows the breakdown of the proposed plan, Alternative 1 plan, and Alternative 2 plan based on cost and RSE.

Figure 3-3: : Alternatives by Cost and RSE Score



A. Alternative Plan 1

Alternative Plan 1 was created based on increasing the scope outlined in the proposed case by an additional 100 stations per year for HPR replacements.

- **M2D – HPR Replacement:** Replace HPRs at identified stations at a rate of 540 a year throughout 2020-2022.

This alternative was not selected since it would require a significant number of resources that may not be foreseeably available, or would limit other work required in the system. Associated RSE and costs for this plan can be found in Table 3-7 below.

Table 3-7: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0163	0.0016	2015	2021	D6, C, T, F	– (C) 9,593 (E)	– (C) 9,593 (E)	– (C) – (E)
M2D	HPR Replacement	0.0154	0.0015	2011	2023	D3, D4	65,283 – 72,154 (C) – (E)	65,283 – 72,154 (C) – (E)	65,283 – 72,154 (C) – (E)
M3C	SCADA Visibility – T	0.0156	0.0016	2015	2025	D5, D6, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility – D			2014	2025	D3, D4,SI, SF, E, R, C, T, F	25,897 – 28,622 (C) – (E)	25,916 – 28,643 (C) – (E)	25,795 – 28,510 (C) – (E)
M4C	Station OPP Enhancements	0.0624	0.0062	2018	2023	D1-D6	6,188 (C) 1,567 (E)	6,176 (C) 1,567 (E)	6,176 (C) 1,567 (E)
TOTAL ALTERNATIVE PLAN 1 RSE: 0.0181 **TOTAL Expense and Capital by Year**							**101,653 – 111,249 (C)** **11,160 (E)**	**100,502 – 110,100 (C)** **11,160 (E)**	**100,381 – 109,967 (C)** **1,567 (E)**

B. Alternative Plan 2

Alternative Plan 2 was created based on decreasing the pace outlined in the proposed case by 100 stations per year for HPR replacements.

- **M2E – HPR Replacement:** Replace HPRs at identified stations at a rate of 340 a year throughout 2020-2022.

Even though this alternative has a lower cost and a slightly higher risk spend efficiency (RSE), it was not chosen as the recommended case. The longer timeframe of Alternative Plan 2 would result in a higher average asset age compared to the proposed case. This is undesirable since as equipment ages and reaches the end of its service life, the probability that it will fail in service increases. Addressing the large population of ageing HPRs with the pace outlined in the proposed case would address this risk in a more timely manner.

Associated RSE and costs for this plan can be found in the table below.

Table 3-8: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0163	0.0016	2015	2021	D6, C, T, F	– (C) 9,593 (E)	– (C) 9,593 (E)	– (C) – (E)
M2E	HPR Replacement	0.0154	0.0015	2014	2023	D3, D4	41,104 – 45,431 (C) – (E)	41,104 – 45,431 (C) – (E)	41,104 – 45,431 (C) – (E)
M3C	SCADA Visibility – T	0.0156	0.0016	2015	2025	D5, D6, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility – D			2014	2025	D3, D4, SI, SF, E, R, C, T, F	25,897 – 28,622 (C) – (E)	25,916 – 28,643 (C) – (E)	25,795 – 28,510 (C) – (E)
M4C	Station OPP Enhancements	0.0624	0.0062	2018	2023	D1-D6	6,188 (C) 1,567 (E)	6,176 (C) 1,567 (E)	6,176 (C) 1,567 (E)
TOTAL ALTERNATIVE PLAN 2 RSE: 0.0189 **TOTAL Expense and Capital by Year**							**77,474 – 84,526 (C)** **11,160 (E)**	**76,223 – 83,377(C)** **11,160 (E)**	**76,202 – 83,244 (C)** **1,567 (E)**

VII. Metrics

The primary risk reduction metric that PG&E is proposing to track risk reduction for this risk is the annual number of large OP events. Monitoring the reduction in large overpressure events per year is an indication of the effectiveness of our controls and mitigation, and therefore, is a measure of risk reduction achieved.

Metrics associated with the mitigation programs are designed to measure if each program is progressing at the desired pace to achieve risk reduction objectives. The targets for these metrics are established based on rate case outcomes through PG&E's Integrated Planning process. Table 3-9 below shows the proposed risk reduction and execution metrics:

Table 3-9: Metrics

Risk/Mitigation	Associated Driver # and Consequence	Proposed Metric	Targets
Risk Reduction Metric			
M&C Failure – Release of Gas with Ignition Downstream	All	Number of large OP events	TBD
Execution Metric			
Critical Documents Program	D6, C, T, F	Number of stations completed.	TBD
HPR Replacement	D3, D4	Number of stations completed.	TBD
SCADA Visibility	D3, D4, D5, D6, SI, SF, E, R, C, T, F	Number of stations completed.	TBD
Station OPP Enhancements	D1-D6	Number of facilities with secondary OP protection installed	TBD

VIII. Next Steps

For the M&C Failure creating a downstream event risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Continue to evolve existing tools to understand and monitor condition and criticality of assets leading to a more data driven process for monitoring and managing assets. In the last few years, PG&E identified that the evaluation of threats and risks associated with M&C assets was largely based on experience and judgment of PG&E SMEs. During the past three years, PG&E has performed several tasks that provide information for monitoring threat and asset health. This includes activities such as industry benchmarking studies, process safety assessments and condition assessments to understand hazards;
- Consider how PG&E can align risk models with different types of planned and forecast units of work; and
    - Refine model inputs. The modeling effort was primarily focused on safety. Given the lack of data to estimate the compliance, reliability and environmental impacts, the team made broad assumptions on new regulations, customer outage and environmental costs. Additionally, the financial impacts require further analysis to better mirror replacement costs for all types of M&C assets. These model inputs are being assessed and, where possible, PG&E will update these inputs in the future.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 4
MEASUREMENT AND CONTROL FAILURE – RELEASE OF GAS WITH IGNITION AT MEASUREMENT AND CONTROL FACILITY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 4
MEASUREMENT AND CONTROL FAILURE – RELEASE OF GAS WITH IGNITION AT MEASUREMENT AND CONTROL FACILITY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Measurement and Control (M&C) Failure – Release of Gas with Ignition at M&C Facility
IN SCOPE	Loss of containment with ignition within an M&C facility resulting in significant impacts to personnel safety, loss of service and/or equipment damage
OUT OF SCOPE	Events resulting in ignition downstream of an M&C facility; risks related to pipeline outside of the M&C facility
DATA QUANTIFICATION SOURCES	Assessment informed by Pipeline and Hazardous Materials Safety Administration (PHMSA) data, PG&E data, Intercontinental Exchange (ICE) data, and Subject Matter Expert (SME) input

A failure at a Measurement and Control (M&C) facility resulting in loss of containment with ignition is a risk event that could result in significant potential injuries and fatalities, loss of service and/or equipment damage. The risk has been on Pacific Gas and Electric Company's (PG&E) risk register since 2013. It is also an Enterprise Risk overseen by the Nuclear Operations and Safety Committee of PG&E's Board of Directors. Although there is another M&C risk[1] discussed in a separate chapter, this risk event is different in that it concerns loss of containment with ignition occurring at the facility itself, as opposed to on downstream assets at or near a customer location. To date, PG&E has never experienced a catastrophic event resulting in loss of life. However, based on a review of Pipeline and Hazardous Materials Safety Administration (PHMSA) data, there have been several events industry-wide. This risk has the potential for serious safety consequences for the public and PG&E's employees and contractors, therefore is one of PG&E's top risks.

There are nine risk drivers as outlined by the American Society of Mechanical Engineers (ASME) B31.8S[2] standard that could lead to this event. These drivers include equipment-related, external corrosion, incorrect operations, internal corrosion, manufacturing-related defects, stress corrosion cracking, third-party/mechanical damage, weather-related/outside force, and welding/fabrication related. The Risk Assessment and Mitigation Phase (RAMP) model uses a combination of PG&E-specific data, industry data, and SME judgement to gain a better understanding of the risk drivers associated with the risk.

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1 See RAMP Chapter 3 for the M&C Failure – Release of Gas with Ignition Downstream risk.

2 See ASME standards B31.8S-2004 "Managing System Integrity of Gas Pipelines." This ASME code is incorporated by reference in federal code 49 Code of Federal Regulations Part 192.7.c.5.

PG&E is actively addressing this risk through a variety of controls and mitigations. These programs promote safe operation and maintenance of the facilities and address specific risk drivers. The mitigation activities include the Critical Documents Program, the Engineering Critical Assessment Phase 1 and Phase 2 programs, Physical Security Upgrades, and Station Strength Testing.

The risk assessment undertaken as part of the RAMP process showed that approximately 7 percent of events could result in a fatality and approximately 15 percent of events could lead to injuries. By implementing the proposed plan outlined in this chapter, PG&E forecasts a potential 1.8 percent reduction in overall risk as measured by a percent reduction in the overall multi-attribute risk score (MARS) between 2017 and 2022.

Going forward, PG&E plans to collect and analyze more data to improve the model inputs and continue the move towards more quantitative, data driven risk models. For the M&C risk described in this chapter, one of the key next steps will be to consider aligning risk models with work plan and forecast development. A detailed list of next steps is included in Section VIII below.

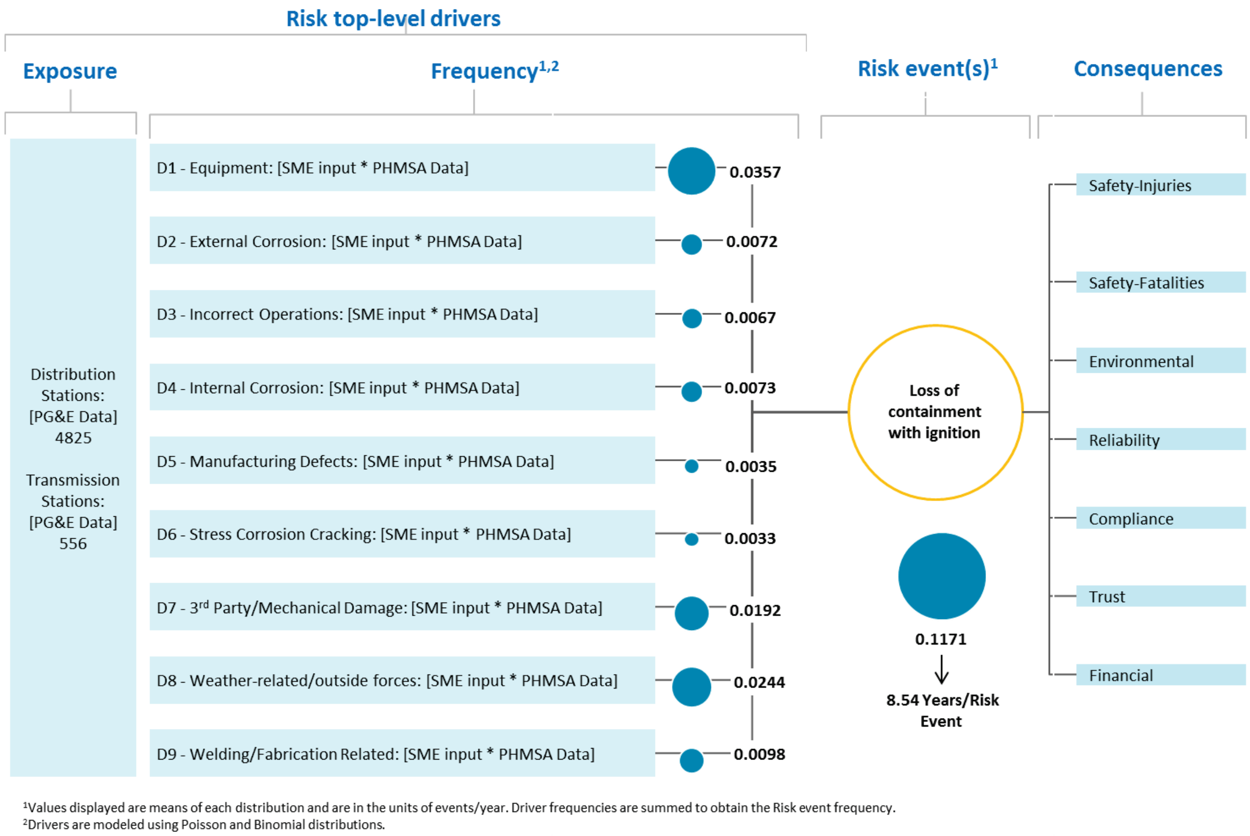
II. Risk Assessment

A. Background

PG&E has approximately 556 gas transmission stations and 4,825 distribution stations in service across its service territory. To date, the risk of a loss of containment event resulting in ignition at an M&C facility has never occurred within PG&E. However, there have been several events within the industry. As this event has the potential to cause serious safety consequences, it is one of PG&E's top risks. PG&E analyzes all drivers included in the ASME B31.8S standards.

Figure 1 below is the bow tie associated with this risk. The risk bow tie illustrates the exposure and frequency drivers for the risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie, is defined as a loss of containment with ignition at an M&C facility. Based on the model inputs for frequency, this risk event is likely to occur approximately every nine years.

Figure 4-1: Risk Bow Tie



B. Exposure

PG&E has categorized its 5,381 M&C stations into three main types based on their function and operational characteristics; these characteristics influence the likelihood of the risk event's occurrence as reflected in historical event data. The categorization also reflects variance in environmental and financial impacts that would result if the risk event were to occur, which in turn impacts the effectiveness of particular mitigations. The categorization and detailed description of each station type can be found below.

- Low Pressure (LP) Stations: Stations that feed systems with pressures measured in inches of water column (typically 10.5 inches water column).
- High Pressure (HP) Stations: Stations are associated with pressures of 60 per square inch gauge (psig) or less.
- Transmission Stations: Stations are associated with pressures of greater than 60 psig.

The table below specifies the category counts for each of the station types that were used in PG&E's model. While there may be a small change in the number of stations over time as stations are decommissioned, removed, or added, the exposure in the RAMP model is assumed constant between 2017 and 2022.

Table 4-1: M&C Station Count by Type

Station Type	Distribution		Transmission
	Low Pressure (LP) Stations	High Pressure (HP) Stations	
Count	206	4,619	556

C. Drivers and Associated Frequency

The frequency of the risk event is based on a review of PHMSA major event data for transmission and distribution[3] to identify each driver's respective contribution to the frequency of loss of containment that results in ignition or explosion. Because the PHMSA data includes all events in the United States, the number of events per year was scaled by the fraction of the PG&E system relative to the U.S. system. Industry data indicates that PG&E's system contains approximately 2 percent of transmission piping in the U.S. Therefore, the assumption was made to use the same scale for both transmission and distribution stations.[4] This data was used in lieu of using station specific PHMSA data for compressor, processing, and regulation stations as there was a lack of data for each of the driver frequency threats. The likelihood of ignition was computed by taking the sum of transmission and distribution ignition events and dividing by the total count of major losses of containment.[5]

For this risk, the associated drivers based on the bow tie are outlined below:

- **D1 – Equipment-Related:** Equipment failures that may result from age, maintenance history, or design configuration can lead to over-pressure excursions (which may produce failure of assets at the facility or of downstream assets) or under-pressure excursions (which may result in customer outages). There are potential safety, operations, reliability and financial impacts associated with the equipment-related threat. The Equipment-related driver is managed by replacing aging and obsolete

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3 PHMSA Major Incident report (Transmission and Distribution) includes a collection of all major incidents in the United States. Time period used is 2010-2016. The PHMSA major incident reporting data includes a filter for commodity types; PG&E filtered the data for Natural Gas and Blanks (Gas Carriers).

4 The number of expected major loss of containment events per year for transmission is 263 events over the 7-year period, assuming that PG&E's assets represent 2 percent of the total or 0.75 events per year. Distribution showed a total of 43 events, amounting to 0.12 events/year.

5 Of the total 306 major loss of containment events, 41 resulted in ignition (13 percent).

equipment, or upgrading or retrofitting equipment to meet current industry and environmental regulations as well as changing business needs. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to equipment failure is 0.0357 per year. This can be interpreted as one event approximately every 28 years.

- **D2 – External Corrosion:** Material deterioration from external corrosion may cause leaks and potential failure of piping and equipment ultimately resulting in loss of containment and/or potential customer outages. External corrosion risks are the result of deterioration of material over time due to external environmental conditions. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to external corrosion failure is 0.0072 per year. This can be interpreted as one event approximately every 139 years.
- **D3 – Incorrect Operations:** Incorrect station operations include those from both automated and manual operation of station equipment. The complexity of performing maintenance at M&C stations could result in human performance error, which could lead to failure of a station. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to incorrect operations failure is 0.0067 per year. This can be interpreted as one event approximately every 149 years.
- **D4 – Internal Corrosion:** Material deterioration from internal corrosion may cause leaks and potential failure of station piping and equipment resulting in loss of containment with potential safety issues and/or customer outages. The risk of internal corrosion results from the deterioration of material over time due to impurities in gas or fluids in the station piping. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to internal corrosion failure is 0.0073 per year. This can be interpreted as one event approximately every 137 years.
- **D5 – Manufacturing Defects:** Manufacturing defects include weld defects such as longitudinal seam defects caused by errors in the welding and material defects caused by various steel impurities. These can occur in transmission pipeline as well as in the piping in gas transmission stations. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to manufacturing defects failure is 0.0035 per year. This can be interpreted as one event approximately every 286 years.
- **D6 – Stress Corrosion Cracking:** The risk of failure of station piping due to stress corrosion cracking that results in a loss of containment may result in public safety issues. Stress corrosion risks are produced by deterioration of material over time due to a combination of factors from pressure cycling, chemicals, stress, and material types. Based on the

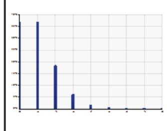
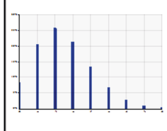
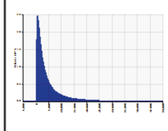
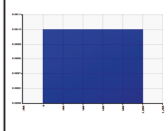
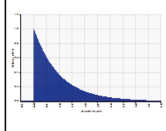
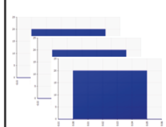
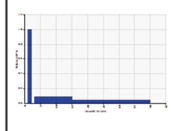
probability distribution used in the model, the average number of loss of containment events with ignition due to stress corrosion cracking failure is 0.0033 per year. This can be interpreted as one event approximately every 303 years.

- **D7 – Third-Party/Mechanical Damage:** Damage caused by third-parties can be mitigated via physical security measures at the M&C stations. Typically, the most common type of third-party damage is dig-ins; dig-ins are prevented at facilities by preventing third-party access to the facilities. Other types of damage that could occur at the M&C facilities in this category include: Vehicle damage, vandalism, terrorism, train derailment etc. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to third-party/mechanical damage failure is 0.0192 per year. This can be interpreted as one event approximately every 52 years.
- **D8 – Weather-Related and Outside Forces (WROF):** Weather and outside forces could potentially result in equipment damage during earthquakes or floods, ultimately resulting in a loss of containment or overpressurization downstream. These events would present potential safety issues and/or customer outages on both the transmission and distribution systems. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to WROF failure is 0.0244 per year. This can be interpreted as one event approximately every 41 years.
- **D9 – Welding/Fabrication:** Risks due to welding or fabrication due to construction are related to inadequate construction practices during the building of the station resulting in potential premature failure or operational difficulties. Additional risks are associated with the documentation and construction records not being sufficient or properly maintained. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to welding/fabrication failure is 0.0098 per year. This can be interpreted as one event approximately every 102 years.

D. Consequences

Figure 4-2 below shows the range of consequences and the attributes used as inputs to calculate the tail average outcome and the associated MARS. In the figure, there is an explanation of the data sources for each of the consequence attributes. Based on the tail average results, trust and safety—fatality outcomes contribute the most to the overall baseline MARS calculation.

Figure 4-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PHMSA and ICE	SME Input	SME Input	PG&E Data	SME Input
Consequence Distributions	Percent of ignition events with injury=14.6% Mean=1 (Poisson) 	Percent of ignition events with fatality=7.3% Mean=2.5 (Poisson) 	Ave=5,822MCF Std Dev=10,744MCF Ave cost of Carbon[3]=$13 /tonne CO_2 (Lognormal) 	Customer hours affected= Min=0 hours*60 Max=1,000 hours*60 (Uniform) 	Ave=$1M (Exponential) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Different for each type of station (Uniform) Distribution=$1M to $2M Trans_simple=$3M to $15M Trans_complex=$15M to $40M 
Outcome-TA-NU[1]	0.18	0.22	$4,732	34,325	$1,163,903	1.88%	$3,081,428
Outcome-TA-MARS[2]	0.05	5.97	0.00	0.09	0.12	9.42	1.85
						MARS Total	17.49

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]To convert MCF to tonne multiply by ~52/1000

Explanation of Consequence Attributes: Data Source, Outcomes

- **Safety – Injuries (SI):** PG&E used the transmission and distribution PHMSA major incident data[6] set filtered for station events to quantify the conditional probability that a major incident results in injuries. Based on this data, the percentage of ignition incidents with injury is 14.6 percent and the average number of injuries per event is one. Based on the tail average model results across the 2017-2022 time periods, the average worst case number of injuries per year is 0.18. This can also be interpreted as approximately one injury every six years. This outcome is higher than anticipated since industry data for ignition events at facilities is very low. PG&E believes that additional data analysis in the future may be able to better identify this risk consequence.
- **Safety – Fatalities (SF):** PG&E used the transmission and distribution PHMSA major incident data set to quantify the conditional probability that a major incident results in fatalities. Based on this data, the percentage of ignition incidents with fatalities is 7.3 percent and the

6 PHMSA Major Incident report includes a collection of all major incidents in the United States. Time period used is 2010-2016. The PHMSA major incident reporting data includes a filter for commodity types; PG&E filtered the data for Natural Gas and Blanks (Gas Carriers).

average number of fatalities per event is 2.5. Based on the tail average model results across the 2017-2022 time period, the average worse case number of fatalities per year is 0.22. This can also be interpreted as approximately one fatality every five years. Similar to the injury results, this outcome is higher than anticipated since industry data of fatalities related to ignition events at facilities is very low. Therefore, additional data analysis in the future may be able to better identify this risk consequence.

- **Environmental (E):** The PHMSA major incident data set for both transmission and distribution related releases of gas with ignition were utilized to compute a weighted average from the 83 transmission and 467 distribution ignition incidents, which resulted in an average gas release volume of 5,822 million cubic feet (MCF).[7] Based on the tail average model results across the 2017-2022 time period, the average worse case environmental related cost is $4,732 per year. This is equivalent to approximately 210 tonnes of CO_2. These results show that environmental impacts play a relatively small role in this risk.
- **Reliability (R):** PG&E leveraged SME judgment to determine the reliability impact of this risk. PG&E assumes zero to a maximum impact of 1,000 customer hours based on an individual station being out of service and the redundancy in PG&E's gas system. Based on the tail average model results across the 2017-2022 time period, the average worse case reliability impact would be of 34,325 customer minutes or approximately 572 customer hours. These results show that reliability plays a relatively small role in this risk.
- **Compliance (C):** PG&E leveraged SME judgment to determine the compliance impact of this risk. PG&E assumes the primary cost of compliance after a major incident with ignition would be associated with additional inspection stemming from new regulations, the cost of which was estimated to be $1,000,000 on average. Based on the tail average model results, the average worse case compliance related impact is $1,163,903. Impacts in this category are relatively low in comparison to other risk consequence outcomes.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all GO risks.[8] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is 1.88 percent a year.

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7 The average cost of carbon was taken from the Intercontinental Exchange (ICE) end of day close for California Carbon Allowance Futures as of day close March 29, 2017, which was $13 per tonne of carbon dioxide (CO_2).

8 Refer to the Risk Model Overview chapter for the trust consequence calculation details.

- **Financial (F):** PG&E leveraged SME judgment to determine the financial impact of this risk by using facility replacement costs as the basis for the model since estimates of downstream damage costs are different for each event. The financial impact was based on estimating lower and upper bound ranges for facility replacement costs with respect to distribution stations, transmission simple stations, and transmission complex stations. The distribution station count includes both LP and HP stations—totaling 4,825 stations. Transmission stations were broken out into those that were considered simple (428) and those that were considered complex (128). Replacement cost by station type is outlined in the table below:

Table 4-2: Station Replacement Costs

Station Type	Lower Bound	Upper Bound
Distribution Station	$1,000,000	$2,000,000
Transmission Simple Station	$3,000,000	$15,000,000
Transmission Complex Station	$15,000,000	$40,000,000

Based on the tail average model results across the 2017-2022 time period, the average worst case replacement costs amount to $3,081,428 a year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

M&C facilities function to maintain the reliability of the gas system to effectively control and monitor the gas system. There are also integrity management requirements to maintain the pressure boundary. The M&C asset family has a robust set of controls in place to manage both reliability and integrity. The controls include ongoing maintenance and inspection activities, ongoing capital work to manage obsolescence and operational requirements, gas quality control and monitoring, and various other integrity management activities related to material condition (corrosion). In addition, to further address integrity management, a series of mitigations are defined to address manufacturing, construction and third-party damage risk drivers. These mitigations have beneficial effects to reduce other risk drivers as well. Table 4-3 below summarizes the controls and associated 2016 recorded costs associated with each control.

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 inspections. This control addresses the Equipment-related driver. This program is identified as a control for the M&C Downstream risk and the Distribution Mains and Services Non-Cross Bore risk. The total cost for this program is not allocated between the risks.

C2 – Corrosion Control: All of PG&E's metallic (steel) assets are subject to corrosion, an electrochemical process where metal degrades due to its interaction with the environment. Corrosion control seeks to either eliminate the elements that lead to corrosion or to manipulate the natural corrosion process with electrical currents. Effective corrosion control monitoring programs are critical to provide timely data that is representative of pipeline and equipment conditions; allows for modifications in corrosion mitigation strategies; and updates risk management tools. This control addresses the External Corrosion, Internal Corrosion and Stress Corrosion Cracking drivers. Corrosion Control is also identified as a control for the Natural Gas Storage Well Failure—Loss of Containment with Ignition risk, Transmission Pipeline Failure—Rupture with Ignition risk, and Compression and Processing (C&P) Failure—Release of Gas with Ignition at Manned Processing Facility risk. The total cost for this program is not allocated among the risks.

C3 – Direct Assessments: Direct Assessment (DA) is another method of conducting assessments of pipeline integrity. DA is used to proactively address time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking and prevent anomalies from growing to a size that affects the structural integrity of the pipeline. The assessment techniques are called External Corrosion Direct Assessment to identify and assess locations likely to have external corrosion, Internal Corrosion Direct Assessment to identify and assess locations likely to have internal corrosion, and Stress Corrosion Cracking Direct Assessment 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 Stress Corrosion Cracking drivers. Direct Assessments is also identified as a control for the Storage risk, Transmission Pipe risk and C&P risk. The total cost for this program is not allocated among the risks.

C4 – Gas Quality Assessment: This program incorporates industry best practices and monitors the quality of gas entering the PG&E system. It is important to assess the quality of the gas in the pipeline to ensure that no debris or water flows through the pipeline which could impact the performance of M&C equipment. This control addresses the Equipment-related and Internal Corrosion drivers. This program is identified as a control for the M&C Failure– Release of Gas with Ignition Downstream risk and the C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The total cost for this program is not allocated between the risks.

C5 – Leak Survey: Pipeline safety regulations require PG&E to conduct periodic leak surveys on its gas system to locate leaks. The frequency depends on the local conditions where the pipe is installed and the material or operating condition of the pipe. Transmission facilities must be surveyed twice a year, distribution facilities located in business districts (or principal business areas in urban communities) must be surveyed annually, while copper services must be surveyed at least once every three years. Other facilities, according to federal code must be surveyed at least once every five years. This control addresses the External Corrosion, Internal Corrosion, Stress Corrosion Cracking, and Welding/Fabrication drivers. Leak Survey is also identified as a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk and Transmission Pipeline Failure – Rupture with Ignition risk. The total cost for this program is not allocated between the risks.

C6 – Preventative Maintenance: Preventative Maintenance includes maintenance and inspection of station equipment to ensure it remains in working order; it also includes work that may be required to comply with pipeline safety regulations. Furthermore, performing annual maintenance on our facilities along with a more robust maintenance procedure which includes replacements (filter elements, diaphragms, etc.) approximately every eight years. This control addresses the Equipment-related driver. This program is also identified as a control for the M&C Failure – Release of Gas with Ignition Downstream risk and the Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore risk. The total cost for this program is not allocated between the risks.

C7 – Regulator Station Component Replacement: This program is intended to replace equipment within a regulator station that has exceeded its useful life or is experiencing performance problems. This control ensures the equipment and components are operating properly and reduce the risk of a failure by managing equipment obsolescence and failure. As such, this control addresses the Equipment-related driver. This program is also identified as a control for the M&C Failure – Release of Gas with Ignition Downstream risk. The total cost for this program is not allocated between the risks.

C8 – Regulator Station Replacement: This program includes the complete or partial rebuild of transmission and distribution stations (above or below ground) to replace old and obsolete equipment and piping, to upgrade configuration 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 and contractor safety. PG&E has concerns regarding employee and contractor safety related to vault access or vaults being located near traffic areas, i.e., conditions that put employees at risk during routine maintenance. This control addresses the Equipment-related driver. This program is also identified as a control for the M&C Failure – Release of Gas with Ignition Downstream risk. The total cost for this program is not allocated between the risks.

In addition, to further address integrity management, a series of mitigations address Equipment-related and Incorrect Operations drivers. The set of mitigation activities is aimed at reducing the risks associated with the integrity of the facilities**.** The mitigations are included in Table 4-3 with costs recorded from 2016 and are described below.[9]

M1A – 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 addresses these risks by ensuring 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 as it reduces the chance of communication error between operator and control room along with the Safety-Injury and Safety-Fatality consequence categories. This program is also identified as mitigation for the M&C Failure – Release of Gas with Ignition Downstream risk and C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The cost for this program was allocated between all three risks with a 65 percent allocation to the two M&C risks and 35 percent to the C&P risk. Both the M&C show the total 65 percent allocation (i.e., the costs that were allocated to the two M&C risks were not separated).

M2A – Engineering Critical Assessment (ECA) Phase 1: Beginning in 2015, PG&E embarked on the ECA Phase 1 Program, which entails reviewing and identifying issues that may compromise station asset integrity. The primary focus of the ECA Phase 1 Program is to identify components which may be under-rated for the service in which they are operating. The ECA Phase 1 work involves identifying component design anomalies, field investigating components and developing and performing associated remediation activities. This program addresses Manufacturing Defects, Weather-Related and Outside Forces, and Welding/Fabrication drivers. Furthermore, it also addresses the compliance, trust, and financial consequence categories. This program is also identified as a mitigation for the C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

M3A – Engineering Critical Assessment Phase 2: At the completion of ECA Phase 1, there will be station components that will require mitigation in addition to any remediation undertaken as part of ECA Phase 1. More specifically, station components where the documentation of the material installed or the pressure test history is incomplete will be subject to ECA Phase 2. Validation of station features provides assurance of facility integrity from a design and installation perspective. This effort includes field work to perform non-destructive examination (NDE) type validation of station features and properties. The ECA Phase 2 addresses multiple threats that affect

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9 For detailed description of the mitigation programs, refer to the workpapers for this chapter.

station integrity and reliability, including External Corrosion, Internal Corrosion, Manufacturing Defects, and Welding/Fabrication drivers. Also, compliance, trust, and financial consequence categories are addressed by this program. This program is also identified as a mitigation for the C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

M4A – Physical Security Upgrades: The Physical Security Program implements security measures recommended in the Security Vulnerability Assessments study performed by Lawrence Livermore National Lab (LLNL). This mitigation provides for installation of additional security measures at facilities, including installation of barriers, cameras, and other recommended actions in accordance with Transportation Security Administration (TSA) Guidelines. This mitigation addresses the Third-Party/Mechanical Interventions driver, and also addresses the Safety-Injury and Safety-Fatality consequence categories. The overall goal is to complete physical security enhancements at critical gas facilities as recommended in the vulnerability study conducted by LLNL in a timely manner. This program is also identified as a mitigation for the C&P Failure – Release of Gas with Ignition at Manned Processing Facility risk. The cost for this program was allocated with a 50 percent allocation to the M&C risk and 50 percent to the C&P risk.

M5A – Supervisory Control and Data Acquisition Visibility: To monitor and operate the gas systems and mitigate potentially abnormal conditions, Gas Control Center personnel must be able to view pressure and flow data from key locations within the system. Typically, these locations are at regulator stations. Due to their importance in operating the system, regulator stations may have multiple Supervisory Control and Data Acquisition (SCADA) devices, one immediately upstream of, downstream of, and inside the station. SCADA devices provide the required visibility to Gas Control Center personnel. If the devices detect conditions that are out of the normal range, they send an alarm to the Gas Control Center – operators then investigate and take necessary measures. This mitigation addresses the Incorrect Operations driver along with all consequence categories. This program is also identified as a mitigation for the M&C Failure – Release of Gas with Ignition Downstream risk. The total cost for this program is not allocated between the risks.

Table 4-3: Summary of Risk Controls and Mitigations and 2016 Recorded Costs

#	Control	Associated Drivers and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Corrective Maintenance	D1	GRC	74,164	–
C2	Corrosion Control	D2, D4, D6	GTS	35,030	35,409
C3	Direct Assessments	D2, D4, D6	GTS	39,368	–
C4	Gas Quality Assessment	D1, D4	GTS	290	–
C5	Leak Survey – T	D2, D4, D6, D9	GTS	3,550	–
	Leak Survey – D	D2, D4, D6, D9	GRC	30,949	–
C6	Preventative Maintenance	D1	GRC	9,007	–
C7	Regulator Station Component Replacement	D1	GRC	–	13,064
C8	Regulator Station Replacement	D1	GRC	–	18,543
M1A	Critical Documents Program	D3, C, T, F	GTS	5,650	–
M2A	ECA Phase 1	D5, D8, D9, C, T, F	GTS	7,695	–
M3A	ECA Phase 2	D2, D4, D5, D9, C, T, F	GTS	1,033	–
M4A	Physical Security	D7, SF, SI	GTS	1,395	10,237
M5A	SCADA Visibility – T	D3, SF, SI, E, R, C, T, F	GTS	–	266
	SCADA Visibility – D		GRC	–	27,616
TOTAL Expense and Capital				**208,131**	**105,135**

IV. Current Mitigation Plan (2017-2019)

The mitigation programs described in detail in the section above are also the mitigations for the 2017-2019 time period. The mitigations include: Critical Documents Program, ECA Phase 1, ECA Phase 2, Physical Security Upgrades, SCADA Visibility, and Station Strength Testing. The scope of the mitigations is described below.

M1B – Critical Documents Program: Continue update of station documentation at identified stations. Based on the forecast for this program, representative[10] numbers of stations for this activity are 66 in 2017, 88 in 2018, and 109 in 2019.

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10 The representative number of stations to be addressed is not the actual number of stations. The representative number of stations to be addressed by the Critical Documents Program has been determined based on the total number of stations to be addressed by the total program, scaled by the fraction that the yearly program forecast represents out of the total program forecast.

M2B – ECA Phase 1: Continue validation of Station Features at identified stations. The representative[11] numbers of stations for this activity are 78, 77, and 59 for 2017, 2018 and 2019, respectively.

M3B – ECA Phase 2: Ongoing work for ECA Phase 2 is related to evaluating NDE techniques for applicability to this effort. The representative numbers of stations to be addressed are 3 in 2017, 8 in 2018, and 10 in 2019.

M4B – Physical Security Upgrades: Continue upgrades of identified stations. This includes one station a year during the 2017-2019 time period.

M5B – SCADA Visibility: Continue SCADA installations at identified distribution and transmission stations to provide visibility into the performance of the system. This includes 237 and 3 transmission stations in 2017, 144 distribution and 13 transmission stations in 2018, and 149 distribution and 8 transmission in 2019.

In addition to the mitigations previously discussed in Section III, the program listed below will begin in 2018.

M6A – Station Strength Testing: The program is designed to address components that cannot be addressed via ECA Phase 2. As a result, the Station Strength Testing Program should be considered the last-resort alternative. Strength testing provides assurance of facility integrity from a design and installation perspective. This effort includes field work to perform strength testing of components. This control addresses the External Corrosion, Internal Corrosion, Manufacturing Defects, Stress Corrosion Cracking, Third-Party/Mechanical Interventions, Weather-Related and Outside Forces, and Welding/Fabrication drivers. This program is also identified as a mitigation for the C&P Failure – Loss of Containment with Ignition at a Manned Compression Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

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11 The representative number of stations to be addressed is not the actual number of stations. The representative number of stations is based on the total number of stations to be addressed, scaled by the fraction that the yearly program forecast represents out of the total program forecast.

No stations will be addressed by Station Strength Testing in 2017 since the scope and implementation of the program is contingent upon the results obtained from the completion of ECA Phase 1 and ECA Phase 2. The equivalent number of stations to be addressed in 2018 and 2019 are 1 and 2,[12] respectively.

Table 4-4: 2017 to 2019 Mitigation Work and Associated Costs

#	Control	Start Date	End Date	Associated Driver # and Consequence	2017 Forecast ($000)	2018 Forecast ($000)	2019 Forecast ($000)
M1B	Critical Documents Program	2015	2021	D3, C, T, F	– (C) 5,842 (E)	– (C) 7,636 (E)	– (C) 9,593 (E)
M2B	ECA Phase 1	2015	2021	D5, D8, D9, C, T, F	6,240 (C) 8,596 (E)	6,240 (C) 9,932 (E)	7,020 (C) 9,377 (E)
M3B	ECA Phase 2	2015	2033	D2, D4, D5, D9, C, T, F	– (C) 2,491 (E)	888 (C) 4,820 (E)	893 (C) 5,870 (E)
M4B	Physical Security Upgrades	2015	2023	D7, SI, SF	3,752 (C) – (E)	5,155 (C) – (E)	4,696 (C) – (E)
M5B	SCADA Visibility – T	2015	2025	D3, SI, SF, E, R, C, T, F	1,696 (C) – (E)	4,151 (C) – (E)	2,740 (C) – (E)
	SCADA Visibility – D	2014	2025	D3, SI, SF, E, R, C, T, F	26,300 (C) – (E)	26,353 (C) – (E)	27,259 (C) – (E)
M6A	Station Strength Test	2018	2033	D2, D4, D5, D6, D7, D8, D9	– (C) – (E)	158 (C) 1,623 (E)	317 (C) 3,248 (E)
TOTAL Expense and Capital by Year					**35,735 (C) 16,929 (E)**	**40,606 (C) 24,011 (E)**	**38,914(C) 28,088 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for M&C Failure – Release of Gas with Ignition at M&C Facility Risk. As previously discussed in Section III, there is a robust set of controls to address the reliability and integrity management at the M&C Facility. The proposed mitigations are the continuation of previously identified actions to further reduce the risk of the events at the facilities.

Mitigations were selected in 2017-2019 to further address integrity management, as well as equipment-related and incorrect operations threats. These mitigations are ongoing and are part of the 2020-2022 strategy. The mitigations are listed below along with the proposed scope of work:

12 The Station Strength Test Program is forecast to extend through 2033. The representative number of stations to be addressed is not the actual number of stations. The representative number of stations is based on the total number of stations to be addressed by the program, scaled by the fraction that the yearly program forecast represents out of the total program forecast.

M1C– Critical Documents Program: Continue update of station documentation, which includes 109 representative stations in 2020 and 88 in 2021. The program is scheduled to complete in 2021.

M2C – ECA Phase 1: Continue validation of Station Features at identified stations. This includes 79 representative stations in 2020 and 51 in 2021. This program is schedules to complete in 2021.

M3C – ECA Phase 2: Ongoing work for ECA2 which includes 11 representative stations per year during the 2020-2022 time period.

M4C – Physical Security Upgrades: Continue upgrades of identified stations. This includes one station a year during the 2020-2022 time period.

M5C – SCADA Visibility: Continue SCADA installations at identified distribution and transmission stations to provide visibility into the performance of the system. This includes 149 distribution stations and 13 transmission stations in 2020, 150 distribution stations and 8 transmission stations in 2021, and 123 stations distribution and 8 transmission stations in 2022.

M6B – Station Strength Testing: Station scope of this mitigation consists of 4 representative stations in 2020, 6 in 2021, and 6 in 2022.

The mitigation programs tend to be long-running in nature and so most will continue through the RAMP period. The control programs help PG&E manage the risks and stay compliant with state and federal requirements. The mitigation programs proactively target risk reduction. As such, these programs are aimed at improving the integrity and health of PG&E's assets, finding and repairing any existing issues and therefore preventing the risk event from occurring.

These selected mitigations and the pace of the mitigation are based on completing these efforts with available qualified resources, and within operational constraints of the system.

Table 4-5: 2020-2022 Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0109	0.0011	2015	2021	D3, C, T, F	– (C) 9,593 (E)	– (C) 9,593 (E)	– (C) – (E)
M2C	ECA Phase 1	0.0049	0.0007	2015	2021	D5, D8, D9, C, T, F	5,460 (C) 9,377 (E)	2,340 (C) 9,377 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0020	0.0002	2015	2033	D2, D4, D5, D9, C, T, F	1,828 (C) 5,870 (E)	1,868 (C) 5,870 (E)	1,868 (C) 5,870 (E)
M4C	Physical Security Upgrades	0.0001	0.0000	2015	2023	D7, SI, SF	4,713 (C) – (E)	4,704 (C) – (E)	4,704 (C) – (E)
M5C	SCADA Visibility - T	0.0057	0.0005	2015	2025	D3, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility - D			2014	2025	D3, SI, SF, E, R, C, T, F	25,897 – 28,622 (C) – (E)	25,916 – 28,643 (C) – (E)	25,795 – 28,510 (C) – (E)
M6B	Station Strength Test	0.0002	0.0003	2018	2033	D2, D4, D5, D6, D7, D8, D9	583 (C) 3,248(E)	795 (C) 3,248 (E)	795 (C) 3,248 (E)
Proposed Plan TA RSE: 0.0051 **TOTAL Expense and Capital by Year**							**42,766 – 45,491 (C)** **28,088 (E)**	**38,750 – 41,477 (C)** **28,088 (E)**	**36,289 – 39,004 (C)** **9,118 (E)**

VI. Alternatives Analysis

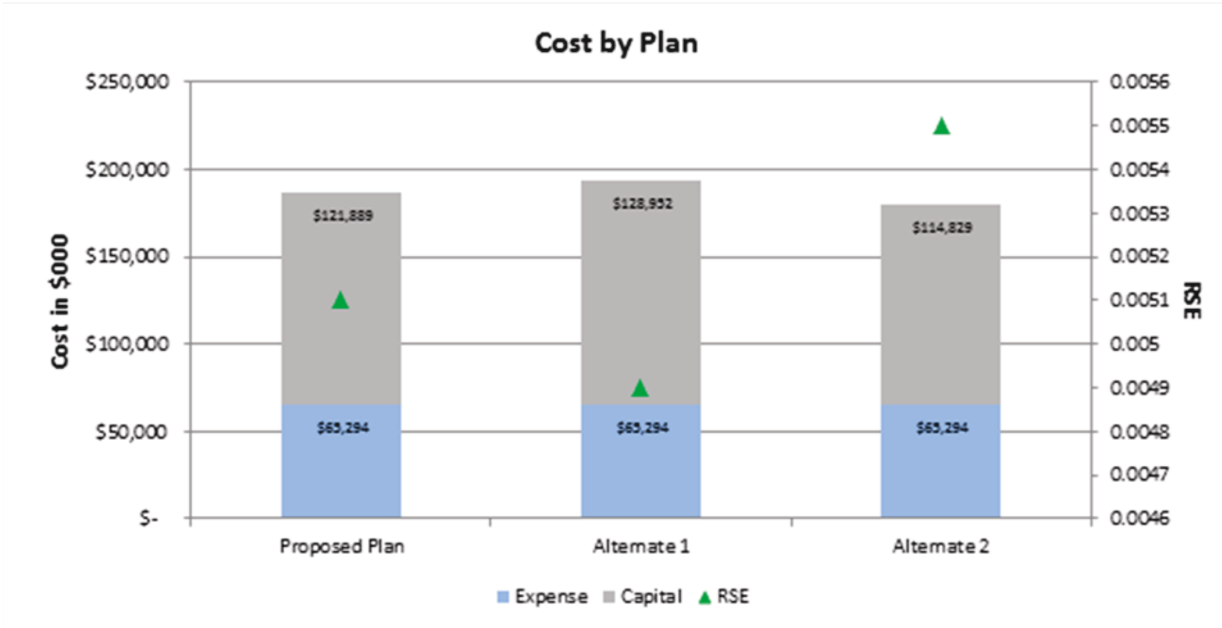
While assessing all of the mitigations, PG&E developed two alternative plans to the proposed mitigation plan. Plan 1 was created based on an increased pace of Physical Security Upgrades at identified stations while Plan 2 considered a decreased pace. The alternatives were chosen to evaluate the sensitivity of the program pace on risk reduction. Both plans are shown below in Tables 4-6 and 4-7.

Table 4-6: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Critical Documents Program	0.0109	0.0011	X	X	X	WP 4-2
M2C	ECA Phase 1	0.0049	0.0007	X	X	X	WP 4-5
M3C	ECA Phase 2	0.0020	0.0002	X	X	X	WP 4-8
M4C	Physical Security Upgrades	0.0001	0.00004	X			WP 4-12
M5C	SCADA Visibility	0.0057	0.0005	X	X	X	WP 4-16
M6B	Station Strength Test	0.0002	0.0003	X	X	X	WP 4-19
M4D	Physical Security Upgrades	0.0001	0.00004		X		WP 4-12
M4E	Physical Security Upgrades	0.0001	0.00004			X	WP 4-12

Figure 4-3 below shows the breakdown of the proposed plan, Alternative Plan 1, and Alternative Plan 2 based on cost and Risk Spend Efficiency (RSE).

Figure 4-3: Alternative Plans by Cost and RSE Score



A. Alternative Plan 1

The mitigation programs described in Section V above are the same in terms of scope of work as the mitigations presented in this alternative, with the exception of Physical Security Upgrades. PG&E chose to analyze the impacts of this mitigation explicitly as Physical Security Upgrades play a key role in reducing the impacts of third-party damage which is a priority for this risk. The change in scope for this alternative is outlined below:

- **M4D – Physical Security Upgrades:** Increase pace of upgrades at identified stations from 1 station a year to 1.5. This includes one station a year during the 2020-2022 time period.

This alternative assumes a more rapid pace of implementation. This alternative was not selected due to operational and resource constraints. Even though physical security upgrades are completed at more stations, this alternative would result in system and resource constraints. To complete the physical security upgrades, certain facilities would be unavailable during the upgrade.

Table 4-7: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0109	0.0011	2015	2021	D3, C, T, F	– (C) 9,593 (E)	– (C) 9,593 (E)	– (C) – (E)
M2C	ECA Phase 1	0.0049	0.0007	2015	2021	D5, D8, D9, C, T, F	5,460 (C) 9,377 (E)	2,340 (C) 9,377 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0020	0.0002	2015	2033	D2, D4, D5, D9, C, T, F	1,828 (C) 5,870 (E)	1,868 (C) 5,870 (E)	1,868 (C) 5,870 (E)
M4D	Physical Security Upgrades	0.0001	0.0000	2015	2023	D7, SI, SF	7,070 (C) – (E)	7,057 (C) – (E)	7,057 (C) – (E)
M5C	SCADA Visibility – T	0.0057	0.0005	2015	2025	D3, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility – D			2014	2025	D3, SI, SF, E, R, C, T, F	25,897 – 28,622 (C) – (E)	25,916 – 28,643 (C) – (E)	25,795 – 28,510 (C) – (E)
M6B	Station Strength Test	0.0002	0.0003	2018	2033	D2, D4, D5, D6, D7, D8, D9	583 (C) 3,248(E)	795 (C) 3,248 (E)	795 (C) 3,248 (E)
Alternative Plan 1 TA RSE: 0.0049 **TOTAL Expense and Capital by Year**							**45,123 – 47,848 (C)** **28,088 (E)**	**41,103 – 43,830 (C)** **28,088 (E)**	**38,642 – 41,357 (C)** **9,118 (E)**

B. Alternative Plan 2

A similar approach was taken in alternative 2 where we examined the impact of a change in scope for the Physical Security Upgrades mitigation; in this case a decelerated pace. The change in scope for this alternative is outlined below:

- **M4E – Physical Security Upgrades:** Decrease in pace of upgrades of identified stations from 1 station a year to 0.5, or 1 station every 2 years.

Even though this alternative has a lower cost and slightly higher risk spend efficiency (RSE), it was not chosen as the recommended case. Vandalism/Terrorist attacks at critical facilities have implications on personal safety and equipment damage. Completing the physical security upgrades for these critical facilities at the proposed pace proactively addresses these threats and is a key strategic objective for the M&C asset family.

Table 4-8: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.0109	0.0011	2015	2021	D3, C, T, F	– (C) 9,593 (E)	– (C) 9,593 (E)	– (C) – (E)
M2C	ECA Phase 1	0.0049	0.0007	2015	2021	D5, D8, D9, C, T, F	5,460 (C) 9,377 (E)	2,340 (C) 9,377 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0020	0.0002	2015	2033	D2, D4, D5, D9, C, T, F	1,828 (C) 5,870 (E)	1,868 (C) 5,870 (E)	1,868 (C) 5,870 (E)
M4E	Physical Security Upgrades	0.0001	0.0000	2015	2023	D7, SI, SF	2,357 (C) – (E)	2,352 (C) – (E)	2,352 (C) – (E)
M5C	SCADA Visibility - T	0.0057	0.0005	2015	2025	D3, SI, SF, E, R, C, T, F	4,285 (C) – (E)	3,127 (C) – (E)	3,127 (C) – (E)
	SCADA Visibility - D			2014	2025	D3, SI, SF, E, R, C, T, F	25,897 – 28,622 (C) – (E)	25,916 – 28,643 (C) – (E)	25,795 – 28,510 (C) – (E)
M6B	Station Strength Test	0.0002	0.0003	2018	2033	D2, D4, D5, D6, D7, D8, D9	583 (C) 3,248(E)	795 (C) 3,248 (E)	795 (C) 3,248 (E)
Alternative Plan 2 TA RSE: 0.0053 **TOTAL Expense and Capital by Year**							**40,410 – 43,135 (C)** **28,088 (E)**	**36,398 – 39,125 (C)** **28,088 (E)**	**33,937 – 36,652 (C)** **9,118 (E)**

VII. Metrics

The primary metric that PG&E is proposing for this risk is to track reportable incidents. This will allow PG&E to track the number of events PG&E experiences that could lead to the catastrophic risk event we are modeling. This metric would include OP events, as well as loss of containment events.

Metrics associated with the mitigation programs are designed to measure if each program is progressing at the desired pace to achieve risk reduction objectives. The targets for these metrics are established based on rate case outcomes through PG&E's Integrated Planning process. Table 4-9 below shows the proposed risk reduction and execution metrics:

Table 4-9: Metrics

Risk/Mitigation	Associated Driver # and Consequence	Proposed Metric	Targets
Risk Reduction Metric			
Measurement and Control (M&C) Failure – Release of Gas with Ignition at M&C Facility	All	Number of reportable incidents.	N/A
Execution Metric			
Critical Documents Program	D3, C, T, F	Number of stations completed.	TBD
ECA Phase 1	D5, D8, D9, C, T, F	Number of station features completed.	TBD
ECA Phase 2	D2, D4, D5, D9, C, T, F	Under development; requires completion of ECA Phase 1.	TBD
Physical Security Upgrades	D7, SI, SF	Number of facilities completed.	TBD
SCADA Visibility	D3, SI, SF, E, R, C, T, F	Number of stations with SCADA implemented.	TBD
Station Strength Test	D2, D4, D5, D6, D7, D8, D9	Under development; requires completion of ECA Phase 1 and ECA Phase 2.	TBD

VIII. Next Steps

For the Measurement and Control Failure at the facility risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Continue to evolve existing tools to understand and monitor condition and criticality of assets leading to a more data driven process for monitoring and managing assets. In the last few years, PG&E identified that the evaluation of threats and risks associated with M&C assets was largely based on experience and judgement of PG&E SMEs. During the past three years, PG&E had performed several tasks that provide information for monitoring threat and asset health. This includes activities such as industry benchmarking studies, process safety assessments and condition assessments to understand hazards.
- Refine model inputs. The modeling effort was primarily focused on safety. Given the lack of data to estimate the compliance, reliability and environmental impacts, the team made broad assumptions on new regulations, customer outage and environmental costs. Additionally, the financial impacts require further analysis to better mirror replacement costs for all types of M&C assets. These model inputs are being assessed and, where possible, PG&E will update these inputs in the future.
- Advance risk quantification and understand and use component level data unique to PG&E for future risk quantification efforts. Given the small sample size of ruptures and ignition at facilities in PG&E, industry data was used to determine the frequency for this risk for the current model.
- Consider how PG&E can align risk models with different units of work planned and forecast.

- Calibrate model outputs and perform sensitivity analysis. For example, the Safety – Injuries consequence is higher than anticipated since industry data on injuries caused by ignition events at stations is very low. Therefore, additional data analysis in the future may be able to better identify this risk consequence.
- Reevaluate different combinations of mitigations in the alternative analysis to optimize for risk reduction and operational efficiency.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 5
RELEASE OF GAS WITH IGNITION ON DISTRIBUTION FACILITIES – CROSS BORE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 5
RELEASE OF GAS WITH IGNITION ON DISTRIBUTION FACILITIES – CROSS BORE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Release of Gas with Ignition on Distribution Facilities – Cross Bore
IN SCOPE	Loss of containment with ignition due to cross bore
OUT OF SCOPE	Loss of containment with ignition due to any other risk driver
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, Pipeline and Hazardous Materials Safety Administration (PHMSA)[1] data and Subject Matter Expert (SME) input

Pacific Gas and Electric Company (PG&E) maintains approximately 42,700 miles of distribution mains and approximately 3.4 million services in its gas distribution system. The distribution mains transport gas downstream of a distribution center and the services lines connect the mains to customer connected equipment. Together the mains and services provide natural gas to PG&E's 4.3 million residential, commercial and industrial customers.

Because operators of waste water and storm drain systems are not required to locate and mark their facilities, an inadvertent placement of a gas main or service through a waste water or storm drain pipeline can occur during trenchless construction resulting in a "cross-bore." Cross-bored sewers are found on many gas distribution systems throughout the United States. The potential number of cross-bored sewers is not well quantified, but the consequence of natural gas migrating in sewer lines is significant. Cross bores are an issue of increasing concern for gas utility operators nation-wide and are identified as a high risk to public and employee safety, which can potentially result in serious injuries and or fatalities.

The risk of release of gas with ignition on distribution facilities due to a cross bore has been on PG&E's risk register since 2014. It is also an Enterprise level risk overseen by the Safety and Nuclear Oversight Committee of PG&E's Board of Directors.

Over the last few years, PG&E has experienced approximately 24 cross bore events involving the release of gas, but with no ignition, injuries or fatalities. However, there have been four injuries and two fatalities associated with this risk reported in the gas industry, with the first instance dating back to 1976.

As discussed in this chapter, PG&E is actively addressing this risk through control and mitigation programs. One of the strategic objectives for the distribution gas assets is to identify and remediate all potential cross bores by 2023. The Cross Bore Prevention

1 Pipeline Hazardous Materials Safety Administration – Major Incident Records Report, March 27, 2017.

Program is identified as a control and includes camera inspections during construction to prevent any new cross bores. As a mitigation strategy, the Cross Bore Program has been identified which includes inspection, identification and remediation of existing cross bores within the PG&E gas distribution system. The details of these programs are discussed in sections below.

By implementing the mitigation strategy outlined in this chapter, PG&E estimates a potential 67 percent reduction of the overall multi-attribute risk score (MARS).

Going forward, PG&E plans to collect and analyze more data to improve the model inputs and continue the move toward more quantitative, data driven risk models. One of the key next steps for this risk is to collect additional data to estimate the number of potential cross bores throughout the system. A detailed list of next steps is included in Section VIII.

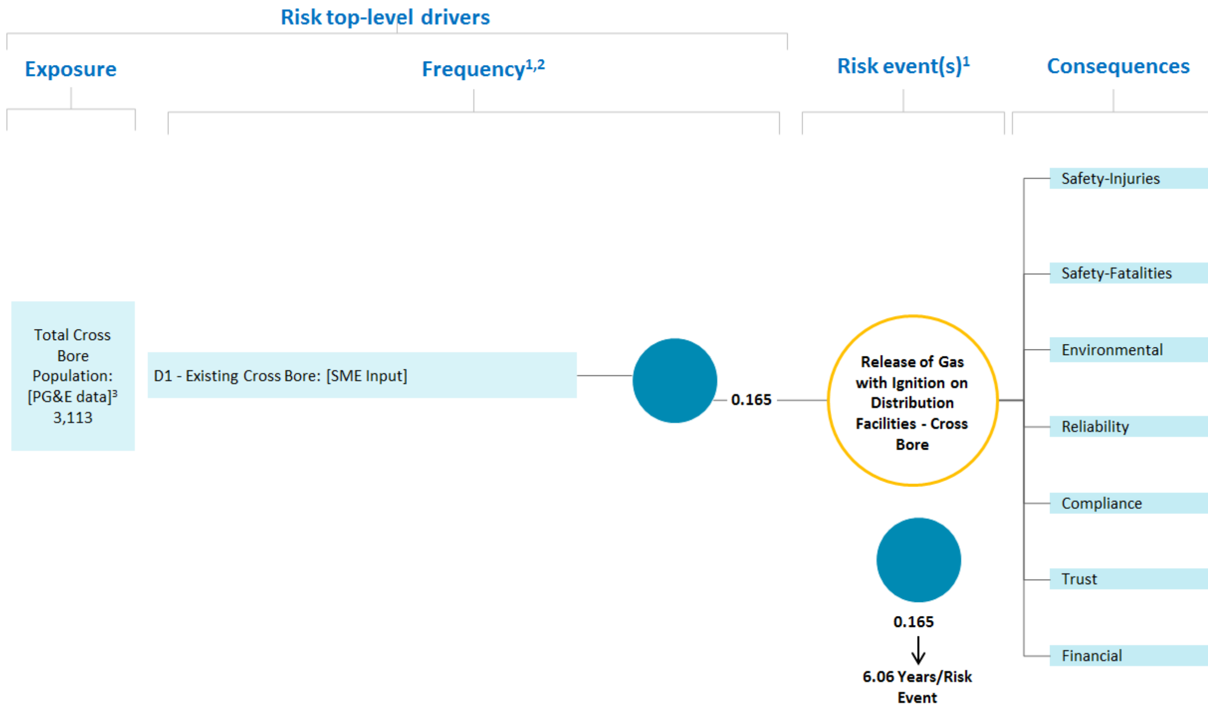
II. Risk Assessment

A. Background

Because operators of waste water and storm drain systems are not required to locate and mark their facilities, an inadvertent placement of a gas main or service through a waste water or storm drain pipeline can occur during trenchless construction resulting in a "cross bore." Cross-bored sewers are found on many gas distribution systems throughout the United States. The potential number of cross-bored sewers is not well quantified, but the consequence of natural gas migrating in sewer lines is significant. Cross bores are an issue of increasing concern for gas utility operators nation-wide and are identified as a high risk to public and employee safety, which can potentially result in serious injuries and or fatalities. Since 2012, there have been approximately 24 losses of containment events due to cross bores in PG&E's gas distribution system. Although none of these events resulted in ignition, due to the potential safety consequences, PG&E considers such an event a risk that requires mitigation.

Figure 5-1 shows the bow tie associated with this risk. The risk bow tie shows the exposure and frequency drivers for the risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie, is defined as a release of gas with ignition on distribution facilities due to cross bores. Based on the model inputs for frequency, this risk event is likely to occur approximately every six years. An event of this nature can lead to severe consequence impacts given that gas can migrate into multiple homes or buildings in high population areas (e.g., downtown San Francisco).

Figure 5-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Driver is modeled using a Binomial distribution.
[3]Total Cross Bore Population = (Parcels * Laterals per parcel * Cross bore existence rate) - historical cross bores found to date.

B. Exposure

Because PG&E has not identified the exact number of existing cross bores, the exposure is uncertain. In PG&E’s 2014 General Rate Case (GRC), PG&E estimated approximately 500,000 sewer lateral inspections would be completed within a 10-year period. For the risk model, the cross bore exposure is estimated on the basis of the historical find rate of 0.6 percent (e.g., 2012-2015 approximately 510 cross bores were found out of the approximately 85,100 inspections completed).

C. Drivers and Associated Frequency

PG&E uses 49 Code of Federal Regulation Part 192, subpart P[2] as the basis for categorizing and evaluating the threats[3] for the distribution assets. Because a cross bore is created during the trenchless construction process, the Incorrect Operations threat is the only identified driver for this risk.

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2 Gas Distribution Pipeline Integrity Management.

3 The terms “threats” and “risk drivers” are used interchangeably throughout this chapter.

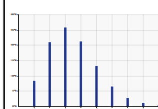
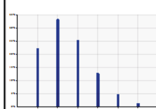
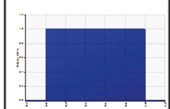
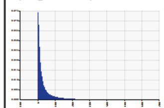
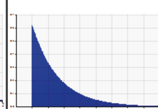
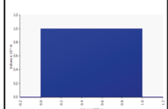
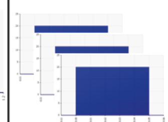
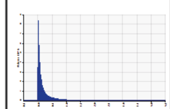
- **D1 – Incorrect Operations –** The Incorrect Operation driver includes human error and incorrect procedures that may lead to safety hazards when procedures are not followed or when improperly trained or untrained personnel perform work on the distribution system.

  The model quantifies the frequency of a cross bore leading to an event with loss of containment and ignition with safety consequences. Not all loss of containment events result in ignition, and not all ignition events result in injuries or fatalities. Since 2012, there have been approximately 24 loss of containment events due to cross bores in PG&E's gas distribution system, which were identified after the occurrence of each event. PG&E has not experienced a cross bore with loss of containment resulting in ignition. As a result, PG&E made a conservative assumption that the next loss of containment cross bore event will result in ignition (1 in 25 chance or 4 percent).

D. Consequences

The range of consequences and the attributes that help describe tail average risks and the MARS are shown in Figure 5-2. In the figure, there is an explanation of the data sources used for each of the consequence attributes. Based on the tail average results, the outcomes in the categories of trust and safety – fatalities contribute the most to the overall baseline MARS total.

Figure 5-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PG&E Data	PG&E Data	SME Input	PG&E Data	PHMSA
Consequence Distributions	Percent of ignition events with injury=28% Mean=2.5 (Poisson) 	Percent of ignition events with fatality=10% Mean=1.5 (Poisson) 	Min=$0 Max=$1M (Uniform) 	Customers Ave customers affected=57 Std Dev=166 (Lognormal)  x Ave duration of outage=1.62 hours*24*60 (Exponential) 	Min=$0 Max=$1M (Uniform) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Ave=$381k Std Dev=$1.3M (Lognormal) 
Outcome-TA-NU[1]	1.13	0.24	$725,419	649,035	$725,419	3.92%	$594,935
Outcome-TA-MARS[2]	0.31	6.41	0.07	1.62	0.07	19.62	0.36
						MARS Total	28.46

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** The PHMSA major incident data set[4] was used to quantify the conditional probability that a cross bore with ignition results in injuries and/or fatalities (e.g., 131 out of the 467 major incidents (28 percent) had injuries with an average of 2.5 injuries per event). Based on the tail average model results across the 2017-2022 time period, the average worst case number of injuries per year is 1.13. This outcome is higher than expected given PG&E has not experienced this to date and industry major incident data was used as a proxy to evaluate this consequence. Additional data analysis in the future may be able to better identify this risk consequence.
- **Safety – Fatalities (SF):** The PHMSA major incident data set was used to quantify the conditional probability that a cross bore with ignition results in injuries and/or fatalities (e.g., 45 out of the 467 major incidents (10 percent) had fatalities with an average number of 1.5 fatalities per event). Based on the tail average model results across the 2017-2022 time period, the average worst case number of fatalities per year is 0.24 or one fatality every four years. Similar to injury outcomes, this is higher than expected and

4 PHMSA Major Incident report includes a collection of all major incidents in the United States. The time period used is 2010-2016.

needs further consideration in future analysis to better understand the associated inputs and outputs.

- **Environmental (E):** Assumed to be zero to a maximum of $1 million based on PG&E's historical environmental remediation costs.[5] Based on the tail average model results across the 2017-2022 time period, the average worst case environmental related costs are approximately $725,400 per year. This result shows that environmental impacts play a relatively small role in this risk.
- **Reliability (R):** Based on PG&E's historical outage events in 2015 and 2016, the average number of customers affected per risk event is 57 with an average duration of 1.62 hours. PG&E historical information was used because this data provided the best estimate of PG&E's time to bring customers back online after an event. Based on the tail average model results across the 2017-2022 time period, the average worst case impact is approximately $650,000. Impacts in this category are relatively low in comparison to other consequences.
- **Compliance (C):** The assumed cost of compliance of zero dollars to $1 million is based upon the assumption that the cost of compliance after a major incident with ignition is additional inspections and requirements. More research is required to better understand how to model the potential impact of compliance. The tail average compliance impact is approximately $725,400 per year.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all PG&E risks.[6] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is approximately 4 percent.
- **Financial (F):** PHMSA major incident data set is used to determine the average cost of loss of containment events estimated at approximately $380,000. However, the range of impact is very wide with a standard deviation of $1.3 million. Based on the tail average model results across the 2017-2022 time period, the average worst case financial impact is calculated at approximately $594,900.

III. 2016 Controls and Mitigation (2016 Recorded Costs)

The control described in this section, the Cross Bore Prevention Program, addresses the incorrect operation risk driver. It is the only control identified for this risk.

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5 This is PG&E internal data and includes costs billed to Gas Operations from PG&E's Land and Environmental Management organizations for remediation work.

6 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

C1 – Cross Bore Prevention Program: In 2015, 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 (e.g., inspect, identify, report and address) required for all gas construction work for PG&E, in an effort to prevent any new cross bores.

The program described below, Cross Bore Program, is the mitigation identified for this risk. In 2014, PG&E estimated approximately 500,000 sewer lateral inspections would be completed within a 10 year period. This program is estimated to be completed by 2023.

M1A – Cross Bore Program: In 2011, 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 loss of containment and gas migration into a structure and ignition.

Table 5-1: Summary of Risk Controls and Mitigations 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Cross Bore Prevention Program	D1	GRC		11,217
M1A	Cross Bore Program	D1	GRC	21,657	
TOTAL Expense and Capital				**21,657**	**11,217**

IV. Current Mitigation Plan (2017-2019)

The Cross Bore Program described in Section III above is also the mitigation for this risk in the 2017-2019 time period. For 2017-2019, PG&E will perform 30,000 inspections in 2017 and 52,500 inspections each year in 2018 and 2019.

Table 5-2: 2017 to 2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1B	Cross Bore Program	2014	2023	D1	31,570 (E)	40,854 (E)	40,851 (E)
TOTAL Expense by Year					**31,570 (E)**	**40,854 (E)**	**40,851 (E)**

V. Proposed Mitigation Plan (2020-2022)

The Cross Bore Program described in Section III above is also the mitigation for this risk for 2020-2022. The proposed case recommends performing 45,000 inspections a year through 2023. The proposed pace for 2020-2022 is consistent with the overall pace identified for 2017-2019.

PG&E believes this is the appropriate scope of work to improve gas system safety by continuing to identify and eliminate cross bores while maximizing the utilization of qualified resources to perform the work.

M1C – Cross Bore Program: The mitigation program is intended to proactively target risk reduction by improving the integrity and health of our assets, finding and repairing any existing issues and therefore preventing the risk event from occurring. PG&E has estimated approximately 500,000 locations for inspection with an estimate to complete the work by December 31, 2023. Approximately 20,000-50,000 inspections are expected to be completed each year.

The recommended plan allows PG&E to mitigate the risk of natural gas migrating inside the sewer system and potentially into a structure should a leak occur, or should the natural gas pipe be cut by equipment during sewer line maintenance operations. The recommended case also prevents the reliability and safety risk associated with gas release due to third party sewer cleaning activities.

The pace reflected in this plan takes into account the ability to plan, conduct records reviews, permitting and execution of the work. PG&E does not have access to an additional number of qualified sewer inspectors that are able to meet its requirements for quality and records. The same resources used for the Cross Bore Program are correspondingly in demand for the Cross Bore Prevention Program, thus the inability to execute a higher volume of work.

Table 5-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	Cross Bore Program	0.0918	0.0092	2020	2022	D1	83,667 - 92,474 (E)	83,779 - 92,598 (E)	82,917 - 91,645 (E)
Proposed Mitigation Plan TA RSE: 0.0918 **TOTAL Expense by Year**							**83,667 - 92,474 (E)**	**83,779 - 92,598 (E)**	**82,917 - 91,645 (E)**

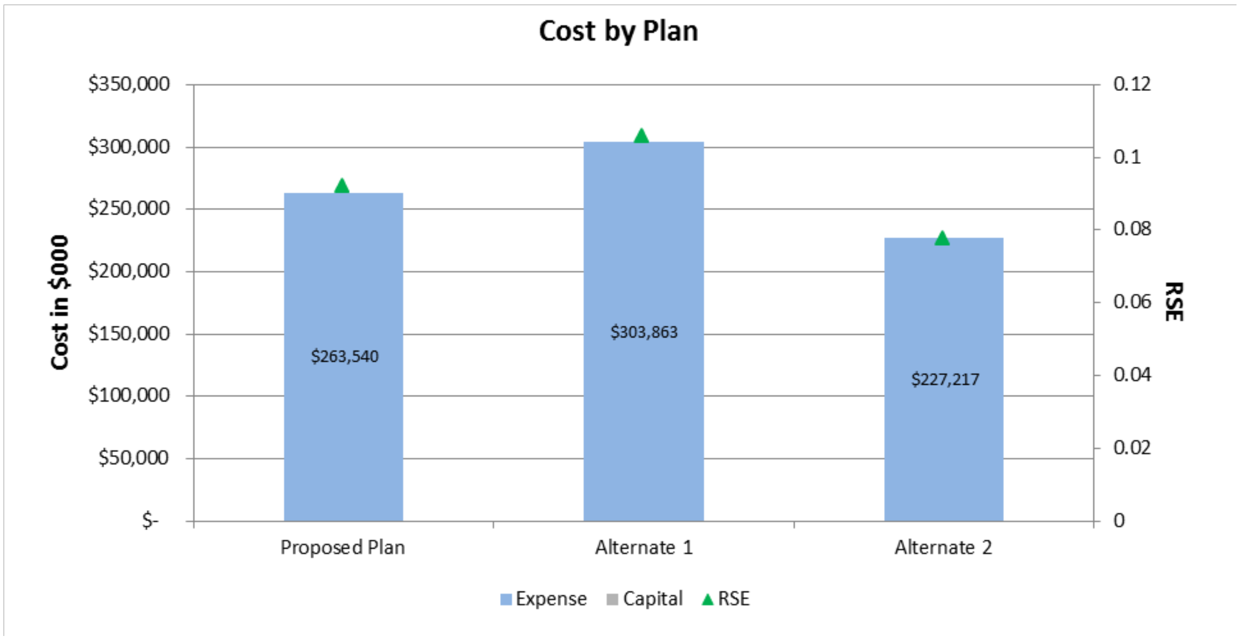
VI. Alternatives Analysis

PG&E analyzed two alternatives to the proposed mitigation plan based on the pace of the program. Plan 1 was created based on increasing the number of inspections performed per year and Plan 2 was created based on a reduction in the number of inspections performed. Both plans are shown below in Table 5-4.

Table 5-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Cross Bore Program	0.0918	0.0092	X			WP 5-2
M1D	Cross Bore Program (Alt 1)	0.1054	0.0106		X		WP 5-2
M1E	Cross Bore Program (Alt 2)	0.0773	0.0078			X	WP 5-2

Figure 5-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

M1D – Cross Bore Program: Alternative one increases the pace of the Cross Bore Program from 45,000 inspections per year to approximately 72,000 inspections per year. This alternative includes incremental work beyond the scope identified in the recommended alternative and is not selected because PG&E does not have access to a sufficient number of qualified sewer inspectors that are able to meet its requirements and the same resources are correspondingly in demand for the prevention program.

Table 5-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Cross Bore Program (Alt 1)	0.1054	0.0106	2020	2022	D1	96,328-106,468 (E)	96,440-106,591 (E)	95,902-105,996 (E)
TOTAL Alternative Plan 1 RSE: 0.1054 **TOTAL Expense by Year**							**96,328-106,468 (E)**	**96,440-106,591 (E)**	**95,902-105,996 (E)**

B. Alternative Plan 2

M1E – Cross Bore Program: Alternative two reduces the pace of the Cross Bore Program from 45,000 inspections per year to 24,000 inspections per year. This alternative is not recommended because of the high risk posed by cross bores. The impact of reducing the scope of inspections is an increase in the risk that a cross bore may be hit and a gas release will occur. The proposed schedule would increase the time to complete 500,000 inspections from 10 years to approximately 20 years.

Table 5-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1E	Cross Bore Program (Alt 2)	0.0773	0.0078	2020	2022	D1	72,248 - 79,853 (E)	72,360 - 79,977 (E)	71,248 - 78,748 (E)
TOTAL Alternative Plan 2 RSE: 0.0773 **TOTAL Expense by Year**							**72,248 - 79,853 (E)**	**72,360 - 79,977 (E)**	**71,248 - 78,748 (E)**

VII. Metrics

The primary metric PG&E is proposing to track for risk reduction is the number of gas releases related to cross bores.

PG&E has selected metrics associated with each of its mitigation programs to ensure each program is progressing at the desired pace in order to ensure risk reduction objectives are achieved. For the Cross Bore Program, the execution metric is tracking the number of inspections completed against the number of inspections planned. If the inspections lead to finding a cross bore, the cross bore is eliminated. As such, the performance metric for this mitigation also provides a good indication of risk reduction. Table 5-7 shows the proposed risk reduction and execution metrics.

Table 5-7: Metrics

Risk/ Mitigation	Associated Driver	Proposed Metric	Targets
Risk Reduction Metric			
Release of Gas with Ignition on Distribution Facilities – Cross Bores	D1	Number of gas releases related to cross bores	TBD
Execution Metric			
Cross Bore Program	D1	Inspections completed versus planned inspections	TBD

VIII. Next Steps

For the Release of Gas with Ignition on Distribution Facilities – Cross Bore risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Improve Gas Operations' quantification methodology by collecting additional data to estimate the number of the potential cross bores throughout the system and the effectiveness of the prevention program.
- Refine the risk bow tie model consequence inputs for safety, environmental, reliability and compliance consequence categories.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 6
COMPRESSION AND PROCESSING FAILURE – RELEASE OF GAS WITH IGNITION AT MANNED PROCESSING FACILITY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 6
COMPRESSION AND PROCESSING FAILURE – RELEASE OF GAS WITH IGNITION AT MANNED PROCESSING FACILITY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility
IN SCOPE	Loss of containment with ignition at a manned compression or processing facility resulting in significant impacts to personnel safety, loss of service and/or equipment damage
OUT OF SCOPE	Related events occurring on transmission pipe or at Measurement and Control (M&C) facilities
DATA QUANTIFICATION SOURCES	Assessment informed by Pacific Gas and Electric Company (PG&E) data, Pipeline and Hazardous Materials Safety Administration (PHMSA) data, and subject matter expertise

A failure at a manned Compression and Processing (C&P) facility leading to a release of gas with ignition is a risk event that can potentially result in significant impacts related to public, contractor and employee safety and system reliability, as well as impacts to nearby equipment and structures. This risk has been on PG&E's risk register since 2013. It is also an Enterprise Risk overseen by the Nuclear, Operations, and Safety Committee of PG&E's Board of Directors. PG&E considers this risk event to be a low frequency, high consequence scenario (i.e., the occurrence of the event is not frequent but if it were to occur, it could result in severe consequences). PG&E has never experienced this catastrophic risk scenario resulting in safety impacts within the C&P facility population; however, PG&E has experienced one loss of containment event (with no injuries or fatalities). Based on industry data, other utilities have experienced this risk event with injuries and fatalities.

There are nine risk drivers that can lead to this event as outlined by the American Society of Mechanical Engineers (ASME) B31.8S[1] standard. These drivers[2] include equipment-related, external corrosion, incorrect operations, internal corrosion, manufacturing defects, stress corrosion cracking, third-party/mechanical damage, weather-related/outside forces, and welding/fabrication related.

PG&E is actively addressing this risk through a variety of controls and mitigations. These control and mitigation programs promote safe operations and maintenance (O&M) of the facilities, and address the specific risk drivers. One of the mitigation programs

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1 See ASME standard B31.8S-2004 "Managing System Integrity of Gas Pipelines." This ASME code is incorporated by reference in the 49 Code of Federal Regulations Part 192.7.c.5.

2 The risk drivers are referred to as "threats" in the ASME B31.8S standard; these two terms are used interchangeably throughout this document.

identified is Physical Security Upgrades, which is designed to mitigate the risk of third-party interference, such as vandalism, at the facilities. Other mitigation programs include Critical Documents, Engineering Critical Assessments (ECA), and Station Strength Testing.

The risk assessment undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process showed that approximately 4 percent of the loss of containment events related to this risk could result in serious safety consequences in the form of fatality and approximately 11 percent of events could lead to injuries. By implementing the mitigation strategy outlined in this chapter, PG&E forecasts a potential 15 percent reduction in the overall Multi-Attribute Risk Score (MARS) between 2017 and 2022.

Going forward, PG&E plans to collect and analyze more data, where possible, to improve the model inputs and continue the move towards more quantitative, data driven risk models. For the C&P risk described in this chapter, one of the key next steps will be to consider aligning risk models with work plan and forecast development. A detailed list of next steps is included in Section VIII below.

II. Risk Assessment

A. Background

PG&E's C&P facilities consist of nine compressor stations[3] and five processing stations. Five of the compressor stations are installed along the northern pipelines (Lines 400 and 401), three stations are installed along the southern pipeline (Line 300) and a ninth compressor station is installed on Line 21 in Santa Rosa. The five processing stations support the three PG&E-owned and operated underground gas storage injection operations.

Failure events do not happen frequently at C&P facilities. To date, PG&E has had one incident at a C&P facility[4] and that event did not result in any safety consequences involving personnel. However, PHMSA major incident reporting data indicates that there have been 28 ignition events at stations (including M&C stations) in the United States (U.S.) between 2010 and 2016. Of these 28 events, 4 events had safety consequences in the form of injuries or fatalities. Even though this risk event has a low probability of occurring, because it could lead to high consequences, it is one of PG&E's top risks.

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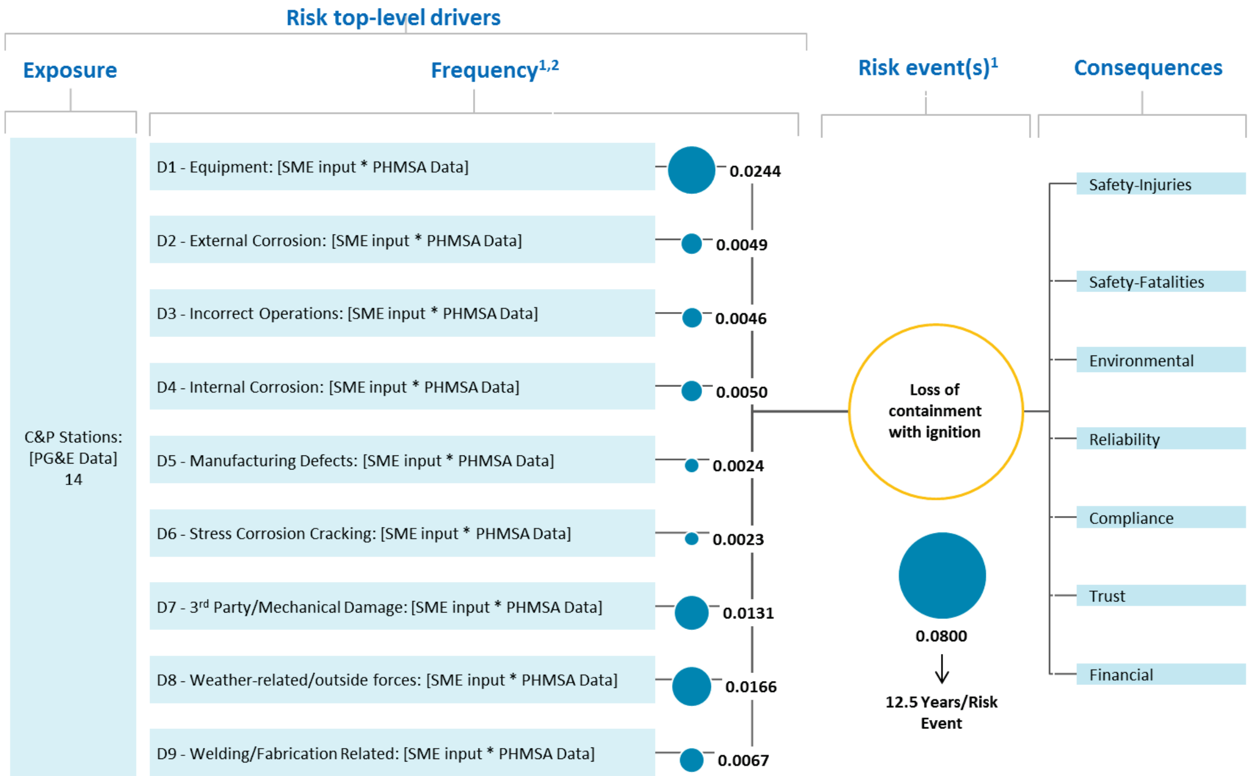
3 The terms "stations" and "facility" are used interchangeably throughout this document.

4 The incident referenced is the Turner Cut fire that occurred in 1993 due to pressure vessel closure failure.

The risk bow tie in Figure 6-1 below shows the exposure and frequency drivers for this risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie, is defined as a loss of containment with ignition at a manned compression or processing facility. Based on the model inputs for frequency, this risk event is likely to occur approximately once every 12.5 years.

Figure 6-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.

B. Exposure

PG&E quantified the risk exposure as the number of C&P facilities owned by PG&E, all of which are considered transmission assets. The number of C&P stations is assumed to stay constant through the 2017-2022 time period because there is no current plan to add or remove stations during this time period. Even though this risk pertains specifically to manned processing facilities, all of PG&E's C&P facilities are considered as part of the RAMP model.

C. Drivers and Associated Frequency

The frequency of the risk event is based on a review of PHMSA major incident data for transmission[5] to identify each driver's respective contribution to the frequency of loss of containment that results in ignition or explosion. Because the PHMSA data includes all events in the U.S., the number of events per year was scaled by the fraction of the PG&E system relative to the U.S. system. Industry data indicates that PG&E's system contains approximately 2 percent of transmission piping in the U.S. Therefore, the assumption was made to use the 2 percent scale for the transmission stations.[6] This data was used in lieu of using station specific PHMSA data for compressor, processing, and regulation stations as there was a lack of data for each of the driver frequency threats. The likelihood of ignition was computed by taking transmission ignition events and dividing by the total count of major losses of containment.[7]

PG&E identified nine risk drivers associated with this risk as described in detail below:

D1 – Equipment-Related: Issues such as equipment age or obsolescence may lead to equipment failures. Equipment obsolescence is defined as the state when equipment may be difficult to maintain, when the vendor no longer supports the product, when spare parts are no longer available, or when equipment parts become incompatible. Although remedial work and upgrades have been done at C&P facilities, much of the equipment and controls systemwide is over 40 years old, obsolete or no longer supported by the manufacturer, and is showing signs of wear and deterioration. If not replaced, there is risk of failure or restricted operation of critical components or systems that could result in a loss of compression services at multiple locations. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to equipment failure is 0.0244 per year. This can be interpreted as one event approximately every 41 years.

D2 – External Corrosion: The risk of through wall leaks from external corrosion forming beneath pipe insulation material may result in loss of service and loss of

5 PHMSA Major Incident report (Transmission) includes a collection of all major incidents in the U.S. Time period used is 2010-2016. The PHMSA major incident reporting data includes a filter for commodity types; PG&E filtered the data for Natural Gas and Blanks (Gas Carriers).

6 The number of expected major loss of containment events per year for transmission is 263 events over the 7-year period, assuming that PG&E's assets represent 2 percent of the total, or 0.75 events per year. Distribution showed a total of 43 events, amounting to 0.12 events/year.

7 Of the total 263 major loss of containment events, 28 resulted in ignition (10.6 percent).

containment. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to external corrosion is 0.0049 per year. This can be interpreted as one event approximately every 204 years.

D3 – Incorrect Operations: The systems and equipment installed in C&P facilities is complex, and their operation requires specialized training. Risks associated with incorrect operations include over pressurization of the gas system, loss of service, and safety impacts due to malfunction or failure of critical assets. There is also the risk of increased operating costs as a result of shortened equipment life. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to incorrect operations is 0.0046 per year. This can be interpreted as one event approximately every 217 years.

D4 – Internal Corrosion: The risk of through wall leaks in storage processing, withdrawal piping and pressure vessels from internal corrosion or erosion may result in loss of containment with ignition, loss of service, and reliability impacts. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to internal corrosion is 0.0050 per year. This can be interpreted as one event approximately every 200 years.

D5 – Manufacturing Defects: Manufacturing defects include weld defects such as longitudinal seam defects caused by errors in the welding and material defects caused by various steel impurities. These can occur in the equipment and piping in gas transmission stations, including compressor stations and processing facilities. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to manufacturing related defect is 0.0024 per year. This can be interpreted as one event approximately every 417 years.

D6 – Stress Corrosion Cracking: The risk of failure of station piping due to stress corrosion cracking that results in a loss of containment may result in public safety issues. Stress corrosion risks are produced by deterioration of material over time due to a combination of factors from pressure cycling, chemicals, stress, and material types. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to an equipment failure is 0.0023 per year. This can be interpreted as one event approximately every 435 years.

D7 – Third-Party/Mechanical Damage: Potential vandalism and cybersecurity breaches present additional risks to the C&P facilities. The third-party damage threat is necessarily expanded to include the risk of unauthorized operation resulting in a loss of service and reliability. Damage to C&P facilities from third-parties can also occur if there is inadequate physical security surrounding the stations. The most common type of third-party damage is dig-ins. Dig-ins are generally prevented at C&P facilities by preventing third-party access to the facilities. Other third-party threats, including vandalism or acts of terrorism, are also prevented by physical security. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to third-party/mechanical damage is 0.0131 per year. This can be interpreted as one event approximately every 76 years.

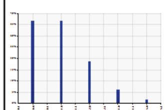
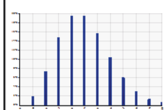
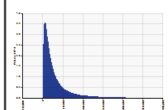
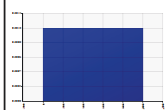
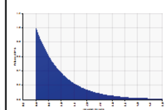
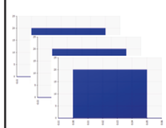
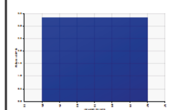
D8 – Weather-Related and Outside Forces (WROF): Damage resulting from WROF may be caused by a wide range of factors including water crossings, unstable soil/erosion, heavy rains/floods, and seismic activity. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to WROF is 0.0166 per year. This can be interpreted as one event approximately every 60 years.

D9 – Welding/Fabrication: Risks due to construction or fabrication are related to inadequate installation of equipment at the station resulting in potential premature equipment failure or operational difficulties. Additional risks are associated with insufficient or improperly maintained facility documentation and construction records. Based on the probability distribution used in the model, the average number of loss of containment events with ignition due to welding/fabrication is 0.0067 per year. This can be interpreted as one event approximately every 150 years.

D. Consequences

Figure 6-2, below, shows the range of consequences and the attributes that help describe the tail average risk and the associated MARS are shown in Figure 6-2 below. These results represent the worst case outcome which is based on the use of the tail average (90-100th percentile). Both PG&E and industry data was used in evaluating these consequence categories. As illustrated below, consequence categories relating to the financial impact is the largest contributor to the overall MARS.

Figure 6-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PHMSA and ICE	SME Input	SME Input	PG&E Data	SME Input
Consequence Distributions	Percent of ignition events with injury=10.7% Mean=1 (Poisson) 	Percent of ignition events with fatality=3.6% Mean=4 (Poisson) 	Ave=35,237MCF Std Dev=56,063MCF Ave cost of Carbon[3]=$13 /tonne CO2 (Lognormal) 	Customer hours affected= Min=0 hours*60 Max=1,000 hours*60 (Uniform) 	Ave=$1M (Exponential) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Min=$40M Max=$70M (Uniform) 
Outcome-TA-NU[1]	0.13	0.25	$19,523	23,585	$798,055	1.39%	$43,219,349
Outcome-TA-MARS[2]	0.03	6.81	0.00	0.06	0.08	6.94	25.93
						MARS Total	**39.86**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]To convert MCF to tonne multiply by ~52/1000

- **Safety – Injuries (SI):** The PHMSA major incident data set[8] filtered for station events was used to quantify the conditional probability that a major incident results in injuries. Data showed a total of 3 out of 28, or 10.7 percent, ignition-related events resulted in injury. Based on this data, the average number of injuries per event is 1. Tail average results showed that we would expect to see 0.13 injuries as the average worst case over the 2017-2022 time period. This can also be interpreted as approximately one injury every eight years. This outcome is higher than anticipated since PG&E has only had one event to-date that did not involve injury.
- **Safety – Fatalities (SF):** The PHMSA major incident data set filtered for station events was used to quantify the conditional probability that a major incident results in fatalities. Data showed one event which resulted in fatality of the 28 ignition-related events or 3.6 percent fatality-related events resulted in fatalities. Also based on this data, the average number of fatalities per event is 4. Tail average results showed that average worst case is 0.25 injuries per year over the 2017-2022 time

8 PHMSA Major Incident report includes a collection of all major incidents in the U.S. The time period used is 2010-2016. The PHMSA major incident reporting data includes a filter for commodity types; PG&E filtered the data for Natural Gas and Blanks (Gas Carriers).

period. This can also be interpreted as approximately one fatality every four years. Similar to injury output, this output is much higher than expected given that PG&E has never experienced an event related to this risk that resulted in a fatality. Additionally, the industry data set showed only one event that included four fatalities; so the sample size is limited.

- **Environmental (E):** PHMSA data set for transmission related releases of gas with ignition resulted in an average gas release volume of 35,237 Millions of Cubic Feet.[9] Based on the tail average model results across the 2017-2022 time periods, the average worst case environmental related costs amount to $19,523. The results show that the environmental consequence attribute models a relatively small impact for this risk.
- **Reliability (R):** PG&E leveraged Subject Matter Expert (SME) judgment to determine the reliability impact of this risk. PG&E assumes an impact of zero to 1,000 customer hours based on an individual station being out of service and the redundancy in PG&E's gas system. Based on the tail average model results across the 2017-2022 time period, the average worst case reliability impact would be of 23,585 customer minutes or approximately 393 customer hours. These results show a relatively small reliability impact for this risk.
- **Compliance (C):** Assumed cost of compliance after a major incident with ignition is mainly seen via additional inspection stemming from new regulations. Based on SME judgment, the cost average associated impact would be $1,000,000. Per the tail average model results, we would expect to see compliance related impacts of $798,055.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all GO risks.[10] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is 1.39 percent a year.
- **Financial (F):** The financial impact is based on SME analysis of costs to rebuild or replace a station. The cost for a single unit replacement ($40 million) was used as the lower bound and the cost of rebuilding a station ($70 million) was used as the upper bound for the financial impact calculation. Based on the tail average model results across the 2017-2022 time periods, the average worst case replacement cost is approximately $43 million. The asset replacement cost is the primary driver of the MARS for this risk.

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9 The average cost of carbon was taken from the Intercontinental Exchange end of day close for California Carbon Allowance Futures as of day close March 29, 2017, which was $13 per tonne of carbon dioxide.

10 Refer to the Risk Model Overview chapter for the trust consequence calculation details.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

The controls and mitigations address reliability and integrity management of the stations to effectively control and monitor the gas system. The C&P asset family has a robust set of controls in place to manage both reliability and integrity. The controls include ongoing maintenance and inspection activities, ongoing capital work to manage obsolescence and operational requirements, gas quality control and monitoring, and various other integrity management activities related to material condition (corrosion). In addition, to further address integrity management, a series of mitigations are defined to address manufacturing, construction and third-party damage threats. These mitigations have beneficial effects to reduce other threat categories. The selected set of mitigation activities is aimed at reducing the risks associated with the integrity of the facilities. Table 1 included below summarizes the controls and mitigations and 2016 recorded costs associated with each control.

C1 – Compressor Replacements: Approximately 65 percent of the units in PG&E's compressor fleet are at or over 40 years old and there is a need for a compressor replacement program to plan for and manage the replacement of these assets and associated infrastructure. While age by itself does not drive replacement, the age of the units increases the likelihood of equipment obsolescence impacts, including inability to obtain spare parts, lack of manufacturer support and expertise, and increased environmental, safety, and reliability risks due to older technology. The compressor replacements eliminate or mitigate Equipment-Related drivers that impact operability of the gas system including loss of service, loss of operating flexibility and reliability, and inability to meet requirements of evolving industry and environmental regulation.

C2 – Compressor Unit Control Replacements: This program has been developed to replace unit controls at individual compressor units. The scope of work includes replacement of Programmable Logic Controls (PLC) equipment as well as programming and system integration. This program helps manage the Equipment-Related (equipment obsolescence and failure) risk driver.

C3 – Corrosion Control: All of PG&E's metallic (steel) assets are subject to corrosion, an electrochemical process where metal degrades due to its interaction with the environment. Corrosion control seeks to either eliminate the elements that lead to corrosion or to manipulate the natural corrosion process with electrical currents. Effective corrosion control monitoring programs are critical to provide timely data that is representative of asset conditions; allow for modifications in corrosion mitigation strategies; and update risk management tools. This control addresses the External Corrosion, Internal Corrosion and Stress Corrosion Cracking drivers. Corrosion Control is also identified as a control for the M&C Facility risk, Storage risk, and Transmission Pipe risk, Measurement & Control (M&C) Failure – Release of Gas with Ignition at M&C Facility risk, Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, and Transmission Pipeline Failure – Rupture with Ignition risk. The total cost for this program is not allocated between the risks.

C4 – Direct Assessments: Direct Assessment (DA) is another method of conducting asset integrity assessments. DA is used to proactively address time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking and prevent anomalies from growing to a size that affects the structural integrity of the pipeline. The assessment techniques are called External Corrosion Direct Assessment, which identifies and assesses locations likely to have external corrosion, Internal Corrosion Direct Assessment, which identifies and assesses locations likely to have internal corrosion, and Stress Corrosion Cracking Direct Assessment, which identifies and assesses 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 Stress Corrosion Cracking drivers. DA is also identified as a control for the Measurement & Control (M&C) Failure – Release of Gas with Ignition at M&C Facility risk, Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, and Transmission Pipeline Failure – Rupture with Ignition risk. The total cost for this program is not allocated among the risks.

C5 – Emergency Shutdown (ESD) Upgrade: This program includes upgrade of existing ESD system to use current technology. This program helps improve the identification and response to gas leak or fire. An ESD system is designed to immediately, automatically, and safely stop operation of equipment, isolate the station piping, and safely vent the natural gas within the station to the atmosphere. This control addresses all consequence categories should the risk event occur.

C6 – Gas Quality Assessment: This program incorporates industry best practices to maintain the desired quality of gas entering the PG&E system. The purpose of the Gas Quality Assessment Program is to address gas particulate and liquids so that equipment operates correctly, materials do not degrade due to corrosion, and gas entering the PG&E system meets California Public Utilities Commission gas quality regulatory requirements. This program manages Internal Corrosion and Equipment-Related drivers and is identified as a control for the M&C Failure – Release of Gas with Ignition Downstream risk and the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The total cost for this program is not allocated among the risks.

C7 – GT Electrical Upgrades: This program has been established in order to upgrade the electrical equipment at both the Hinkley and Topock Compressor Stations. This control addresses the Equipment-Related driver for obsolescence and also addresses worker safety during maintenance and operation of the equipment.

C8 – Other O&M: Gas Transmission O&M activities are planned, tracked and managed to address regulatory compliance and increase the useful life of the Gas Transmission assets. Gas Transmission O&M expense includes costs to perform compliance, preventive and corrective tasks. This program helps manage the Equipment-Related driver. Other O&M is also identified as a control for the Natural Gas Storage Well Failure – Loss of Containment with Ignition risk, and Transmission Pipeline Failure – Rupture with Ignition risk. The total cost for this program is not allocated between the risks.

C9 – Routine Spend C&P: The scope of work includes repair or replacement of failed or malfunctioning equipment and instrumentation. This program helps manage the Equipment-Related and Incorrect Operations drivers.

C10 – Upgrade Station Controls: This program has been specifically developed to replace and upgrade the station PLCs for all C&P facilities. There are two PLC station controls: (1) a PLC that interfaces with the compressor unit controllers; and (2) a PLC input/output interface module that receives information about the current operating conditions of the station, translates that information, and makes it available to other devices for data transmission or control. The scope includes installation of new PLC-based controllers; re-writing control philosophy; and addition of computer/terminal stations required; and rebuild of existing panels in control room. This program helps manage the Equipment-Related and Incorrect Operations drivers.

In addition, to further address integrity management, a series of mitigations as discussed below are defined to address specific risk drivers. The selected set of mitigation activities is aimed at reducing the risks associated with the integrity of the facilities. This list of mitigations is included in Table 6-1 below since there are costs recorded from 2016 related to these programs.[11]

M1A – 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 addresses these risks by ensuring that the drawings and documents used to operate and maintain the facility are commensurate with the complexity of the facility. This mitigation addresses the transmission Incorrect Operations driver as it reduces the chance of communication error between operator and control room along with the Compliance, Trust, and Financial consequence categories. This program is also identified as mitigation for the M&C Failure – Release of Gas with Ignition Downstream risk and the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The cost for this program was allocated between all three risks with a 65 percent allocation to the

11 For detailed description of the mitigation programs, refer to the workpapers for this chapter.

two M&C risks and 35 percent to the C&P risk. Both the M&C risks show the total 65 percent allocation (i.e., the costs that were allocated to the two M&C risks were not separated).

M2A – Engineering Critical Assessment (ECA) Phase 1: Beginning in 2015, PG&E embarked on the ECA Phase 1 Program, which entails reviewing and identifying issues that may compromise station asset integrity. The primary focus of the ECA Phase 1 Program is to identify components which may be under-rated for the service in which they are operating. The ECA Phase 1 work involves identifying component design anomalies, field investigating components and developing and performing associated remediation activities. This program affects the likelihood of an event occurring due to the following drivers: Manufacturing Defects, Weather-Related/Outside Force, and Welding/Fabrication Related. Furthermore, the Compliance, Trust, and Financial consequence categories are affected. This program is also identified as mitigation for the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

M3A – Engineering Critical Assessment (ECA) Phase 2: At the completion of ECA Phase 1, there will be station components requiring mitigation in addition to any remediation undertaken as part of ECA Phase 1. More specifically, station components where the documentation of the material installed or the pressure test history is incomplete will be subject to ECA Phase 2. Validating station features provides facility integrity assurance from a design and installation perspective. This effort includes field work to perform non-destructive examination type validation of station features and properties. The ECA Phase 2 addresses multiple threats that affect station integrity and reliability, including: External Corrosion, Internal Corrosion, Manufacturing Defects, and Welding/Fabrication Related. Also, Compliance, Trust, and Financial consequence categories are addressed by this program. This program is also identified as mitigation for the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

M4A – Physical Security Upgrades: The Physical Security Program implements security measures recommended in the Security Vulnerability Assessments study performed by Lawrence Livermore National Laboratory (LLNL). This mitigation provides for installation of additional security measures at facilities, including installation of barriers, cameras, and other recommended actions in accordance with Transportation Security Administration (TSA) Guidelines. This mitigation provides the means to identify and mitigate potential third-party interventions impacting the facilities and also addresses both the Safety consequence categories. The overall goal is to complete physical security enhancements in a timely manner at critical gas facilities as recommended in the vulnerability study conducted by LLNL. This program is also identified as mitigation for the M&C Failure – Release of Gas with Ignition at M&C Facility risk. The cost for this program was allocated with a 50 percent allocation to the M&C risk and 50 percent to the C&P risk.

Table 6-1: Risk Controls and Mitigations, 2016 Recorded Costs

#	Control/Mitigation	Associated Driver # and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Compressor Replacements	D1	GTS	–	22,661
C2	Compressor Unit Control Replacements	D1	GTS	–	199
C3	Corrosion	D2, D4, D6	GTS	35,030	35,409
C4	Direct Assessments	D2, D4, D6	GTS	39,368	–
C5	Emergency Shutdown Upgrade	SI, SF, E, R, C, T, F	GTS		1,910
C6	Gas Quality Assessment	D1, D4	GTS	290	–
C7	GT Electrical Upgrades	D1	GTS	–	224
C8	Other O&M	D1	GTS	30,953	–
C9	Routine Spend C&P	D1, D3	GTS	7,353	54,278
C10	Upgrade Station Controls	D1, D3	GTS	–	2,389
M1A	Critical Documents Program	D3, C, T, F	GTS	5,650	–
M2A	ECA Phase 1	D5, D8, D9, C, T, F	GTS	7,695	–
M3A	ECA Phase 2	D2, D4, D5, D9, C, T, F	GTS	1,033	–
M4A	Physical Security Upgrades	D7, SI, SF	GTS	1,395	10,237
TOTAL Expense and Capital				**128,767**	**127,307**

IV. Current Mitigation Plan (2017-2019)

The mitigation activities described in section III above continue through the 2017-2019 time period. The mitigations include Critical Documents Program, ECA Phase 1, ECA Phase 2, Physical Security Upgrades, as well as Station Strength Testing. The scope of each mitigation for this time period is described below.

M1B – Critical Documents Program: Continue station documentation update. This includes 2 representative stations[12] in 2017, 2 in 2018, and 4 in 2019.

12 The representative number of stations to be addressed is not the actual number of stations. The representative number of stations to be addressed by the Critical Documents Program has been determined based on the total number of stations to be addressed by the total program, scaled by the fraction that the yearly program forecast represents out of the total program forecast.

M2B – ECA Phase 1: Continue validation of Station Features at identified stations. The representative[13] numbers of stations for this activity are 3, 3, and 2 for 2017, 2018 and 2019, respectively.

M3B – ECA Phase 2: Ongoing work for ECA Phase 2 in 2017 and 2018 is related to evaluating non-destructive examination techniques for applicability to this effort. This consists of studies, assessments and other preparatory activities in 2017 and 2018 to address one representative station in 2019.

M4B – Physical Security Upgrades: Continue upgrades of identified stations. This includes one station a year during the 2017-2019 time period.

In addition to these ongoing mitigations, one new mitigation will begin in 2018.

M5A – Station Strength Testing: The program is designed to address components that cannot be addressed via ECA Phase 2. As a result, the Station Strength Testing Program should be considered the last-resort alternative. Strength testing provides assurance of facility integrity from a design and installation perspective. This effort includes field work to perform strength testing of components. This control addresses the External Corrosion, Internal Corrosion, Manufacturing Defects, Stress Corrosion Cracking, Third-Party/Mechanical Interventions, Weather-Related and Outside Forces, and Welding/Fabrication drivers. This program is also identified as a mitigation for Measurement and Control Failure – Release of Gas with Ignition at M&C Facility risk. The cost for this program was allocated with a 65 percent allocation to the M&C risks and 35 percent to the C&P risk.

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13 The representative number of stations to be addressed is not the actual number of stations. The representative number of stations is based on the total number of stations to be addressed, scaled by the fraction that the yearly program forecast represents out of the total program forecast.

No stations will be addressed by Station Strength Testing in 2017 since the scope and implementation of the program is contingent upon the results obtained from the completion of ECA Phase 1 and ECA Phase 2. The equivalent number of stations to be addressed in 2018 and 2019 are 0.04 and 0.07,[14] respectively.

Table 6-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Forecast ($000)	2018 Forecast ($000)	2019 Forecast ($000)
M1B	Critical Documents Program	2015	2021	D3, C, T, F	– (C) 3,146 (E)	– (C) 4,112 (E)	– (C) 5,165 (E)
M2B	ECA Phase 1	2015	2021	D5, D8, D9, C, T, F	3,360 (C) 4,628 (E)	3,360 (C) 5,348 (E)	3,780 (C) 5,049 (E)
M3B	ECA Phase 2	2015	2033	D2, D4, D5, D9, C, T, F	– (C) 1,341 (E)	478 (C) 2,595 (E)	481 (C) 3,161 (E)
M4B	Physical Security Upgrades	2015	2023	D7, SI, SF	3,752 (C) – (E)	5,155 (C) – (E)	4,696 (C) – (E)
M5B	Station Strength Testing	2018	2033	D2, D4, D5, D6, D7, D8, D9	– (C) – (E)	85 (C) 874 (E)	171 (C) 1,749 (E)
TOTAL Expense and Capital by Year					**7,112 (C) 9,115 (E)**	**9,078 (C) 12,929 (E)**	**9,128 (C) 15,124 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered above in Section III and how each relates to the drivers for C&P Failure – Release of Gas with Ignition at a Manned Processing Facility Risk. PG&E relies on its control programs to manage risks and remain compliant with state and federal requirements. The mitigation programs are intended to proactively reduce risk. As such, these programs are aimed at improving the integrity and health of PG&E's assets, finding and repairing any existing issues and therefore preventing the risk event from occurring.

M1C – Critical Documents Program: Continue station documentation update: 3 representative stations in 2020 and 3 in 2021. The program is scheduled to complete in 2021.

M2C – ECA Phase 1: Continue Station Features validation at identified stations. The representative numbers of stations for this activity are 3 in 2020 and 3 in 2021. This program is scheduled to complete in 2021.

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14 The Station Strength Test Program is planned to extend through 2033. The representative number of stations to be addressed is not the actual number of stations. The representative number of stations is based on the total number of stations to be addressed by the program, scaled by the fraction that the yearly program forecast represents out of the total program period.

M3C – ECA Phase 2: Ongoing ECA Phase 2 work which includes 2 representative stations during the 2020-2022 time period.

M4C – Physical Security Upgrades: Continue identified station upgrades at a pace of one station per year during the 2020-2022 time period.

M5C – Station Strength Testing: The representative number of stations that will be addressed are 0.13 in 2020, 0.18 in 2021, and 0.27 in 2022.

The mitigations selected for this risk will provide additional assurance as to the reliability of these facilities. Along with ongoing controls for equipment and system replacement to address obsolescence and equipment performance, these mitigations provide additional safeguards against third-party damage, weather and outside forces, incorrect operations, and manufacture/fabrication drivers. The upgrade of documents improves system operations. The confirmation of design relative to manufacture and welding/fabrication issues reconfirms structural integrity of the system. The installation of added physical security measures provides protection against third-party threats.

Table 6-3: 2020-2022 Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.4070	0.0573	2015	2021	D3, C, T, F	– (C) 5,165 (E)	– (C) 5,165 (E)	– (C) – (E)
M2C	ECA Phase 1	0.4093	0.0448	2015	2021	D5, D8, D9, C, T, F	2,940 (C) 5,049 (E)	1,260 (C) 5,049 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0689	0.0136	2015	2033	D2, D4, D5, D9, C, T, F	984 (C) 3,161 (E)	1,006 (C) 3,161 (E)	1,006 (C) 3,161 (E)
M4C	Physical Security Upgrades	0.2872	0.0211	2015	2023	D7, SI, SF	4,713 (C) – (E)	4,704 (C) – (E)	4,704 (C) – (E)
M5C	Station Strength Testing	0.1359	0.0102	2018	2033	D2, D4, D5, D6, D7, D8, D9	314 (C) 1,749 (E)	428 (C) 1,749 (E)	428 (C) 1,749 (E)
Proposed Mitigation Plan TA RSE: 0.3014 **TOTAL Expense and Capital by Year**							**8,951 (C)** **15,124 (E)**	**7,398 (C)** **15,124 (E)**	**6,138 (C)** **4,910 (E)**

VI. Alternatives Analysis

While assessing mitigation options, PG&E identified two alternative plans. Alternative Plan 1 was created based on an increased pace of Physical Security Upgrades at identified stations while Alternative Plan 2 considered a decreased pace. The alternatives were chosen to evaluate the impact of the program pace on risk reduction.

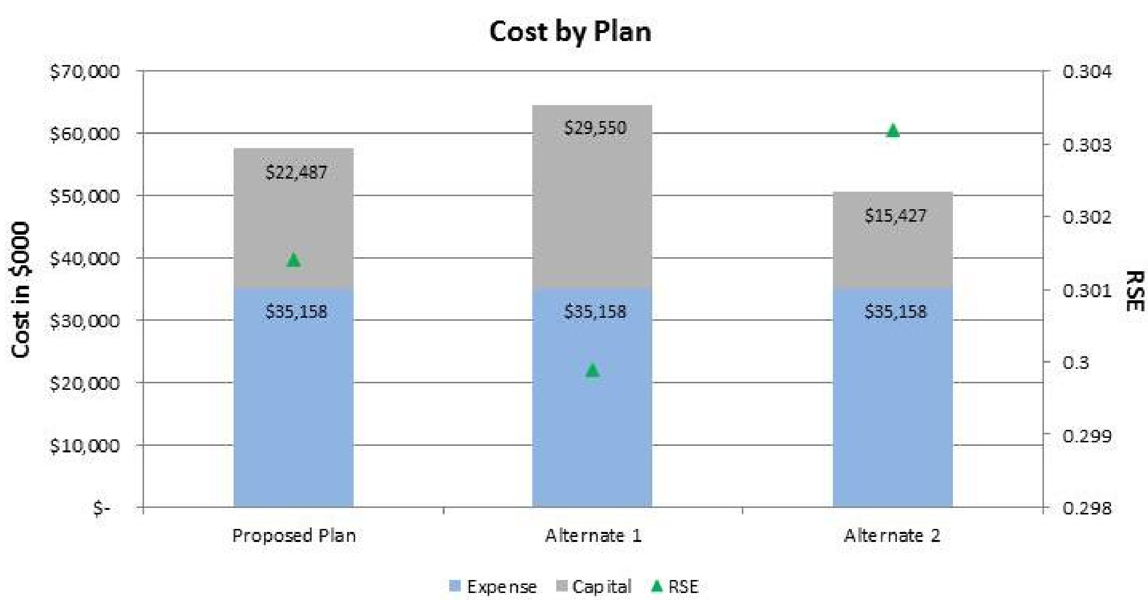
Both plans are shown below in Tables 6-5 and 6-6.

Table 6-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Critical Documents Program	0.4070	0.0573	X	X	X	WP 6-2
M2C	ECA Phase 1	0.4093	0.0448	X	X	X	WP 6-5
M3C	ECA Phase 2	0.0689	0.0136	X	X	X	WP 6-8
M4C	Physical Security Upgrades	0.2872	0.0211	X			WP 6-12
M5C	Station Strength Testing	0.1359	0.0102	X	X	X	WP 6-16
M4D	Physical Security Upgrades	0.2872	0.0211		X		WP 6-12
M4E	Physical Security Upgrades	0.2872	0.0211			X	WP 6-12

Figure 6-3 below shows the breakdown of the Proposed Plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE.

Figure 6-3: Alternative Plans by Cost and RSE Score



A. Alternative Plan 1

The mitigation programs described in Section V above are the same in terms of pace of work as the mitigations presented in this alternative, with the exception of Physical Security Upgrades. PG&E chose to analyze the impacts of this mitigation explicitly as Physical Security Upgrades play a key role in reducing the impacts of third-party damage which is a priority driver for this risk. The change in pace for this alternative is outlined below.

M4D – Physical Security Upgrades: Increase pace of upgrades of identified stations from 1 station a year to 1.5.

This alternative assumes a more rapid pace of implementation. This alternative was not selected due to operational and resource constraints. To complete the physical security upgrades, certain facilities would be unavailable during the upgrade, potentially leading to operational issues.

Table 6-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.4070	0.0573	2020	2021	D3, C, T, F	– (C) 5,165 (E)	– (C) 5,165 (E)	– (C) – (E)
M2C	ECA Phase 1	0.4093	0.0448	2020	2021	D5, D8, D9, C, T, F	2,940 (C) 5,049 (E)	1,260 (C) 5,049 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0689	0.0136	2020	2022	D2, D4, D5, D9, C, T, F	984 (C) 3,161 (E)	1,006 (C) 3,161 (E)	1,006 (C) 3,161 (E)
M4D	Physical Security Upgrades	0.2872	0.0211	2020	2022	D7, SI, SF	7,070 (C) – (E)	7,057 (C) – (E)	7,057 (C) – (E)
M5C	Station Strength Testing	0.1359	0.0102	2020	2022	D2, D4, D5, D6, D7, D8, D9	314 (C) 1,749 (E)	428 (C) 1,749 (E)	428 (C) 1,749 (E)
Alternative Plan 1 TA RSE: 0.2999 **TOTAL Expense and Capital by Year**							**11,308 (C)** **15,124 (E)**	**9,751 (C)** **15,124 (E)**	**8,491 (C)** **4,910 (E)**

B. Alternative Plan 2

A similar approach was taken in alternative 2 where the impact of a change was examined in scope for the Physical Security Upgrades mitigation; in this case a decelerated pace. The change in scope for this alternative is outlined below:

M4E – Physical Security Upgrades: Decrease in pace of upgrades of identified stations from 1 station a year to 0.5, or 1 station every two years.

Even though this alternative has a lower cost and slightly higher risk spend efficiency (RSE), it was not chosen as the recommended case. Vandalism/ Terrorist attacks at critical facilities have implications on personal safety and equipment damage. Completing the physical security upgrades for these critical facilities at the proposed pace proactively addresses these threats and is a key strategic objective for the C&P asset family.

Table 6-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Critical Documents Program	0.4070	0.00573	2020	2021	D3, C, T, F	– (C) 5,165 (E)	– (C) 5,165 (E)	– (C) – (E)
M2C	ECA Phase 1	0.4093	0.0448	2020	2021	D5, D8, D9, C, T, F	2,940 (C) 5,049 (E)	1,260 (C) 5,049 (E)	– (C) – (E)
M3C	ECA Phase 2	0.0689	0.0136	2020	2022	D2, D4, D5, D9, C, T, F	984 (C) 3,161 (E)	1,006 (C) 3,161 (E)	1,006 (C) 3,161 (E)
M4E	Physical Security Upgrades	0.2872	0.0211	2020	2022	D7, SI, SF	2,357 (C) – (E)	2,352 (C) – (E)	2,352 (C) – (E)
M5C	Station Strength Testing	0.1359	0.0102	2020	2022	D2, D4, D5, D6, D7, D8, D9	314 (C) 1,749 (E)	428 (C) 1,749 (E)	428 (C) 1,749 (E)
Alternative Plan 2 TA RSE: 0.3032 **TOTAL Expense and Capital by Year**							**6,595 (C)** **15,124(E)**	**5,046 (C)** **15,124 (E)**	**3,786 (C)** **4,910 (E)**

VII. Metrics

The primary metric that PG&E is proposing for this risk is to track reportable incidents. This will allow PG&E to track the number of events PG&E experiences that could lead to the catastrophic risk event we are modeling. This metric would include OP events, as well as loss of containment events.

Metrics associated with the mitigation programs are designed to measure if each program is progressing at the desired pace to achieve risk reduction objectives. The targets for these metrics are established through PG&E's Integrated Planning process. Table 6-7 below shows the proposed risk reduction and execution metrics:

Table 6-7: Metrics

Risk/Mitigation	Associated Driver # and Consequence	Proposed Metric	Targets
Risk Reduction Metric			
Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility	All	Number of reportable incidents.	N/A
Execution Metric			
Critical Documents Program	D3, C, T, F	Number of stations completed.	TBD
ECA Phase 1	D5, D8, D9, C, T, F	Number of station features completed.	TBD
ECA Phase 2	D2, D4, D5, D9, C, T, F	Under development; requires completion of ECA Phase 1.	TBD
Physical Security Upgrades	D7, SI, SF	Number of facilities completed.	TBD
Station Strength Test	D2, D4, D5, D6, D7, D8, D9	Under development; requires completion of ECA Phase 1 and ECA Phase 2.	TBD

VIII. Next Steps

For the Compression and Processing Failure risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Continue to evolve existing tools to understand and monitor condition and criticality of assets leading to a more data driven process for monitoring and managing assets. In the last few years, PG&E identified that the evaluation of threats and risks associated with C&P assets was largely based on experience and judgement of PG&E SMEs. During the past three years, PG&E has performed several tasks that provide information for monitoring threat and asset health. This includes activities such as industry benchmarking studies, process safety assessments and condition assessments to understand hazards.
- Refine model inputs. The modeling effort was primarily focused on safety. Given the lack of data to estimate the compliance, reliability, financial and environmental impacts, the team made general assumptions on new regulations, rebuilding a station, customer outage and environmental costs. These model inputs are being assessed and, where possible, PG&E will update these inputs in the future.
- Advance risk quantification and component level data understanding and utilization, where that information is unique to PG&E. Given the small sample size of ruptures and ignition at facilities in PG&E, industry data was used to determine the frequency for this risk for the current model.

- Consider how PG&E can align risk models with different types of planned and forecast units of work.
- Calibrate model outputs and perform sensitivity analysis. For example, the model results for the Safety – Injuries consequence is higher than anticipated since industry data on injuries caused by ignition events at stations is very low. Therefore, additional data analysis in the future may be able to better identify this risk consequence.
- Re-evaluate different combinations of mitigations in the alternative analysis to attempt to risk reduction and operational efficiency optimization.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 7
RELEASE OF GAS WITH IGNITION ON DISTRIBUTION FACILITIES – NON-CROSS BORE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 7
RELEASE OF GAS WITH IGNITION ON DISTRIBUTION FACILITIES – NON-CROSS BORE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore
IN SCOPE	Loss of containment with ignition due to any risk driver other than Cross Bore
OUT OF SCOPE	Loss of Containment with Ignition due to Cross Bore
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, Pipeline and Hazardous Materials Safety Administration (PHMSA)[1] data and subject matter expert (SME) input.

Pacific Gas and Electric Company (PG&E) maintains approximately 42,700 miles of distribution mains and approximately 3.4 million services in its gas distribution system. The distribution mains transport gas downstream of a distribution center and the services lines connect the mains to customer connected equipment. Together the mains and services provide natural gas to PG&E's 4.3 million residential, commercial and industrial customers.

Over the last seven years, there have been 59 loss of containment incidents[2] on PG&E's distribution facilities, in which 36 resulted in ignition.[3] This chapter addresses the risk of rupture of a distribution pipeline which may result in loss of containment and migration and ignition of gas, leading to a safety impact or property damage and PG&E's proposed plan to mitigate this risk.

Previously there were many risks listed in Gas Operations' (GO) Risk Register that could result in a loss of containment with ignition for distribution facilities. During the Risk Assessment and Mitigation Phase (RAMP) modeling process, GO decided to create a roll-up risk that combined all drivers into one representative risk. This representative risk is now an Enterprise level risk overseen by the Safety and Nuclear Oversight Committee of PG&E's Board of Directors.

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1 See Pipeline and Hazardous Materials Safety Administration (PHMSA) Data Report – March 27, 2017.

2 Loss of containment is considered a situation where the volume of escaped methane makes the pipeline inoperable and a leak is where operation of the pipeline and its facilities can continue to operate as intended.

3 See PHMSA Data Report – March 27, 2017.

Through the development of the model, data showed that 38 percent of the events associated with this risk could result in serious safety consequences in the form of a fatality or serious injury. By implementing the mitigation strategy outlined in this chapter, PG&E estimates a potential 90 percent reduction in the overall multi-attribute risk score (MARS).

Going forward, PG&E plans to collect and analyze more data to improve the model inputs and continue the move towards more quantitative, data driven risk models. One of the key next steps is to identify the data needed to quantify the compliance category. A detailed list of next steps is included in Section VIII.

II. Risk Assessment

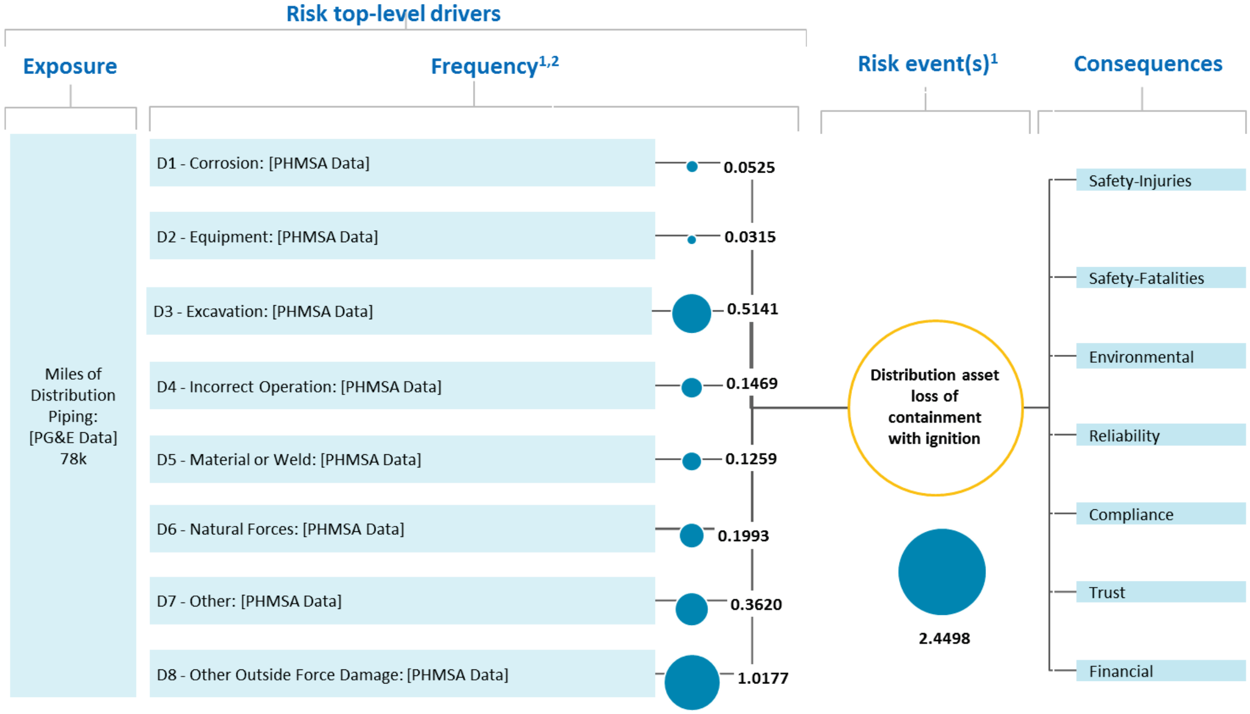
A. Background

There are approximately 42,700 miles of distribution mains and approximately 3.4 million services in PG&E's gas distribution system. Together the mains and services provide natural gas to PG&E's 4.3 million residential, commercial and industrial customers. The risk of a distribution pipeline rupture may result in loss of containment and ignition leading to a public safety issue. According to the March 27, 2017 PHMSA report, there were 59 incidents that PG&E recorded over the last seven-year period in which 36 resulted in ignition.

For this RAMP filing, PG&E used the bow tie framework to develop a probabilistic operational risk model. This model includes the risk event at the center of the bow tie, risk drivers and associated frequencies and the consequences that result from the occurrence of the risk event. The model uses a combination of PG&E data, industry data and SME input. The consequences of Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore are simulated using PHMSA consequence data.

Figure 7-1 shows the bow tie associated with this risk. The risk bow tie shows the exposure and frequency drivers for the risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie is defined as Distribution Assets- a loss of containment with Ignition. Based on the model inputs for frequency, this risk event is likely to occur approximately 2.5 times per year. This is a risk event that is more frequent than other risks within Gas Operations and may or may not lead to severe consequences depending on the location of the event, presence of people and various other factors.

Figure 7-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.

B. Exposure

PG&E measured the exposure as the total miles of distribution mains and services operated by PG&E. It is assumed the number of PG&E mains and services expands with the national average rate.[4] Table 7-1, below, shows the number of distribution main miles (defined as pipeline that transports gas downstream of a distribution center that carries gas to customers who purchase it for consumption) as well as the estimated service lines (defined as lines operating at less than or equal to 60 pounds per square inch gauge (psig) connecting the main to customer connected equipment). For purposes of the model, the service lines have been converted to miles (defined as number of services multiplied by the average length of a service in feet (54 feet)[5] divided by 5,280). In 2017, there were a total of 78,209 miles of distribution pipe.

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4 The growth assumption was based on calculated compound annual growth rate of year-over-year change in industry mileage between 2010 and 2015.

5 See PG&E's Annual PHMSA Report for 2016 Gas Distribution System.

Table 7-1: Total Miles

Year	Distribution Main Miles	Estimated Service Miles	Total Miles
2017	43,135	35,074	78,209
2018	43,463	35,254	78,717
2019	43,793	35,435	79,228
2020	44,126	35,617	79,743
2021	44,461	35,799	80,261
2022	44,799	35,983	80,782

C. Drivers and Associated Frequency

PG&E uses 49 CFR Part 192, Subpart P[6] as the basis for categorizing and evaluating the threats for the distribution assets. The risk drivers and the corresponding frequency – the number of events per exposure unit per time – are described below.

- **D1 – Corrosion:** External and Internal Corrosion is a key threat affecting metallic distribution facilities. Corrosion can, over time, reduce the wall thickness of the pipe and subsequently reduces the strength in the pipe resulting in the release of gas. Based on the probability distribution used in the model, the average number of risk events due to corrosion is 0.0525 per year. This can be interpreted as one event approximately every 19 years.
- **D2 – Equipment Related:** 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. Based on the probability distribution used in the model, the average number of risk events due to equipment related defects is 0.0315 per year. This can be interpreted as one event approximately every 32 years.
- **D3 – 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, cathodic protection or the housing for the line device or facility (e.g., third-party dig-ins). Based on the probability distribution used in the model, the average number of risk events due to excavation damage is 0.5141 per year. This can be interpreted as one event approximately every two years. This is one of the leading drivers for this risk event.

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6 Gas Distribution Pipeline Integrity Management.

- **D4 – Incorrect Operations:** Incorrect operations threats include human error and incorrect procedures. These threats 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., incorrect manual operation of a valve, which can cause an over or under pressure event). Based on the probability distribution used in the model, the average number of risk events due to incorrect operations is 0.1469 per year. This can be interpreted as one event approximately every seven years.
- **D5 – Material or Weld:** Any material or weld that does not perform its intended function or design in accordance with PG&E or industry standards. Based on the probability distribution used in the model, the average number of risk events due to material or weld defects is 0.1259 per year. This can be interpreted as one event approximately every eight years.
- **D6 – Natural Forces:** This risk driver may be caused by a wide range of factors including seismic activity, flooding, earth movement, lightning, and root damage. Based on the probability distribution used in the model, the average number of risk events due to natural forces is 0.1993 per year. This can be interpreted as one event approximately every five years.
- **D7 – Other:** Other concerns that could threaten the integrity of the pipeline (e.g., a gas leak in which the pipeline was replaced without exposing the leak source and the cause of the leak was undetermined). Based on the probability distribution used in the model, the average number of risk events due to other drivers is 0.3620 per year. This can be interpreted as one event approximately every three years.
- **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. This risk driver is the largest cause of distribution failures. Based on the probability distribution used in the model, the average number of risk events due to other outside force damage is 1.0177 per year. This can be interpreted as one event approximately every year. This driver is the primary cause for this risk event to occur.

D. Consequences

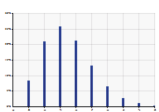
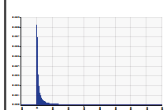
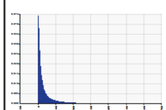
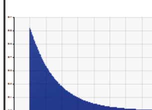
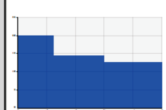
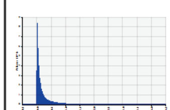
From January 2010 through March 2017, there have been 59 distribution failures experienced by PG&E in which 36 of those resulted in an event with ignition.[7] Given the proximity of the public near the distribution facilities, a member of the public or an employee or contractor could be impacted by a failure. Within the

7 See PHMSA records – March 27, 2017.

industry, 28 percent of distribution failures result in an injury and 10 percent result in fatality.

Figure 7-2 below shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated multi-attribute risk score (MARS). In the figure, there is an explanation of the data sources used for each of the consequence attributes. Trust and Safety – Fatalities outcomes are the biggest contributors to the overall MARS.

Figure 7-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PHMSA	PG&E Data	NA	PG&E Data	PHMSA
Consequence Distributions	Percent of ignition events with injury=28% Mean=2.5 (Poisson) 	Percent of ignition events with fatality=10% Mean=1.5 (Poisson) 	Ave=594MCF Std Dev=2,690MCF Ave cost of Carbon[3]=$13 /tonne CO2 (Lognormal) 	Customers Ave customers affected=57 Std Dev=166 (Lognormal)  x Ave duration of outage=1.62 hours*24*60 (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Ave=$381k Std Dev=$1.3M (Lognormal) 
Outcome-TA-NU[1]	7.32	2.86	$5,600	7,140,130		17.63%	$4,837,902
Outcome-TA-MARS[2]	2.00	77.92	0.00	17.85		88.16	2.90
						MARS Total	**188.84**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]To convert MCF to tonne multiply by ~52/1000

- **Safety – Injuries (SI):** The PHMSA major incident data set was used to quantify the conditional probability that a major incident results in injuries. Based on this data, 28 percent of the events result in injury with an average number of 2.5 injuries per event. Based on the tail average model results across the 2017-2022 time period, the calculated number of injuries is approximately seven per year. This outcome is higher than expected and will be evaluated further during next steps.
- **Safety – Fatalities (SF):** The PHMSA major incident data set was used to quantify the conditional probability that a major incident results in injuries. Based on this data, 10 percent of ignition events result in fatalities with an average number of 1.5 fatalities per event. Based on the tail average model results across the 2017-2022 time period, the calculated number of fatalities is approximately three per year. This

outcome is higher than expected given that PG&E has only experienced one fatality since December 2008.

- **Environmental (E):** The PHMSA data set for distribution related releases of gas with ignition were used to compute an average gas release volume of 594 million cubic feet (MCF) per event.[8] Based on the tail average model results across the 2017-2022 time period, the average worst case environmental related cost is $5,600 per year. This is equivalent to approximately 430 tons of CO2. These results show that environmental impacts play a relatively small role in this risk.
- **Reliability (R):** Based on PG&E's historical outage events in 2015 and 2016, the average number of customers affected per risk event is 57 and with an average duration of 1.62 hours. PG&E historical information was used because this data provided the best estimate of PG&E's time to bring customers back online after an event. Based on the tail average model results across the 2017-2022 time period, the reliability impact is approximately 7,140,130 customer minutes or approximately 120,000 customer hours.
- **Compliance (C):** There was insufficient data to estimate the impact of compliance after a failure of a distribution asset.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all risks.[9] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is approximately 18 percent. This consequence category had the biggest impact on the overall MARS as it aligns to the high fatality impacts previously discussed.
- **Financial (F):** PHMSA major incident data set is used to determine the average cost of loss of containment events estimated at approximately $380,000. However, the range of impact is very wide with a standard deviation of $1.3 million. The average worst case financial impact is calculated to be $4.8 million.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls described in this section addresses one or more drivers for this risk. Table 7-2 summarizes the controls and 2016 recorded costs associated with each control. The controls identified below are representative programs and not a

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8 The average cost of carbon was taken from the Intercontinental Exchange (ICE) end of day close for California Carbon Allowance Futures as of day close March 29, 2017, which was $13 per ton of carbon dioxide (CO_2).

9 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

comprehensive list of all the work that GO does to address this risk. The controls in place in 2016 for the risk include the following programs.

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 Cathodic Protection 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 Cathodic Protection 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 Distribution Integrity Management Program (DIMP) Leak Survey Program is a targeted risk mitigation program that goes beyond the regulatory required leak survey.[10] 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 follows:

- Grade 1 (immediate repair required)
- Grade 2 (repair to be completed within 15 months)
- 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 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.

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10 See 49 CFR §192.1007(d).

C6 – Pipeline Replacement Program: There are three programs within the overall Pipeline Replacement Program:

- The Gas Pipeline Replacement Program (GPRP) focuses on replacement of cast iron[11] and pre-1940 steel pipeline. The objective of this program is to reduce the risk to public safety associated with the highest risk steel pipe.
- The Aldyl-A 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 Aldyl-A Plastic 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.[12] 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.[13] The equipment related driver is addressed by this control.

C8 – Public Awareness Program: As required by Code 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 (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

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11 As of the end of 2014, PG&E no longer has cast iron installed within its gas distribution system.

12 49 CFR §192.613.

13 49 CFR §192.721.

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.

In addition to the controls listed above, the mitigation programs are identified below to proactively address various risk drivers associated with this risk.

M1A – DIMP Emergent Work: Emergent work consists of unanticipated work resulting from investigation into risk drivers and operational events. For the purposes of this chapter, the Curb Valve Replacement Program, covered by DIMP Emergent Work, is the mitigation of focus. The specific mitigation of curb valve replacement addresses the material or weld driver.

M2A – New Valve Installations: The purpose of the valve program is to replace or install gas valves greater than or equal to 2 inches in diameter. Valves are required to be 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. As such, this program impacts the consequences if the risk event were to occur. For the purposes of the model calculation, an assumption has been made to convert the number of valves installed to its equivalent of number of miles impacted. This conversion was necessary for the model because the exposure is measured in miles; however, in rate case testimony the scope of this program is discussed as the number of valves installed. By converting the scope to number of the miles, the inferred unit cost for each installation in the RAMP filing is an estimate not used for planning purposes. The program impacts the Safety – Injuries, Safety – Fatalities and Financial consequence categories if a risk event were to occur. In addition, GO believes this mitigation addresses the following frequency drivers: material or weld, equipment related, and natural force. However, the impact of this mitigation on the frequency drivers was not included in the risk model and is identified as a next step in Section VIII.

M3A – Enhanced Cathodic Protection (CP) Survey and Unprotected Main Evaluation:

- **Enhanced CP Survey:** This is an enhanced five year CP Survey of PG&E's entire metallic distribution pipeline system to fully and comprehensively identify the CPA boundaries of all steel distribution pipe, clear all electrical grounds and contacts from the pipe, perform current requirement testing, and design and install additional CP systems as needed.
- **Unprotected Main Evaluation:** This program is to evaluate the condition of currently unprotected pipe and determine the appropriate strategy for protecting the pipeline. This program was developed to close a gap identified in the program, reduce risk and maintain safety of the pipeline.

The CP Resurvey and Unprotected Main Evaluation mitigations address the corrosion driver, more specifically for the purposes of this chapter, external corrosion.

M4A – Electrically Connected Isolated Steel Services (ECISS) Program: This program is designed to identify the location of electrically connected isolated steel and the segments that are electronically continuous through tracer wire to form a cathodic protection area (CPA). These new CPAs will be monitored on an annual read cycle. For the purposes of the model calculation, an assumption has been made to convert the number of risers inspected to an equivalent of number of miles of pipeline. This conversion was necessary for the model to make its probabilistic calculations; however, in rate case testimony the scope of this program is discussed as the number of risers inspected. By converting the scope to number of the miles, the inferred unit cost for each installation in the RAMP filing is an estimate that is not used for planning purposes. This mitigation addresses the corrosion driver, more specifically for the purposes of this chapter, external corrosion.

Table 7-2: Risk Controls and Mitigations 2016 Recorded Costs

#	Control/Mitigation	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000s)	2016 Recorded Capital ($000s)
C1	Corrective Maintenance	D1, D2, D3, D4, D5, D6, D8	GRC	89,990	–
C2	Corrosion Control	D1	GRC	7,435	–
C3	DIMP Leak Survey	D1, D2, D3, D4, D5, D6, D8	GRC	252	–
C4	Leak Management	D1, D2, D3, D4, D5, D6, D8	GRC	69,549	–
C5	Locate and Mark	D3	GRC	27,197	–
C6	Pipeline Replacement Program	D1, D5	GRC	1,817	348,030
C7	Preventative Maintenance	D1, D2	GRC	12,113	–
C8	Public Awareness Program	D3	GRC	1,879	–
C9	Quality Assurance/ Quality Management	D4, D5	GRC	7,969	–
C10	Training	D4, D5	GRC	3,126	–
M1A	DIMP Emergent Work	D2	GRC	3,062	–
M2A	New Valve Installations	SI, SF, F	GRC	–	8,356
M3A	Enhanced CP Survey and Unprotected Main Evaluation	D1	GRC	1,372	–
M4A	ECISS Program	D1	GRC	1,028	–
TOTAL Expense and Capital				**226,789**	**356,386**

IV. Current Mitigation Plan (2017-2019)

In addition to the controls listed above, the mitigation work listed also spans the 2017-2019 period and is currently authorized through 2019. The mitigations include DIMP Emergent Work (Curb Valve Replacement), New Valve Installations, CP Resurvey, and the ECISS Program. The scope of work to be completed during this time is described below.

M1B – DIMP Emergent: For 2017-2019, the specific mitigation addressed in this chapter is the Curb Valve Replacement Program in San Francisco. PG&E expects to replace valves associated with approximately seven miles of pipeline per year. While there is a focus on curb valve replacements, DIMP will continue to investigate issues as they arise as part of the overall DIMP Emergent Work to determine the risk to the distribution system and to the public.

M2B – New Valve Installations: PG&E expects to install 275 valves per year through 2019. New valves are primarily installed to improve PG&E's ability to isolate the gas system through Emergency Shutdown Zones. The model exposure input in equivalent miles is approximately 4,308 miles.

M3B – Enhanced CP Survey and Unprotected Steel Main Evaluation: For 2017-2019, PG&E expects to resurvey approximately 4,000 miles of pipe per year. The CP Resurvey minimizes the risk of steel corrosion and the Unprotected Steel Main Evaluation is a program to evaluate if the pipe should be put under protection or be replaced with plastic pipe.

M4B – ECISS Program: PG&E proposes to inspect approximately 50,000 ECIS risers every year. This program is to identify new CPAs to be monitored and put on an annual read cycle. The model exposure input in equivalent miles is approximately 600 miles per year.

Table 7-3: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1B	DIMP Emergent work (Proposed, Alt 1, Alt 2)	2017	2019	D2	1,700 (E)	1,700 (E)	1,700 (E)
M2B	New Valve Installations (Proposed)	2017	2019	SI, SF, F	20,991 (C)	20,991 (C)	18,791 (C)
M3B	Enhanced Cathodic Protection Survey & Unprotected Main Program (Proposed, Alt 2)	2017	2019	D1	6,976 (E)	5,949 (E)	5,949 (E)
M4B	Electrically Connected Isolated Steel Service (Proposed, Alt 2)	2017	2019	D1	3,005 (E)	2,531 (E)	2,531 (E)
TOTAL Expense and Capital by Year					**20,991 (C)** **11,681 (E)**	**20,991 (C)** **10,180 (E)**	**18,791 (C)** **10,180 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for Release of Gas with Ignition on Distribution Facilities Risk. The mitigation programs described in detail in Section III are also the mitigations for this risk in the 2020-2022 time periods.

PG&E proposes the continuation of these mitigations because they have been identified to have the largest impact for risk reduction at this time. Below is a description of the scope and pace for the proposed mitigations.

M1C – DIMP Emergent: For 2020-2022, this mitigation is focused on curb valve replacements in San Francisco. PG&E expects to replace valves associated with approximately seven miles of pipeline per year. The curb valve replacement mitigation is expected to be completed by 2021. After 2021, mitigation activities for other emerging risks will continue. Emergent work consists of unanticipated work resulting from investigation into risk drivers and operations events. Because of this it is difficult to predict what work will be completed. DIMP will continue to investigate issues as they arise to determine the risk to the distribution system and to the public.

M2C – New Valve Installations: PG&E proposes to install 275 valves per year through 2022 as described in Section III. The model exposure input in equivalent miles is approximately 3,008 miles.

M3C – Enhanced CP Survey and Unprotected Steel Main Evaluation: As stated in Section III, PG&E proposes to continue the pace for cathodic protection Resurvey of 4,000 miles of pipe per year through 2021.

M4C – ECISS Program: PG&E proposes to inspect 50,000 ECISS risers every year through 2022 as described in Section III. The model exposure input in equivalent miles is approximately 600 miles per year.

Table 7-4: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$ M)	EV RSE (Units/$ M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	DIMP Emergent work (Proposed, Alt 1, Alt 2)	0.0014	0.0015	2020	2021	D2	1,615 - 1,785 (E)	1,615 - 1,785 (E)	–
M2C	New Valve Installations (Proposed)	0.2141	0.0329	2020	2022	SI, SF, F	11,075 - 12,240 (C)	9,893 - 10,934 (C)	8,797 - 9,723 (C)
M3C	Enhanced Cathodic Protection Survey & Unprotected Main Program (Proposed, Alt 2)	0.0891	0.0974	2020	2021	D1	5,652 - 6,247 (E)	5,652 - 6,247 (E)	–
M4C	Electrically Connected Isolated Steel Service (Proposed, Alt 2)	0.0353	0.0376	2020	2022	D1	2,404 - 2,657 (E)	2,404 - 2,657 (E)	2,404 - 2,657 (E)
PROPOSED PLAN TA RSE: 0.1566 **TOTAL Expense and Capital by Year**							**11,075 - 12,240 (C)** **9,671 - 10,689 (E)**	**9,893 - 10,934 (C)** **9,671 - 10,689 (E)**	**8,797 - 9,723 (C)** **2,404 - 2,657 (E)**

VI. Alternatives Analysis

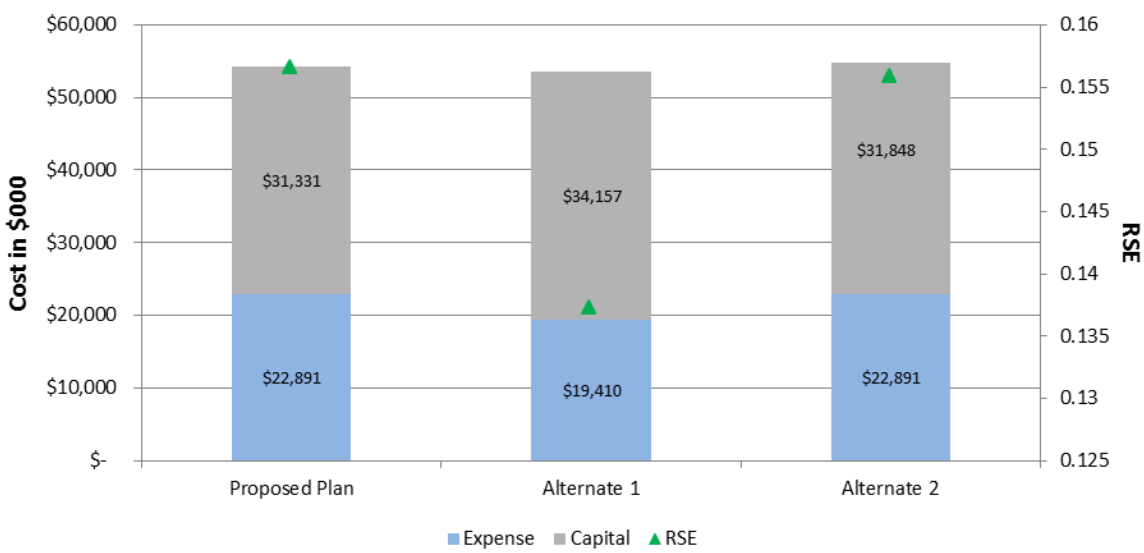
The table below identifies the various mitigations that make up the proposed and alternative plans. While the mitigations to address this risk remain unchanged because of their high impact for risk reduction, PG&E evaluated the varying pace of work for cathodic protection, ECIS, and new valve installations to determine what effect it would have toward risk reduction efforts.

Table 7-5: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	DIMP Emergent Work (Proposed, Alt 1, Alt 2)	0.0014	0.0015	X	X	X	WP 7-2
M2C	New Valve Installations (Proposed)	0.2141	0.0329	X			WP 7-5
M3C	Enhanced Cathodic Protection Survey & Unprotected Main Program (Proposed, Alt 2)	0.0891	0.0974	X		X	WP 7-8
M4C	Electrically Connected Isolated Steel Service (Proposed, Alt 2)	0.0353	0.0376	X		X	WP 7-11
M3D	Enhanced Cathodic Protection Survey & Unprotected Main Program (Alt 1)	0.0993	0.1058		X		WP 7-8
M5A	Electrically Connected Isolated Steel Service (Alt 1)	0.0271	0.0296		X		WP 7-11
M2D	New Valve Installations (Alt 1)	0.1811	0.0270		X		WP 7-5
M2E	New Valve Installations (Alt 2)	0.2126	0.0326			X	WP 7-5

Figure 7-3 shows the breakdown of the proposed plan, alternative plan 1, and alternative plan 2 based on cost and RSE.

Figure 7-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

Of the mitigation programs described above three of them have alternative proposals which are listed below.

M2D – New Valve Installations: Install 467 valves in 2020 and the remaining 107 valves in 2021. This is an increase of 192 valve installations from the proposed case. The increase in scope would complete this work within a 2-year time period as opposed to the 6-year program identified in the recommended plan. This alternative is not recommended because of the amount of work necessary to identify, plan and execute the accelerated work schedule given the limited resources available.

M3D – Enhanced CP Survey and Unprotected Steel Main Evaluation: Resurvey of 2,000 miles of pipe per year for 2020-2022 instead of the proposed case recommendation of 4,000 miles of pipe per year. The enhanced CP Resurvey Program would extend from five years to seven years. This alternative is not recommended because it would potentially leave unprotected main in the system longer which could increase risk exposure.

M5D – ECISS: Inspection of 70,000 ECISS risers every year instead of the proposed plan recommendation of 50,000 ECISS risers. The increase in scope reduces the amount of time to complete the mitigation from seven years to five years. This alternative is not recommended because of the amount of work necessary to identify, plan and execute the accelerated work schedule given the limited resource availability.

Table 7-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	DIMP Emergent work (Proposed, Alt 1, Alt 2)	0.0014	0.0015	2020	2021	D2	1,615 - 1,785 (E)	1,615 - 1,785 (E)	–
M2D	New Valve Installations (Alt 1)	0.1811	0.0270	2020	2021	SI, SF, F	26,936 - 29,772 (C)	5,513 - 6,093 (C)	–
M3D	Enhanced Cathodic Protection Survey & Unprotected Main Program (Alt 1)	0.0993	0.1058	2020	2022	D1	2,826- 3,123 (E)	2,826- 3,123 (E)	2,826 - 3,123 (E)
M5D	Electrically Connected Isolated Steel Service (Alt 1)	0.0271	0.0296	2020	2021	D1	3,366 - 3,720 (E)	3,366 - 3,720 (E)	–
ALTERNATIVE PLAN 1 TA RSE: 0.1373 **TOTAL Expense and Capital by Year**							**26,936 - 29,772 (C) 7,807 - 8,628 (E)**	**5,513 - 6,093 (C) 7,807 - 8,628 (E)**	**2,826 - 3,123 (E)**

B. Alternative Plan 2

Two of the mitigation programs described in Section VI A above are also the mitigation programs for the alternative proposals below. For alternative 2, the only mitigation program that is different is New Valve Installations as described below.

M2E – New Valve Installations: Install 224 valves per year for 2020-2021 and the remaining 126 valves in 2022. This alternative is a reduction in scope of 51 valve installations per year. Even though the risk spend efficiency is highest for this option, the reduction in scope is not recommended because it would increase the amount of time to reduce the size of emergency shut down zones, which would reduce the time in shutting down customers during gas emergencies.

Table 7-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	DIMP Emergent work (Proposed, Alt 1, Alt 2)	0.0014	0.0015	2020	2021	D2	1,615 – 1,785 (E)	1,615 – 1,785 (E)	–
M2E	New Valve Installations (Alt 2)	0.2126	0.0326	2020	2022	SI, SF, F	12,920- 14,280 (C)	11,541- 12,756(C)	5,794- 6,404 (C)
M3E	Enhanced Cathodic Protection Survey & Unprotected Main Program (Proposed, Alt 2)	0.0891	0.0974	2020	2022	D1	5,652 – 6,247 (E)	5,652 – 6,247 (E)	–
M4	Electrically Connected Isolated Steel Service (Proposed, Alt 2)	0.0353	0.0376	2020	2022	D1	2,404 – 2,657 (E)	2,404 – 2,657 (E)	2,404 - 2,657 (E)
ALTERNATIVE PLAN 2 TA RSE: 0.1519 **TOTAL Expense and Capital by Year**							**12,920- 14,280 (C) 9,671 – 10,689 (E)**	**11,541 – 12,756(C) 9,671 - 10,689 (E)**	**5,794 – 6,404 (C) 2,404- 2,657 (E)**

VII. Metrics

The primary metric that PG&E is proposing to track for risk reduction is the number of open leaks. Although this model did not use the existing PG&E leak data, it is one of the next steps that we have identified for this model. Using leaks as a means to understand risk reduction allows PG&E to tie back directly to the basis of the risk model and compare actual versus estimate risk reduction year over year.

PG&E has also selected metrics associated with each of its mitigation programs to confirm each program is progressing at the desired pace in order to achieve risk reduction objectives. The targets for these metrics are established based on rate case outcomes and PG&E's Integrated Planning process.

Table 7-8: Metrics

Risk/Mitigation	Associated Driver #	Proposed Metric	Targets
Risk Reduction Metric			
Release of Gas with Ignition on Distribution Assets – non-Cross Bore	All	# of leaks	TBD
Execution Metric			
DIMP Emergent work	D2	Number of kerotest valves replaced versus planned	TBD
New Valve Installations	SI, SF, F	Number of new valve installed versus planned	TBD
Enhanced CP Survey and Unprotected Main Evaluation	D1	Miles of CP survey and main evaluations completed versus planned	TBD
ECISS	D1	Number of ECISS risers inspected versus planned	TBD

VIII. Next Steps

For the Release of Gas with Ignition on Distribution Facilities – Non-Cross Bore risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Use PG&E data instead of industry data, when we can, to enable actionable conclusions from risk quantification. For example, PG&E's historical leak and excavation damage data are possible areas of further analysis for inclusion.
- Research and determine data needed to quantify the compliance consequence category.
- Refine model inputs for reliability consequence category and consider looking at a longer time period. Generally, the modeling effort was primarily focused on safety. PG&E will look for opportunities for data maturity to better estimate the reliability and environmental impacts, so as to improve estimates regarding the customer outage and environmental costs. These model inputs are being assessed and, where possible, GO will update these inputs in the future.
- Consider how GO can align risk models with work plan and estimate development. For example, New Valve Installations Program is estimated in terms of number of valves installed, however, the quantification model for this risk is in terms of number of miles addressed by each mitigation program.
- Evaluate risk reduction metrics further and identify if there are additional metrics that can be defined to measure risk reduction.

- Include additional rigor on alternative plan creation and evaluation given growing institutionalized knowledge of the risk model.
- Continue evolution of the model to better reflect risk reduction and mitigation effectiveness for the mitigations.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 8
NATURAL GAS STORAGE WELL FAILURE – LOSS OF CONTAINMENT WITH IGNITION AT STORAGE FACILITY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 8
NATURAL GAS STORAGE WELL FAILURE – LOSS OF CONTAINMENT WITH IGNITION AT STORAGE FACILITY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility
IN SCOPE	Natural Gas Storage Well Failure owned and operated by Pacific Gas and Electric Company (PG&E) – loss of containment with ignition at a storage facility and the consequences of the risk event.
OUT OF SCOPE	Risks related to pipeline facilities and non-well sub-surface equipment facilities within storage fields are modeled with Transmission Pipe risk and Station/Facilities risk respectively. PG&E ownership interest of 25 percent of the wells operated by Gill Ranch is also out of scope.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data and subject matter expertise. Industry data includes URS Corporation Study, Det Norske Veritas™ (DNV) Report,[1] Pipeline and Hazardous Materials Safety Administration (PHMSA) Major Incident Reporting Data, and PG&E's response to PHMSA Interim Final Rule for Underground Storage Facilities.

This risk is defined as a loss of containment with ignition at a storage facility resulting in significant injuries and fatalities, prolonged outages, property damage, and/or environmental damage.

PG&E owns and operates three underground gas storage fields: McDonald Island, Los Medanos, and Pleasant Creek. These three storage fields currently include 117 injection and withdrawal wells.

Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility Risk has been on PG&E's risk register since 2013. It is also an Enterprise level risk overseen by the Nuclear Operations and Safety Committee of PG&E's Board of Directors. This risk is a low frequency event, but if it occurred could lead to severe consequences. As such, this risk is identified as a top risk for the company.

PG&E is actively addressing this risk through a variety of controls and mitigations that are aimed at improving the integrity and health of PG&E's storage and related assets to prevent the risk event from occurring. Because of significant new requirements for storage maintenance activities, PG&E is also proposing to modify its portfolio of storage assets which will reduce exposure to this risk.

Based on historic events and Subject Matter Expert (SME) judgement, it is estimated that 97 percent of events where there is a loss of containment with ignition at a storage well could result in serious safety consequences in the form of fatality or injury. By

1 The Det Norske Veritas™ Report documents the results from the coarse Quantitative Risk Assessment for PG&E's McDonald Island facilities. The report was issued January 29, 2014.

implementing the mitigation strategy outlined in this chapter of decommissioning wells and increasing storage well inspections through 2022, PG&E forecasts a potential 27 percent reduction in in the overall Multi-Attribute Risk Score (MARS) between 2017 and 2022.

Risk Assessment and Mitigation Phase (RAMP) provided a platform to accelerate PG&E's transition from a qualitative risk assessment to more probabilistic risk modeling. Going forward, PG&E plans to continue to collect and analyze more data, where available, to improve the model inputs and continue the move toward more quantitative, data driven risk models. For the storage well failure risk described in this chapter, one of the key next steps is to consider equipment-related failures as a driver for this risk. A detailed list of next steps is included in Section VIII below.

II. Risk Assessment

A. Background

On October 23, 2015, a leak was detected at Southern California Gas Company's Aliso Canyon Natural Gas Storage Facility. On January 6, 2016, Governor Edmund G. Brown Jr. declared a State of Emergency in Los Angeles County to facilitate the state's ongoing efforts to stop the leak at Aliso Canyon. The governor issued a proclamation establishing 14 directives that required the California Public Utilities Commission (Commission), the California Energy Commission (CEC), the California Air Resources Board (CARB), the California Independent System Operator, the Division of Oil, Gas and Geothermal Resources (DOGGR), and other state agencies to work together to address specific items related to gas storage wells. Directive Number 13 authorized DOGGR to issue emergency regulations for California gas storage operators, including PG&E. On September 26, 2016, the California Legislature enacted Senate Bill 887 which modifies DOGGR and CARB oversight of gas storage wells and significantly increased the scope of work related to maintaining and operating gas storage wells.

As described in PG&E's 2019 Gas Transmission and Storage (GT&S) Rate Case,[2] PG&E reviewed its Storage Family assets in light of the anticipated significant increase in capital and expense requirements due to both currently effective and proposed regulations. Based on these reviews and reviewing the risk exposure, PG&E—working with stakeholders—is proposing to change its portfolio of

2 See 2019 GT&S Rate Case, Chapter 6, Section A and Chapter 11 for details.

storage assets. PG&E's proposed Natural Gas Storage Strategy (NGSS)[3] has an impact on PG&E's risk exposure. In summary, this strategy involves reducing PG&E's risk through ceasing operations at the Los Medanos and Pleasant Creek storage facilities, leaving McDonald Island in operation. The McDonald Island facility will increase the number of wells in operation to address reduced capacity associated with implementing the new regulations. The NGSS evaluation considered three scenarios:

1. **Scenario 1 – NGSS (Proposed)**
   i. Continue operations of McDonald Island;
   ii. Drill 11 new wells to mitigate the reduction in existing injection and withdrawal capabilities;
   iii. Sell or decommission Los Medanos and Pleasant Creek (27 wells) starting in 2022;
   iv. Implement DOGGR rules as currently drafted; and
   v. Complete well retrofits and baseline storage well inspections by 2020 at McDonald Island.
2. **Scenario 2 (Alternative 1)**
   i. Continue operations of four existing storage fields;[4]
   ii. Implement DOGGR rules as currently drafted; and
   iii. Drill 33 new wells to mitigate the reduction existing injection and withdrawal capabilities.
3. **Scenario 3 (Alternative 2)**
   i. Continue operations of McDonald Island;
   ii. Assumes DOGGR adopts PG&E's proposal for a risk-informed implementation pace completing baseline storage well inspections and well retrofits by 2025;
   iii. Drill 11 new wells to mitigate the reduction in existing injection and withdrawal capabilities; and
   iv. Sell or decommission Los Medanos and Pleasant Creek (27 wells) starting in 2022.

Scenario 1 is presented as the recommended mitigation plan for this RAMP submittal and for approval by the Commission in the 2019 GT&S Rate Case. Scenario 2 is

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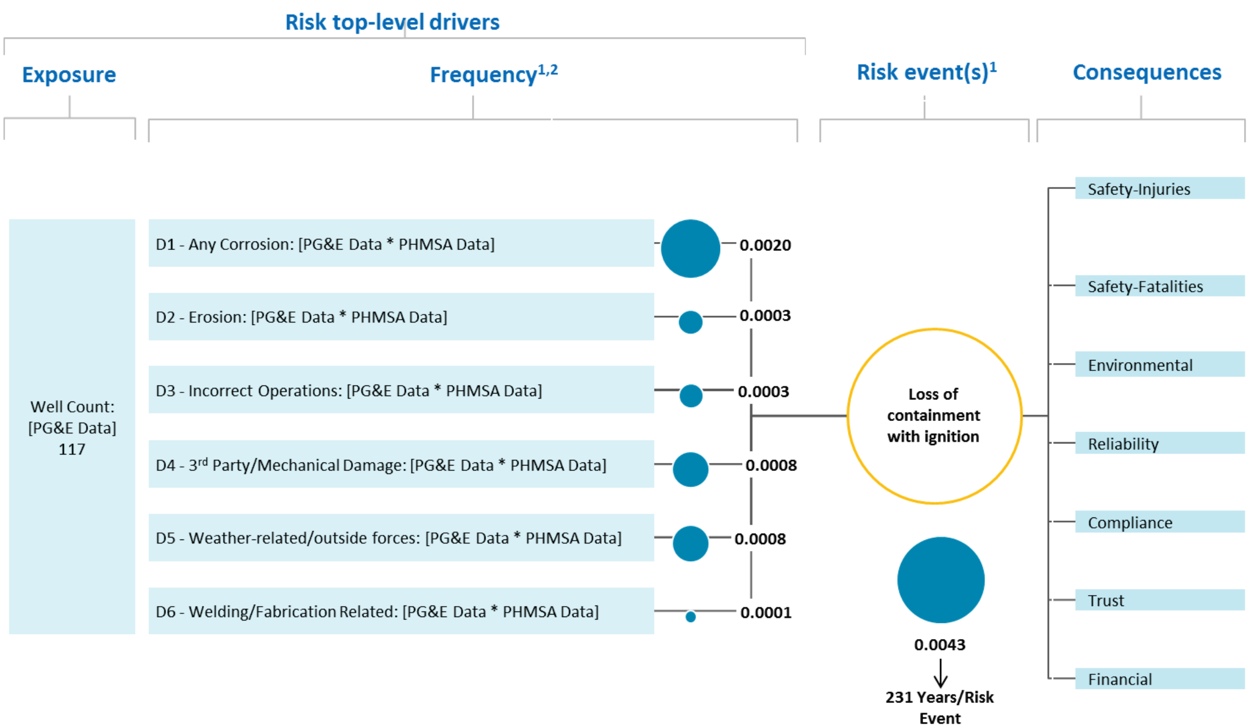
3 See 2019 GT&S Rate Case, Chapter 11, for details on the NGSS.

4 PG&E owns and operates three storage fields: McDonald Island, Los Medanos, and Pleasant Creek. PG&E holds a 25 percent interest in the Gill Ranch storage fields. Under Scenario 2, PG&E would continue operations at the three PG&E owned storage facilities and would continue its 25 percent interest at Gill Ranch. Risks at Gill Ranch are not included in this Risk Analysis.

Alternative 1, and Scenario 3 is Alternative 2. The work plan associated with each scenario is described below.

The risk bow tie, in Figure 8-1 below, shows the exposure and frequency drivers for this risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bow tie, is defined as a loss of containment with ignition at a storage well. Based on the model inputs for frequency, this risk event is expected to occur approximately every 231 years on average.

Figure 8-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.

B. Exposure

The exposure for this risk is the total count of storage wells at the three storage reservoirs owned and operated by PG&E. There are 117 wells at PG&E's three storage facilities and there are 88, 22, and 7 wells at the McDonald Island, Los Medanos, and Pleasant Creek facilities, respectively.

For the Storage risk, PG&E examined three exposure scenarios as part of the NGSS. Table 8-1 below is a table that shows the number of wells expected for the upcoming years and the exposures based on the three scenarios.

Table 8-1: Exposure, Number of Wells per Year

Number of Wells				
Years	Baseline[5]	Proposed	Alternative 1	Alternative 2
2017	117	117	117	117
2018	115	115	115	115
2019	115	120	133	120
2020	115	126	148	126
2021	115	126	148	126
2022	115	113	148	113

Each scenario and associated exposure set is discussed in Sections IV, V and VI below.

C. Drivers and Associated Frequency

PG&E uses API RP 1171[6] as the basis for categorizing and evaluating the risk drivers or threats. The risk drivers identified for this risk are as follows:

- **D1 – Corrosion (all types):** Corrosion is a threat that adversely affects the longevity and reliability of storage well equipment (e.g., tubulars and casings, seals, packers, natural gas pipelines, valves, pressure vessels, and other pipeline appurtenances). There are several types of corrosion threats: external, internal, atmospheric, and stress corrosion cracking. Based on the probability distribution used in the model, the average number of incidents with ignition due to any corrosion failure is 0.0020 per year. This can be interpreted as one event due to any corrosion type approximately every 500 years. Corrosion is the biggest contributor to the risk event by nearly a factor of 3.
- **D2 – Erosion:** Erosion poses a threat to all components of the storage asset. The associated risks are the loss of integrity of the component which may result in loss of containment of the storage gas with pressures ranging from 600 pounds per square inch gauge (psig) to 2,160 psig. This risk to the Gas Storage asset family relates to the quality of the storage gas being withdrawn from the storage formation. In storage operations, the gas withdrawn from the storage formation and moved through the storage asset generally contains water, sand, and other gas components

5 PG&E plans to plug and abandon two wells at the Los Medanos Storage Field sometime in the fourth quarter of 2017.

6 American Petroleum Institutes Recommended Practice (API RP 1171) - "Functional Integrity of Natural Gas Reservoirs and Aquifer Reservoirs," Section 8, Table 1. Currently, this API RP is incorporated in whole in PHMSA's IFR (Interim Final Rule) for Storage into the Title 49 of the Code of Federal Regulations – Transportation Part 191 and 192. The threats in API RP 1171 are aligned with the American Society of Mechanical Engineers standard B31.8S "Managing System Integrity of Gas Pipelines."

(e.g., carbon dioxide (CO_2), hydrogen sulfide (H_2S)) that can cause either corrosion or erosion of the internal components. Due to the geological nature and complexity of PG&E's storage fields and wells, the high potential to produce sand increases the likelihood of a risk of erosion at the impingement points (e.g., valves, elbows, tees) within the surface components. Based on the probability distribution used in the model, the average number of incidents with ignition due to erosion failure is 0.0003 per year. This can be interpreted as one event due to erosion approximately every 3,300 years.

- **D3 – Incorrect Operations**: The threat of incorrect operations can lead to the risk of incorrect procedures of all asset components and human error that could result in a loss of integrity of the storage well as gas is injected and withdrawn. For example, there is a risk of over-pressurization during injection of fluids by a third party or PG&E that results in the reservoir integrity becoming compromised which leads to the migration, loss of gas, or need to abandon the storage field indefinitely. Based on the probability distribution used in the model, the average number of incidents with ignition due to incorrect operations is 0.0003 per year. This can be interpreted as one event due to any incorrect operations approximately every 3,300 years.
- **D4 – Third Party/Mechanical Damage:** Third-party threats and the risks associated with vandalism, immediate hits,[7] and delayed damage could result in loss of integrity of the transmission pipe within the storage well as gas is injected and withdrawn from the facility. Based on the probability distribution used in the model, the average number of incidents with ignition due to third-party damage is 0.0008 per year. This can be interpreted as one event due to any third-party damage approximately every 1,250 years.
- **D5 – Weather and Outside Forces:** The threat of outside forces is associated with the risk of cold weather, lightning, heavy rains/flooding, and earth movement that could result in a loss of integrity of the storage wells as gas is injected and withdrawn from the facility or could affect access to the asset. Based on the probability distribution used in the model, the average number of incidents with ignition due to weather-related outside force is 0.0008 per year. This can be interpreted as one event due to weather-related outside forces approximately every 1,250 years.
- **D6 – Welding/Fabrication Related:** Welding/fabrication threat from a third party or PG&E drilling through and/or into the storage reservoir, and/or reworking storage wells can result in an improperly completed and poorly constructed well. The risk associated with improper

7 "Immediate hits" is defined as damage that is caused instantly when someone digs or drills into assets in the storage fields.

connection of the tubulars and/or defective cement work is the loss of integrity of the well to contain the storage gas. Based on the probability distribution used in the model, the average number of incidents with ignition due to welding/fabrication failure is 0.0001 per year. This can be interpreted as one event due to welding/fabrication approximately every 10,000 years.

Frequencies were defined for the drivers listed above as the total number of events in a given well and in a given year. Given the small sample set of failures with ignition at PG&E,[8] industry data was used to estimate average failure rates. The event frequencies are based on a study prepared for the Gas Research Institute by URS Corporation in March 2005, "Risk Assessment Methodology for Accidental Natural Gas and Highly Volatile Liquid Releases from Underground Storage, Near-Well Equipment."

D. Consequences

The consequences of loss of containment with ignition at a storage facility risk is simulated using PHMSA consequence data, PG&E data, SME judgement as well as risk assessment studies conducted at PG&E's McDonald Island storage fields.

The range of consequences and the attributes that help describe the tail average risks and the associated MARS are shown in Figure 8-2 below. In the figure, PG&E identifies the data sources used for each of the consequence attributes. Based on the tail average results, Safety – Fatalities and Trust outcomes contribute the most to the overall baseline MARS.

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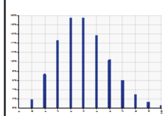
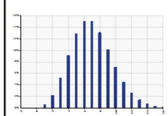
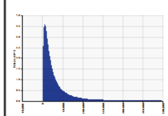
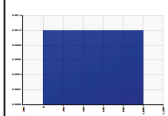
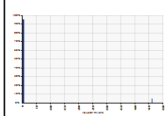
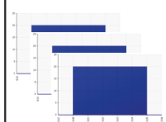
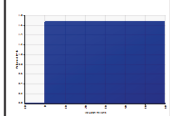
8 In 1974, PG&E experienced a well blowout during the development of the McDonald Island facility with fire as a result of improper operations during the drilling of the well and not as a result of well casing failure.

Figure 8-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PHMSA	PHMSA	PHMSA and ICE	SME Input	SME Input	PG&E Data	PG&E Data
Consequence Distributions	Percent of ignition events with injury=97% Mean=4 (Poisson) 	Percent of ignition events with fatality=97% Mean=7 (Poisson) 	Ave=35,237MCF Std Dev=56,063MCF Ave cost of Carbon[3]=$13 /tonne CO2 (Lognormal) 	Customer hours affected= Min=0 hours*60 Max=1,000 hours*60 (Uniform) 	95%=4M 5%=462M (Discrete) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Min=$0M Max=$60M (Uniform) 
Outcome-TA-NU[1]	0.17	0.30	$1,042	1,316	$1,238,444	0.72%	$1,311,598
Outcome-TA-MARS[2]	0.05	8.14	0.00	0.00	0.12	3.59	0.79
						MARS Total	**12.68**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]To convert MCF to tonne multiply by ~52/1000

- **Safety – Injuries (SI):** Based on two key assumptions: (1) PG&E estimated the percentage of ignition incidents leading to injury to be approximately 97 percent;[9] (2) the DNV Coarse Quantitative Risk Analysis (CQRA) report informed the SME assumption to estimate the average injury outcomes to be approximately half that of the fatalities. Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case number of injuries per year would be 0.17. This can also be interpreted as 1 injury every 6 years.
- **Safety – Fatalities (SF):** Based on two key assumptions: (1) the input of the percentage of incidents resulting in a fatality is the same percentage as that used for injury above, (2) the DNV CQRA report informed the SME assumption to estimate the average fatality at 7 per event. Based on the tail average model results for the 2017-2022 time period, the calculated average worst case number of fatalities per year would be 0.3. This can also be interpreted as 1 fatality every 3 years. This outcome is higher than anticipated since industry data for ignition events at storage

9 Assume that there is a 50 percent likelihood that someone is impacted at an unmanned well (7 wells) and 100 percent likelihood that someone is impacted at a manned well (110 wells); (50 percent * 7 wells) + (100 percent * 110 wells) divided by the 117 total wells = 97 percent.

facilities is very limited. PG&E believes that additional data analysis in the future may better identify this risk consequence.

- **Environmental (E):** PHMSA data set for transmission related releases of gas with ignition resulted in an average gas release volume of 35,237 millions cubic feet.[10] Based on the tail average model results across the 2017-2022 time periods, the average worst case environmental related cost is $1,042 per year. This is equivalent to approximately 80 tonne of CO_2. These results show that environmental impacts play a relatively small role in this risk.
- **Reliability (R):** PG&E leveraged SME judgment to determine the reliability impact of this risk. PG&E assumes zero to a maximum impact of 1,000 customer hours based on the assumption of the scoring using the Risk Evaluation Tool and previous risk scoring efforts. Based on tail average model results for the 2017-2022 time period, the average worst case reliability impact per year would be 1,316 customer minutes or approximately 22 customer hours.
- **Compliance (C):** The compliance is modeled as a binary distribution such that if a risk event occurs, there is a 95 percent chance that it will result in a $4 million impact (for a single well replacement) and a 5 percent chance of a $462 million impact (for a full field replacement). The well replacement cost is assumed to be $4 million based on the study – "STO – 05 - Response to PHMSA IFR for Underground Storage Facilities 2-17-17.pdf." Based on the tail average model results for the 2017-2022 time periods, the average worst case compliance related impact is approximately $1.2 million.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as low, severe, and high. This methodology was used across all GO risks.[11] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on brand favorability is 0.72 percent a year.
- **Financial (F):** The average value of financial impact from the risk event is assumed to be $59.8 million. This estimate is based on two items – well replacement cost ($4 million) and the cost of replacement of gas lost due to the event ($55.8 million). Based on the tail average model results for the 2017-2022 time period, the average financial impact is approximately $1.3 million.

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10 The average cost of carbon was taken from the Intercontinental Exchange end of day close for California Carbon Allowance Futures as of day close March 29, 2017, which was $13 per tonne of CO_2.

11 Refer to the Risk Model Overview chapter for the trust consequence calculation details.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

The controls described in this section manage one or more drivers of the Natural Gas Storage – Loss of Containment with Ignition Risk and allow PG&E to stay compliant with regulations. In the case of Storage, seven key controls have been identified for this risk and include the programs listed below. Table 8-2 below summarizes the controls, mitigations and 2016 recorded costs associated with each.

C1 – Corrosion Control: All of PG&E's metallic (steel) assets are subject to corrosion, an electrochemical process where metal degrades due to its interaction with the environment. Corrosion control seeks to either eliminate the elements that lead to corrosion or to manipulate the natural corrosion process with electrical currents. Effective corrosion control monitoring programs are critical to provide timely data that is representative of pipeline conditions, allows for modifications in corrosion mitigation strategies, and updates risk management tools. This control addresses the External Corrosion, Internal Corrosion and Stress Corrosion Cracking drivers thereby reducing the likelihood of the risk event occurring due to these drivers. Corrosion Control is identified as a control in other risk chapters including Transmission Pipe risk, Measurement & Control, and Compression & Processing risks. The total cost for this program is not allocated among the risks.

C2 – Leak Survey: PG&E conducts leak surveys on the gas transmission pipeline system by foot, mobile, and/or aerial leak surveys. Leak survey is performed daily at each storage wells and includes a 100-foot radius in alignment with the DOGGR Emergency Regulations enacted in February 2016. Expansion of CARB requirements effective March 2017 will replace the DOGGR requirements and require leak repair at an accelerated pace. This control manages all identified risk drivers for Storage Wells.

- Foot survey: Foot survey is the most common method to conduct leak survey and requires personnel to carry a portable gas leak detector in close proximity to the storage wells.
- Mobile survey: Ground-based mobile technology is a portable gas detector transported on all-terrain vehicles (or possibly cars or trucks) around the storage wellheads.
- Aerial survey: Aerial leak surveys using Light Detection and Ranging Infra-Red technology are being used more frequently, and are typically transported by helicopter along the pipeline right-of-way or adjacent to storage wells.

For each case, leaks are detected and recorded on the instrument before being downloaded to a database for immediate or scheduled repair.

Leak Survey is also identified as a control for the Transmission Pipeline Rupture with Ignition risk. The total cost for this program is not allocated between the risks.

C3 – Storage Well Work: Included in this control program are integrity assessments, repair and replacement work, and rework. This program addresses the External Corrosion, Internal Corrosion, and Incorrect Operations thereby reducing the likelihood of the event occurring due to these drivers.

C4 – Other O&M: Gas Transmission operations and maintenance is planned, tracked and managed regulatory compliance activities that can increase the useful lives of the Gas Transmission assets. Gas Transmission operations and maintenance tasks include compliance, preventive, and corrective activities. This control addresses all drivers. This program is identified as a control for Transmission Pipeline Failure – Rupture with Ignition risk, Measurement & Control failure risk and Compression & Processing failure risk. The total cost for this program is not allocated among the risks.

C5 – Public Awareness: PG&E is required to develop and implement public education programs that comply with American Petroleum Institute's (API) Recommended Practice 1162, First Edition (RP 1162). The overall goal of the Public Awareness Program is to enhance public safety, emergency preparedness and environmental protection through increased public awareness and knowledge. This control addresses the Third Party/Mechanical Damage driver.

C6 – Technology: This program includes Gas Operations Technology and Research and Development. This includes new casing inspection hardware, risk management software, utilization of fiber optics for storage monitoring, etc. The drivers addressed are Corrosion and Incorrect Operations.

C7 – Valve Program: This program addresses inoperable and hard to operate storage well valves, and proactively repairs or replaces valves that are on the verge of becoming inoperable or are leaking or are presenting a safety or reliability threat. This program addresses Incorrect Operations, Weather Related Outside Force, and Third-party/Damage drivers thereby reducing the likelihood of these events occurring due to these drivers.

The mitigation identified for the Natural Gas Storage Well Failure risk is described below:

M1A - Storage Well Inspection Program: This mitigation began in 2013 and the mitigation end date is based on three scenarios discussed in the sections below.

A total of 26 baseline inspections were completed by the end of 2016. Of those, 20 were completed using pre-2016 testing criteria and the remainder as described above. This pace was set in alignment with the 2015 GT&S Rate Case and assumes 6-8 reworks per year. The initial pace only included Noise and Temperature Surveys; however, in

2016 the breadth of baseline casing inspection surveys performed was expanded to meet the Aliso Canyon testing criteria put forth by DOGGR.

The program post-2016 includes performing condition assessment of both surface and production casing. Condition assessments provide insight into the health of the asset as the wells are evaluated for repair/reconditioning or decommissioning. Tools and technology are used to conduct these assessments and include: Noise and Temperature Logs, Cement Bond Logs, Casing Wall Thickness Inspection, Gamma Ray Neutron, Caliper Inspections, Ultrasonic Surveys, Pressure Tests, and Pressure Monitoring. The pre-2016 program did not include Caliper Inspections, Ultrasonic Surveys, and Pressure Tests up to 115 percent of maximum allowable operating pressure and pressure monitoring.

The data collected informs the necessary frequency of subsequent well assessments to monitor the baseline condition (i.e., degree of metal loss observed in a survey may warrant a more frequent inspection cycle to measure corrosion rate).

This mitigation addresses all the identified risk drivers except welding and fabrication related drivers by identifying anomalies and determining if the anomalies need to be immediately addressed or monitored thereby reducing the likelihood of the risk occurring due to the risk drivers.

Table 8-2: Summary of Controls and Mitigations and 2016 Recorded Costs

#	Control/Mitigation	Associated Driver # and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Corrosion Control	D1	GT&S	35,030	35,409
C2	Leak Survey	All drivers	GT&S	3,550	–
C3	Storage Well Work	D1, D3	GT&S	1,294	2,969
C4	Other O&M	All drivers	GT&S	30,953	–
C5	Public Awareness	D4	GT&S	3,084	–
C6	Technology	D1, D3	GT&S	3,074	25,257
C7	Valve Program	D3 – D5	GT&S	1,946	–
M1A	Storage Well Inspections[12]	D1 – D5	GT&S	3,548	21,159
TOTAL Expense and Capital				**82,479**	**84,794**

IV. Current Mitigation Plan (2017-2019)

The proposed mitigation aligns with Scenario 1 - NGSS. The mitigation program described in Section III above continues through the 2017-2019 time period. As

12 Within the GT&S rate case, "Storage Well Inspections" is referred to as "Integrity Inspections" (expense) and "Reworks and Retrofits Program" (capital).

described in the exposure section above, this risk has multiple scenarios which are being considered for the 2017-2019 time period.

Exposure for the Scenario 1: As described in the exposure section above, the exposure for this risk varies between the baseline risk and the proposed and alternative scenarios. The exposure that the proposed volume of work addresses for is listed in the Table 8-3 below:

Table 8-3: 2017-2019 Number of Wells

Scenario 1 - NGSS		
Year	**Number of Storage Wells**	**Baseline # of Wells**
2017	117	117
2018	115	115
2019	120	115

Two wells are being plugged and abandoned during the 2017 rework season. This scenario includes the planned addition of 11 wells at McDonald Island and assumes that five of the wells are drilled in 2019.

Proposed Volume of Work

M1B – Storage Well Inspection Program: For 2017-2019, Scenario 1 outlines completing baseline assessments on 64 wells: 8 in 2017, 12 in 2018, and 44 in 2019. This pace allows completion of all baseline assessments by 2020 to comply with the proposed DOGGR regulations.

Overall, PG&E selected this option because it is aligned with the new proposed DOGGR regulations and will allow PG&E to meet both the regulatory requirements and customer demand.

Table 8-4: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Forecast ($000)	2018 Forecast ($000)	2019 Forecast ($000)
M1B	Storage Well Inspection Program	2013	2020	D1 – D5	19,500 (C) 6,906 (E)	35,904 (C) 3,155 (E)	160,321 (C) 6,011 (E)
TOTAL Expense and Capital					**19,500 (C) 6,906 (E)**	**35,904 (C) 3,155 (E)**	**160,321 (C) 6,011 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for the Natural Gas Storage Well Failure - Loss of Containment with Ignition at Storage Facility risk. For the 2020-2022 time period, in addition to the Storage Well

Inspection program, a new mitigation – Decommissioning of Wells is also identified and is described below.

Exposure for the proposed scenario: The exposure for the 2020-2022 time period is outlined in the Table 8-5 below.

Table 8-5: 2020-2022 Proposed Number of Wells

Scenario 1 - NGSS		
Year	**Number of Storage Wells**	**Baseline # of Wells**
2020	126	115
2021	126	115
2022	113	115

Six wells are added in 2020 to complete the addition of 11 wells at McDonald Island. In addition, this scenario includes beginning decommissioning of Los Medanos and Pleasant Creek (13 wells decommissioned in 2022).

Proposed Volume of Work

M1C – Storage Well Inspection Program: For 2020-2022, the proposed case outlines completing baseline assessments on 44 wells in 2020, resulting in all baseline assessments being complete by 2020. As explained in Section IV above, the proposed case allows PG&E to meet compliance requirements.

M2 – Decommissioning of Wells: This mitigation includes decommissioning 13 wells in 2022. This mitigation is not an existing program but instead is work that PG&E will perform starting in 2022 and is driven by the proposed regulations and PG&E's NGSS. It involves plugging and abandoning wells that are currently in use and removing them from service. The fields these wells located in Los Medanos and Pleasant Creek, will be decommissioned as part of the NGSS and thus these wells will no longer be needed.

Table 8-6: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Driver	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1C	Storage Well Inspection Program	0.0480	0.0048	2013	2020	D1 – D5	164,599 (C) 6,010 (E)	–	–
M2C	Decommissioning of Wells	0.0833	0.0083	2022	2023	All drivers	–	–	16,739 (C)
RSE: 0.0495 **TOTAL Expense and Capital by Year**							**164,599 (C)** **6,010 (E)**	–	**16,739 (C)**

VI. Alternatives Analysis

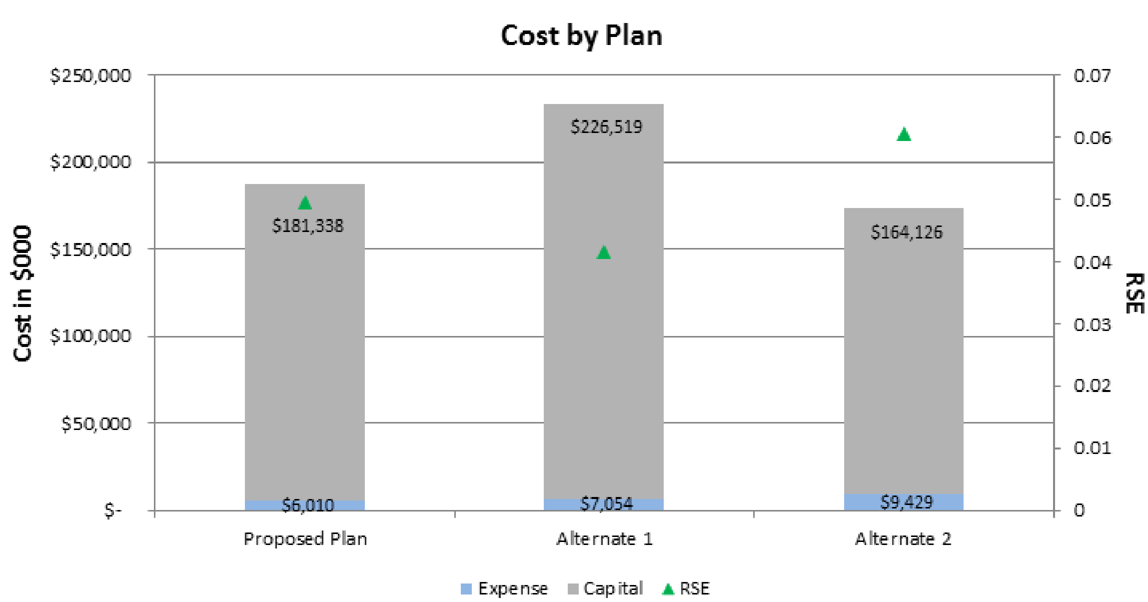
After assessing all of the mitigations, PG&E has two alternative plans to the proposed mitigation plan. Alternative 1 plan is based on maintaining current storage capacity to customers. Alternative 2 plan is based on PG&E's assessment of a risk-informed implementation pace of completing baseline assessments. Both plans are shown below in Table 8-8 and Table 8-9.

Table 8-7: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1C	Storage Well Inspection Program	0.0480	0.0048	x			8-2
M1D	Storage Well Inspection Program	0.0417	0.0042		x		8-2
M1E	Storage Well Inspection Program	0.0592	0.0059			x	8-2
M2	Decommissioning of Wells	0.0833	0.0083	x		x	8-8

The graph below shows the breakdown of the proposed plan, Alternative 1 plan, and Alternative 2 plan based on cost and RSE. The RSE in the chart below for the exposure identified for each scenario.

Figure 8-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

This alternative is based on maintaining current storage capacity to our customers. This includes the Storage Well Inspection Program as described in detail in Section III above: completing 47 baseline inspections by 2020. In this alternative, PG&E would not decommission any storage wells at the Los Medanos or Pleasant Creek facilities.

PG&E did not select this alternative because it is inconsistent with the economic and regulatory developments shaping the gas storage marketplace that underlie the NGSS (see 2019 GT&S Rate Case Testimony, Chapter 11). The NGSS entails moving PG&E's storage function to a reliability-only model, with the gas commodity price-management function becoming incidental. Under the NGSS, PG&E does not require its current high level of storage capacity to maintain reliability, and intends to retire its storage facilities at Los Medanos and Pleasant Creek.

Exposure for Alternative Plan 1 (Scenario 2): The exposure addressed for this alternative case is outlined in the Table 8-8 below and includes drilling more wells than the proposed case.

Table 8-8: Alternative Plan 1 Number of Wells

Scenario 2		
Year	**Number of Storage Wells**	**Baseline # of Wells**
2017	117	117
2018	115	115
2019	133	115
2020	148	115
2021	148	115
2022	148	115

Two wells are being plugged and abandoned at Los Medanos during the 2017 rework season. Alternative 1 includes adding 33 wells overall – 18 wells at McDonald Island in 2019 and 15 wells in 2020 (12 at McDonald Island and 3 at Los Medanos). No wells will be removed from service after 2017 in this alternative.

Volume of work (Alternative Plan 1)

M1D – Storage Well Inspection Program: For 2020-2022, the alternative case outlines completing baseline assessments on 47 wells in 2020.

Table 8-9: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1D	Storage Well Inspection Program	0.0417	0.0042	2013	2020	D1 – D5	226,519 (C) 7,054 (E)	–	–
TOTAL RSE: 0.0417 **TOTAL Expense and Capital by Year**							**226,519 (C)** **7,054 (E)**	–	–

B. Alternative Plan 2

This alternative plan includes both mitigations: Storage Well Inspection program and Decommissioning of Wells. Overall, this alternative is based on performing initial baseline assessments at a pace optimized for risk rather than the biennial assessments as outlined in the proposed case. PG&E has submitted comments to both DOGGR and PHMSA advocating for a risk-informed, rather than a time-based, approach to the ongoing integrity assessment requirements, which could affect the gas storage expenditures. This alternative was not selected because the proposed regulations require the faster biennial pace and PG&E does not know whether DOGGR and PHMSA will accept its proposal for a risk-based pace. The risk-based pace includes completing baseline inspections by 2025. The volume of work for each year in 2020-2022 is outlined below.

Exposure for Alternative 2 (Scenario 3): The exposure addressed for this alternative case is outlined in the Table 8-10 below and is the same as in the proposed case.

Table 8-10: Alternative Plan 2 Number of Wells

Scenario 3		
Year	**Number of Storage Wells**	**Baseline # of Wells**
2017	117	117
2018	115	115
2019	120	115
2020	126	115
2021	126	115
2022	113	115

Six wells are added in 2020 to complete the addition of 11 wells at McDonald Island. In addition, this scenario includes beginning decommissioning of Los Medanos and Pleasant Creek (13 wells decommissioned in 2022).

Volume of work (Alternative Plan 2)

M1E – Storage Well Inspection Program: For 2020-2022, this alternative case outlines completing baseline assessments on 12 wells each year in 2020-2022.

M2 – Decommissioning of Wells: This mitigation is the same as outlined in the proposed case and includes decommissioning of 13 wells in 2022.

Table 8-11: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver and Consequence	2020 Forecast ($000)	2021 Forecast ($000)	2022 Forecast ($000)
M1E	Storage Well Inspection Program	0.0592	0.0059	2013	2025	D1 – D5	69,043 (C) 3,143 (E)	39,172 (C) 3,143 (E)	39,172 (C) 3,143 (E)
M2	Decommissioning of Wells	0.0833	0.0083	2022	2023	All drivers	–	–	16,739 (C)
RSE: 0.0606 **TOTAL Expense and Capital by Year**							**69,043 (C)** **3,143 (E)**	**39,172 (C)** **3,143 (E)**	**55,911 (C)** **3,143 (E)**

VII. Metrics

PG&E is proposing to define risk reduction metrics for this risk after completion of the storage well baseline inspections. The well condition data will provide of new information to facilitate meaningful risk reduction metric development.

Metrics associated with mitigation programs are designed to measure if each program is progressing at the desired pace to achieve risk reduction objectives. The targets for these metrics are established based on rate case outcomes and PG&E will utilize its Integrated Planning process to confirm and determine targets. The execution metric for the mitigation is:

Mitigation	Associated Drivers	Proposed Metric	Targets
Storage Well Inspection Program	D1-D5	Baseline Inspections performed	Percent of the total population of wells that have baseline inspections performed.

VIII. Next Steps

For the Natural Gas Storage Well Failure risk discussed in this chapter, PG&E plans to continue to mature risk quantification efforts in the following ways:

- Consider equipment related failures as a driver for storage well failure risk;
- Use PG&E data instead of industry data, when possible, to enable more actionable conclusions from risk quantification;
- Refine model inputs. The modeling effort was primarily focused on safety. Given the lack of data to estimate the reliability and financial impacts, the team made assumptions on customer outage and financial costs. For example, the reliability impact is low and may be understated. These model inputs are being assessed and, where possible, PG&E will update these inputs in the future.
- Evaluate and define an appropriate risk reduction metric once baseline assessments are completed; and

- Continue support for the development of the Joint Industry Task Force Storage Risk model and integration with DNV's risk and integrity product. DNV was an awardee of CEC GFO-16-508 research grant.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 9
DISTRIBUTION OVERHEAD CONDUCTOR PRIMARY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 9
DISTRIBUTION OVERHEAD CONDUCTOR PRIMARY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Distribution Overhead Conductor – Primary
IN SCOPE	This risk includes risk drivers and consequences related to failure of or contact with an energized distribution primary conductor.
OUT OF SCOPE	Wildfires caused by wire down events.[1] All Pacific Gas and Electric Company (PG&E or the Company) employee and contractor contact events.[2]
DATA QUANTIFICATION SOURCES	Risk assessment performed using PG&E data, industry data, and subject matter expert (SME) judgement.

The Distribution Overhead Conductor – Primary (DOCP) risk has been on PG&E's risk register since 2013. PG&E's experience and data show that contact with energized conductor can lead to serious injuries or fatalities to the public and third-party contractors. This risk continues to be a top priority to the Company, as demonstrated through ongoing investments in conductor replacement, compliance, and public safety programs.

This filing has been prepared and submitted against the backdrop of catastrophic wildfires that occurred in PG&E's service area beginning on October 8, 2017. Northern California experienced strong wind gusts up to at least 79 miles per hour. These destructive winds, along with millions of trees weakened by years of drought and recent renewed vegetation growth from record winter rains, all contributed to some trees, branches, and debris impacting PG&E's electric lines across northern California.

Given this backdrop, it is important to note that the scope of this risk analysis specifically excludes Wildfire, but DOCP is included as a risk driver to the Wildfire risk analysis.[3] The wildfire-related impacts that may be caused by DOCP assets are addressed in the Wildfire chapter, and not here, to avoid duplication. Further, proposed mitigations that address both DOCP risk and Wildfire risk are included in both chapters,

1 Refer to Wildfire Risk Chapter 11.

2 Refer to Contractor Safety and Employee Safety Chapters 14 and 15, respectively.

3 The "Equipment Failure – Conductor" risk driver included in the Wildfire risk analysis includes wildfires initiated by transmission overhead conductors (TOHC) and distribution overhead conductors.

as appropriate, in an effort to show a comprehensive proposed mitigation plan for each risk (i.e., M5 – Overhang Clearing).

At the time of this filing, wildfire investigations are still underway; however, as with all risks in this filing, PG&E expects to update this analysis, modeling and proposed mitigations when more information becomes available.

To better understand this risk, PG&E used the bow tie methodology to develop a quantitative operational risk model specific to the DOCP risk. The DOCP operational risk model is presented in this chapter and uses a combination of PG&E-specific data, industry data, and SME judgement to gain a better understanding of the risk drivers associated with the risk, the range of consequences, and where to target new mitigations.

As a result of this analysis, PG&E identified two main events that could lead to safety impacts: (1) contact with intact[4] conductors (either directly or via an object); and (2) contact with energized conductors from wire down events. PG&E's analysis shows that 100 percent of contacts with intact conductor result in serious injuries or fatalities; whereas, 0.07 percent of wire down events result in serious injuries or fatalities. Correspondingly, PG&E's public safety controls and targeted mitigation strategy focus on enhancements to public outreach programs to reduce the probability of members of the public contacting intact conductors.

Based on PG&E's historical data, 72 percent of the injury or fatality events related to the DOCP risk were due to contact with intact conductors, with residential customers being involved in 46 percent of those events. PG&E has also experienced approximately 3,000 wire down events per year (based on data collected over the past five years—2012-2016). Vegetation is the single largest cause, making up approximately 42 percent of the wire down events in that timeframe.

Therefore, PG&E's proposed mitigation plan, described later in this chapter, is focused on reducing the safety-related incidents for both contact with intact conductor and wire down events, and the reliability impacts of vegetation caused wire down events.

The risk quantification effort undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process has provided a first step toward using a data driven statistical model to compare DOCP risk investments and guide changes to PG&E's investment plan. As PG&E continues to refine, further evaluate, and analyze the DOCP operational risk

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4 Contact with Intact is defined as any public safety incident where the distribution overhead primary conductor is in its intended position.

model, PG&E will continue to align model outputs with the investment planning process as appropriate.

The DOCP operational risk model also provided insight into the overall consequences of the risk and highlighted the need to differentiate between contact with intact conductor and wire down events. Going forward, PG&E will evaluate the impacts of separating the Contact with Intact driver from the DOCP risk and continue to assess alternatives for reducing wire down events related to vegetation and equipment failures.

II. Risk Assessment

A. Background

The DOCP risk has been a top safety risk since its identification and inclusion into Electric Operation's (EO) risk register in 2013. Mitigating PG&E's exposure to DOCP risk continues to be a priority for EO and PG&E and mitigation plans are reviewed annually. Ongoing investment in public safety programs, conductor replacement and compliance activities demonstrate PG&E's commitment to reducing the DOCP risk. Public contacts with intact conductors continues to be a leading cause of injuries and fatalities associated with this asset as measured by safety incidents reported to the California Public Utilities Commission (CPUC or Commission).[5]

Contact with intact conductor generally occurs when people are working aloft near energized overhead lines, or when working near energized overhead lines with long implements such as ladders, pole trimmers, or in aerial lifts. The main parties involved with third-party contact with intact conductors are:

- Third-party contractors
- Residential customers

Wire down events can be caused by a variety of circumstances such as vegetation knocking a wire down, failure of support structures and connectors, failure of overhead conductor, forces of nature, or third-party interference such as a car-pole accident. Additionally, if wire down events occur in populated areas and remains energized, members of the public could come in contact with the conductor potentially causing significant injuries or death. Extended drought and shifting weather patterns have intensified the challenges associated with minimizing wire down events.

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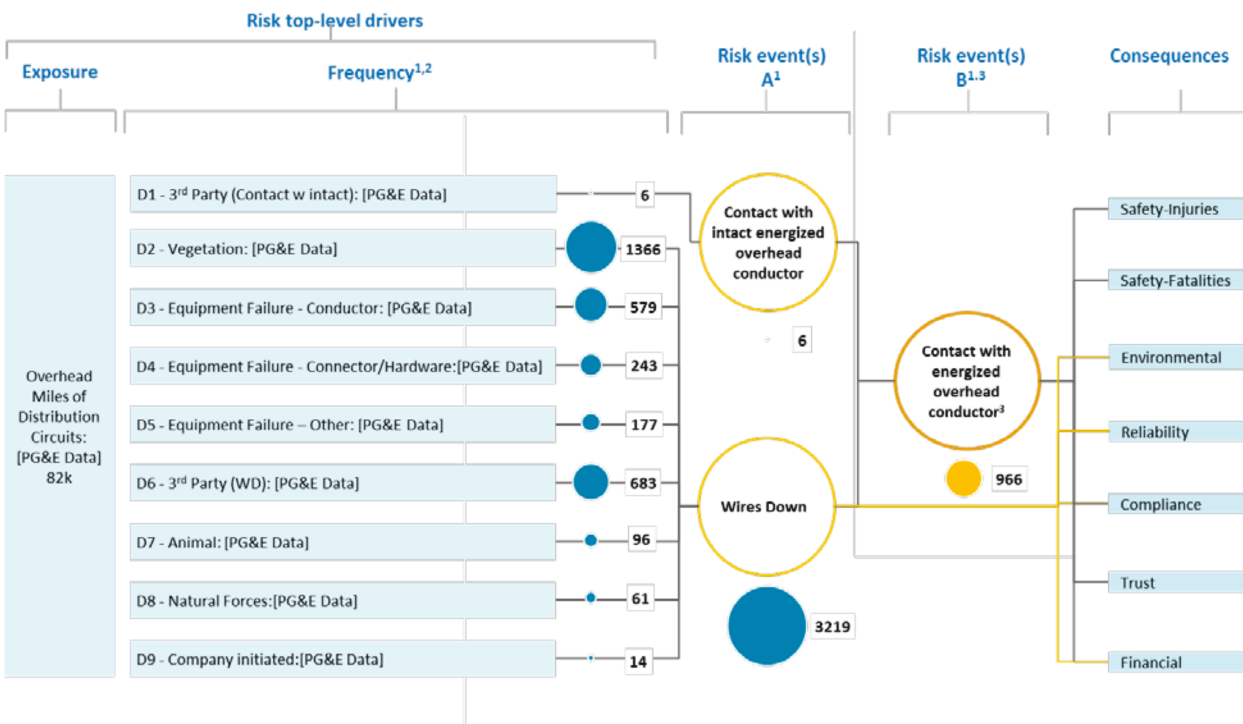
5 CPUC reportable incidents are defined as third-party fatalities or injuries, rising to the level of inpatient hospitalization, attributable or allegedly attributable to contact with energized PG&E-owned electric transmission, substation, and distribution facilities.

The main causes for wire down events are:

- Vegetation
- Equipment Failures – Conductor
- Equipment Failures – Connector/Hardware
- Equipment Failures – Other
- Third-Party Wire Down (WD)

Figure 9-1 provides an overview of the bow tie analysis completed for the two events covered by the DOCP risk and includes the exposure, the risk drivers (including frequencies), the events, and the consequence attributes that were simulated as part of the analysis.

Figure 9-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.
[3]Approximately 100% of D1 and 30% of D2-D9 may potentially remain energized.

B. Exposure

PG&E maintains approximately 82,000 circuit miles[6] of distribution overhead primary conductor. The DOCP risk exposure includes all of PG&E distribution overhead primary conductor, including conductor in designated corrosion zones and fire areas.

C. Drivers and Associated Frequency

PG&E has identified nine top-level risk drivers for the two events associated with the DOCP risk. Similar to the TOHC risk described in Chapter 10, PG&E divides these nine drivers into two sets based on the two distinct events examined when assessing this risk:

1. Contact with intact conductor events (where the overhead conductor is in its intended position); and
2. Wire down events (where the overhead conductor falls on the ground or an object).

For the purpose of modeling this risk, contact with intact events were grouped as a single driver. The model uses PG&E's CPUC reportable data from the years 2012-2016.

- **D1 – Third Party (Contact With Intact):** Incidents where a member of the public came in contact with an intact distribution primary conductor, resulting in fatalities or injuries requiring in-patient hospitalization.[7] This driver includes 28 Third Party Contact with Intact public injury and fatality events from the years 2012-2016[8] involving overhead distribution primary conductor.

Wire down events are incidents where the overhead primary conductor fell from its original intended position. PG&E has categorized each of these events back to the following risk drivers: Vegetation; Equipment Failure; Third Party (WD); Animal; Natural Forces; and Company Initiated incidents. Equipment Failure events are further divided into three drivers that show failures related to conductor, connector/hardware, or other. Equipment failure as a group is the second largest cause of wire down events.[9] By separating equipment failure

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6 The source for the distribution conductor miles is PG&E's Electric Distribution Asset Management Geographic Information System.

7 Employee and contractor events are considered under Employee Safety and Contractor Safety risks.

8 There were 39 total 2012-2016 CPUC public contact events, 28 were due to contact with intact conductors and 11 involved wire down events.

9 During 2012-2016, equipment failures as a group make up approximately 31 percent of PG&E's historical wire down events.

into its subcomponents this approach provides additional granularity which allows PG&E to consider different potential mitigation alternatives, designed to address those specific subcomponents.

PG&E used wire down events data from the previous five years (2012-2016) to analyze this risk. This time period aligns with the implementation of PG&E's wire down metric. Over the five-year period, PG&E has seen a total of 16,123 distribution wire down events. Based on a sample of post event investigations conducted by Distribution Engineers, PG&E estimates that 30 percent of wire down events involved wires that may potentially remain energized for some period during the event. When applying this estimate to the overall number of incidents, PG&E assumes approximately 4,800 of the wire down events that occurred in PG&E's service territory in the past five years may have remained energized for some period during the event and could have had the potential to result in safety related incidents. PG&E uses this estimate in the DOCP operational risk model.

The wire down events drivers are:

- **D2 – Vegetation:** Wire down events caused by vegetation such as trees, tree limbs, and other vegetation. This driver was associated with 6,841 out of 16,123 wire down events from 2012-2016 or approximately 42 percent.
- **D3 – Equipment Failure – Conductor:** Wire down events due to conductor failures. This driver was associated with 2,901 out of 16,123 wire down events from 2012-2016 or approximately 18 percent.
- **D4 – Equipment Failure – Connector/Hardware:** Wire down events due to connector or splice failures. This driver was associated with 1,216 out of 16,123 wire down events from 2012-2016 or approximately 7.5 percent.
- **D5 – Equipment Failure – Other:** Wire down events due to all other overhead equipment failures such as transformers, cross-arms, poles, etc. This driver was associated with 887 out of 16,123 wire down events from 2012-2016 or approximately 5.5 percent.
- **D6 – Third Party (Wire Down):** Third party caused wire down events from vehicles, metallic balloons, vandalism, etc. This driver was associated with 3,420 out of 16,123 wire down events from 2012-2016 or approximately 21 percent.
- **D7 – Animal:** Wire down events caused by animals such as birds or squirrels. This driver was associated with 481 out of 16,123 wire down events from 2012-2016 or approximately 3 percent.

- **D8 – Natural Forces:** Wire down events caused by earthquakes, lightning, flood, ice or snow, etc. This driver was associated with 307 out of 16,123 wire down events from 2012-2016 or approximately 2 percent.
- **D9 – Company Initiated:** Wire down events caused by PG&E employees based on improper construction, operating error, or other actions. This driver was associated with 70 out of 16,123 wire down events from 2012-2016 or less than 1 percent.

D. Consequences

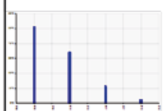
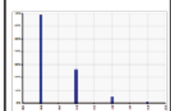
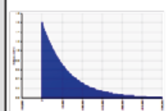
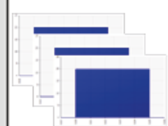
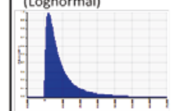
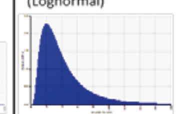
Contact with intact conductor historically has resulted in more severe safety consequences (injuries or fatalities) than wire down events and represent the majority of the safety portion of the Multi-Attribute Risk Score (MARS) associated with the DOCP risk. Wire down events happen much more frequently than contact with intact conductor events (annual average of 3,224 as compared to 6) but generally result in power outages, not safety events.

Over the last 5 years (2012-2016), there have been 39 public contact events meeting the CPUC's reporting criteria involving PG&E's overhead distribution primary conductor. A total of 28 resulted from contact with intact conductors.

- 14 of the 39 total events resulted in fatalities. Of the 14 fatal incidents, 8 were due to contact with intact conductor; and 6 involved wire down events. For the wire down events; 3 involved vehicles where the fatality occurred after the occupant exited the vehicle, the other 3 involved a metal road, gunshot, and a bird that caused the distribution primary conductor to fall to the ground.
- The remaining 25 events resulted in injuries requiring in-patient hospitalization, 20 of which were due to contact with intact conductor; and 5 involved wire down events. For the wire down events; 3 involved vehicles and the other 2 related to vegetation and a bird that caused the distribution primary conductor to fall to the ground.

Figure 9-2 shows the range of consequences and the attributes that help describe the tail average (i.e., the average of the worst 10 percent of all outcomes) and the associated MARS.

Figure 9-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	CPUC Data	CPUC Data	NA	PG&E Data	NA	PG&E Data and SME Input	PG&E and Claims Data
Consequence Distributions	Safety consequences are only on OHC that stay energized Percent of events with an injury=0.81% Mean=0.67 (Poisson) 	Safety consequences are only on OHC that stay energized Percent of events with a fatality=0.81% Mean=0.38 (Poisson) 	Covered in the wildfire risk model	Percent of OHC events with resulting in an outage=99.7% Ave duration of outage=62k min (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=6-10% Severe=2.5-6% Low=0-2.5% (Uniform) 	Restoration costs results from all OHC events: Ave=$11k Std Dev=$13k Shift=-$0.4k (Lognormal)  + Compensatory claims from OHC events that stay energized: Ave=$4.1M Std Dev=$3.3M Shift=$65k (Lognormal) 
Outcome-TA-NU[1]	11.11	7.07		209,056,881		9.78%	$94,814,643
Outcome-TA-MARS[2]	3.03	192.89		522.64		48.90	56.89
						MARS Total	824.35

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** Safety consequences are applied to the overhead conductor events that stay energized. As an input into the model, PG&E is using the CPUC reportable public contact events involving distribution overhead primary conductor, for the years 2012-2016. Based on this data, the percent of events with injuries or fatalities are 0.81 percent with a mean value of 0.67 injuries per event. This resulted in a tail average of 11.11 injuries a year and a contribution of 3.03 MARS units for this consequence category.
- **Safety – Fatalities (SF):** Safety consequences are applied to the overhead conductor events that stay energized. As an input into the model, PG&E is using the CPUC reportable public contact events involving distribution overhead primary conductor, for the years 2012-2016. Based on this data, the percent of events with injuries or fatalities are 0.81 percent with a mean value of 0.38 fatalities per event. This resulted in a tail average of 7.07 fatalities a year and a contribution of 192.89 MARS units for this consequence category.
- **Environmental (E):** Environmental impacts are excluded from this risk as they are being measured with PG&E's Wildfire risk.
- **Reliability (R):** As an input into the model, PG&E is using outages (PG&E customer minutes out) tracked within PG&E's wires down database involving distribution overhead primary conductor for the years 2012-2016. The data shows that the impact was approximately

62,000 customer minutes per outage event. This resulted in a tail average of approximately 209 million customer minutes out a year and a contribution of 522.64 MARS units for this consequence category.

- **Compliance (C):** Per CPUC requirements, monetary fines and penalties associated with notice of violations are not included as they are shareholder costs.
- **Trust (T):** Events are dependent on safety outcomes, both injury and fatalty, as categorized as: low, severe, and high. This methodology was used across all risks.[10] For this risk, PG&E assumed approximately half of the impact based on SME judgement. This approach resulted in high severity bounds of 6-10 percent, severe bounds of 2.5-6 percent, and a low bound of 0-2.5 percent. This calculated a tail average of 9.78 percent reduction a year and a contribution of 48.90 MARS units for this consequence category.
- **Financial (F):** Financial impacts related to public contact events were determined using two factors, historical industry insurer data to approximate potential litigation claims exposure and 2016 average cost for overhead conductor replacement jobs to approximate wire down events restoration costs. The average value of restoration costs was calculated to be $10,560 per event. To ensure a large enough sample of compensatory claims, PG&E used national insurer data from 1983-2010 which included 127 claims. Claims included both contact with intact and wire down events. The average financial settlement per claim was approximately $4.1 million, equating to over $500 million in claims over the 27-year period. This resulted in a tail average of approximately $95 million a year and a contribution of 56.89 MARS units for this consequence category.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

PG&E has in place eleven controls for this risk ranging from Public Awareness programs to capital replacement of overhead conductor.

Wire down events result when an overhead conductor fails for any number of reasons. In most instances, protective devices will automatically de-energize the conductor. However, approximately 30 percent of the time, conductors may remain energized for at least some amount of time after the wire falls and pose a potential public safety risk. This risk is mitigated primarily by addressing the condition of the conductor before a failure occurs. Other controls include reliability related work such as the targeted circuit program and the installation of overhead protective devices. While this work is primarily intended to improve reliability, it also reduces the safety risk. For example,

10 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

targeted circuit work can involve replacing distribution wood poles, distribution system components and overhead primary conductor. Protective devices de-energize portions of the distribution system when failures occur, which limits the exposure of the public to a potentially hazardous condition.

Each of the controls described in this section manages one or more drivers of the DOCP risk.

C1 – 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. They are intended to reduce the number of third-party electrical contacts. This control has the potential to reduce exposure to Third-Party (Contact with Intact) (D1), Third-Party (Wire Down) (D6) drivers and the consequences related to Safety Injuries (SI) and Fatalities (SF). This program consists of the following outreach efforts describing the hazards associated with working around power lines:

- Third-Party Tree Workers Program: Communications targeting 11,000+ companies with operations within PG&E's service territory.
- Orchard Safety Worker 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.
- Worker Beware Program: Communications targeting 99,000+ third-party contractors within PG&E's service territory. Includes direct mailings of safety material, offers of additional complimentary safety and training materials.

C2 – Vegetation Management: PG&E's Vegetation Management Program supports public safety, service reliability and regulatory compliance through management of vegetation near PG&E's electric distribution facilities. Vegetation Management work includes routine inspections of overhead distribution lines to identify trees that need pruning or removal to reduce contact with conductors and thus reduce Wildfire and DOCP risks. The Public Safety and Reliability (PS&R) vegetation management program is part of the broader Vegetation Management control and focuses on the trimming and removal of vegetation that is in compliance with regulatory clearance requirements; however, due to tree characteristics, represents an increased wire down events, outage and reliability risk. PG&E uses a programmatic, circuit-based approach to patrolling and addresses any tree that is determined to have the potential to grow or fail into the overhead conductors by the next annual cycle. Additional inspections are conducted to address wildfire risk as described further in Chapter 11. This program focuses on compliance with applicable regulatory requirements and results in approximately 82,000 line miles of overhead primary distribution conductor being inspected and approximately 1.2 million trees addressed annually. This control has the potential to reduce the Vegetation (D2) driver.

C3 – Catastrophic Event Memorandum Account (CEMA) Vegetation Management: Due to lingering impacts of drought and the resulting levels of tree mortality (in November 2016, the U.S. Forest Service reported upwards of 102 million trees died in the California forest), CEMA captures costs intended to address the vegetation impacts associated with the ongoing tree mortality state of emergency.[11]

The inspection and subsequent tree work helps to prevent trees from coming in contact with overhead conductors. This work decreases the likelihood of vegetation caused wire down events. This control has the potential to reduce the Vegetation (D2) driver.

C4 -–Overhead Electric Distribution Preventive Maintenance: PG&E's Maintenance and Construction (M&C) organization builds new facilities in accordance with engineering specifications and uses a construction checklist to confirm the specifications are met. M&C also repairs and replaces deteriorated facilities as deemed necessary through the patrol and inspection process. Work identified by patrols and detailed inspections that does not need to be addressed within 24 hours is planned and scheduled in accordance with its assigned priority level. Priority levels are determined based on the probability and impact of the asset failure, and defined in PG&E's Electric Distribution Preventative Maintenance (EDPM) manual.[12] This control has the potential to reduce the Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), and Equipment Failure – Other (D5) drivers.

C5 – Overhead Conductor Replacement Program: The overhead conductor replacement program targets conductor spans 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 environmental areas. In addition, the program includes post wire down event investigations to identify the cause and equipment involved with the wire down events and splice data reviews to support identification of future replacement projects. This control has the potential to reduce the Equipment Failure – Conductor (D3) and Equipment Failure – Connector/Hardware (D4) drivers.

C6 – Overhead Patrols and Inspections: Visual patrols of overhead distribution facilities are performed annually in urban[13] areas and every other year in rural[14] areas, to

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11 Governor proclamation of a state of emergency on tree mortality October 30, 2015 and CPUC resolution ESRB-4, dated June 16, 2014 directed Investor Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.

12 EDPM manual is a resource handbook that details PG&E distribution preventative maintenance practices around patrols and inspections.

13 "Urban" shall be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.

identify obvious structural problems or hazards for compliance with General Order (GO) 165[15] and PG&E's manual. Patrolled facilities include primary, secondary, and service drops, and other associated electric distribution facilities outside the substation fence to the end of the line. Steel towers supporting only distribution facilities are included in the overhead patrol program. Patrols can be performed from a vehicle, on foot, or by helicopter.

Detailed inspections of other overhead distribution facilities are performed every five years to examine and record abnormal conditions that could potentially impact safety or reliability in compliance with GO 165 and PG&E's EDPM manual. Inspected facilities include PG&E solely and jointly owned poles, including all equipment and facilities on the pole, primary and secondary risers and services, primary and secondary conductor, transmission poles with distribution underbuilds, distribution towers and lattice steel structures, streetlights on PG&E solely owned or joint poles, and primary metering. This control has the potential to reduce the Vegetation (D2), Equipment Failure - Conductor (D3), Equipment Failure – Connector/Hardware (D4), and Equipment Failure – Other (D5) drivers.

C7 – Overhead Infrared Inspections: The infrared inspection program targets the physical inspection of overhead conductors using infrared thermographic technology to identify conductor anomalies as evidenced by excessive component heating. Conductor anomalies can occur when conductors and/or connectors have been damaged or have deteriorated below their original ratings and exhibit increased resistance to power flows. Infrared inspections also include identifying and recording the location and number of splices that exist on the distribution overhead primary conductors for future use in evaluating system risk and prioritizing conductor replacement projects. Both types of data collected are key indicators of increased probability of conductor failures. This control has the potential to reduce the Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), and Equipment Failure – Other (D5) drivers. The program includes the following three components:

- Annual infrared inspection prior to fire season in the Urban Wildland Fire (UWF) and Other Wildland Fire (OWF) designated areas.

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14 "Rural" shall be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census.

15 CPUC GO 165 establishes requirements for electric distribution and transmission facilities (excluding those facilities located in substations) regarding inspections in order to ensure safe and high-quality electrical service.

- Infrared inspection of select circuits with the goal to complete PG&E's entire overhead distribution system by the end of 2019. All conductor anomalies are corrected through the maintenance process.
- Splice Data Collection. The number of splices on each span is identified and uploaded into PG&E's Geographic Information System where the data can be used to inform the conductor replacement program.

C8 – Targeted Circuits Program: PG&E's Targeted Circuits Program was initiated in 2009 to address the Company's worst performing circuits from a customer reliability perspective. The program focuses on those circuits which experience disproportionate number of customer interruptions and customer outage minutes based on a 3-year average. In order to continue to improve PG&E's electric distribution system reliability, continued reliability improvement for the worst performing circuits is essential. Since the inception of the Targeted Circuits Program, PG&E has completed work on 407 circuits (compared to approximately 3,200 distribution circuits in the system). Distribution engineers analyze the causes and characteristics of historical outages as well as circuit design to identify targeted work that will improve reliability. Typically, the work involves a combination of new fuse and line recloser installations, conductor replacements, installation of fault indicators, reframing poles to increase phase separation, installation of animal/bird guards, repairing or replacing equipment, completing reliability related maintenance tags, performing infrared inspections, and additional targeted vegetation management. This control has the potential to reduce the Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), and Equipment Failure – Other (D5) drivers.

C9 – 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 provides benefits through improved operating efficiency, enabling better outage response and diagnosis, improving system protection, and improving employee and public safety by enabling PG&E to automatically and remotely shut off electricity during emergencies. The work activities associated with system automation can also improve public and electric system safety through remote and faster operation of electric facilities. For example, the ability to de-energize lines remotely can reduce the risks associated with identified wire down events. This control has the potential to reduce the Vegetation (D2), Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), Equipment Failure – Other (D5) drivers, and Third-Party (Wire Down) (D6) drivers.

C10 – 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 Vegetation (D2), Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), Equipment Failure – Other (D5) drivers, and Third-Party (Wire Down) (D6) drivers.

C11 – 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, overhead line equipment and conductors can fail as a result of an overload. In most instances, protection devices will de-energize the facilities. However, when overloaded line equipment and conductors fail, service reliability is reduced and customers will be out of service until line reconfiguration can occur or the line is repaired. These effects are mitigated by addressing the potential overload condition before it occurs. The work in the capacity program generally involves installing and/or replacing both substation and distribution line facilities. Line capacity work can mitigate substation risks (e.g., enabling field switching to reduce loading on a substation transformer) and substation work can mitigate line risks (e.g., establishing a new circuit position in a substation can facilitate field switching to reduce load on line conductors). Some projects in the capacity program can also result in conductor replacement of overhead lines. This control has the potential to reduce the Equipment Failure – Conductor (D3), Equipment Failure – Connector/Hardware (D4), and Equipment Failure – Other (D5) drivers.

Table 9-1 below summarizes the controls and 2016 recorded costs associated with each control.

Table 9-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Public Awareness Programs	D1, D6, SI, SF	GRC TO	225 109[16]	–
C2	Vegetation Management	D2	GRC	200,115[17]	–
C3	CEMA Vegetation Management	D2	CEMA	190,204	–
C4	Overhead Electric Distribution Preventive Maintenance	D3, D4, D5	GRC	14,697	58,514
C5	Overhead Conductor Replacement Program	D3, D4	GRC	–	31,858
C6	Overhead Patrols and Inspections	D2, D3, D4, D5	GRC	15,678	–
C7	Overhead Infrared Inspections	D3, D4, D5	GRC	3,625[18]	–
C8	Targeted Circuits Program	D3, D4, D5	GRC	–	35,317
C9	Supervisory Control and Data Acquisition	D2, D3, D4, D5, D6	GRC	–	57,789
C10	Annual Protection Reviews	D2, D3, D4, D5, D6	GRC	9,650	–
C11	Electric Distribution Line and Equipment Capacity	D3, D4, D5	GRC	–	13,581
TOTAL Expense and Capital				**243,990 (GRC) 190,204 (CEMA) 109 (TO)**	**197,059 (GRC)**

In addition to the existing control programs described above, PG&E is currently developing supporting technologies that have the potential to further improve the effectiveness of the controls when fully deployed. Below is a summary of those key projects under development.

System Tool for Asset Risk (STAR) is a technology under the development which when fully implemented will provide asset replacement direction for Overhead Conductor Replacement Program (C5). Each asset will receive a risk score that considers the

16 Orchard Safety Worker Program and a portion of the Worker Beware Program are funded by Transmission Operations, the 2016 costs totaled $48,163 and $61,000, respectively.

17 Third-Party Tree Worker Program and Mind the Lines campaign are funded through Vegetation Management, the 2016 costs totaled $95,000 and $5,000, respectively.

18 The overhead infrared inspection program costs are a part of the overhead patrols and inspection programs (C6), however for the purpose of this chapter, they are presented separately since it is an existing mitigation for the DOCP risk.

probability of failure (based on asset health factors) and the resulting consequences (based on the function and location of the asset.) Highest risk assets will then be prioritized for replacement.

Initial uses of STAR[19] are focused on programs for evaluating the benefits of additional pole and conductor replacements, as well as optimization of inspection cycles based on health and risk. Future STAR uses may include addition of more electric asset classes, or focus on different programs (e.g., vegetation management) so that STAR can be used to target assets with the most effective programs to mitigate the risks specific to each asset.

Vegetation Management Data Enablement is a technology that will support and enhance the existing Vegetation Management control (C2). Overhead lines are presently inspected at least annually by inspectors driving and walking the lines. The Electric Vegetation Management department has acquired remote sensing data (LiDAR,[20] video, orthoimagery, etc.) in recent years to improve transmission and distribution routine maintenance, inspection, reliability and wildfire mitigation activities by providing more accurate baseline data to enable managers to see how vegetation interacts with other risk factors such as asset health and failure probability. This ability to see the convergence of multiple risk drivers holds promise for enhancing PG&E's operational risk models

Approximately 31 percent of the 2012-2016 wire down events occurred on designated storm days.[21] The Storm Outage Prediction Project (SOPP) model is a storm damage prediction system. The model allows PG&E to properly prepare and respond to storm events. With proper staffing and resource preparations made ahead of a storm, restoration and 911 response time can be greatly improved, allowing for faster mitigation of events. The aim of the SOPP Objective Upgrade technology project is to improve and automate the SOPP model, which will give PG&E the advanced knowledge of how assets will be damaged in a wide variety of storm scenarios and incorporate grid resiliency investments.

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19 Initial asset classes (Distribution Poles and OH Primary Conductor, Substation Transformers and Breakers) were selected based on volume, data availability, and historical replacement costs.

20 LiDAR—Light Detection and Ranging—is a surveying method that measures distance to a target by illuminating that target with a pulsed laser light, and measuring the reflected pulses with a sensor.

21 Storm day is defined as a weather-day with more than 90 unplanned sustained outages with a daily System Average Interruption Duration Index impact greater than 6.2 minutes.

IV. Current Mitigation Plan (2017-2019)

The mitigations planned for 2017-2019 are listed below.

- **M1 – Overhead Infrared Inspection:** The 2017-2019 mitigation plans include continuation of the infrared inspection program targeting approximately 12,500 circuit miles a year to complete the entire distribution overhead primary conductor system by the end of 2019. With the completion of the program, PG&E will have a complete inventory of the number of splices within the distribution overhead primary conductor system and identification of the health of each span. The data collected will help prioritize and target the conductors with the highest potential for failure and may reduce the number of wire down events related to Equipment Failure drivers (D2, D3, D4).
- **M2 – Public Awareness Programs:** The 2017-2019 mitigation plans include the continuation of the annual Worker Beware Public Awareness program targeting third-party contractors, additional social media distributions for the Mind-the-Lines campaign, and inclusion of electric safety messaging into existing gas public outreach programs targeting homeowners associations and landscaping companies. The increased number of public outreach messages distributed to third-party contractors and residential customers may reduce the number of Third-Party Contact with Intact events (D1) or Third-Party (Wire Down) contact events (D6).
- **M3 – Additional Public Awareness Outreach:** This mitigation represents an addition to PG&E's existing public awareness (C1) portfolio discussed in the controls and 2017-2019 mitigation work section (M2) above. The mitigation creates additional safety material warning residential customers of the dangers related to wire down events and informs them of the hazards associated with performing activities around intact overhead conductors. The material will be distributed in paper form and electronically within a monthly bill prior to the beginning of summer each year. Adding additional bill inserts to the public awareness portfolio would increase 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 (D1) and the exposure related to the Third-Party (Wire Down) contact events (D6). Effectiveness of this mitigation would be measured primarily through monitoring of injury and fatality reportable incidents to the CPUC. This mitigation is shared with the TOHC risk, and costs are split evenly between the two risks.
- **M5 – Overhang Clearing:** The Overhang Clearing mitigation performs clearing of vegetation above overhead distribution primary conductors to reduce the chances of a branch falling on the line leading to wire down events. Branch caused outages represent approximately 24 percent of vegetation caused outages historically. Of the branch caused outages, approximately 70 percent were due to overhanging

branches. The mitigation includes approximately 24,000 miles of overhang clearing over a 5-year period in high wildfire risk areas[22] from 2018 and 2022.

This mitigation is also part of the Wildfire risk proposed plan.[23] By targeting the overhang clearing in designated high risk wildfire areas the proposed mitigation could potentially mitigate both risks by reducing the chances of vegetation caused wired down events and the possibility of fire ignitions. That is why the same mitigation is included in both chapters. This chapter describes the assumed effectiveness and corresponding RSE as it relates the DOCP risk.

Table 9-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1	Infrared Inspection	2017	2019	D3, D4, D5	– (C) 1,969 (E)	– (C) 2,083 (E)	– (C) 2,151 (E)
M2	Public Awareness Programs	2017	2019	D1, D6, SI, SF	– (C) 250 (E)	– (C) 258 (E)	– (C) 267 (E)
M3	Additional Public Awareness Outreach	2018	2022	D1, D6, SI, SF	– (C) – (E)	– (C) 40 (E)	– (C) 40 (E)
M5	Overhang Clearing	2018	2022	D2	– (C) – (E)	– (C) 17,280[24] (E)	– (C) 17,280 (E)
TOTAL Expense (E) and Capital (C) by Year					**– (C) 2,219 (E)**	**– (C) 19,661 (E)**	**– (C) 19,738 (E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for DOCP risk. All mitigations considered are listed below:

- **M3 – Additional Public Awareness Outreach:** This mitigation is a continuation of the current mitigation as described in Section IV.
- **M4 – Distribution Right of Way Clearing:** The Distribution right-of-way clearing mitigation aims to establish a 20 foot right-of-way around targeted portions of overhead distribution primary conductors, which reduces the probability of vegetation caused wire down events. Approximately 42 percent of PG&E's historical

22 The approximately 24,000 circuit miles represent all of the draft July 31 2017 Fire Map 2 elevated and extreme areas.

23 Refer to Wildfire Chapter 11, Mitigation M4.

24 2018-2019 overhang clearing work will utilizing existing resources by re-prioritizing the current vegetation management PS&R Program. 2020-2022 will be incremental work focused solely in Wildfire areas in addition to the previously planned PS&R work.

wire down events from 2012-2016 were related to trees or branches falling into overhead distribution primary conductors. This mitigation includes 165 miles of right-of-way clearing per year for 2020-2022. The program would target the circuits with the highest historical vegetation caused outages due to wire down events in PG&E's system during 2012-2016.

As part of the Wildfire risk, one of the proposed mitigations is also related to reducing vegetation near targeted portions of overhead distribution lines (Fuel Reduction and Powerline Corridor Management(WF)).[25] However, the proposed Wildfire risk mitigation targets the work in designated high risk wildfire areas rather than the circuits with the highest historical vegetation caused outages due wire down events. The different target areas required different approaches when calculating the potential effectiveness of the risk mitigation and the corresponding RSEs. Although the proposed mitigation for Wildfire risk targets different areas it does also have the potential to benefit the DOCP risk by reducing vegetation caused wire down events in the areas cleared.

- **M5 – Overhang Clearing:** This mitigation is a continuation of the current mitigation as described in Section IV.
- **M6 – Targeted Conductor Replacement (#4 Aluminum Conductor Steel-Reinforced (ACSR) in Corrosion Zones):** This mitigation would target #4 ACSR distribution primary conductors in designated corrosion zones for replacement, reducing the probability of wire down events due to equipment failures. Over the 5-year period 2012-2016, equipment failures due to conductor or connectors make up approximately 26 percent of PG&E's historical wire down events (second largest category behind Vegetation (42 percent)). Based on PG&E's historical data, the failure rate per 100 miles of #4 ACSR in corrosion zones is 4.25 times higher than the system average. This mitigation would significantly increase the amount of conductor replacement by adding an additional 210 circuit miles per year[26] specifically targeting #4 ACSR in corrosion zones.

As part of the Wildfire risk one of the proposed mitigations is also related to Targeted Conductor Replacement (WF),[27] however it targets the work in designated high risk wildfire areas rather than specifically #4 ACSR in corrosion zones. The different target areas required different approaches when calculating the potential effectiveness of the risk mitigation and the corresponding RSEs. Although the proposed mitigation for Wildfire risk targets different areas it does also have the potential to benefit the DOCP risk by reducing wire down events in the areas worked.

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25 Refer to Wildfire Chapter 11, Mitigation M3.

26 PG&E proactively replaces approximately 90 miles of distribution overhead conductor a year.

27 Refer to Wildfire Chapter 11, Mitigation M7.

- **M7 – Targeted Underground Conversion:** The targeted underground conversion mitigation would convert overhead primary distribution conductor to underground primary conductor, and hence remove any opportunity for wire down events or contact with intact events associated with overhead primary distribution conductor on the circuit miles converted. However, this comes at a significantly higher cost. This mitigation includes 50 circuit miles of targeted underground conversion per year from 2020-2022. The program would target the circuits with the highest historical vegetation caused outages in PG&E's system.

PG&E's proposed 2020-2022 mitigation plan consists of the **Additional Public Awareness Outreach (M3)** and **Overhang Clearing (M5)** mitigations.

Infrastructure mitigations such as targeted conductor replacement or underground conversion show relatively low RSEs in part because the model does not fully factor the benefits over the life of the investment,[28] extending beyond the 2020 General Rate Case (GRC) period.

PG&E considered the RSE of each of the programs but also considered work execution constraints, long-term benefits and long-term overall costs of each option when making the final decision to select the following mitigation actions for the proposed plan:

- **M3 – Additional Public Awareness Outreach:** This mitigation has the potential for reducing Third-Party (Wire Down) contact events (0.58 percent calculated effectiveness)[29] (D6), Third-Party Contact with Intact events (1.08 percent calculated effectiveness) (D1), and minimizing the safety consequences (injury/fatality) related to car-pole incidents involving energized lines (0.33 percent calculated effectiveness) (SI, SF). For PG&E, contact with intact overhead conductors events make up 72 percent of all electric CPUC reportable events with residential customers being involved in 46 percent of those events.

  This mitigation would begin in the spring 2018, and would continue each following year. Analysis of the impact of this mitigation would rely primarily on metrics tracking fatalities and injuries reportable to the CPUC. Further methods to measure impact and effectiveness, such as customer surveys, may be developed in the future.

In 2015, the Worker Beware Program was implemented as part of the broader Public Awareness program to focus on providing safety messages and training material for third-party contractors. The program was implemented to target the second largest category for CPUC reportable events. The random nature and circumstances that can lead to a public contact event make it difficult to predict future occurrences. This

28 Refer to Risk Model Overview section for details.

29 Refer to WP 9-2 for details of the effectiveness calculation.

combined with the size of PG&E's service territory requires a messaging approach that can reach a large number of PG&E's customers at one time. Residential customers continue to be one of the most at-risk stakeholders when it comes to contact with intact events. The bill inserts would represent an expansion of PG&E's existing electric public awareness outreach programs described above. PG&E believes that combining this program with the existing customer safety and education initiatives (C1) provides another opportunity to communicate public safety messages and assist in increasing awareness around the hazards associated with contact with PG&E's overhead lines at a relatively low cost.

- **M5 – Overhang Clearing:** This mitigation has the potential for reducing Vegetation caused wire down events (16.92 percent calculated effectiveness)[30] (D2). For PG&E, Vegetation makes up 42 percent of the historical (2012-2016) wire down events involving distribution overhead primary conductor.

As mentioned above, this mitigation is the same mitigation that is in the Wildfire Risk proposed plan. The mitigation would begin in 2018, and would continue each following year. Analysis of the impact of this mitigation would rely primarily on metrics tracking distribution wire down events caused by vegetation. Table 9-3 summarizes the mitigations, associated drivers, RSEs, and associated costs for each year covered by the 2020 GRC. The funding for the Additional Public Awareness program will be split equally between Transmission and Distribution Operations since it supports both overhead conductor risks[31] while the Overhang Clearing mitigation would be solely funded by Distribution Operations because it focuses only distribution lines.

30 Refer to WP 9-10 for details of the effectiveness calculation.

31 The total program cost is approximately $80,000 a year with Transmission and Distribution Operations each funding $40,000 a year.

Table 9-3: Proposed Mitigation Plan and Associated Costs[32]

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Drivers & Consequences	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M3	Additional Public Awareness Outreach	21.133	18.335	2020	2022	D1, D6, SI, SF	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
M5	Overhang Clearing	0.490	0.459	2020	2022	D2	– (C) 13,824 – 20,736 (E)	– (C) 13,824 - 20,736 (E)	– (C) 13,824 - 20,736 (E)
TOTAL PROPOSED PLAN TA RSE: 0.538 **TOTAL Expense and Capital by Year**							**– (C) 13,862 - 20,778 (E)**	**– (C) 13,862 - 20,778 (E)**	**– (C) 13,862 - 20,778 (E)**

VI. Alternatives Analysis

After assessing all of the mitigations, PG&E has two alternative plans to the proposed mitigation plan. Alternative Plan 1 was created to include a mitigation to address each of the three top drivers to the risk, Third-Party Contact with Intact conductor (D1), Vegetation caused wire down events (D2), and Equipment Failure caused wire down events (D3-D5). Alternative Plan 2 was created to include all dissimilar alternative mitigations[33] (M3, M4, M5, M6, M7). Both alternative plans considered and the proposed plan are shown in Table 9-4.

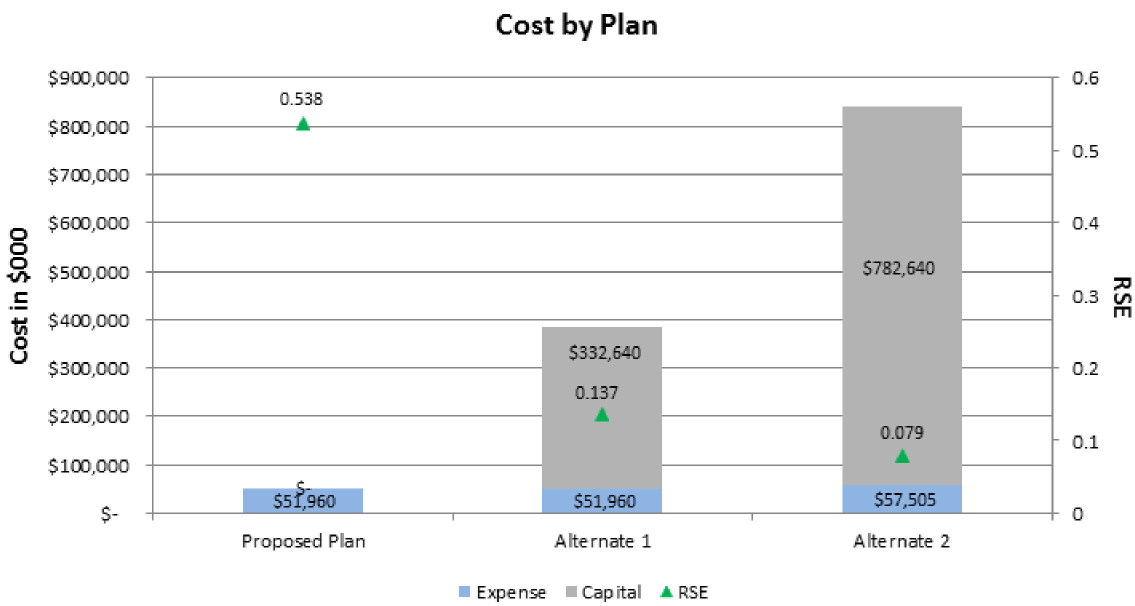
Table 9-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M3	Additional Public Awareness Outreach	21.133	18.335	x	x	x	WP 9-2
M4	Distribution Right-of-Way Clearing	0.413	0.389			x	WP 9-6
M5	Overhang Clearing	0.490	0.459	x	x	x	WP 9-10
M6	Targeted Conductor Replacement (#4 ACSR in Corrosion Zone)	0.033	0.031		x	x	WP 9-14
M7	Targeted Underground Conversion	0.021	0.020			x	WP 9-18

32 Proposed mitigation plan costs are listed without escalation. In the 2020 GRC, values will be adjusted to include escalation.

33 PG&E also evaluated two additional Targeted Conductor Replacement mitigations that would focus solely on #4 copper and #6 copper overhead primary conductors in corrosion zones respectively. However, when comparing, the results of three similar alternative mitigations, the mitigation targeting #4 ACSR had the largest RSE and therefore the 2 copper conductor mitigations were not included in any of the mitigation plans.

Figure 9-3: Alternatives by Cost[34] and RSE Score



A. Alternative Plan 1

PG&E's Alternative Plan 1 considered for DOCP risk includes a mitigation to address each of the top three risk drivers (Third-Party Contact with Intact, Vegetation and Equipment Failure caused wire down events).

The Additional Public Awareness Outreach mitigation (M3) in PG&E's Alternative Plan 1 maintains the same scope and cost as in the proposed plan.

The incremental vegetation Overhang Clearing mitigation (M5) in PG&E's Alternative Plan 1 maintains the same scope and cost as in the proposed plan.

To minimize equipment failures related to conductor or connector caused wire down events, PG&E calculated the value of increasing the annual volume of replaced overhead primary conductor. Wire down events related to conductor or connector failures is the second largest risk driver, behind vegetation, making up an average of 26 percent of the annual wire down events. For this alternative plan PG&E considered increasing the annual target of overhead conductor replacement by 210 additional miles a year, tripling the current annual targets for the program. The additional miles would solely focus on size #4 ACSR in corrosion zones which has a 4.25 times greater likelihood of failure per 100 miles when compared to the system average. This alternative plan would require an additional $110.9 million annually, beginning in 2020. The alternative mitigation

34 Total cost over the life of the mitigations in each respective plan.

plan was deemed not viable based on the low expected RSE and the need for the program to replace conductor related to other prioritization factors.[35]

Due to the low total RSE for this alternative plan and the proposed conductor replacement projects within the Wildfire risk, additional conductor replacement focused solely on #4 ACSR in corrosion zones were not deemed reasonable at this time. PG&E will incorporate the prioritization methodologies developed during the RAMP process where applicable to the existing programs while continuing to evaluate opportunities to reduce equipment failure caused wire down events and improve risk quantification efforts.

Table 9-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M3	Additional Public Awareness Outreach	21.133	18.335	2018	2022	D1, D6, SI, SF	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
M5	Overhang Clearing	0.490	0.459	2018	2022	D2	– (C) 13,824 - 20,736 (E)	– (C) 13,824 - 20,736 (E)	– (C) 13,824 - 20,736 (E)
M6	Targeted Conductor Replacement (4 ACSR in Corrosion Zone)	0.033	0.031	2020	2022	D3, D4	105,336 - 116,424 (C) – (E)	105,336 - 116,424 (C – (E)	105,336 - 116,424 (C) – (E)
TOTAL ALTERNATIVE PLAN 1 TA RSE: 0.137 **TOTAL Expense and Capital by Year**							**105,336 - 116,424 (C)** **13,862 - 20,778 (E)**	**105,336 - 116,424 (C)** **13,862 - 20,778 (E)**	**105,336 - 116,424 (C)** **13,862 - 20,778 (E)**

B. Alternative Plan 2

PG&E's Alternative Alan 2 considered for DOCP risk includes all dissimilar mitigations to address the top three risk drivers (Third-Party Contact with Intact, Vegetation and Equipment Failure caused wire down events).

The Additional Public Awareness Outreach mitigation (M3) in PG&E's Alternative Plan 2 maintains the same scope and cost as in the proposed plan.

The incremental vegetation Overhang Clearing mitigation (M5) in PG&E's Alternative Plan 2 maintains the same scope and cost as in the proposed plan.

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[35] The current Overhead Conductor Replacement Program prioritization factors include: splice count, wire down history, fault duty, location (corrosion or wildfire zone), and wire type.

The increase in Targeted Conductor Replacement of #4 ACSR in corrosion zones mitigation (M6) in PG&E's Alternative Plan 2 maintains the same scope and cost as in Alternative Plan 1.

To further reduce the number of potential future vegetation caused outages, PG&E calculated the value in establishing a new 20-foot right-of-way around targeted portions of overhead primary distribution lines. During 2012-2016, 579 out of 6841 (8.46 percent) vegetation caused wire down events involved trees located within nine feet of the primary conductor. PG&E would establish the right-of-way around the most historically impacted line segments targeting 165 miles a year.[36] The initial cost to establish the right-of-way would be approximately $10,000 a mile, with future maintenance costs estimated to be approximately $1,200 a mile. Due to the low total RSE for this alternative plan and the proposed Fuel Reduction and Powerline Corridor Management projects within the Wildfire risk, additional right-of-way clearing focused solely in the circuits with the highest historical vegetation caused outages were not deemed reasonable at this time. PG&E will continue to rely on the ongoing vegetation management activities described above and the proposed incremental vegetation overhang clearing to reduce vegetation caused wire down events.

To eliminate future third-party contact with intact and wire down events, PG&E calculated the value of performing targeted underground conversion of overhead primary distribution conductor. PG&E would target conversion to underground cable starting with the most historically impacted line segments targeting 50 miles a year.[37] The annual cost would be approximately $150 million a year.[38] The alternative mitigation was not viable based on the low expected RSE and the complexity to execute.

Similar to Alternative Plan 1, due to the low total RSE of the Alternative Plan 2 combined with the overhead conductor replacement and Fuel Reduction and Powerline Corridor Management projects proposed in the Wildfire risk, the additional conductor replacement projects and underground conversions were not deemed reasonable at this time. PG&E will incorporate the prioritization

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36 13 circuits make up 11 percent (774) of all the Vegetation caused outage on PG&E's system from 2012-2016. The 13 circuits totaled 1,160 miles, which represents 1.43 percent of PG&E's overall system.

37 The targeted underground conversion mitigation used the same approach as the distribution right-of-way clearing mitigation described in footnote 19.

38 Estimated a $3 million per mile cost based on a 2016 CPUC California Overhead Conversion Program, Rule 20A report using an average for urban areas in Table 1 of the report.

methodologies developed during the RAMP process where applicable to the existing programs while continuing to evaluate opportunities to improve risk quantification efforts.

Table 9-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M3	Additional Public Awareness Outreach	21.133	18.335	2018	2022	D1, D6, SI, SF	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
M4	Distribution Right-of-Way Clearing	0.413	0.389	2020	2022	D2	– (C) 1,568 - 1,733(E)	– (C) 1,756 - 1,940 (E)	– (C) 1,944 - 2,148 (E)
M5	Overhang Clearing	0.490	0.459	2018	2022	D2	– (C) 13,824 - 20,736 (E)	– (C) 13,824 - 20,736 (E)	– (C) 13,824 - 20,736 (E)
M6	Targeted Conductor Replacement (#4 ACSR in Corrosion zone)	0.033	0.031	2020	2022	D3,D4	105,336 - 116,424 (C) – (E)	105,336 - 116,424 (C – (E)	105,336 - 116,424 (C – (E)
M7	Targeted Underground Conversion	0.021	0.020	2020	2022	D1-D9	142,500 - 157,500 (C) – (E)	142,500 - 157,500 (C) – (E)	142,500 - 157,500 (C) – (E)
TOTAL ALTERNATIVE PLAN 2 TA RSE: 0.079 **TOTAL Expense and Capital by Year**							**18,022 - 19,919 (E)** **247,836 - 273,924 (C)**	**18,210 - 20,126 (E)** **247,836 - 273,924 (C)**	**18,398 - 20,334 (E)** **247,836 - 273,924 (C)**

VII. Metrics

Current outcome metrics used to track the DOCP risk include the following:

- Public Contacts: The number of electric incidents reported to the CPUC involving third party fatalities or injuries, rising to the level of inpatient hospitalization, attributable or allegedly attributable to contact with energized PG&E-owned electric transmission, substation, and distribution facilities.
- Distribution Wire Down Events: The number of instances where an electric overhead primary distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object.
- Electric Overhead Conductor Index (EOCI): Tracks work which directly supports safe, reliable operations of overhead electric system conductor.
  - EOCI index consists of 3 equally weighted metrics:
    - Infrared Inspection Program: measures the number of circuit miles of distribution overhead conductors inspected using infrared thermographic technology.

- Conductor Replacement Program: measures the number of overhead primary distribution conductors that have been upgraded or replaced.
- Vegetation Management: tracks the number of trees trimmed and/or removed as part of the distribution vegetation management PS&R Program.

Proposed accountability metrics include the following, related to the proposed mitigation and associated drivers:

Mitigation	Associated Drivers & Consequences	Proposed Metric	Annual Target
Additional Public Awareness Outreach	D1, D6, SI, SF	Public Contacts with Energized Facilities (Overhead Distribution Primary Conductor events only)	< 9
Overhang Clearing	D2	Miles of Overhang Clearing work performed in high risk Wildfire areas	4,800 miles per year in 2018 through 2022

VIII. Next Steps

The risk quantification effort undertaken as part of the RAMP process has provided an important step into using a data driven statistical model to compare DOCP risk investments and guide changes to PG&E's investment plan. As PG&E continues to refine risk modeling, PG&E will increase integration of model outputs into the investment planning process as appropriate.

DOCP risk continues to be largely influenced by technical and subject matter expertise. The DOCP operational risk model has helped PG&E consolidate alternative mitigations into one place and provide a potential mechanism to compare those mitigations against one another utilizing common units.

The DOCP operational risk model also provided insight into the overall consequences of the risk and highlighted the need to differentiate between the two events currently included in the DOCP risk, i.e., contact with intact conductor and wire down events. The data collected for the model shows that fatalities on overhead primary distribution conductors are mainly due to third-party contact with intact conductors, which is an external event that is difficult for PG&E to control.

Additionally, when combined with the wire down events, the outputs of the model are overstated due to the effects of combining the safety consequences related to third-party contact with intact conductors, with the reliability impacts of wire down events. This is illustrated in the MARS totals for Safety and Reliability (Figure 9-2).

It should be noted that the data, assumptions, and analysis used in this chapter represent the information available at the time it was prepared. This information is expected to change in the future for many reasons including additional or improved data availability, environmental risk factor changes and technology improvements.

Going forward, PG&E will evaluate the impacts and value of separating the third-party contact with intact driver (D1) from the DOCP risk and continue to assess different alternatives for reducing wire down events related to vegetation and equipment failures.

The miles and age of conductors on PG&E's system compared to current replacement targets,[39] means that future infrastructure investment needs will arise in this area.[40] This fact emphasizes the importance of the work currently underway to continue improving the quantification capabilities that will be used to define and prioritize those future investment needs. PG&E also will continue to leverage future technology developments and additional data to explore new ways to quantify DOCP risk and manage the asset effectively and efficiently.

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39 PG&E proactively replaces approximately 90 miles of distribution overhead conductor a year.

40 PG&E is currently performing a study of the overhead conductor system to learn its expected service life, the distribution of asset vintages across PG&E's system, the primary factors associated with the need to replace overhead conductor, and to derive a reasonable estimate of near- and long-term replacement rates.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 10
TRANSMISSION OVERHEAD CONDUCTOR (TOHC)

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 10
TRANSMISSION OVERHEAD CONDUCTOR (TOHC)

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Transmission Overhead Conductor (TOHC)
IN SCOPE	Public contact with energized intact overhead transmission conductor and TOHC wire down.
OUT OF SCOPE	Wildfires caused by wire down events.[1] Employee or contractor contact with overhead transmission conductor.[2]
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data, and subject matter expert (SME) input

Pacific Gas and Electric Company's (PG&E or the Company) Electric Operations (EO) department has been reviewing the TOHC risk since the creation of the risk register in early 2013. Overhead transmission lines are energized at high voltages, are exposed to the public, and form the backbone of PG&E's electrical system. Because of these attributes, there are inherent risks associated with overhead transmission conductors. Contact with these conductors could result in injuries and fatalities from shock and electrocution, and failure of these conductors could result in large outages or system instability. This risk continues to be a top priority for PG&E, as demonstrated through on-going investments in conductor replacement, compliance, and public safety programs.

This filing has been prepared and submitted against the backdrop of catastrophic wildfires that occurred in PG&E's service area beginning on October 8, 2017. Numerous investigations are underway. Depending on the results of those investigations, there could be an impact on PG&E's future transmission and distribution risk management approaches. PG&E has prepared this filing prior completion of the investigations as to the causes of any of the recent wildfires. The filing needs to be considered in this context. As with all risks in this filing, as more information becomes available, PG&E will make any updates to this analysis, modeling and proposing mitigations that might become appropriate.

Given this backdrop, it is important to note that the scope of this risk analysis specifically excludes Wildfire, but TOHC is included as a risk driver to the Wildfire risk

1 Refer to Risk Chapter 11 – Wildfire.

2 Refer to Risk Chapter 14 – Contractor Safety and Risk Chapter 15 – Employee Safety.

analysis.[3] The wildfire-related impacts that may be caused by TOHC assets are addressed in the Wildfire chapter, and not here, to avoid duplication.

To better understand this risk, in 2017, through the Risk Assessment and Mitigation Phase (RAMP) process, PG&E's EO department developed a probabilistic model to quantify the TOHC risk. The inputs into the TOHC risk model were developed using a bow tie risk assessment and incorporated a combination of PG&E-specific data, industry data, and SME judgement. The TOHC risk model was used to gain a better understanding of the risk drivers associated with the risk, the range of consequences, and where to target new mitigations.

As a result of the assessment, PG&E identified two main events associated with the risk: (1) third-party contact with intact conductor (either directly or via an object) and (2) third-party contact with wire down.

The assessment confirms that this risk is primarily a reliability risk rather than a safety risk based on the risk events examined in the TOHC model. PG&E has approximately 18,000 circuit miles of overhead transmission line. Using PG&E collected data, from 2012 through 2016, there have been an average 0.6 third-party injuries and 0.6 third-party fatalities a year, due to contact with overhead transmission conductor. The fatalities were caused by the unauthorized climbing of PG&E structures, an external event that is difficult for PG&E to control given the scope of its overhead transmission system. In that same time period, there has been an average of 55.8 PG&E transmission overhead wire down events per year, none resulting in injuries or fatalities. The highest frequency drivers that cause wire down events are vegetation, third-party actions (such as vehicle collisions with PG&E assets), and conductor failures due to factors such as equipment deterioration.

Through the risk assessment process, PG&E objectively evaluated its ability to reduce the TOHC risk at a reasonable cost. This risk quantification brought greater visibility to actual system exposure and drove PG&E to better quantify effectiveness of risk mitigations. To reduce TOHC risk, PG&E will implement a mitigation plan that consists of four mitigations: (1) Additional Public Awareness Outreach; (2) Additional Right of Way Expansion; (3) Additional Overhead Conductor Replacement; and (4) Additional Insulator Replacement. These mitigations address some of the largest drivers to wire down, including Vegetation and Equipment Failure – Conductor, and align with PG&E's overall asset lifecycle management objectives, where PG&E proactively replaces equipment that is approaching the end of its useful life.

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3 The "Equipment Failure – Conductor" risk driver included in the Wildfire risk analysis includes wildfires initiated by TOHCs and distribution overhead conductors.

Areas for continued model development and risk quantification include potential refinement of the assumptions used to model the efficacy of the mitigations included in the model. Refinement may include increasing the granularity of the modeled mitigations, including mitigation benefits beyond the current RAMP timeframe, and factoring in benefits from the mitigations outside of the specific TOHC risk events. Another opportunity for improvement involves modeling the increase in risk with time due to degradation of asset health as legacy equipment reaches the end of its useful life. This forward looking approach would enable effective quantification of steady state controls and identify opportunities to increase or decrease asset lifecycle replacement to manage risk within a given tolerance.

II. **Risk Assessment**

A. **Background**

Overhead transmission lines are energized at high voltages, are exposed to the public, and form the backbone of PG&E’s electrical system. Because of these properties, overhead transmission conductors have inherent risk. Contact with these conductors could result in injuries and fatalities, and failure of these conductors could result in large outages or system instability.

To help manage this risk, PG&E’s EO department has been reviewing the risk since the creation of the risk register in early 2013. PG&E’s assessment of the risk has evolved since that time, and PG&E currently assesses two potential events associated with the risk: third-party contact with intact conductor and third-party contact with wire down.

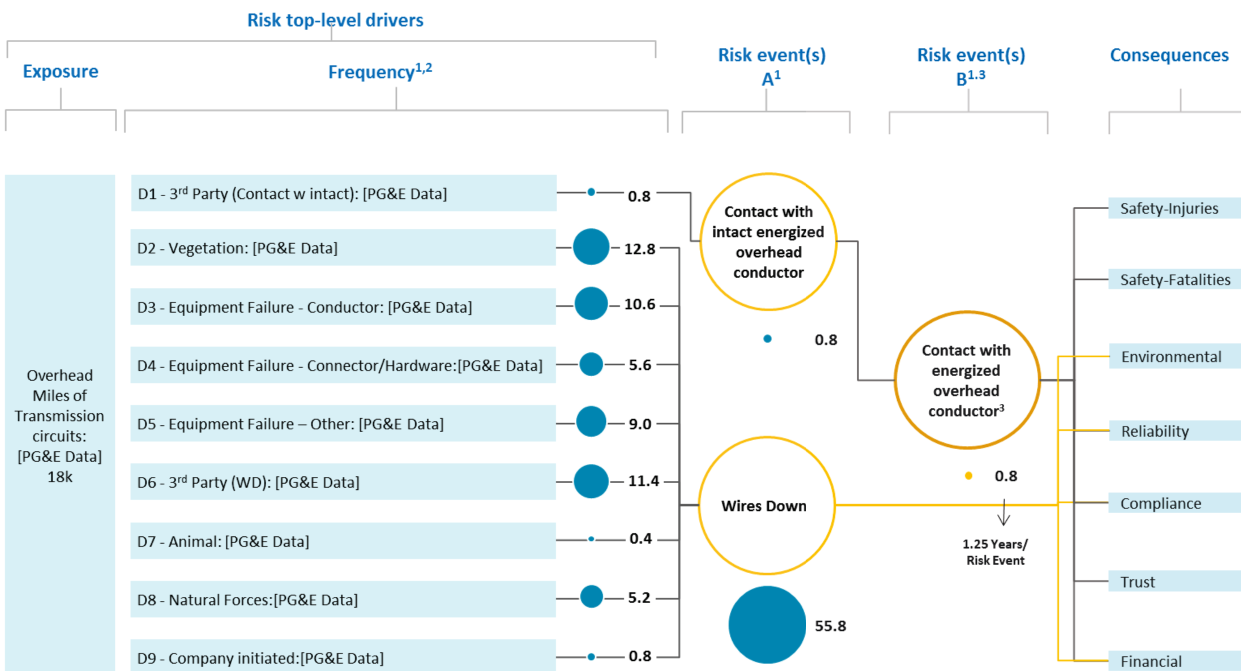
In a third-party contact with intact conductor event, a member of the public makes contact with a conductor that has not failed. Generally, on the transmission system, this involves contact with conductor through unauthorized climbing of PG&E structures or work occurring near the conductor.

In a wire down event, a conductor falls to the ground. Wires could fail due to several drivers, including vegetation falling onto lines, equipment failure, and third-party vehicle collisions with support structures and conductors. Wire down events do not generally result in safety incidents because the transmission system has stringent system protections which de-energize lines relatively quickly. High voltage faults are more easily detected by the protection system, and transmission lines are generally located in less populated areas. All of these factors tend to reduce the safety issues associated with wire down events.

The events examined in this risk may also result in wildfire. Because wildfire is a risk with several drivers, including drivers that are not included in the TOHC risk, the wildfire related risks of TOHC assets are described separately in detail in the Wildfire risk chapter.

This chapter discusses the inputs to and outputs of PG&E's quantitative model for the TOHC risk. It outlines the risk exposure, drivers, and consequences, and discusses current controls in place that manage this risk, as well as mitigations PG&E plans to implement to reduce this risk.

Figure 10-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.
[3]100% of D1 and 0% of D2-D9 may potentially remain energized.

B. **Exposure**

This risk is modeled using 18,352 circuit miles of TOHC as an exposure input, which is expected to remain relatively constant throughout the time horizon addressed by this filing. Circuit miles of TOHC have not materially changed since 2012 and there are no projects, developments, or expansions underway or planned that would change this exposure to any significant degree.

The circuit mileage data is sourced from historical end-of-year overhead line mileage reports extracted from PG&E's Electric Transmission Geographic Information System.[4]

4 The circuit mileage for this model includes idle line circuit miles. Idle transmission lines may remain energized at a designated voltage to help locate faults, which is important in the event those lines.

Risk exposure is not evenly distributed across PG&E's transmission overhead system. Some lines have a higher risk of failure than others. For example, lines have a higher likelihood of wire down when built near dense vegetation or when constructed in areas that experience more extreme weather. Due to this geographic and environmental diversity, the risk profile for PG&E's transmission overhead system is quite asymmetric resulting in a small fraction of PG&E's transmission overhead system representing a majority of the system risk exposure. As such, mitigations targeted in these higher risk areas have a greater impact in reducing risk. Where possible, PG&E has factored increased risk reduction from targeted work into its mitigation efficacy assumptions.

C. **Drivers and Associated Frequency**

Similar to Distribution Overhead Conductor Primary (DOCP) risk, PG&E divides the drivers of this risk into two sets based on the two risk events examined in this risk. The first set is related to the public contact with energized intact overhead conductor risk event. For the purpose of modeling this risk, contact with intact events were grouped as a single driver:

- **D1 – 3rd Party (Contact with intact)**. Third-party contact with intact conductor. This driver represents public contact with intact transmission conductor where there were fatalities or injuries, requiring in-patient hospitalization. The frequency of this driver is based on the public injury and fatality data that PG&E reports to the California Public Utilities Commission (CPUC). In the TOHC risk model, PG&E used data from the years 2012-2016. These years were selected to be consistent with the data available for the wire down drivers described below. The information is sourced from PG&E's electric incident reporting database. Between 2012 and 2016, there were four third-party events involving contact with intact conductor that resulted in injury or fatality, or an average of 0.8 events per year. Three of those events resulted in a single fatality each (or 0.6 fatalities per year), and one resulted in injuries to three people (or 0.6 injuries per year).

  The second set of drivers is related to the TOHC wire down risk event. The drivers to this event include the different causes that lead to wire down. The frequencies of these drivers are based on data that has been collected on PG&E transmission wire down events between 2012 (when PG&E first began collecting this data) and 2016. The data is comprised of information which includes the cause of each wire down event and the impact of any resulting outage.

  For wire down events, the TOHC risk model assumes that transmission overhead wires do not remain energized when there is a wire down event. This assumption is based on PG&E SME experience—according to which, no wire down has remained energized from a primary source. In some cases, wire down may remain energized at less than nominal voltage due to secondary sources such as induction from other circuits or phases, or it may remain energized, due to backfeed from substation transformers, but PG&E does not currently have data to determine how often this occurs.

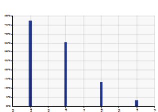
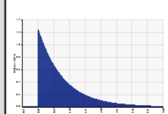
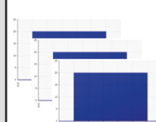
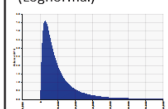
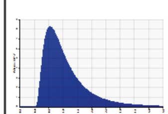
Based on the wire down data, PG&E has categorized the wire down events into eight drivers summarized below in order of highest frequency to lowest. Note that the driver numbering (D2 through D9) is based on the order of the drivers as they are listed in the model rather than the order in which they appear below.

- **D2 – Vegetation:** Tree, tree limb, or other vegetation contact with conductors that result in wire down events. Vegetation can physically bring down conductors when it falls onto conductors or it could cause faults that result in conductor failure and wire down. This driver was associated with 64 out of 279 (22.9 percent) wire down events from 2012-2016, or an average of 12.8 events per year.
- **D6 – 3rd Party (Wire Down):** Actions initiated by third parties that result in wire down events. This driver includes aircraft contacts, automobile collisions, vandalism (e.g. Gunshots), and contact with other foreign objects such as ships, balloons, cranes, etc. This driver was associated with 57 out of 279 (20.4 percent) wire down events from 2012-2016, or an average of 11.4 events per year.
- **D3 – Equipment Failure – Conductor:** Deterioration of conductor due to wear and tear that results in wire down events. This includes failures due to stressors such as vibration. This driver was associated with 53 out of 279 (19.0 percent) wire down events from 2012-2016, or an average of 10.6 events per year.
- **D5 – Equipment Failure – Other:** Failure of other line equipment such as poles, insulators, and distribution lines which result in wire down events. Includes all equipment failures not in the Equipment Failure – Conductor and Equipment Failure – Connector/Hardware driver categories. This category also includes wire down due to contamination by animal waste or dust. This driver was associated with 45 out of 279 (16.1 percent) wire down events from 2012-2016, or an average of 9.0 events per year.
- **D4 – Equipment Failure – Connector/Hardware:** Deterioration of connectors, splices, or other connecting hardware that results in wire down events. This driver was associated with 28 out of 279 (10.0 percent) wire down events from 2012-2016, or an average of 5.6 events per year.
- **D8 – Natural Forces:** Natural phenomena such as fire and lightning that can bring down PG&E assets and result in wire down events. This driver was associated with 26 out of 279 (9.3 percent) wire down events from 2012-2016, or an average of 5.2 events per year.
- **D9 – Company Initiated:** Actions initiated by PG&E workers, such as those initiated through work procedure errors, which result in wire down. This driver was associated with 4 out of 279 (1.4 percent) wire down events from 2012–2016, or an average of 0.8 events per year.
- **D7 – Animal:** Animal contacts that result in wire down. Typically, this involves animals making contact with multiple conductors of a transmission line, creating a fault between the two conductors that result in wire down. This driver was associated with 2 out of 279 (0.7 percent) wire down events from 2012-2016, or an average of 0.4 events per year.

III. **Consequences**

PG&E applies a standardized approach to measuring consequences as part of its enterprise risk program. As such, the consequences of this risk are based on six impact categories: safety, environmental, reliability, compliance, trust, and financial. For additional granularity, safety category is further divided into injuries and fatalities. Figure 10-2 below shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated Multi-Attribute Risk Score (MARS) values.

Figure 10-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	CPUC Data	CPUC Data	NA	PG&E Data	NA	PG&E Data and SME Input	PG&E and Claims Data
Consequence Distributions	Safety consequences are only on OHC that stay energized Percent of events with an injury =100% Mean=0.75 (Poisson) 	Safety consequences are only on OHC that stay energized Percent of events with a fatality=100% Mean=0.75 (Poisson) 	Covered in the wildfire risk model	Percent of OHC events with resulting in an outage=57% Ave duration of outage=805k min (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=6-10% Severe=2.5-6% Low=0-2.5% (Uniform) 	Restoration costs results from all OHC events: Ave=$23k Std Dev=$28k (Lognormal)  + Compensatory claims from OHC events that stay energized: Ave=$1.1M Std Dev=$0.9M (Lognormal) 
Outcome-TA-NU[1]	2.97	2.97		38,163,873		9.42%	$5,221,186
Outcome-TA-MARS[2]	0.81	81.03		95.41		47.12	3.13
						MARS Total	**227.50**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI)**: This risk focuses on injury consequences resulting from shock due to contact with energized conductor. As inputs into the TOHC risk model, PG&E is using historical injury data reported to the CPUC for the years 2012-2016. These years were used to be consistent with the wire down data used in the model. Over that time period, there have been a total of 3 injuries from 1 contact with intact conductor event, and no injuries from wire down events. Using this input, the TOHC operational risk model calculated a baseline tail average of 2.97 injuries a year for this risk, resulting in a contribution of 0.81 MARS units from this consequence category.

  Safety – Fatalities (SF): This risk focuses on fatality consequences resulting from electrocution due to contact with energized conductor. As inputs into the model, PG&E is using historical fatality data reported to the CPUC for the years 2012-2016. These years were used to be consistent with the wire down data used in the model.

Over that time period, there have been a total of three fatalities from three separate contacts with intact conductor events, and no injuries from wire down events. All fatalities were related to the unauthorized climbing of PG&E structures. Using this input, the TOHC risk model calculated a baseline tail average of 2.97 fatalities a year, resulting in a contribution of 81.03 MARS units from this consequence category.

- **Environmental (E):** Environmental consequences are measured in dollars. Environmental consequences for wire down and contact with intact events revolve around wildfire. These consequences are discussed in the Wildfire chapter and are excluded from the TOHC risk model to avoid duplication in model outputs.
- **Reliability (R)**: Reliability consequences are measured in customer outage minutes. To model reliability consequences, PG&E is using wire down outage information from the 2012-2016 wire down data. Because the TOHC risk is limited to examining two specific public safety events (third-party contact with intact conductor and wire down), outages that do not result from these safety events are not included in the model. Because redundancy is designed into the transmission system, about 57 percent of wire down events have resulted in outages over the 2012-2016 timeframe. For the wires down events that did result in outages, the average event resulted in 804,788 customer outage minutes. Using this input, the TOHC risk model calculated a baseline tail average of 38,163,873 customer outage minutes per year, resulting in a contribution of 95.41 MARS units from this consequence category.
- **Compliance (C):** Compliance consequences are measured in dollars. Compliance costs were not used in the model because regulatory fines are shareholder funded and not applicable in the RAMP analysis.
- **Trust (T)**: Events are dependent upon safety outcomes, both injury and fatality, and categorized as: low, severe, and high. This methodology was used across all risks.[5] For this risk, PG&E assumed approximately half of the impact, based on qualitative observation of the consequences of past wire down and contact with intact events. This results in a high severity bounds of 6-10 percent, severe bounds of 2.5-6 percent, and a low bound of 0-2.5 percent. Using this input, the TOHC risk model calculated a baseline tail average of 9.42 percent brand favorability reduction per year, resulting in a contribution of 47.12 MARS units from this consequence category.
- **Financial (F)**: Financial consequences are measured in dollars. To model financial consequences, PG&E is using, as inputs, wire down restoration costs and compensatory claim costs related to TOHC. Restoration cost data was collected by sampling maintenance work orders that involved broken conductor, wire down, or conductor repair. The average value of restoration costs was calculated to be $22,645 per event. Compensatory claim costs are based on two data sources. The first data source is PG&E's claims database which contains information on claims

5 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

filed with PG&E involving TOHC. This database generally includes smaller claim amounts. Industry data was also used as an input to capture larger compensatory claim amounts. The data used represents major liability losses incurred by litigation or claims on the utilities (not limited to PG&E incidents). PG&E's internal database shows 15 claims related to transmission overhead facilities, all without payment in the time period (note that some claims may still be open). The data shows four transmission overhead items between 2011 and 2016 with loss amount values. On average, these four items resulted in an average $1,125,000 self-insured retention amounts paid out by the utilities. Using these inputs, the TOHC risk model calculated a baseline tail average of $5,221,186 of financial costs per year, resulting in a contribution of 3.13 MARS units from this consequence category.

IV. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the items described in this section helps to control the frequency or consequence of one or more drivers of the TOHC risk. Table 10-1 at the end of this section summarizes the 2016 recorded costs for the controls.

- **C1 – Design, Construction, and Operation**: Includes procedures such as engineering standards, material specifications, operation manuals, etc., and the work where those procedures are implemented. This category encompasses a large number of individual controls that are in place to control the TOHC risk, including warning signage requirements, fencing, and conductor clearance requirements, all of which are designed to ensure the correct installation and operation of TOHC and associated equipment. This control reduces the exposure related to all risk drivers for this risk.
- **C2 – Anti-Climbing Guards**: PG&E installs these guards per PG&E guarding guidance documents, which are aligned with CPUC requirements.[6] These documents contain criteria for where climbing guards must be installed. In addition to those requirements, PG&E also has processes in place to evaluate the installation of additional anti-climbing guards on structures with evidence of climbing in the past. Anti-climbing guards deter the unauthorized climbing of PG&E structures by members of the public, reducing the risk of contact with intact conductor. This control reduces the exposure related to the third-party Contact with Intact Conductor driver.
- **C3 – Inspection and Maintenance**: This control represents PG&E inspection and maintenance of overhead lines. It includes visual and infrared inspections, completion of maintenance work identified through those inspections, and maintenance work identified through other work streams. This control reduces the risk exposure associated with all the drivers for this risk, e.g., clearances corrected, reducing chance of animal contact.

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6 The guarding requirements can be found in CPUC General Order 95 Rules 51.6-B and 61.6-B.

- **C4 – Public Awareness Programs**: This control represents PG&E external communication and outreach programs designed to educate the public on the hazards associated with wire down and contact with intact conductor. These programs also include communications to educate third-party workers who may work near transmission lines of the danger of working around those lines. This control reduces the exposure related to the Third-party Contact with Intact Conductor and 3rd Party (WD) risk drivers, and directly reduces safety consequences (both injury and fatality) – members of the public who understand the hazards associated with conductors are less likely to contact conductors.
- **C5 – Aircraft Line Markers**: This control represents PG&E's installation of line markers (such as marker balls) on conductor spans to increase visibility of those spans to aircraft. PG&E also installs lighting on structures supporting the conductor to increase visibility of those structures. This control reduces the likelihood of aircraft contact into overhead lines, therefore reducing the exposure related to the Third-party Contact with Intact Conductor and 3rd Party (WD) risk drivers.
- **C6 – Animal Abatement**: This control represents PG&E's installation of equipment, such as bird and squirrel guards, on overhead lines to prevent animal contact with conductors. These devices deter animals from perching or walking on areas of line where they may come between conductors, creating a fault on a line. Reducing the likelihood of faults on lines due to animal contact reduces the likelihood of wire down. This control reduces the exposure related to the Animal risk driver.
- **C7 – Capacity Program**: This control represents PG&E's programs to monitor and control loading on lines. This control includes modelling electrical loading on lines, and constructing and upgrading lines to provide additional capacity to reliably support increased load. These programs reduce the likelihood of overloading, which can accelerate the deterioration of line equipment and eventually cause wire down events. This, in turn, results in reduction to the exposure related to the Equipment Failure – Other, Equipment Failure – Connector/Hardware, and Equipment Failure - Conductor risk drivers.
- **C8 – Restoration and Response**: This control represents PG&E's processes to respond to and restore outages, and the work where those processes are implemented. It includes procedures to make areas safe after wire down events, and the repair of those wires down. PG&E's response after a wire down event limits the potential consequences of that event, directly reducing consequences associated with safety (injury and fatality), reliability, trust, and financial impacts.
- **C9 – System Protection Program**: This control represents system protection schemes and the devices that activate when abnormalities are detected on PG&E transmission lines. Protective relaying, which can de-energize lines when faults are detected fall into this control category. System protection limits the potential consequences of wire down events, directly reducing consequences associated with safety (injury and fatality), trust, and financial impacts.
- **C10 – Vegetation Management**: This control represents PG&E programs to manage vegetation near transmission lines. It includes the annual patrol of vegetation around lines, and the work to manage vegetation (clearing, removal) identified

through those patrols. Vegetation management reduces the likelihood of vegetation contact with overhead conductor, which may lead to wire down events. This control reduces the exposure related to the Vegetation and Natural Forces risk drivers.

Two mitigations described below are categories of work performed in 2016. As discussed in later sections, these two mitigations will continue through 2022. PG&E may propose continuation beyond 2022 based on the results and lessons learned from the mitigation work.

- **M1A – Conductor/Equipment Replacement Programs (2016):** These programs were mitigations in 2016, and represent PG&E work to proactively replace conductor and equipment on PG&E lines. It includes work such as conductor replacement, targeted circuit reliability work, and insulator replacement work, where assets are replaced on circuits for reliability and lifecycle purposes. The conductor and insulator replacement portions of this mitigation will, in general, increase in scope going into 2019 (mitigations M4 and M5 discussed below), then increase further in scope through 2022 (mitigations M7 and M8 discussed below). This control reduces the exposure related to the Equipment Failure – Other, Equipment Failure - Connector/Hardware, Equipment Failure – Conductor, and Natural Forces risk drivers.
- **M2A – Right of Way Expansion (2016):** Right of way expansion was a mitigation in 2016. This mitigation represents programs to extend the rights of way around transmission overhead lines most at risk for vegetation related outages, and the clearing of vegetation within those rights of way. The vegetation related work involved in right of way expansion is typically larger in scope than general vegetation management in that it requires the removal of all trees and other vegetation within the transmission lines' right of way. In 2016, PG&E began increasing the scope of its Right of Way Expansion work. The increase in scope will continue into 2019 then increase further in scope through 2022 (as discussed below). This control reduces the exposure related to the Vegetation risk driver.

Table 10-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Design, Construction and Operation	D1-D9	TO	–	178,565
C2	Anti-Climbing Guards	D1	TO	–	297
C3	Inspection and Maintenance	D1-D9	TO	39,249	2,969
C4	Public Awareness Programs	D1, D6	TO	61	–
C5	Aircraft Line Markers	D1, D6	GRC TO	225 109	17,980
C6	Animal Abatement	D7	TO	28	1,164
C7	Capacity Program	D3-D5	TO	–	104,157
C8	Restoration and Response	SI, SF, R, T, F	TO	1,492	10,219
C9	System Protection Program	SI, SF, T, F	TO	N/A	N/A
C10	Vegetation Management	D2, D8	TO	45,473	–
M1A	Conductor/Equipment Replacement Programs (2016)	D3-D5, D8	TO	–	20,278
M2A	Right of Way Expansion (2016)	D2	TO	–	3,236
TOTAL Expense and Capital				GRC 225 TO 86,351	338,867

In addition to these controls, PG&E is also building foundational tools that will provide further controls for this risk, such as the Transmission Support Structures (TSS) tool, which will improve the process for Transmission Support Structures Loading Calculations. The aim of the TSS technology project is to centralize the data for all PG&E transmission structure assets, improve data quality, improve data access, and improve response to outages. This will enhance risk management decision-making on transmission assets.

V. Current Mitigation Plan (2017–2019)

In addition to the work listed above, PG&E is performing incremental mitigations in 2017-2019 as listed below. Much of this work consists of expansion in scope to the two existing mitigations listed in the controls section above (M1A – Conductor/Equipment Replacement Programs, M2A – Right of Way Expansion). These mitigations were chosen, in part, because of their alignment with existing asset strategy plans that were developed based on technical evaluation and subject matter expertise. These mitigations will continue to expand in scope through 2022, and potentially beyond based on the results and learnings from the mitigation work.

The mileages referenced below are approximations and may change as project plans are completed and finalized.

- **M1B – Additional Overhead Conductor Replacement (2017–2019):** This mitigation will expand PG&E's conductor replacement program, a part of the Conductor/Equipment Replacement Programs mitigation (M1A) described in the controls section of this chapter. The program is intended to improve asset life and performance by replacing conductor that is approaching end of life, is obsolete, or is poorly performing. By replacing more conductors, this mitigation further reduces the likelihood that the above factors will result in conductor failure and wire down. This mitigation will further reduce the exposure related to the Equipment Failure – Conductor (D3) as well as the Equipment Failure – Connector/Hardware (D4) drivers, since replacing conductor would also eliminate splices on the replaced line. Effectiveness of this mitigation will be measured primarily through metrics that track wire down events. This mitigation will be performed on approximate average of 7 circuit miles per year between 2017 and 2019, targeting primarily 60 kilovolt (KV) and 115 kV circuits, which data shows are more at risk of conductor failure related wire down.
- **M1C – Additional Insulator Replacement (2017–2019):** This mitigation will expand PG&E's insulator replacement program, a part of the Conductor/Equipment Replacement Programs mitigation (M1A) described in the controls section of this chapter. By expanding insulator replacements, PG&E will improve asset life and performance by replacing insulators that are obsolete, approaching end of life, or are poorly performing. By replacing more insulators, this mitigation will further reduce the likelihood that the above factors will result in insulator failure and wire down. This mitigation will further reduce the exposure related to the Equipment Failure - Other (D5) risk driver, which includes wires down due to insulator failure. Effectiveness of this mitigation will be measured primarily through metrics that track wire down events. This mitigation will be performed on an approximate average of 59 miles per year between 2017 and 2019.
- **M2B – Additional Right of Way Expansion (2017–2019):** This mitigation will increase PG&E's right of way expansion program described in mitigation M2A in the controls section of this chapter. The additional work will target the worst performing 8 percent of transmission line miles that experience 80 percent of PG&E's vegetation related outages. These targeted circuits will be prioritized in

3 tiers determined by outage activity over the previous 3 and 10 year periods. The two time periods were chosen to ensure that circuits with both a long history, as well as those with only a more recent history of vegetation related outages are addressed by the plan. The first tier covers 60 percent of the vegetation related transmission line outages and represents worst performing circuits using both the 3 and 10 year data sets. Tier 2 covers an additional 10 percent of vegetation related outage activity and is based on the last 3 years of outage data. Tier 3 covers an additional 10 percent of outage activity as define by the worst performing circuits over the last 10 years. Because a majority of vegetation issues are on this small population of lines, the work will efficiently reduce the exposure related to the Vegetation (D2) risk driver. Effectiveness of this mitigation will be measured primarily through metrics tracking wire down events. The mitigation will be performed on an approximate average of 119 circuit miles per year between 2017 and 2019.

- **M3A – Additional Public Awareness Outreach (2017–2019):** This mitigation represents an addition to PG&E's Public Awareness Programs (C4) discussed in the controls section of this chapter. This mitigation involves the creation of a new program to draft and mail out, twice per year, bill inserts that warn customers of the dangers of wire down, and to inform them of the hazards associated with performing activities around intact overhead conductor. Adding these outreach materials to the public awareness portfolio will make the general public more aware of the hazards associated with overhead conductors, which may reduce the number of contacts with energized conductors and reduce the exposure related to the Third-Party (Contact w intact) (D1) driver. The risk model assumes negligible impact to post risk event consequences, such as contact with wires down, since TOHCs are significantly less likely to remain energized during wire down events. Effectiveness of this mitigation will be measured primarily through monitoring of injury and fatality reportable incidents to the CPUC. This mitigation is shared with EO's DOCP risk, and costs are split evenly between the two risks. This mitigation will begin in 2018.

The scope of the mitigations between 2017 and 2019 are based, generally, on PG&E's ability to execute the projects contained in each mitigation plan. Most transmission line work has a multi-year duration, and work execution can fluctuate year over year as parallel projects are started and completed. Additionally, project execution may take time to ramp up, as dependencies such as design, planning and permitting limit the amount of work that can be done early in the program/project lifecycle.

Table 10-2 shows the estimated costs associated with 2017-2019 TOHC risk mitigation work.

Table 10-2: 2017 to 2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1B	Additional Overhead Conductor Replacement (2017-2019)	2017	2019 (Will lead into mitigation M1D in 2020)	D3, D4	3,721 (C) – (E)	12,667 (C) – (E)	6,977 (C) – (E)
M1C	Additional Insulator Replacement (2017-2019)	2017	2019 (Will lead into mitigation M1E in 2020)	D5	619 (C) – (E)	14,917 (C) – (E)	18,443 (C) – (E)
M2B	Additional Right of Way Expansion (2017-2019)	2017	2019 (Will lead into mitigation M2C in 2020)	D2	6,737 (C) – (E)	10,024 (C) – (E)	12,007 (C) – (E)
M3A	Additional Public Awareness Outreach (2017-2019)	2018	2019	D1	– (C) – (E)	– (C) 40 (E)	– (C) 40 (E)
TOTAL Expense and Capital by Year					11,077 (C) – (E)	37,609 (C) 40 (E)	37,426 (C) 40 (E)

VI. Proposed Mitigation Plan (2020–2022)

PG&E performed an evaluation of all mitigations considered and how each relates to the TOHC risk drivers. The mitigations included in the proposed plan are listed below. The mileages referenced are approximations and may change as project plans are completed and finalized.

- **M1D – Additional Overhead Conductor Replacement (2020–2022):** This mitigation represents an increase to the conductor replacement work previously described in mitigations M1A and M1B to further reduce exposure related to the Equipment Failure - Conductor (D3) and Equipment Failure – Connector/Hardware (D4) wire down drivers. It increases overhead transmission conductor replacements from an average of 7 miles per year in 2017-2019 to an approximate average of 26 miles per year in 2020-2022.
- **M1E – Additional Insulator Replacement (2020–2022):** This mitigation represents an increase to the insulator replacement work previously described in mitigations M1B and M1C to further reduce exposure to the Equipment Failure – Other (D5) wire down risk driver. It increases insulator replacements from an average of 59 miles per year in 2017-2019 to an approximate average of 139 miles per year in 2020-2022.
- **M2C – Additional Right of Way Expansion (2020–2022):** This mitigation represents an increase to the right of way expansion work previously described in mitigations

M2A and M2B to further reduce exposure related to the Vegetation (D2) risk driver. It increases right of way expansion from an average of 119 miles per year in 2017-2019 to an approximate average of 177 miles per year in 2020-2022.

- **M3B – Additional Public Awareness Outreach:** The proposed plan also includes the continuation of the Additional Public Awareness Outreach mitigation (M3A) outlined in Section IV - Current Mitigation Plan (2017 to 2019).

The proposed plan was established based on PG&E's current overall TOHC asset strategy plan. PG&E's asset strategy is informed by the risk quantification generated by the TOHC risk model, PG&E's Wildfire risk model, and additional quantification of reliability risk exposure modeled outside of RAMP. PG&E is continuing its evaluation of the model outputs and using the outputs to confirm, inform, and adjust its transmission investment strategy rather than to completely replace that strategy. As a result, not all the proposed mitigations have the highest Risk Spend Efficiencies (RSEs) per the TOHC risk model.

The proposed plan fulfills PG&E's safety, reliability improvement, and lifecycle replacement asset strategy goals in a cost effective way. Because several of these mitigations are expansions of existing work, PG&E has a good understanding of the benefits of the work, and can take advantage of existing experience to complete the work efficiently. In addition, the proposed mitigations will help to avoid an increase in PG&E's risk profile driven by increased likelihood of asset failure as assets reach "end of useful life". Much of PG&E's transmission infrastructure was constructed in the years following WWII. As such, many assets are nearing "end of useful life". As these of assets near the end of their expected useful lives, PG&E will need to increase its level of asset replacements to avoid degradation in overall customer reliability and system performance.

The Additional Right of Way Expansion (M2B) mitigation was chosen for the proposed plan because it reduces exposure to the largest driver to transmission wire down, Vegetation. This, combined with the fact that the work to clear vegetation from right of ways is not as costly as other work, such as asset replacement, means that this mitigation is more cost effective. Through right of way expansion, PG&E will also be able to reduce the frequency of its on-going right of way maintenance cycle. In turn, this reduction in right of way maintenance activity will reduce cost for PG&E's customers. PG&E was not able to reflect these cost savings in the operational risk model, which would have improved the associated RSE score for the mitigation. As discussed in mitigation M2B PG&E has observed that a small population of its lines (approximately 8 percent) is responsible for approximately 80 percent of its vegetation related wire down events. This means that the planned targeting of this mitigation to the small population of worst performing lines will have an outsized impact in reducing vegetation wire down events, making this mitigation even more cost effective. This mitigation has the second highest RSE of the six mitigations examined in the model.

The Additional Overhead Conductor Replacement (M1D) and Additional Insulator Replacement (M1E) mitigations were chosen because replacements represent a core part of any asset management program. Replacing assets that are approaching end of life expectancy, are obsolete, or are poorly performing is essential to ensuring that those assets do not fail and result in events such as the wire down risk event. PG&E is increasing the pace of its replacement programs to prevent impacts from aging infrastructure. These mitigations have low RSEs based on model outputs due to the high cost of transmission asset replacement work. PG&E plans to perform this work despite the low RSEs because of its classification as core asset strategy work. The work will continue until the impact of model limitations on mitigation RSEs can be understood. Model limitations may be under calculating additional benefits of this mitigation. Specifically, the model only calculates benefits over a short timeframe (asset replacements may provide decades of benefits), it does not model future deterioration of assets and the consequences of deferred mitigation (if this work is not performed, risk does not remain static, but may increase), and it only narrowly includes the benefits related to the risk events (replacing assets may also reduce reliability events that do not involve wire down).

The Additional Public Awareness Outreach (M3B) mitigation was primarily chosen due to its very low relative cost and its ability to reach a large number of PG&E customers. Though the model shows that the absolute risk reduced by the outreach materials is relatively low based on the assumption that a limited number of customers likely read the inserts, it does have the largest RSE of all mitigations examined in its model because the cost is much lower than any of the other mitigations. Despite this mitigation's high RSE resulting from its relatively low cost, PG&E will not be expanding the scope of the mailings (i.e., by sending out numerous mailers per year) until the impact of the inserts can be measured. PG&E suspects that benefits of the inserts will decrease by a large margin with each additional annual mailing. Going forward, PG&E will explore additional opportunities for outreach via different forms of media, which may counter the diminishing returns associated with more frequent mailings.

Table 10-3 below summarizes the mitigations' RSE and associated estimated costs for each year covered by the 2020 General Rate Case (GRC).[7]

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[7] Note that though the years examined are the years included in the 2020 GRC, transmission costs are recovered through a separate Transmission Owner rate case.

Table 10-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	2020	2022 (May lead into additional mitigation past 2022)	D3, D4	21,321-23,565 (C) – (E)	29,763-32,895 (C) – (E)	35,625-39,375 (C) – (E)
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	2020	2022 (May lead into additional mitigation past 2022)	D5	28,500-31,500 (C) – (E)	24,700-27,300 (C) – (E)	23,275-25,725 (C) – (E)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
M3B	Additional Public Awareness Outreach (2020-2022)	6.6628	4.2298	2020	2022 (Will become a control)	D1	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
PROPOSED PLAN TA RSE: 0.0670 TOTAL Expense and Capital by Year							64,068-70,812 (C) 38 - 42 (E)	68,238-75,420 (C) 38 - 42 (E)	71,250-78,750 (C) 38 - 42 (E)

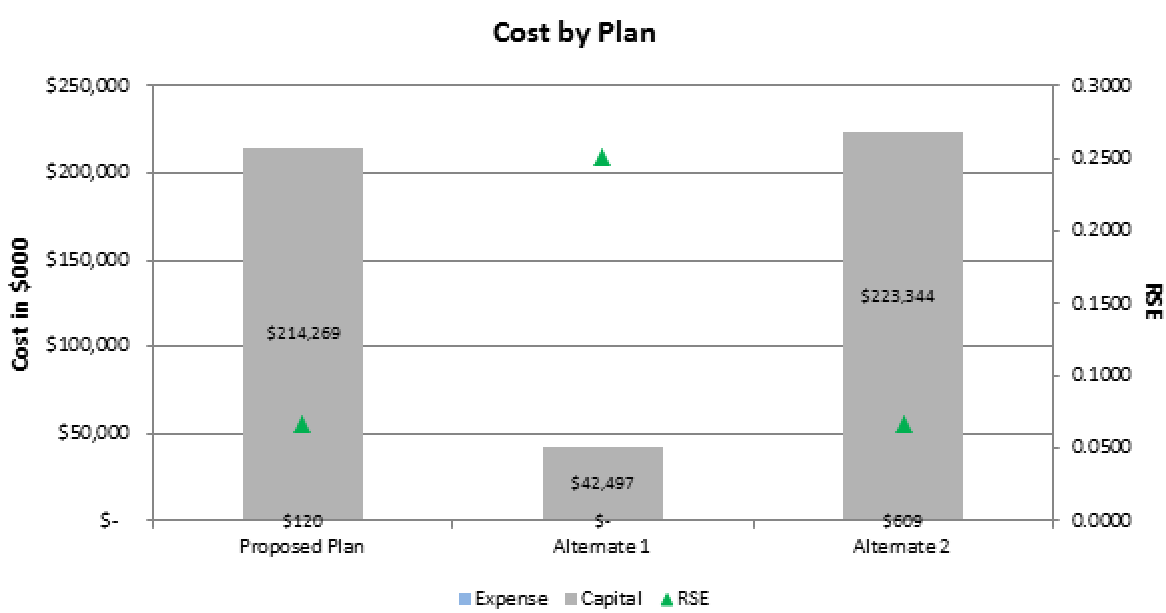
VII. **Alternatives Analysis**

After assessing all of the mitigations, PG&E has two alternative plans to the proposed mitigation plan. Alternative Plan 1 was created as a limited cost alternative. This plan was developed around the idea that PG&E would choose to perform only one of the risk mitigations examined in the model. Alternative Plan 2 was developed around the idea that PG&E would perform all of the risk mitigations examined in the model. The mitigations included in each of the alternative plans and the proposed plan are shown below in Table 10-4. Figure 4 presents the costs associated with the proposed and alternative plans.

Table 10-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	x		x	WP 10-2
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	x		x	WP 10-8
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	x	x	x	WP 10-14
M3B	Additional Public Awareness Outreach	6.6628	4.2298	x		x	WP 10-20
M4	Additional Anti-Climbing Guard Installation	0.0659	0.0449			x	WP 10-26
M5	Additional Vibration Damper Installation	0.0150	0.0123			x	WP 10-32

Figure 10-3: Alternatives by Cost and RSE Score



A. **Alternative Plan 1**

This alternative proposal represents a limited cost mitigation plan. As mentioned above, this plan was developed around the idea that PG&E would limit its mitigations to only one of the risk mitigations examined in the model. The mitigation chosen for this alternative plan was Additional Right of Way Expansion (M2C).

Additional Right of Way Expansion was chosen for the reasons outlined in the discussion of the proposed plan above. If PG&E were to limit itself to performing one mitigation over the others, this mitigation makes sense because it targets the largest risk driver, is cost effective, and has the second highest RSE. Although the Additional Public Awareness Outreach (M3B) mitigation has a larger RSE than the Additional Right of Way Expansion (M2C), additional outreach was not chosen as the sole mitigation for this limited cost plan because the model shows that in absolute terms, outreach reduces the risk by a relatively small amount.

PG&E does not plan to implement this alternative plan. Although this limited cost approach alternative involves the most effective mitigation, PG&E believes that this mitigation should not be undertaken in isolation. A more diverse mitigation portfolio would be better suited to reducing the overall risk. Performing several mitigations will allow PG&E to utilize its existing diverse resources (construction resources along with vegetation management resources) and will ensure that drivers other than Vegetation are addressed.

Table 10-5 below summarizes the RSEs for the single mitigation in Alternative Plan 1 and the associated estimated costs for each year covered by the 2020 GRC if they were to be implemented.

Table 10-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
ALTERNATIVE PLAN 1 TA RSE: 0.2507 **TOTAL Expense vs. Capital by Year**							14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)

B. Alternative Plan 2

This alternative proposal represents a mitigation plan where PG&E implements all the mitigations included in the proposed plan, with an additional two mitigations: Additional Anti-Climbing Guard Installation and Additional Vibration Damper Installation. These two additional mitigations are described as:

- **M4 – Additional Anti-Climbing Guard Installation**: This mitigation represents an expansion of the criteria under which climbing guards are installed on PG&E facilities. Three out of the four TOHC public injury and fatality events that occurred from 2012 through 2016 were related to the unauthorized climbing of PG&E structures. As discussed above in the control section of this chapter, the Anti-Climbing Guards (C2) control, as currently implemented is aligned with the requirements of CPUC GO 95. However, installing additional anti-climbing guards or other types of public protection above and beyond the current requirements may further reduce the number of public safety incidents related to the unauthorized climbing of PG&E structures. If implemented, this mitigation would reduce the exposure related to the third-party (Contact w intact) (D1) driver. Effectiveness of this mitigation would be measured primarily through monitoring of injuries and fatalities constituting reportable incidents to the CPUC. This mitigation represents anti-climbing guard installations on approximately 55 miles of line per year beginning in 2020.
- **M5 – Additional Vibration Damper Installation**: This mitigation represents a program to install vibration dampers on existing conductors that did not meet damping criteria per the standards in effect when they were constructed, but that would require dampers if installed under today's more stringent damping criteria. Vibration dampers reduce wind induced conductor motion (aeolian vibration), which can cause fatigue on those conductors. This wind induced fatigue may eventually result in conductor failure and wire down. This mitigation would entail identifying conductors without dampers which would require dampers if installed today, assessing whether they require damping, then installing vibration dampers if it is determined that additional damping is necessary. Installing these additional dampers would further reduce the likelihood of wire down, reducing exposure to the Equipment Failure – Conductor (D3) risk driver. Effectiveness of this mitigation would be measured primarily through metrics that track wire down events. This mitigation represents vibration damper installations on approximately 10 miles of line per year beginning in 2020.

Though Additional Anti-Climbing Guard Installations and Additional Vibration Damper Installations have the third and fourth highest RSEs per the TOHC model, PG&E does not plan to implement this alternative mitigation plan at this time for two reasons.

First, this work is already bundled into other work streams. For example, whenever PG&E constructs or replaces conductors or line support structures, PG&E uses standards that include requirements for damping and guarding. PG&E believes that this work may be an adequate substitute to specialized guarding and damping programs. Moreover, the incremental cost of implementing damping and guarding as part of other programs is small. While bundling these activities may decrease the rate of installation, the reduction in cost associated with efficient implementation makes this approach superior to standalone installation programs.

Second, PG&E does not have an existing targeted Anti-Climbing Guard or a targeted Vibration Damper installation program. Before initiating these specialized programs, PG&E would seek to validate their benefits. Unlike the other mitigations, PG&E does not have detailed studies on the efficacy of climbing guards, or in-depth studies on vibration caused conductor failure, so PG&E has relied upon assumptions that PG&E would need to further assess before going forward. For example, anti-climbing guard efficacy was based on studies of the efficacy of suicide barriers on bridges because PG&E currently does not have or know of a methodology to quantify the efficacy of anti-climbing guards, and PG&E intends to further evaluate use of these studies as a proxy.

Table 10-6 below summarizes the RSEs for the mitigations in Alternative Plan 2 and the associated estimated costs for each year covered by the 2020 GRC if they were to be implemented.

Table 10-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ 1$M)	EV RSE (Units/ 1$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Additional Overhead Conductor Replacement (2020-2022)	0.0052	0.0042	2020	2022 (May lead into additional mitigation past 2022)	D3, D4	21,321-23,565 (C) – (E)	29,763-32,895 (C) – (E)	35,625-39,375 (C) – (E)
M1E	Additional Insulator Replacement (2020-2022)	0.0031	0.0025	2020	2022 (May lead into additional mitigation past 2022)	D5	28,500-31,500 (C) – (E)	24,700-27,300 (C) – (E)	23,275-25,725 (C) – (E)
M2C	Additional Right of Way Expansion (2020-2022)	0.2507	0.2040	2020	2022 (May lead into additional mitigation past 2022)	D2	14,247-15,747 (C) – (E)	13,775-15,225 (C) – (E)	12,350-13,650 (C) – (E)
M3B	Additional Public Awareness Outreach	6.6628	4.2298	2020	2022 (Will become a control)	D1	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)	– (C) 38 - 42 (E)
M4	Additional Anti-Climbing Guard Installation	0.0659	0.0449	2020	2022	D1	2,874-3,176 (C) – E)	2,874-3,176 (C) –(E)	2,874-3,176 (C) – (E)
M5	Additional Vibration Damper Installation	0.0150	0.0123	2020	2022	D3	–(C) 155-171(E)	–(C) 155-171(E)	–(C) 155-171(E)
ALTERNATIVE PLAN 2 TA RSE: 0.0669 TOTAL Expense and Capital by Year							66,942-73,988 (C) 193 -213 (E)	71,112-78,596 (C) 193 -213 (E)	74,124-81,926 (C) 193 -213 (E)

VIII. Metrics

Current outcome metrics used to track the TOHC risk include the following:

- **Public Contacts:** The number of electric incidents that were reported to the CPUC involving third-party fatalities or injuries, rising to the level of inpatient hospitalization, attributable or allegedly attributable to contact with energized PG&E-owned electric transmission, substation, and distribution facilities.
- **Transmission wires down**: The number of instances where a normally energized electric transmission conductor is broken, or remains intact, and falls from its intended position to rest on the ground or a foreign object.

Proposed accountability metrics include those shown in Table 10-7 below, as well as their associated drivers and mitigations they monitor and the proposed targets to be set.

Table 10-7: Proposed Accountability Metrics

Mitigation	Associated Driver and Consequence	Proposed Metric	Targets
Additional Public Awareness Outreach	D1	Public Contacts (Transmission & Distribution)	Maximum 9 Incidents
Additional Right of Way Expansion	D2	Transmission Wires Down	Maximum 42 Wires Down
Additional Overhead Conductor Replacement	D3, D4	Transmission Wires Down	Maximum 42 Wires Down
Additional Insulator Replacement	D5	Transmission Wires Down	Maximum 42 Wires Down

IX. Next Steps

The risk quantification effort undertaken as part of the RAMP process has provided an important step toward using a data driven statistical model to compare TOHC risk investments and guide changes to PG&E's investment plan. As PG&E continues to refine risk modeling, PG&E will increase integration of model outputs into the investment planning process. It should be noted that the data, assumptions and analysis used in this chapter represent the information available at the time and is expected to change in the future for many reasons including additional or improved data availability, environmental risk factor changes and technology improvements.

As the risk model is a significant step towards quantification, and because PG&E understands the uncertainties in model outputs due to the model limitations, PG&E's transmission overhead risk mitigation plan continues to be largely based on work established by technical and subject matter expertise prior to the RAMP process. Much of the analysis used to develop the prior work plan was based on data similar to that used in the model. Where the model is helpful, however, is its ability to consolidate those mitigations into one place and provide a potential mechanism to compare those mitigations against one another using common units.

The risk model also provided some insight into the overall consequences to the risk. PG&E qualitative assumption was that this risk is primarily a reliability risk to the company, and less so a safety risk. The data gathered for the model provides quantitative support for that assumption. The safety incident data shows that fatalities on transmission lines are uncommon, and are primarily due to the unauthorized climbing of PG&E structures by members of the public, an external event that is difficult for PG&E

There are several key areas of model improvement necessary to allow PG&E to further rely on the model outputs for investment planning decisions.

First, through the modelling process, PG&E has identified significant differences in the risk profiles of the two TOHC risk events. The consequences of, and the mitigations to third-party contact with intact events are very different than those of wire down events. For example, the data used in the model shows that safety consequences are primarily the result of contact with intact events and not wire down events. Additionally, wire down event frequency can be reduced through direct mitigation such as right of way expansion and conductor replacement, whereas third-party contact with intact events are generally mitigated through indirect means such as public awareness outreach. Because of the differences between these risk events, PG&E will evaluate the impacts and value of separating the third-party contact with intact event from the wires down event.

Second, in calculating RSE, PG&E needs to be able to include benefits that are not specifically related to the risk event. At present, some RSE calculations are understating benefits for higher cost mitigations, which are inappropriately deflating the associated RSE for the mitigation. For example, Additional Overhead Conductor Replacement will reduce the frequency of outages caused by the wire down risk event, but may also reduce outages that are not associated with wire down. At present, the benefits of the mitigation that are not associated with wire down events are not included in the RSE calculation.

Third, further refinements to quantify the change in PG&E's future risk profile are warranted. At present, the model only looks at historical data and assumes a static risk level. For many of PG&E's assets, the asymmetric distribution of asset age and health will result in an increase failure rate and degraded system performance as waves of assets reach "end of useful life". The current model does not account for this prospective increase in system risk. Further, refinement will be needed to effectively quantify the appropriate level of asset replacement required to meet risk tolerance.

Another opportunity for PG&E will be to apply RSE modeling to current controls to optimize steady state investment plans. Leveraging quantification generated by the risk model will allow additional targeting of controls to increase effectiveness where the current risk profile is largely asymmetric. The risk model may allow PG&E to maximize risk reduction by reprioritizing investments within it existing controls.

Finally, enhancements to the model's representation of mitigation cost and other economic factors would allow PG&E to fully rely on risk modeling for investment decisions and analysis of alternatives. Examples of these enhancements include capturing the full value of a given mitigation across its entire useful life, accounting for avoided cost associated with mitigation investments, and normalizing expense and capital costs across time. Adjustment in the model to transform financial components into a Net Present Value or Present Value of Revenue Requirement may allow for optimization of investment to maximize the benefits to PG&E customers.

While additional improvements will allow PG&E to fully operationalize this risk model, the work to develop this model to date has helped the company mature in the area of risk quantification. PG&E expects to build off this momentum and continue to improve its asset and risk management strategies through increasing levels of risk quantification and modeling.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 11
WILDFIRE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 11
WILDFIRE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Wildfire[1]
IN SCOPE	Fire ignitions and associated impacts resulting from interaction with Pacific Gas and Electric Company (PG&E) electric assets
OUT OF SCOPE	Fire ignitions and associated impacts not related to PG&E electric assets
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data and Subject Matter Expert (SME) input

Extreme weather, extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. Environmental extremes, such as drought conditions followed by periods of wet weather, can drive additional vegetation growth (fuel) and influence both the likelihood and severity of extraordinary wildfire events.

Over the past five years, as we have seen across California, inconsistent and extreme precipitation, coupled with more hot summer days, have increased the wildfire risk and made it increasingly more difficult to manage.

The risk posed by wildfires has increased in PG&E’s service area as a result of an extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases resulting from record rainfall following the drought, among other environmental factors. Other contributing factors include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk.

This filing has been prepared and submitted against the backdrop of extraordinary wildfires that occurred in PG&E’s service area beginning on October 8, 2017. Northern California experienced strong wind gusts up to at least 79 miles per hour. These destructive winds, along with millions of trees weakened by years of drought and recent renewed vegetation growth from winter storms, all contributed to some trees, branches and debris impacting PG&E’s electric lines across northern California.

PG&E has prepared this Risk Assessment and Mitigation Phase (RAMP) filing while numerous investigations associated with the October 2017 Northern California Wildfires are ongoing. PG&E’s mitigation plan includes: continued roll-out of the Wildfire Reclosing Operation Program; fuel reduction and powerline corridor management; overhang clearing; and targeted conductor replacement. PG&E will review the results of the Northern California Wildfire investigations and incorporate them in future wildfire

1 Wildfire risk is defined as: PG&E assets may initiate a wildland fire that endangers the public, private property, sensitive lands, and/or leads to long duration service outages.

risk management approaches, as appropriate. PG&E expects to update the wildfire risk analysis, modeling and proposed mitigations as more information becomes available.

Based on PG&E's analysis, the main drivers for fire ignitions related to PG&E facilities are:

- Vegetation contact with conductors;
- Equipment failure; and
- Third party contact.

PG&E's controls focus on reducing the probability of wildfire ignitions overall, with particular emphasis on limiting ignitions in high-risk wildfire areas and on days when fire risk is elevated.

Managing wildfire risk is a top priority for PG&E; the annual total investment in 2016 for all wildfire risk related controls was approximately $750 million.[2] Most of this investment, about $435 million,[3] was focused on PG&E's biggest wildfire risk driver—Vegetation Management (VM). In recent years, the significant increase in wildfire controls spend has been driven by vegetation-related Catastrophic Event Memorandum Account (CEMA) work to remove trees impacted by drought and bark beetles.[4]

Through the RAMP process, PG&E evaluated its ability to reduce the wildfire risk, and concluded that VM work continues to be the most significant and effective control in reducing fire ignitions. VM work addresses the highest wildfire risk driver (37 percent of ignitions),[5] and was shown in the wildfire operational risk model to have a significantly higher Risk-Spend Efficiency (RSE) than infrastructure replacement work. PG&E plans to continue investing significant resources in VM throughout the 2017-2022 timeframe.

PG&E will continue to implement four wildfire mitigations for the 2017-2019 timeframe. The first is continuing expansion of the Wildfire Reclosing Operation Program in

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2 This is the approximate amount shown in Table 11-1.

3 This is the approximate total of VM and CEMA VM, as shown in Table 11-1.

4 CEMA vegetation work began in 2014 and increased to about $190 million, annually, as of 2016.

5 The fire ignitions are defined based on the reportable fire ignition definition from the California Public Utilities Commission (CPUC) per Decision (D.) 12-02-015.

elevated and extreme areas, based on Fire Map 2.[6] The Wildfire Reclosing Operation Program expansion potentially reduces risk for all top drivers,[7] including: vegetation, equipment failure, third party and animal (any drivers which are associated with wire down events), by potentially avoiding an ignition during wire down events. The second mitigation is replacement of non-exempt[8] surge arresters with exempt surge arresters certified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk—this work will continue through 2022. The other two mitigations are further expansion of VM practices: fuel reduction and powerline corridor management; and overhang clearing.

Additionally, PG&E will perform the following mitigations in the 2020 through 2022 time frame:

- Continued expansion of Wildfire Reclosing Operation Program by adding Supervisory Control and Data Acquisition (SCADA) capabilities to existing circuit breakers and line reclosers in extreme fire risk areas (2020-2022), building on PG&E's ongoing SCADA expansion as part of its Distribution Automation Program;
- Continued fuel reduction and powerline corridor management (2018-2020);
- Continued overhang clearing (2018-2020);
- Continued replacement of non-exempt surge arresters(2017-2022); and
- Expanded targeted conductor replacement (2020-2022).

PG&E considered several alternative mitigations in its analysis beyond the five mitigations described above, including: targeted underground conversion, additional pole replacements, and other possible mitigations. Ultimately, the five proposed mitigations were chosen because they have relatively high RSEs, focus on the main risk drivers and have additional benefits, as reflected in the Distribution Overhead Conductor – Primary Risk. However, as noted above, the ongoing wildfire

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6 Fire Map 2 is being developed by the Fire Safety Technical Panel, as required by Order Instituting Rulemaking (OIR) 15-05-006. Fire Map 2 is not final as of this filing, and has gone through numerous revisions. PG&E leveraged Fire Index Areas to use as the exposure for the RAMP model. In future iterations of the model, the exposure can be changed to align with Fire Map 2 elevated and extreme areas. In addition PG&E leveraged the outputs of the Ignition Spread Model, which provides a quantified risk output used to compare the relative risk reduction of performing mitigations in higher risk areas.

7 The drivers are defined in Section II.c, below.

8 Exempt equipment is certified by CAL FIRE as having low fire risk, and thus exempt from vegetation clearing requirements associated with Public Resource Code (PRC) 4292.

investigations may identify additional drivers and mitigations that will be reflected in PG&E's assessment of wildfire risk going forward.[9]

The Fire Safety Rulemaking,[10] which is currently underway, is developing a state-wide regulatory fire map, known as Fire Map 2, and new fire safety rules. PG&E will make adjustments, as necessary, to the current plans to comply with new rules stemming from the Fire Safety Rulemaking. In addition, the incremental mitigations, which are beyond compliance requirements proposed in this chapter, will be targeted in the elevated and extreme areas of Fire Map 2.

In 2018 and beyond, PG&E will continue to look for opportunities to prioritize the existing substantial investment in wildfire-related controls in ways that most effectively reduce the wildfire risk.

PG&E will continue to build on the assessment completed as part of RAMP by refining the modeling capabilities and quantification of the wildfire risk to improve identification and prioritization of work that has a significant impact on wildfire risk reduction. One area for future model enhancement is to break out transmission and distribution (T&D) circuit miles separately in the wildfire operational risk model. Exposure in the model is by circuit mile, and currently does not consider the relatively higher number of ignitions per circuit mile that occur on distribution circuits, as compared to transmission circuits. Additional areas for enhancement include modeling the RSE of select existing

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9 One alternative, that PG&E understands may be part of future public discussions, is whether there are locations and conditions where electric facilities should be preemptively de-energized. In such a discussion, there are many important issues that would need to be addressed. Proactively de-energizing parts of the electric grid is highly complex, due to significant public safety issues such actions can pose. De-energizing lines can have an immediate and very broad impact on public safety, affecting first responders, and the operation of critical facilities, such as: hospitals; schools; the provision of water and other essential services; traffic signals; communications systems; operation of building systems, such as elevators; and much more. The many potential public safety issues associated with de-energizing lines are the same reasons electric systems must be designed to be highly reliable. Modern society relies on these systems, which are essential to public safety. Widespread de-energizing would therefore introduce additional safety risks that would have to be carefully considered, communicated and addressed across many agencies and with the communities and customers PG&E serves. Potential actions that would have to be considered range from the establishment of communications protocols to notify customers of plans to de-energize lines to working with public agencies and critical service providers to implement emergency energy systems among critical customer classes.

10 Fire Safety Rulemaking ((R.) 15-05-006).

controls and further calibration of tail outputs[11] of the model against the impacts of recent catastrophic fires that have occurred across California.

II. Risk Assessment

A. Background

PG&E defines wildfire risk as: PG&E assets may initiate a wildland fire that endangers: the public, private property, sensitive lands, and/or leads to long-duration service outages.

PG&E has designated wildfire as an enterprise risk[12] (in addition to being a top safety risk) since 2006. This risk is reviewed annually by the Safety, Nuclear and Operations, Committee of PG&E's Board of Directors. PG&E's exposure to wildfire risks continues to escalate despite increasing investment in compliance and public safety programs given various environmental and human factors. The most notable investments are the T&D routine VM work and the CEMA VM work related to the drought and the ongoing tree mortality state of emergency.[13] The CEMA work investment alone amounts to $190 million in 2016 and $208 million in 2017.[14] Environmental variations, such as drought conditions or periods of wet weather that drive additional vegetation growth and wildfire fuel increases, can influence both the likelihood and severity of a wildfire event.

PG&E used the bow tie methodology, as shown in Figure 11-1, below, to develop a quantitative risk model specific to wildfire risk (wildfire operational risk model). This model uses a combination of PG&E-specific data, industry data, and SME input, to gain a better understanding of the risk drivers for wildfire. PG&E also used an Ignition Spread Modeldeveloped by REAX Engineering described in a report for PG&E which simulates ignitions across PG&E's service territory, incorporating climatology, terrain, and fuel, in a probabilistic computer simulation, to help prioritize where to perform work which most effectively reduces the risk of catastrophic fires related to PG&E facilities.

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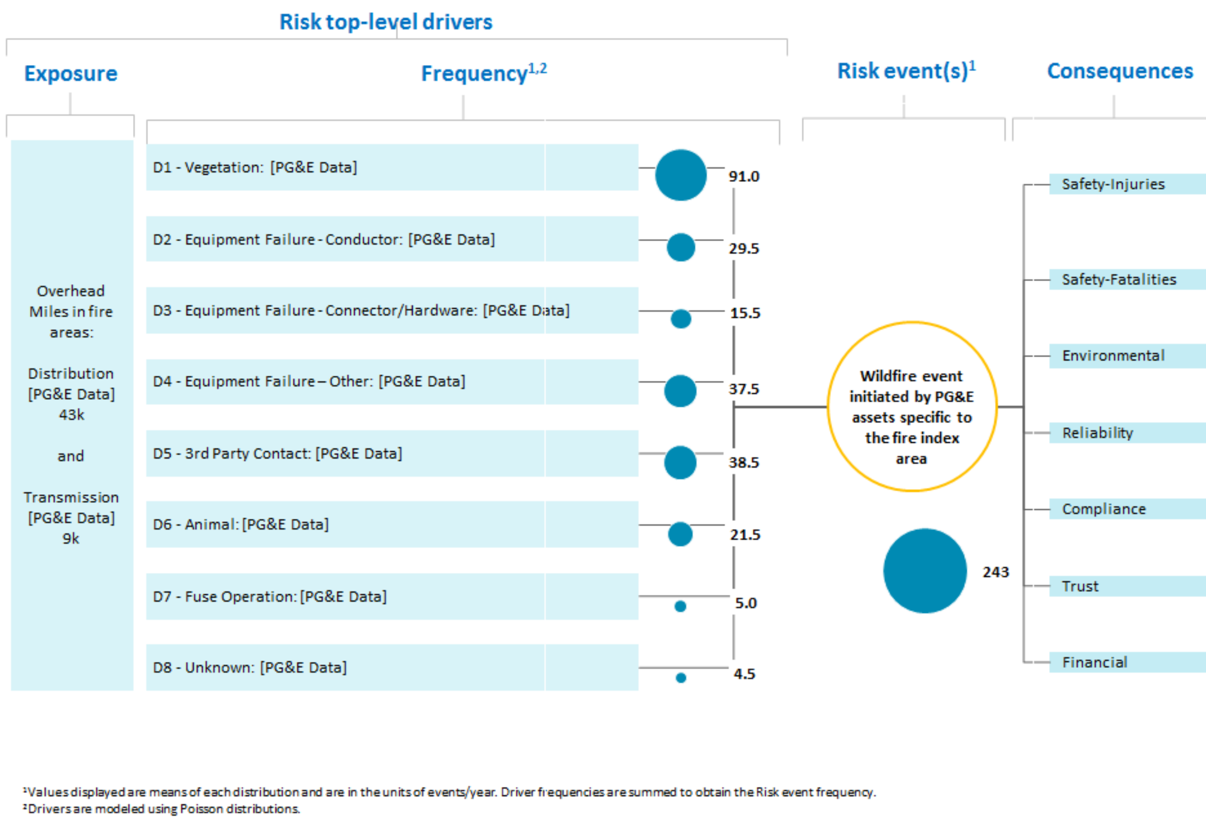
11 Tail outputs refer to the lower probability, higher consequences for each consequence category (safety, environmental, reliability, trust, financial).

12 Enterprise risk is defined in the introduction chapter.

13 Proclamation of a state of emergency declared on October 30, 2015. This proclamation states in part "State agencies, utilities, and local governments to the extent required by their existing responsibilities to protect the public health and safety, shall undertake efforts to remove dead or dying trees in these high hazard zones that threaten power lines, roads and other evacuation corridors, critical community infrastructure, and other existing structures."

14 This is the estimated 2017 forecast spend as of October 1, 2017.

Figure 11-1: Risk Bow Tie



B. Exposure

PG&E has approximately 82,000 distribution overhead circuit miles and 18,000 transmission overhead circuit miles. The exposure included in the wildfire operational risk model is 43,000 overhead distribution circuit miles and 9,000 overhead transmission circuit miles, which are the total circuit miles that fall within Fire Index Areas, as determined by the Fire Danger Rating System.[15] The Fire Index Areas were created by federal and state agencies to enable an area-based fire danger rating, based on local weather conditions. The parts of PG&E service territory not fire-indexed, have significantly lower fire risk, and are excluded from the model.

Not all overhead line miles in Fire Index areas have equal risk. The probability of ignitions related to PG&E facilities varies from area to area, as do the consequences. In order to compensate for the differences in ignition probability and consequence, multipliers were applied to certain mitigations implemented in targeted areas within the total exposure area.

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15 The area fire-indexed, as part of the Fire Danger Rating system, encompasses nearly all elevated and extreme areas, as defined by the draft Fire Map 2. After the Fire Map 2 is finalized, the wildfire operational risk model will be updated to align with it.

When a mitigation that addresses a specific risk driver is implemented in a targeted area, and a risk driver frequency per circuit mile is quantifiable, a multiplier is used to estimate the effectiveness of the proposed mitigation in reducing the targeted risk driver.[16] Using the Ignition Spread Model, described above, PG&E was able to develop a quantified estimate of the relative effectiveness of performing work in the highest risk circuit miles (estimated at 16,500 circuit miles), as compared to applying the mitigation across the entire system. This multiplier is used as part of the mitigation effectiveness estimate input in the Wildfire Operational Risk Model.

After Fire Map 2 is finalized, the Ignition Spread Model can be used to develop multipliers to quantify the relative effectiveness of performing work in the elevated versus extreme fire risk areas, which can then be used in for future wildfire risk assessments.

C. Drivers and Associated Frequency

There were 486 fire ignitions[17] associated with PG&E facilities that occurred in Fire Index areas within PG&E's service territory during the 2-year period 2015-2016. These 486 ignitions (or an average of 243 per year) were related to eight top-level risk drivers:

- **D1 – Vegetation:** Tree, tree limb, or other vegetation contact with conductors that result in fire ignition. The vegetation risk driver accounts for 37 percent[18] of 243 ignitions, or 91 per year.
- **D2 – Equipment Failure – Conductor:** Failure of conductor resulting in wire down and fire ignition. All three equipment failures categories may be influenced by weather and other environmental factors (e.g., corrosive environment). The Equipment Failure – Conductor risk driver accounts for 12 percent of 243 ignitions, or 29.5 per year.
- **D3 – Equipment Failure – Connector/Hardware:** Failure of connectors, splices, or other connecting hardware resulting in wire down and fire ignition. The equipment Failure – Connector/Hardware risk driver accounts for 6 percent of 243 ignitions, or 15.5 per year.

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16 The workpaper for each mitigation explains the estimates and multipliers used in determining the overall effectiveness of the mitigation in reducing each risk driver and how it was derived.

17 Note the bow tie in Figure 11-1 shows the annualized risk driver frequency which is half of 486. The fire ignitions are defined, based on the reportable fire ignition definition from CPUC, per D.12-02-015. Fire ignitions used in the model are the subset that were located in fire-Indexed areas.

18 The total of all risk drivers percentages do not add up to 100 percent, due to rounding.

- **D4 – Equipment Failure – Other:** Failure of other line equipment, such as: poles, insulators, transformers, and capacitors, that leads to fire ignition. The Equipment Failure – Other risk driver accounts for 15 percent of 243 ignitions, or 37.5 per year.
- **D5 – Third Party Contact:** Contact caused by a third party, leading to fire ignition, such as cars hitting poles and Mylar balloon contacts. The Third-Party Contact risk driver accounts for 16 percent of 243 ignitions, or 38.5 per year.
- **D6 – Animal:** Animal contacts that result in fire ignition, such as birds contacting energized conductors then falling to the ground and causing an ignition. The Animal risk driver accounts for 9 percent of 243 ignitions, or 21.5 per year.
- **D7 – Fuse Operation:** Operation of a fuse for a faulted condition that results in fire ignition from the blown fuse. The Fuse Operation risk driver accounts for 2 percent of 243 ignitions, or 5 per year.
- **D8 – Unknown:** Situations where PG&E was unable to determine the cause of the ignition; however, it appeared that the ignition may have been attributable to PG&E facilities. The Unknown risk driver accounts for 2 percent of 243 ignitions, or 4.5 per year.

D. Consequences

In the overwhelming majority of cases,[19] the fires are extinguished quickly, resulting in very little damage, but in some cases, larger wildfires can result. There is a range of potential public safety risks resulting from a fire ignition associated with PG&E assets. Figure 11-2 shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated Multi-Attribute Risk Score (MARS). This probabilistic modeling was created based on a CPUC requirement.[20] The data sources used for each of the consequence attributes are provided in the table. This table represents PG&E's first effort at modeling the full consequence distribution related to the wildfire risk. While this work represents a significant step, there is still work to be done to calibrate the consequence distribution using additional data sets, especially for lower probability, higher consequence events. The results of investigations into the catastrophic October 2017 Northern California Wildfires, and other wildfire events from 2017, could inform future iterations of PG&E's wildfire operational risk model, depending on the outcome of those investigations.

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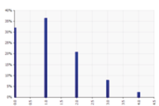
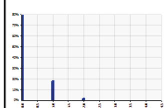
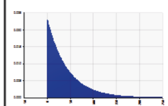
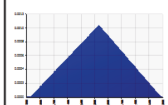
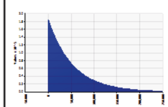
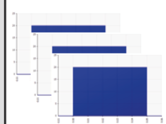
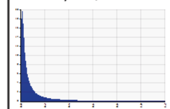
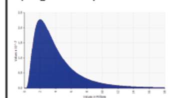
19 359 of 486 fire ignitions or 74 percent of CPUC-reportable fire ignitions in Fire Index Areas in 2015 and 2016 were less than 1/4 acre in size.

20 CPUC D.16-08-018, p. 151.

Figure 11-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	Calfire and NFIRS Data	Calfire and NFIRS Data	Calfire, PG&E & Pacific Union settlement Data	PG&E Data	NA	PG&E Data	PG&E and Claims Data
Consequence Distributions	Percent of wildfire events with an injury = 0.51% Percentage of events with injury or fatality = 0.62% Mean=1.14 (Poisson) 	Percent of wildfire events with a fatality = 0.10% Percentage of events with injury or fatality = 0.62% Mean=0.23 (Poisson) 	Ave # acres burned/wildfire event = 44 acres (exponential)  x Cost per acre: Min = $855/acre Ave = $1,865/acre Max = $2,778/acre (Triangular) 	Percentage of events resulting in outage = 95% Ave = 54k customer minutes (Exponential) 		Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Property: destroyed: Ave=0.392 Std Dev=1.454 Shift=0.018 (Lognormal) x Cost/property destroyed=$778k  + Compensatory claims from safety events: Ave=$4.1M Std Dev=$3.3M Shift=$66k (Lognormal) 
Outcome-TA-NU[1]	5.89	1.78	$27,649,728	14,791,813		18.5%	$125,436,835
Outcome-TA-MARS[2]	1.61	48.54	2.76	36.98		92.43	75.26
						MARS Total	257.58

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI)**: As part of the wildfire operational risk model, PG&E estimates a ratio of five injuries for every one fatality. This assumption was based on data from the National Fire Incident Reporting System. The expected number of injuries based on the model is 1.7, the tail average is 5.89, and the corresponding MARS contribution is 1.61 MARS units.
- **Safety – Fatalities (SF)**: The model leverages CAL FIRE data[21] to determine the probability of a fire leading to a fatality. The CAL FIRE data, which includes data from state-wide events, provides a more complete distribution of low probability events, including fatalities per fire. Based on the model assumptions, the number of fatalities is 0.3, the tail average is 1.78, and the corresponding MARS contribution is 48.54 MARS units.
- **Environmental (E):** Cost per acre distribution is based on the compensatory amounts paid to the United States (U.S.) Forest Service. In addition, a distribution of the number of acres impacted per fire, based on CAL FIRE data, is also used. These two distributions are multiplied together in the model to determine the environmental cost per ignition. The U.S. Forest Service (USFS) compensatory claims are used because the costs are considered strongly-linked to environmental impacts. Other non-environmental costs are included in the Financial Impact section. The expected environmental impact, based on the model, is $23 million, the tail

21 CAL FIRE data is recorded by CAL FIRE on fires responded to and attributes of those fires.

average is $28 million and the corresponding MARS contribution is 2.76 MARS units.

- **Reliability (R)**: Measured as minutes of outage time (PG&E customer-minutes) related to fire ignitions in 2015 and 2016. Reliability is also another measure of public safety. Power outages impact a wide array of public safety systems, including: traffic lights, hospitals, police and fire stations, telecommunications systems, in-home respirators and other medical devices, water pumps, and electric garage door openers. The expected reliability impact, based on the model, is 13 million customer-minutes; the tail average is 15 million customer minutes, and the corresponding MARS contribution is 36.98 MARS units.
- **Compliance (C)**: Compliance costs were not included in the model because regulatory fines are typically shareholder-funded and therefore not applicable in the RAMP analysis.
- **Trust (T)**: Events are dependent upon safety outcomes, both injury and fatality, and categorized as: low, severe, and high. This methodology was used across all risks.[22] Based on the tail average model results across the 2017-2022 time periods, the calculated average worst case impact on trust is approximately 18.5 percent.
- **Financial (F)**: For financial impacts, the model utilizes the preliminary costs associated with the Butte Fire[23] as a benchmark to determine the estimated cost-per-structure impacted. The total costs associated with the Butte Fire have not been finalized and will need to be updated in future analysis. The environmental costs are taken out of the total, and the remaining cost is modelled as a cost-per-structure impacted. A distribution for number of structures-impacted-per-fire is created in the model, based on CAL FIRE data. The expected financial impact, based on the model, is $84 million, the tail average is $125 million, and the corresponding MARS contribution is 75.26 MARS units.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

This section describes PG&E's existing controls for wildfire risk. The efficacy of these controls is reflected in the current performance of the risk.[24] Each of the controls described in this section manages one or more risk drivers of the Wildfire risk.

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22 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

23 See PG&E 2017 Annual Report page 56 note 3, Third-party claims and Utility clean-up, repair, and legal costs [http://s1.q4cdn.com/880135780/files/doc_financials/2017/annual/2017-Proxy-Statement-Final.pdf].

24 Current performance of the risk is the baseline risk model outputs discussed in Section II consequences.

Table 11-1, included below, summarizes the controls and associated 2016 recorded costs associated with each control.

C1 – Overhead Patrols and Inspections: PG&E patrols and inspects its overhead electric facilities to identify damaged facilities and other conditions that may pose a risk of wildfire ignition. Patrols and inspections are performed annually, in urban and high-risk wildland interface areas, and bi-annually, in rural areas. Any corrective actions required in wildland interface areas receive priority treatment, and are scheduled and tracked to completion prior to peak fire season. Maintaining auditable documentation of patrol and inspection activity and findings is another key program feature. This control reduces exposure to all wildfire risk drivers.

C2 – Vegetation Management: PG&E has a VM Program focused on compliance with General Order (GO) 95 Rule 35, PRC 4292, and PRC 4293. The program includes specific inspection[25] and identification of potentially problematic vegetation, clearing and removal, and quality assurance. The main components of this work are the routine VM Program, Vegetation Control (VC) and quality assurance.

- The Routine Vegetation Program is designed to comply with GO 95 Rule 35, and PRC 4292 and PRC 4293[26] through annual inspection and associated tree work. In addition to routine compliance work, PG&E performs Public Safety and Reliability vegetation work, which targets areas with risk factors associated with a higher likelihood of vegetation-caused outages and vegetation-caused wires down. Moving into 2018, PG&E is building on previous VM wildfire risk reduction work. The VM work plan is being developed to focus even more on the highest risk wildfire areas, based on the extreme Fire Risk Area of Fire Map 2.[27] Further prioritizing work in the highest risk areas will continue to build upon the improvements to the effectiveness of this work in reducing the probability of catastrophic wildfires.
- The VC Program performs vegetation clearing around approximately 120,000 utility poles that have non-exempt equipment and are subject to PRC 4292[28] or local requirements.

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25 Vegetation inspections are performed separately from the overhead patrols and inspections referred to in C1. Vegetation inspections are performed by VM contractors trained to evaluate potential vegetation interactions with power lines.

26 CPUC GO 95 Rule 35, PRC 4293 and PRC 4294 are regulatory compliance requirements for VM and clearance from vegetation to conductors.

27 Fire Map 2 proceeding (R.16-05-006). PG&E is developing draft plans using a draft version of Fire Map 2, and will update these plans as Fire Map 2 is finalized.

28 PRC 4292 requires that PG&E maintain a firebreak of at least 10 feet in each direction from the outer circumference of the base of subject poles to prevent the spread of fire.

- PG&E performs audits through the VM Quality Assurance Program throughout the year, independent of pre-inspection and tree work. These audits are designed to verify inspections and tree work performed by contractors.

This control reduces exposure to Vegetation risk driver (D1).

C3 – Catastrophic Event Memorandum Account – Vegetation Management: This control includes five initiatives intended to address the vegetation impacts associated with prolonged drought conditions and the ongoing bark beetle-related tree mortality state of emergency.[29] The five initiatives are as follows:

- Enhanced Vegetation Inspection and Mitigation – Additional ground and air inspection and tree work in high fire threat areas to provide increased assurance that changing forest conditions will not result in vegetation interactions with power lines.
- Wild Land Urban Interface Protection – Additional VM inspections and tree work in Local Responsibility Areas[30] (LRA) and providing VC work in high fire risk LRAs.
- Fuel Reduction and Emergency Response Access – Funding local Fire Safe Councils[31] to support fuel reduction in high fire danger areas around PG&E's electric distribution facilities.
- Early Detection of Forest Disease/Infection – Formed cooperative information sharing with universities, CAL FIRE and the USFS on forest health.
- Early Detection and Response to Wildfires – Funding fire lookouts, aerial patrols, and fire detection cameras located near PG&E's electric distribution facilities.

This control reduces exposure to vegetation risk driver (D1).

C4 – Non-exempt Equipment Replacement: Exempt equipment is certified by CAL FIRE as having low fire risk. This control refers to the planned replacement of equipment not exempt from PRC 4292 requirements with equipment that is exempt. This control reduces exposure to Equipment Failure – Other risk driver (D4).

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29 The Governor proclaimed a state of emergency on tree mortality on October 30, 2015, and CPUC resolution ESRB-4, dated June 16th, 2014 directed Investor-Owned Electric Utilities to take remedial measures to reduce the likelihood of fires started by or threatening utility facilities.

30 LRAs include incorporated cities, cultivated agriculture lands, and portions of the desert. LRA fire protection is typically provided by city fire departments, fire protection districts, counties, and by CAL FIRE under contract to local government [http://www.fire.ca.gov/fire_prevention/fire_prevention_wildland_faqs#desig01].

31 Fire Safe Councils are community-based, self-governed groups of people that focus on fire safety; they: distribute fire safety materials; teach fire-safe home construction techniques; conduct fuel reduction projects; fund defensible space projects around homes and escape routes; sponsor lookout towers; and form community safety networks, and the like.

C5 – Overhead Conductor Replacement: This control refers to programs that replace overhead conductor either proactively through a targeted program or reactively after a failure occurs. Conductor in high-risk wildfire areas and conductor with higher likelihood of failure are prioritized in the proactive replacement. This control reduces exposure primarily to the Equipment Failure – Conductor and Equipment Failure – Connector/Hardware risk drivers (D2, D3). In addition, it reduces some wire down events and associated possible fire ignition for Equipment Failure – Other, Third-Party Contact, and Animal. (D4, D5, D6).

C6 – Animal Abatement: Includes installing new equipment or retrofitting existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on T&D poles, such as jumper covers, bushing covers, perch guards, or perching platforms. This control reduces exposure to the animal risk driver (D6).

C7 – Protective Equipment: 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 reduces exposure for all wildfire risk drivers.

C8 – Overhead Equipment Replacement: Proactive identification and replacement of critical overhead distribution equipment, such as: cross-arms, transformers, capacitors, reclosers, and switches. Equipment is identified for replacement through the inspection and patrols control (C1) or through ad hoc inspection. This control reduces exposure to the equipment failure-other risk driver (D4).

C9 –Pole Replacement: This control includes the identification and replacement of wood T&D poles, including intrusive inspection work (pole test and treat), and replacement or remediation. GO 165[32] requires intrusive inspections on a 20-year cycle. PG&E's program tests poles every 10 years for most poles[33]—exceeding the inspection cycle compliance requirements—and incorporates wood preservation practices that exceed compliance requirements. These factors allow PG&E to identify and mitigate the decay of wood to reduce failures. Additionally, there is an accelerated retirement program[34] underway, which will proactively replace additional poles in 2018 and 2019 assessed to have higher likelihood of failure prior to their next scheduled inspection. This control reduces exposure to the Equipment Failure – Other risk driver (D4).

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32 GO 165 mandates inspection requirements for Electric Distribution and Transmission Facilities.

33 Intrusive testing for penta-treated poles under 50 years old is done every 20 years.

34 Part of the 2017 General Rate Case (GRC) Settlement Agreement was to replace additional poles in 2018 and 2019 beyond those identified by the Pole Test and Treat Program.

C10 – Wood Pole Bridging: This control refers to the installation of a bonding wire, which connects the insulator bracket through-bolt of all phases of a distribution wood pole, to reduce the probability of a pole fire occurring, due to current traveling through the wooden cross arms. Pole fires tend to occur after a light rain, likely due to increased current leakage through the insulators. This control reduces exposure to the Equipment Failure – Other risk driver (D4).

C11 – Design Standards: This control refers to general standards for proper application of equipment to ensure safe and reliable operation. For example, it includes conductor size, and conductor types in corrosion zones, or the use of specific types of connectors and splices. This control reduces exposure to all wildfire risk drivers.

C12 – Restoration, Operational Procedures and Training: This control refers to procedures contained in Utility Standard TD-1464S[35] for increased wildfire controls when a Fire Index Area has a rating of "Very High" or "Extreme."[36] A summary of Utility Standard TD-1464S is provided below:

- General readiness requirements for all employees are covered, including awareness of all laws, rules, and regulations of fire agencies having jurisdiction over areas in which they work or travel. Each crew must be equipped with well-maintained firefighting equipment.
- Fire Index ratings,[37] as determined on a daily basis during the fire season, are in effect from 8 a.m. to two hours after sunset.
- PG&E is restricted from manually energizing any section of line that experiences an outage in a Fire Index Area rated "Extreme" or "Very High," as determined by the daily Fire Index Map, until the line has been patrolled and all trouble cleared.

This control reduces exposure to all wildfire risk drivers.

Table 11-1 summarizes the controls and 2016 recorded costs associated with each control.

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35 Utility Standard TD-1464S is the utility standard for fire danger precautions in hazardous fire areas.

36 Daily fire index ratings are determined by PG&E meteorology using the National Fire Danger Rating System (NFDRS).

37 PG&E meteorology determines the fire index rating using a high resolution weather model to drive an industry standard fire danger rating model, NFDRS, to produce fire indices required for fire danger rating. Fire danger ratings are represented as adjectives that range from low to extreme for each Fire Index Area.

Table 11-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Overhead Patrols and Inspections	All	GRC TO	19,303 1,218	–
C2	VM	D1	GRC TO	200,115 45,473	–
C3	CEMA VM	D1	CEMA	190,204	–
C4	Non-Exempt Equipment Replacement	D4	GRC	–	3,457
C5	Overhead Conductor Replacement	D2, D3, D4, D5, D6	GRC	–	31,858
C6	Animal Abatement	D6	GRC TO	1,097 28	5,476 1,164
C7	Protective Equipment	All	GRC	–	47,744
C8	Overhead Equipment Replacement	D4	GRC	20,084	77,717
C9	Deteriorated Pole Replacement	D4	GRC TO	11,503 2,461	79,874 18,819
C10	Wood Pole Bridging	D4	GRC	46	–
C11	Design Standards	All	GRC TO	n/a	n/a
C12	Restoration, Operational Procedures and Training	All	GRC TO	n/a	n/a
TOTAL Expense and Capital				**252,148 (GRC)** **49,181 (TO)** **190,204 (CEMA)**	**246,127 (GRC)** **19,983 (TO)**

There are also four technologies which are under development which if fully implemented will provide benefits to the Wildfire risk controls described above. These technologies: (1) System Tool for Asset Risk (STAR); (2) Joint Use Map and Portal (JUMP); (3) VM Data Enablement; and (4) Next Generation Wildfire Detection are described briefly below.

STAR is a technology under development, which, when fully-implemented, will provide asset replacement direction, including Overhead Conductor Replacement (C5), Overhead Equipment Replacement (C8) and pole replacement (C9), based on asset-specific data for every piece of equipment in the three asset classes identified above. Each asset will receive a risk score that considers the probability of failure (based on asset health factors) and the resulting consequences (based on the function and location of the asset). Highest risk assets will then be prioritized for replacement.

Initial uses of STAR are focused on programs for evaluating the benefits of additional pole and conductor replacements, as well as optimization of inspection cycles based on health and risk. Future STAR uses may include addition of more electric asset classes, or focus on different programs (e.g., VM), so that STAR can be used to target assets with the most effective programs to mitigate the risks specific to each asset.

JUMP is technology that will support the existing Pole Replacement (C9) control. Incorrect pole loading calculations, due to erroneous or missing information on attachments to poles used jointly with other utilities and third parties, could contribute to pole failures, which is a potential cause of wildfires. Unauthorized pole attachments to joint poles are particularly problematic. The JUMP technology project will streamline the sharing of pole loading data with joint tenants or joint owners, and helps prevent incorrect loading of poles used jointly with other utilities and third parties. JUMP will help ensure that PG&E meets the requirements of CPUC pole and conduit (Order Instituting Investigation/OIR) in providing pole and conduit information.

VM Data Enablement is a technology that will support and enhance the existing VM control (C1). Overhead lines are presently inspected at least annually by inspectors driving and walking the lines. The Electric VM Department has acquired remote sensing data (e.g., Light Detection and Ranging (LiDAR),[38] video, orthoimagery, etc.) in recent years to improve T&D routine maintenance, inspection, reliability and wildfire mitigation activities, by providing more accurate baseline data to enable Managers to see how vegetation interacts with other risk factors, such as asset health and failure probability. This ability to see the convergence of multiple risk drivers holds promise for enhancing PG&E's operational risk models.

The Next Generation Wildfire Detection Technology Project directly impacts the detection and response wildfire strategies. Currently, PG&E manually gathers fire ignition reports from disparate sources. Reports of new fires and subsequent mitigating actions can be delayed, depending on remoteness and the time it takes to manually gather and disseminate intelligence. The National Oceanic and Atmospheric Administration and the National Aeronautics and Space Administration recently launched the next generation of satellites via the Geostationary Operational Environmental Satellite (GOES) Program, which will significantly improve fire detection timeliness and resolution. This system will provide extremely timely fire ignition data. This technology project will integrate existing PG&E meteorology systems to deploy a wildfire detection and alerting system utilizing the new GOES data.

IV. Current Mitigation Plan (2017-2019)

PG&E's plan includes: continuation of the Wildfire Reclosing Operation Program, fuel reduction and powerline corridor management, overhang clearing, and targeted

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38 LiDAR is a surveying method that measures distance to a target by illuminating that target with a pulsed laser light, and measuring the reflected pulses with a sensor.

conductor replacement. As described above, PG&E may make further changes to its current and proposed mitigation plans as more is learned about the causes of the wildfires and how the electric system risks should be evaluated and mitigated going forward.

M1 – Wildfire Reclosing Operation Program (SCADA programming): In the 2017 fire season, PG&E piloted its Wildfire Reclosing Operation Program on 38 select circuit breakers and line reclosers in high-risk wildfire areas. The procedure disables the reclosing operation of circuit breakers and line reclosers during "Very High" and "Extreme" fire risk weather conditions. The 38 locations were selected because they were in the high fire risk areas designated by the Fire Map 1,[39] and the equipment already had SCADA remote control capabilities installed. Disabling reclosing has both the potential to reduce the risk of fire ignition during a wire down event and a negative impact on reliability and the other associated public safety benefits described earlier in this chapter. When reclosing is disabled, a PG&E employee must be dispatched to patrol the line and determine if sustained damage has occurred prior to reclosing protective devices. Reclosing is disabled on days that are rated "Very High" or "Extreme" in a particular Fire Index Area utilizing the Fire Danger Rating System. During the 2017 fire season, PG&E monitored the impacts of disabling reclosing to better understand the wildfire risk reduction that might be achieved, and the public safety and reliability impacts to test the efficacy of the program. PG&E's plan has been, and continues to be, the expansion of the Wildfire Reclosing Operation Program to include additional SCADA enabled reclosers and circuit breakers that are within Fire Map 2 extreme and elevated areas.

In addition to the planned expansion of the Wildfire Reclosing Operation Program, PG&E looks forward to a multi-party discussion about locations and conditions under which PG&E should preemptively shut off power to reduce wildfire risk without jeopardizing public safety and reliability. As part of these discussions, it will be important to consider the implications of preemptively initiating potentially large power outages. Large power outages impact a wide array of critical public safety systems, including: traffic lights, hospitals, police and fire stations, mobile phone systems, wi-fi networks, in-home respirators and other medical devices, water pumps, and electric garage door openers. Given these public safety risks, PG&E will engage with communities and other stakeholders to assess the full societal impact of preemptively shutting off power under high-fire risk conditions.

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39 Fire Map 1 is the interim map adopted in D. 16-05-036. This map was the most relevant fire risk map available when target locations were determined in 2016.

M3 – Fuel Reduction and Powerline Corridor Management: The Fuel Reduction and Powerline Corridor Management mitigation reduces vegetation near targeted portions of overhead distribution lines. This clearing is expected to reduce the frequency and impact of ignitions caused by the vegetation risk driver. This mitigation targets approximately 3,600 miles of line for work over a five year period (2018-2022). The 3,600 circuit miles represent all of the draft Fire Map 2 extreme area.[40] The effectiveness of this work depends heavily on property owner agreements necessary to perform the work. In addition, it should be noted that as part of the Transmission Overhead Conductor risk, one of the proposed mitigations is also Additional Right of Way Expansion. This mitigation also reduces vegetation-caused outages on transmission overhead conductor; however, the impact on the wildfire risk overall is relatively small, as the transmission-caused vegetation ignitions are rare, based on historical PG&E ignition data.[41]

M4 – Overhang Clearing:[42] The Overhang clearing mitigation involves clearing vegetation above the overhead electrical distribution lines to reduce the chances of a branch falling on the line. The mitigation includes approximately 24,000 miles of overhang clearing over a five year period in high wildfire risk areas from 2018 and 2022. The 24,000 circuit miles represent all of the draft Fire Map 2 elevated and extreme areas.

M5 – Non-Exempt Surge Arrester Replacement Program: This mitigation started in 2017 and is expected to continue through 2022. This program increases the use of exempt equipment as described in PG&E's existing exempt, fire safe equipment Control C4. This program will replace non-exempt surge arresters, with exempt surge arresters which have been certified by CAL FIRE as low fire risk.

Additionally, while performing the surge arrester replacement, a previously identified grounding issue also will be corrected.[43] Replacing the surge arresters at the same time as correcting the grounding issue helps reduce wildfire risk and reduces ongoing

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40 The draft Fire Map 2 area as of July 31, 2017 has approximately 3,600 Tier III (extreme) distribution circuit miles and 20,500 Tier II (elevated) distribution circuit miles.

41 The 2015 and 2016 PG&E fire ignition data used for RAMP does not include any transmission related vegetation cause ignitions.

42 This Overhanging Clearing mitigation, defined in the wildfire risk, is the same as the Overhang Clearing mitigation defined in the Distribution Overhead Conductor – Primary (DOCP) risk, and is proposed as a mitigation in both risks in order to show the RSE for both risks.

43 The Surge Arrester Program described in PG&E's 2017 GRC was a maintenance program intended to correct the grounding issue only that did not provide any wildfire risk reduction benefit.

maintenance costs associated with maintaining fire breaks that are no longer required once the surge arresters are replaced.

In total, this program will replace approximately 90 percent of non-exempt surge arresters throughout the system, or approximately 90,000 surge arresters, between 2017 and 2022. Half of these locations are in Fire Index areas and provide wildfire risk reduction which is reflected in the wildfire operational risk model. The costs modeled to determine the RSE are based on the investment to replace the surge arresters in Fire Index areas less the total cost to correct the grounding issues at those locations.

Table 11-2: 2017 to 2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1	Wildfire Reclosing Operation Program[(a)]	2017	2019	D1, D2, D3, D4, D5, D6		800 (E) 50 (C)	200 (E)-
M3	Fuel Reduction and Powerline Corridor Management	2018	2019	D1	-	7,986 (E)	7,986 (E)
M4	Overhang Clearing	2018	2019	D1	-	17,280 (E)	17,280 (E)
M5	Non-Exempt Surge Arrester Replacement[(b)]	2017	2019	D4	7,520 (C)	41,824 (C)	43,192 (C)
TOTAL Expense and Capital by Year					**- (E) 7,520 (C)**	**25,466 (E) 41,824 (C)**	**25,266 (E) 43,192 (C)**

(a) Approximately $50,000 in overhead expenses were incurred in 2016 for SCADA programming and standard revision to enable this program which was in place for the 2017 fire season.

(b) Costs associated with the Non-Exempt Surge Arrester Replacement are shown in Table 11-2, Table 11-3, Table 11-5, and Table 11-6 is the total cost of the Non-Exempt Surge Arrester Replacement Program. The cost used in the wildfire operational model was adjusted to include only incremental equipment replacement costs in the Fire Index Areas. See related mitigation workpaper for further details.

V. Proposed Mitigation Plan (2020-2022)

The RAMP analysis and subsequent 2020-2022 mitigation planning largely was completed prior to the unprecedented October 2017 Northern California wildfires. Similar to the current mitigation plan described in Section IV above, PG&E may change its proposed mitigation plan as more is learned about the causes of the wildfires and how the wildfire risk should be evaluated and mitigated going forward.

To develop its proposed mitigation plan, PG&E evaluated the RSE for a number of mitigations and took into consideration other factors such as addressing top risk drivers and capability to drive down the highest risk ignitions. PG&E also will be evaluating the actual risk reduction effectiveness of each mitigation included in the proposed mitigation plan, post-implementation, to validate its effectiveness and to inform future plans. In some cases, PG&E may decide to expand those mitigations that show the most promise for risk reduction, or implement new mitigations as more is learned.

In anticipation of risk reduction from the current plan, PG&E's proposed mitigation plan includes a continued expansion of the Wildfire Recloser Operation Program, the non-exempt surge arrester replacement, overhang reduction, and fuel reduction and powerline corridor management mitigations included in the 2017-2019 current mitigation plan. These mitigations are expected to help PG&E reduce the frequency of wildfire events related to all three of the equipment failure risk drivers and the vegetation risk driver, which together represent the biggest opportunities for overall wildfire risk reduction.

M2 – Wildfire Reclosing Operation Program (SCADA Capability Upgrades): This mitigation installs SCADA capabilities for reclosers in Fire Map 2 extreme areas.[44] This entails installation of SCADA on more than 100 reclosers per year from 2020 through 2022, building on PG&E's existing programs adding SCADA capabilities to existing circuit breakers and line reclosers as part of its Distribution Automation Program. After SCADA capabilities are added to the reclosers they will become part of the Wildfire Reclosing Operation Program. PG&E needs to further assess the equipment at applicable locations to determine if other upgrades are needed to allow for remote reclosing disablement. As required these costs will be updated and included in PG&E's 2020 General Rate Case (GRC) filing.

M3 – Fuel Reduction and Powerline Corridor Management: This mitigation is a continuation of the current mitigation as described in Section IV.

M4 – Overhang Clearing:[45] This mitigation is a continuation of the current mitigation as described in Section IV.

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44 The estimated reclosers and circuit breakers are based on the draft Fire Map 2 area as of July 31, 2017. The Fire Map 2 area will change prior to being finalized and plans will be adjusted accordingly to reclosers and breakers in elevated and extreme areas.

45 This Overhanging Clearing mitigation defined in the wildfire risk is the same as the Overhang Clearing mitigation defined in the DOCP risk and is a proposed mitigation in both risks in order to show the RSE for both risks.

M5 – Non-Exempt Surge Arrester Replacement: This mitigation is a continuation of the current mitigation as described in Section IV. Replace 17,232 non-exempt surge arresters with exempt surge arresters each year from 2020 through 2022, resulting in replacement approximately 90 percent of all exempt surge arresters[46] in the distribution system.

M7 – Targeted Conductor Replacement (WF): This mitigation includes an additional 190 circuit miles of conductor replacement per year for 2020 through 2022 as part of a Targeted Conductor Replacement. This mitigation replaces select spans of overhead conductor in high-risk wildfire areas with hybrid tree wire (or covered conductor).

Table 11-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Drivers #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 - 2,205 (C) n/a (E)	1,995 - 2,205 (C) n/a (E)	1,995 - 2,205 (C) n/a (E)
M3	Fuel Reduction and Powerline Corridor Management[47]	0.9496	0.7977	2020	2022	D1	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)
M4	Overhang Clearing	0.3762	0.3160	2020	2022	D1	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
M7	Targeted Conductor Replacement (WF)	0.0049	0.0041	2020	2022	D2, D3, D4, D6	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)
TOTAL PROPOSED PLAN RSE: 0.0965 **TOTAL Expense and Capital by Year**							**234,977 - 259,712 (C) 20,213 – 30,319 (E)**	**236,363 - 261,243 (C) 20,213 – 30,319 (E)**	**237,794 - 262,825 (C) 20,213 – 30,319 (E)**

VI. Alternatives Analysis

PG&E performed an assessment of the following mitigations considered for inclusion in the proposed plan and how each relates to the risk drivers of wildfire:

- **M2 – Wildfire Reclosing Operation Program**: This is the mitigation as described in Section V.

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46 The percentage of surge arresters is an estimate based on SME judgement. The remaining approximately 10 percent are surge arresters installed on poles that do not have a distribution transformer.

47 M3, M4 and M7 mitigations are listed without escalation. In the 2020 GRC values will be adjusted to include escalation.

- **M3 – Fuel Reduction and Powerline Management**: This is the mitigation, as described in Section IV.
- **M4 – Overhang Clearing**: This is the mitigation as described in Section IV.
- **M5 – Non-Exempt Surge Arrester Replacement**: This is the mitigation, as described in Section IV.
- **M6 - Targeted Underground Conversion**: The targeted underground conversion mitigation replaces overhead conductor, and hence removing any opportunity for fire ignition with electrical overhead equipment on circuit miles. This mitigation is targeted in areas with high vegetation outages in high-risk wildfire areas based on Fire Map 2. However, the RSE is relatively small due to the high cost of underground conversion. This mitigation evaluated 50 circuit miles of targeted underground conversion per year from 2020-2022.
- **M7 – Targeted Conductor Replacement (WF)**: This is the mitigation as described in Section V.
- **M8 – Avian Mitigation for Wildfire Risk**: The Avian Mitigation for wildfire risk performs avian mitigation upgrades to structures near the location of an avian contact if the location is within the designated high-risk wildfire area. This includes jumper covers, bushing covers, perch guards, or perching platforms on high-risk poles.
- **M9 – Targeted Pole Replacement**: Targeted pole replacement reviews poles which are at higher risk of failure, performs a loading assessment and replaces poles if they do not meeting the loading criteria. Replacement will reduce the probability of failure and associated possible fire ignition. This mitigation replaces additional poles per year than the existing pole replacement program control from 2020-2022.

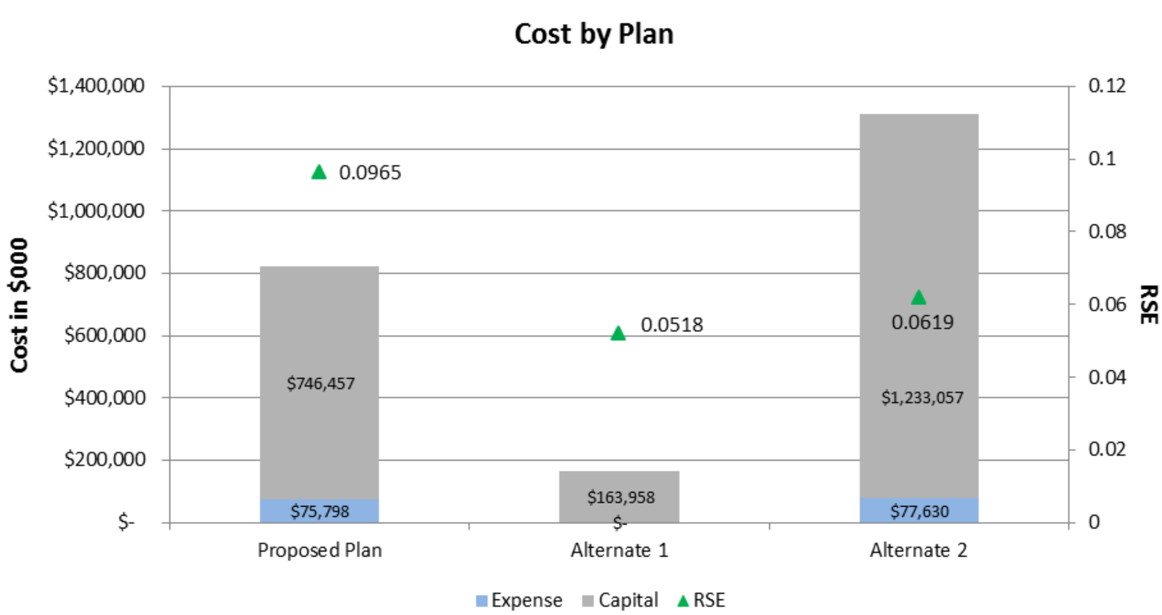
PG&E looked at key factors that ensure public safety, reliability, and drive down risk on the system. The Alternative 1 Plan does not go far enough for supporting public safety and reliability, while reducing risk on the system. The Alternative Plan 2 does not address the major risks, while providing a cost-effective solution for PG&E's customers. PG&E's proposed plan strikes the right balance, delivering safe and reliable service, while reducing system risk by focusing on the highest risk drivers and unnecessary costs to customers.

Table 11-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	X	X	X	WP 11-2
M3	Fuel Reduction and Powerline Corridor Management	0.9496	0.7977	X		X	WP 11-7
M4	Overhang Clearing	0.3762	0.3160	X		X	WP 11-10
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	X	X	X	WP 11-13
M6	Targeted Underground Conversion	0.0058	0.0048			X	WP 11-17
M7	Targeted Conductor Replacement	0.0049	0.0041	X		X	WP 11-21
M8	Avian Mitigation for Wildfire Risk	0.0016	0.0013			X	WP 11-25
M9	Targeted Pole Replacement	0.0002	0.0002			X	WP 11-28

Figure 11-3, below, shows the breakdown of the proposed plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE.

Figure 11-3: Alternative Plans by Cost and RSE Score



A. Alternative Plan 1

The Alternative 1 Plan does not go far enough in supporting public safety and reliability while reducing risk on the system.

Table 11-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 – 2,205 (C)	1,995 – 2,205 (C)	1,995 – 2,205 (C)
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
TOTAL ALTERNATIVE PLAN 1 RSE: 0.0518 **TOTAL Expense and Capital by Year**							**44,369 – 49,040 (C)**	**45,755 – 50,571 (C)**	**47,186 – 52,153 (C)**

B. Alternative Plan 2

The Alternative Plan 2 does not address the major risks while providing a cost-effective solution for PG&E's customers.

Table 11-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Wildfire Reclosing Operation Program	0.1007	0.0841	2020	2022	D1, D2, D3, D4, D5, D6	1,995 – 2,205 (C) n/a (E)	1,995–- 2,205 (C) n/a (E)	1,995 – 2,205(C) n/a (E)
M3	Fuel Reduction and Powerline Corridor Management	0.9496	0.7977	2020	2022	D1	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)	n/a (C) 6,389 – 9,583 (E)
M4	Overhang Clearing	0.3762	0.3160	2020	2022	D1	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)	n/a (C) 13,824 – 20,736 (E)
M5	Non-Exempt Surge Arrester Replacement	0.0470	0.0388	2020	2022	D4	42,374 – 46,835 (C)	43,760 – 48,366 (C)	45,191 – 49,948 (C)
M6	Targeted Underground Conversion	0.0058	0.0048	2020	2022	D1, D2, D3, D4, D5, D6, D7, D8	142,500 – 157,500(C) n/a (E)	142,500 – 157,500(C) n/a (E)	142,500 – 157,500(C) n/a (E)
M7	Targeted Conductor Replacement	0.0049	0.0041	2020	2022	D2, D3, D4, D6	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)	190,608 – 210,672 (C) n/a (E)
M8	Avian Mitigation for Wildfire Risk	0.0016	0.0013	2020	2022	D6	2,090 – 2,310 (C) 570 - 630 (E)	2,090 – 2,310 (C) 570 - 630 (E)	2,090 – 2,310 (C) 570 - 630 (E)
M9	Targeted Pole Replacement	0.0002	0.0002	2020	2022	D4	9,500 – 10,500 (C) n/a (E)	9,500 – 10,500 (C) n/a (E)	9,500 – 10,500 (C) n/a (E)
TOTAL ALTERNATIVE PLAN 2 RSE: 0.0619 **TOTAL Expense and Capital by Year**							**389,067 – 430,022 (C) 24,583 - 27,170 (E)**	**390,453 – 431,553 (C) 25,583 - 27,170 E)**	**391,884 – 433,135 (C) 25,583 - 27,170 (E)**

VII. Metrics

Current metrics used to track the Wildfire risk include the following:

Fire Ignitions: A reportable fire incident includes all of the following: (1) Ignition is associated with PG&E powerlines; (2) something other than PG&E facilities burned; and (3) the resulting fire traveled more than one meter from the ignition point.

Transmission and Distribution Wires Down: This metric tracks the number of instances where an electric primary distribution or transmission conductor is broken and falls from its intended position to rest on the ground or a foreign object.

911 Calls Responded to Within 60 Minutes: This metric measures the percentage of time that PG&E personnel respond (are on site) within 60 minutes after receiving a 911 call, with onsite defined as arriving at the premises where the 911 agency personnel are waiting. The presence of PG&E first responders is critical to enable safe fire response. PG&E's response rate benchmarks as best in class compared to other participating utilities in the country.

Proposed accountability metrics include the following, related to the proposed mitigations and drivers mitigated:

Table 11-7: Metrics

Mitigation	Associated Driver #	Proposed Metric	Targets
Non-Exempt Surge Arrester Replacement	D4	Exempt Surge Arresters Installed per year	17,000 per year in 2020 through 2022
Wildfire Reclosing Operation Program	D1, D2, D3, D4, D5, D6	Recloser SCADA installations in high-risk wildfire areas	More than 100 reclosers per year in 2020 through 2022
Fuel Reduction and Powerline Corridor Management	D1	Miles of work performed in target areas	720 miles per year in 2020 through 2022
Overhang Clearing	D1	Miles of work performed in target areas	4,800 miles per year in 2020 through 2022
Targeted Conductor Replacement	D2, D3, D4, D6	Miles of conductor replaced in target areas	190 miles per year in 2020 through 2022

PG&E will continue to evaluate and adjust the metrics used to track the wildfire risk to improve risk reduction monitoring capabilities.

VIII. Next Steps

In order to maintain the safety of the communities we serve, managing wildfire risk is a top priority for PG&E. It is paramount that PG&E maintains the appropriate investments in order to reduce the wildfire risk exposure to the public and PG&E's workforce. As mentioned earlier in this filing, PG&E will incorporate the analysis of the October 2017

Northern California Wildfires, and update mitigations as needed. In order to best serve PG&E's customers, PG&E will leverage the wildfire operational risk model and Fire Map 2 to improve the effectiveness of the existing $750 million[48] annual wildfire-related safety investments. In addition the mitigations planned for 2018-2022 will further reduce wildfire risk by performing essential vegetation and infrastructure work in the highest risk areas and targeting key risk drivers.

PG&E will continue to build on the work completed as part of RAMP by refining the modeling capabilities and quantification of wildfire risk to improve identification and prioritization of work that has a significant impact on wildfire risk reduction. It should be noted that the data, assumptions and analysis used in this chapter represent the information available at the time the model was developed and mitigations were selected.

One specific area for future enhancement is to break out T&D circuit miles separately. Exposure in the model is by circuit mile, and does not consider the increased number of ignitions, which occur per-distribution-circuit-mile, compared to transmission.

Additional areas for continued model development and risk quantification include modeling the RSE of select existing controls. Another future model enhancement is to further calibrate the tail-end outputs of the model against actual impacts of the 2017 Northern California Wildfires and other high impact fires that have occurred across California in recent years.

As discussed in the alternatives section, PG&E will monitor the implementation of the existing control plan and refine assumptions about wildfire reduction effectiveness, as appropriate, to determine how to most-effectively implement the proposed mitigation plan.

PG&E is determined to learn more: as additional and improved data becomes available; as technology improves; and as energy companies, regulators and legislators understand more about how climate change and extreme weather, and other environmental factors, affect the long-term resiliency of PG&E's critical infrastructure.

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48 This is the approximate amount shown in Table 11-1, which is the 2016 actual spend.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 12
NUCLEAR CORE DAMAGING

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 12
NUCLEAR CORE DAMAGING

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Nuclear Operations and Safety – Core Damaging Event
IN SCOPE	Pacific Gas and Electric Company (PG&E) owns, maintains, and operates a two-unit nuclear power plant with a combined capacity of 2,240 megawatts (MW). This risk encompasses both of these units. The Diablo Canyon Power Plant (DCPP) Probabilistic Risk Assessment (PRA) model includes seismic, internal fire and internal flooding risks.
OUT OF SCOPE	The two nuclear power plant units are in scope in their entirety. No portion of the plant has been excluded for consideration of impact on the core damaging event risk. Nevertheless, risk from external flooding, external fire, aircraft accidents, evacuation activities directed and coordinated by the county, and other external events are not included in the DCPP PRA model due to the very low risk contribution from these hazard categories.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data, the Nuclear Regulatory Commission (NRC), and subject matter expert (SME) judgement.

PG&E's Enterprise and Operational Risk Management effort is designed to minimize various risks, including risks associated with the ongoing operation of the DCPP.

This risk is defined as a Core Damaging Event, which is the potential for radiological release at DCPP due to natural disaster, equipment failure or some other significant event. The risk of a core damaging event has always been assessed since DCPP was placed in operation. The NRC requires every nuclear power plant to be designed and operated to minimize the risk of a core damaging event.[1] This is quantified via a "Probabilistic Risk Assessment" model that takes into account the potential drivers to a core damaging event.

PG&E performed an updated risk evaluation as part of the Risk Assessment and Mitigation Phase (RAMP) quantitative analysis in 2017 to review the key risk drivers and evaluate their potential impact, to evaluate the effectiveness of existing controls, and to develop additional planned mitigating activities, if necessary, to maintain the overall level of risk as currently evaluated. Through this risk evaluation process, it was determined that no additional mitigations will be proposed for this risk since PG&E considers this risk to be well below the regulatory required threshold, i.e., one event for every 10,000 reactor years. As shown in the bow tie assessment below, the PRA

1 Regulatory Guide 1.174 An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the License Basis.

assumptions which feed the RAMP modeling performed resulted in one event for every 18,376 reactor years.

However, with continuing seismic evaluations being performed in response to NRC regulations, DCPP will continue to evaluate the core damaging event risk and need for mitigations based on the evaluation. In addition, the NRC continues to evaluate if additional actions may be taken based on lessons learned from the Fukushima nuclear accident in 2011. Any new actions identified and imposed would lead to additional mitigations in the future.

PG&E will maintain the controls through the RAMP timeframe of 2022. These controls include:

- Maintaining the plant systems
- Operating the facility
- Plant and system configuration
- Security from external and internal threats and emergency response
- Independent oversight and training
- Regulatory required improvements and ongoing seismic evaluations

II. Risk Assessment

A. Background

Nuclear Operations and Safety – Core Damaging Event: An event with the potential for radiological release at DCPP due to natural disaster, equipment failure or some other significant event.

DCPP is an electricity-generating nuclear power plant located on about 12,000 acres 9 miles northwest of Avila Beach in San Luis Obispo County, California. DCPP has two Westinghouse-designed 4-loop pressurized-water nuclear reactors. The two units have a combined capacity of 2,240 MW.

This risk is an Enterprise risk and is reported to the PG&E Board of Directors on an annual basis.

The NRC regulations associated with all operating nuclear power plants within the United States (U.S.) require each plant to be designed and operated such that the quantitative risk of a core damaging event does not exceed a risk threshold of 10^{-4} events in a reactor year (one event for every 10,000 reactor years).[2] This is quantified via an industry required use of a PRA model that takes into account the effects of external initiating events and internal initiating events that could affect the plant and lead to a core damaging event. Constant monitoring of the plants performance to meet the PRA threshold of 10^{-4} core damaging events per reactor year is performed through the use of a PRA program to ensure that plant changes or maintenance activities do not place the plant in a condition outside of this threshold.

External initiating events, if unmitigated, are defined as those events that could impact a nuclear plant and could lead to a core damaging event. Examples of potential external initiating events are seismic events, tornados or tsunamis. Internal initiating events are those events that originate from within the power plant that could lead to a core damaging outcome if appropriate controls were not in place. Examples of internal initiating events include a loss of coolant accident or a station blackout. Some internal events are more likely than others such as a fire or flood (due to the amount of water within plant systems) and hence are analyzed separately for their specific impact.

The specifics of the drivers and the evaluated results are shown in Figure 12-1 below in the risk bow tie.

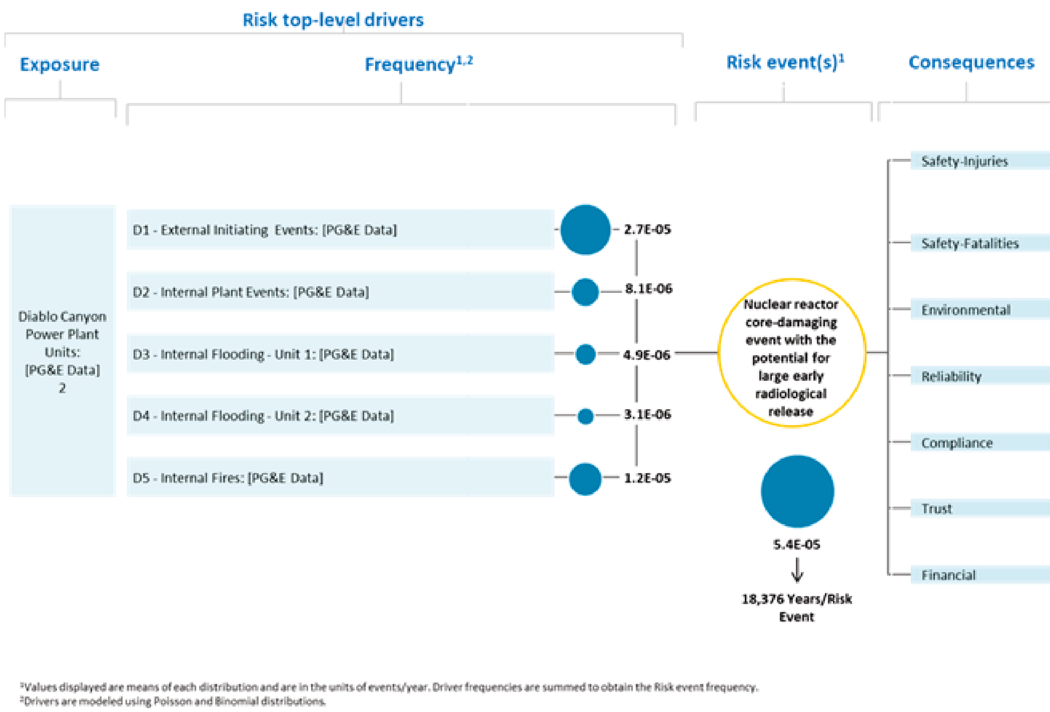
B. Exposure

Data, PRA modeling and industry operating experience were considered in the DCPP RAMP evaluation. Figure 12-1, below, shows the frequency that a core damaging event would reasonably be expected to occur for each of the five evaluated risk drivers and the combination of these drivers.

It is important to note that elements of this risk evaluation are ongoing, and results could change based on additional seismic and fire evaluations that are currently in progress.

2 Regulatory Guide 1.174 An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the License Basis.

Figure 12-1: Risk Bow Tie



C. Drivers and Associated Frequency

The RAMP model uses PRA frequencies to inform the bow tie assessment. The drivers are not dependent on each other as the contributors to each driver do not play a role in the other drivers. The data, and PG&E's experience, suggests that the risk drivers that could result in a core damaging event occur very rarely making the probability of a core damaging event from any one of these causes to also be very rare.

These drivers and associated risk frequency are discussed below:

- **D1 – External Initiating Events:** Nuclear energy facilities are robust structures with multiple layers of safety designed and built into them. Federal regulations require that these plants be able to withstand extreme natural events that may occur in the region where they are located, including earthquakes, hurricanes, and tornadoes which could disable nuclear safety equipment. The PRA frequency modeled in RAMP for other external initiating events resulting in core damage is represented by a seismic event with frequency of $2.67E^{-05}$ or once every 37,453 years.
- **D2 – Internal Plant Events:** Internal events originate from a postulated catastrophic failure of nuclear safety related equipment such as electric power supply systems or the reactor coolant system. Internal events

have been analyzed for RAMP to have a frequency of $8.12E^{-06}$ or once every 123,153 years.

- **D3 – Internal Flooding – Unit 1:** Floods pose a hazard to nuclear power plant safety for two reasons. First, flood waters can submerge and disable primary safety systems and their backups. Second, flood waters can impair efforts by operators to compensate for disabled systems and breached barriers. PG&E has submitted a "Flooding Walkdown Report" in response to the NRC requirements following the Fukushima nuclear accident. No equipment operability issues were identified in the walkdown. No additional flood protection enhancements or mitigation measures at DCPP resulted from the flood protection walkdowns. The PRA frequency which fed the RAMP modeling for flooding events resulting in core damage is $4.90E^{-06}$ for Unit 1. This equates to once every 204,082 years.
- **D4 – Internal Flooding – Unit 2:** The reason for the frequency difference between Unit 1 and Unit 2 is differences in the locations of various water storage tanks and the routing of their respective piping systems relative to various nuclear safety related equipment. The PRA frequency which fed the RAMP modeling for flooding events resulting in core damage is $3.10E^{-06}$ for Unit 2. This equates to once every 322,581 years.
- **D5 – Internal Fires:** Fire has the potential to damage equipment and electrical cables important to plant safety. A fire can damage cables for power, control systems and instrumentation, and affect reactor safety systems. A fire could damage enough cables that operators could not operate or monitor the plant normally and would have to take emergency actions to shut down the reactor safely. Fire protection regulations reasonably ensure a reactor maintains the ability to shut down safely in the event of a fire by:
  - Minimizing the potential for fires and explosions;
  - Rapidly detecting, controlling and extinguishing fires that do occur; and
  - Ensuring that operators can shut down the reactor safely despite a fire to minimize the risk of significant radioactive releases to the environment.

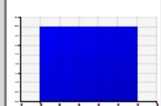
In the RAMP model, internal fires have a PRA frequency of $1.16E^{-05}$ or once every 86,207 years.

D. Consequences

The effects of a nuclear core damaging event depend on the safety features designed into a reactor and the trained operators who safely operate the plant. The nuclear safety principles of defense-in-depth ensure that multiple layers of safety systems are always present to make such accidents unlikely. DCPP is designed both to make a core damaging event unlikely, and to contain the accident inside the reactor's containment structure should it occur. Thus while the core damaging event will impact the reactor itself, the defense–in-depth layers of protection would preclude a release of significant radioactivity and protect the health and safety of the public.

The RAMP model inputs to each consequence are described with their respective consequence attribute below in Figure 12-2. In the figure, there is an explanation of the data sources used for each of the consequence attributes and the resultant tail average outcomes and multi-attribute risk score values.

Figure 12-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	NRC Data	NRC Data	Reuters	PG&E Data	NA	SME Input	PG&E Data
Consequence Distributions	Percent of core damaging events with the potential for either an injury or fatality per year = 0.00018% Mean=78k (Poisson) 	Percent of core damaging events with the potential for either an injury or fatality per year = 0.00018% Mean=78k (Poisson) 	5% value=$2B 95% value=$188B (Exponential) 	Zero impact based on study performed by CAISO and PG&E on the reliability impacts if DCPP were to trip. Also verified with PG&E's transmission planning org.		High severity=50-75% (Uniform) 	5% value=$2.75B 95% value=$5.5B (Exponential) 
Outcome-TA-NU[1]	0.00	0.00	$47,583,321			0.05%	$2,738,796
Outcome-TA-MARS[2]	0	0	4.76			0.25	1.64
						MARS Total	6.65

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** Zero injuries were experienced as a result of nuclear accidents at Three Mile Island (TMI). There were no deaths or cases of radiation sickness from either nuclear accident. Additionally, more than a dozen major, independent studies have assessed the radiation releases and possible effects on the people and the environment around TMI since the 1979 accident. The most recent was a 13-year study on 32,000 people. None has found any adverse health effects such as cancers which might be linked to the accident.[3] TMI and Fukushima are relevant since they are the only two commercial nuclear

3 Sources: American Nuclear Society, Nuclear Energy Institute, US NRC, World Nuclear Association.

plants that have ever experienced a core damaging event that are of similar plant design construction (Light Water Reactor Design). The licensing basis of the plant addresses potential accident scenarios and assumes the integrity of the containment is maintained. However, going beyond the design basis, the individual probabilities associated with the core damaging event, failure of containment, and dispersal of radioactivity are estimated. NRC studies have shown that this combination of events is extremely unlikely (estimated risk is ~$1x10^{-10}$ per reactor-year) . Using the $1x10^{-10}$ value represents a probability that is essentially zero due to the large uncertainties associated with such small numbers.

- **Safety – Fatalities (SF):** The same distributions as Safety-Injuries consequence attribute are used as input to the Safety-Fatalities consequence attribute. As noted in the section above for Safety-injuries, NRC studies have shown that occurrence of an accident that includes, core damage, failure of containment and dispersal of radioactivity is extremely unlikely (estimated risk is ~$1x10^{-10}$ per reactor-year).[4] Using the $1x10^{-10}$ value represents a probability that is essentially zero due to the large uncertainties associated with such small numbers.
- **Environmental (E):** The environmental impact is expressed as an exponential distribution with a 5th percentile value of $2 billion for TMI impacts escalated from 1993 data to present day at 3 percent. The 95th percentile value used in the distribution is $188 billion, representing the present day estimate of the total Fukushima environmental cost.[5] These are the only two relevant and comparable commercial nuclear accidents from which to draw. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of $48 million.
- **Reliability (R):** There are zero customer black-out events anticipated based on a study by the California Independent System Operator and PG&E analyzing impacts of sudden loss of both nuclear generating units at the same time during peak demand. These results have been corroborated by PG&E transmission planning and Energy Procurement departments.

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4 Sources: $1x10^{-10}$ is the short term Station Blackout (SBO) frequency for the unmitigated scenario found in Table 12-7 of the SOARCA (State of the Art Reactor Consequence Analysis) Report published by the US Nuclear Regulatory Commission https://www.nrc.gov/docs/ML1233/ML12332A057.pdf. SMEs expect that this scenario was similar to the events that would occur if there was a large early radiological release from Diablo Canyon. Note that caution should be used when estimating risks below $1x10^{-7}$ because of the inherent uncertainty in very small calculated numbers.

5 Sources: March 2001 World Nuclear Association source for 1993 TMI figure, Reuters December 9, 2016 source for Fukushima data.

- **Compliance (C):** Monetary fines and penalties are not included in this analysis as these costs cannot be recovered from customers and PG&E shareholders must bear the cost.

  In the aftermath of a nuclear core damaging event, there would be costs related to new compliance, however these costs are not included because it is expected, based on historical industry events, the plant would not restart.

- **Trust (T):** Due to the sensitive nature and public perception of any nuclear event, the trust impact for this risk is such that if any core damaging event is simulated to occur in the model, there is a high severity trust consequence. The distribution used is between a 50-75 percent brand favorability impacts based on SME input. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of 0.05 percent change in brand favorability.

- **Financial (F):** The financial impacts reflect the cost of replacing the power plant assets and of replacement power resulting from the failure. These costs were modeled with an exponential distribution with a 95th percentile value of $5.5 billion which consists of the current book value of assets of $1.8 billion with depreciation to 2019 using straight line depreciation and replacement power costs at $1.7 million/day for both units for 6.5 years. The 5th percentile value of the exponential distribution is based on 50 percent value of the above cost estimate. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of $3 million.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Operation of a nuclear power plant in the U.S. requires adherence to a significant number of NRC regulations which require controls to be in place, implemented, and constantly verified. These controls are implemented by the utility and are required to be independently reviewed by the NRC (daily inspections as well as focused deep dive team inspections), a Nuclear Safety Oversight Committee (NSOC), an independent utility Quality Verification organization, and the Diablo Canyon Independent Safety Committee (DCISC) (in California only). These controls described below include but are not limited to, maintaining the Plant Systems, operating the facility, plant and system configuration control, security from external and internal threats, and emergency response, independent oversight and training, and regulatory required improvements[6] and ongoing seismic evaluations.

6 Specifically, regulatory required improvements made to address Beyond Design Basis (BDB) Events.

C1 – Maintaining the Plant Systems: These controls address all plant event drivers that could initiate a core damaging event. This includes the following specific programs:

- A risk-informed work management program provides proper priorities for performing maintenance on permanent plant equipment, and requires detailed instructions to assure the proper performance of maintenance, specification of in-process and post-maintenance quality checks, proper specification of materials to be used, and post-maintenance testing to confirm functionality of equipment following maintenance.
- A NRC required program for performing preventive maintenance and testing on permanent plant equipment and some non-permanent plant equipment to assure equipment functionality.
- DCPP implemented a program consistent with the NRC maintenance rule, Chapter 10 of the Code of Federal Regulations (10 CFR) Section 50, Subsection 65 50.65) which requires the reliability of permanent plant equipment that is critical to mitigation of off-normal conditions (an unpredictable failure of production equipment) or whose failure could cause plant transients (a change in the reactor coolant system temperature, pressure, or both, attributed to a change in the reactor's power output) to be monitored, and actions initiated (such as increased preventive maintenance or testing) to meet minimum reliability standards as defined by this rule.
- DCPP implements an NRC required procedure program that maintains: (1) an extensive library of maintenance instructions, including instructions for major maintenance activities; (2) a fully staffed, qualified, and experienced maintenance craft and planning team capable of prompt response to significant equipment failures; (3) a fully qualified and experienced engineering staff capable of prompt response to significant equipment failures; and (4) an extensive spare parts inventory.

C2 – Operating the Facility: These controls address all event drivers that could initiate a core damaging event.

- DCPP implements an NRC required program that contains Operations and Emergency Response personnel that are trained on the implementation of procedures for mitigating natural phenomena and other external initiating events within the current design basis.
- DCPP has in place Emergency Operating Procedures, Severe Accident Management Guidelines (SAMGs), and Extreme Damage Mitigating Guidelines to address design basis and BDB events. Operators are trained and requalified in these guidelines on a periodic basis.
- DCPP also implements a BDB event response program established to address lessons learned from the Fukushima event to ensure alternative methods of core cooling are available for a BDB event to minimize the potential for core damage. This includes implementation of associated procedures and training.

- Operations and maintenance activities at DCPP are conducted in accordance with established procedures and processes.

C3 – Plant and system Configuration Control: These controls address all plant event drivers that could initiate a core damaging event.

- An NRC required PRA program is used to assess vulnerabilities to a wide range of events and to risk inform decisions and changes, including priority, and controls applied to such activities as maintenance and testing.
- Permanent plant equipment needed for core cooling/prevention of radiological release within established design bases are designed with appropriate levels of redundancy and diversity, as required by NRC regulations (e.g., 10 CFR 50 Appendix A). An NRC resident inspector and the Quality Verification Department evaluate compliance with NRC regulations and plant license basis.
- DCPP has extensive NRC required design control processes which assure that design changes are thoroughly evaluated for conformance to regulations, technical adequacy, and impact to other activities.
- DCPP has a configuration control program and personnel in place that assures that changes to the plant are thoroughly evaluated to determine whether they have the potential to adversely impact program effectiveness or require prior NRC approval.

C4 – Security From External and Internal Threats, and Emergency Response: This control addresses all event drivers of this risk that could initiate a core damaging event.

- DCPP has an “insider mitigation program” based on NRC regulatory requirements and which addresses trustworthiness of personnel granted access to DCPP. This program includes several provisions: (1) initial and periodic background checks of personnel who are provided access to the plant’s protected and vital areas; (2) a behavior observation program to identify the onset of any aberrant behavior; and (3) a fitness-for-duty program which ensures personnel are fit to perform their required safety functions.
- As part of this control DCPP maintains an extensive emergency plan that is integrated with the county state and federal governments to mitigate the consequences of events. This control ensures necessary actions are well rehearsed and understood to mitigate an issue early enough to prevent a core damaging event.

C5 – Independent Oversight and Training: This control addresses all plant event drivers that could initiate a core damaging event.

- Accredited and non-accredited training programs based on an industry standardized “Systematic Approach to Training” are in place and maintained to assure the technical capabilities of plant personnel responsible for performing activities affecting plant safety.
- The NRC, the Institute of Nuclear Power Operations, the NSOC, the DCISC, and Quality Verification provide intrusive independent oversight of a broad range of plant activities including operations, maintenance, engineering, quality verification,

project management, learning services, emergency planning, security, and plant management.

- Quality of procured permanent plant equipment and some temporary equipment, spare parts, and materials is verified through a NRC-required quality assurance program (10 CFR 50 Appendix B).
- DCPP maintains a corrective action program, as required by 10 CFR 50 Appendix B, to assure that performance shortcomings are identified, captured, and evaluated for corrective action.
- DCPP maintains an operating experience program wherein information on events in the industry is captured and analyzed for applicability and action at the plant.

C6 – Regulatory required improvements[7] and ongoing seismic evaluations: This control addresses all the drivers of this risk that could initiate a core damaging event. The plant's Long-Term Seismic Program is ongoing and has been in place since early in the plant's life. This program searches for and critically examines new information regarding the seismology around DCPP for changes in plant susceptibility to seismic events. The Long-Term Seismic plan is updated as new information is identified.

- DCPP acquired diesel-driven pumps and piping to provide replacement cooling for critical equipment in the event that the normal cooling methods are rendered unavailable.
- DCPP has acquired equipment for backup cooling for the spent fuel pools for both units and has created a program and procedures to implement the use of the equipment in the event of a failure of the permanent design basis equipment.

The following Table 12-1 displays the 2016 recorded spend for each of the previously identified controls.

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7 Specifically, regulatory required improvements made to address BDB Events.

Table 12-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Maintaining the plant systems	All	GRC	100,053	–
C2	Operating the facility requirements	All	GRC	51,630	–
C3	Plant and system configuration control	All	GRC	38,705	–
C4	Security from external and internal threats, and emergency response	All	GRC	53,683	–
C5	Independent oversight and training	All	GRC	18,171	–
C6	Regulatory required improvements and ongoing seismic evaluations	All	GRC	19,799	13,239
TOTAL Expense and Capital				**282,041**	**13,239**

IV. Current Mitigation Plan (2017-2019)

There are no new mitigations identified for this risk to be implemented through 2019 at this time. The last of the identified mitigations were completed in 2016. Based on the plant design, and current controls, the RAMP model results indicate a risk of a core damaging event for DCPP is $5.4E^{-05}$ or once every 18,376 years. This result provides adequate margin to the NRC Core damage risk threshold in Regulatory Guide 1.174 of 10^{-4} events per reactor year, or one every 10,000 reactor years. The cost of the existing controls is planned to continue in accordance with the regulatory requirements to maintain the programs described above.

The NRC is requiring additional seismic evaluations and continues to evaluate additional BDB requirements (identified as tier 2 and 3 equipment and process impacts). With the continuing seismic evaluations being performed in response to NRC regulations, DCPP will continue to evaluate the core damaging event risk and need for mitigations based on the evaluation.

V. Proposed Mitigation Plan (2020-2022)

Because this risk is adequately maintained within established requirements, and the controls are strong, there are no new additional mitigations identified for this risk to be implemented through 2022 at this time. The cost of the existing controls is planned to continue in accordance with the regulatory requirements to maintain the programs described above.

VI. Alternatives Analysis

Mitigations are fully established to optimize safety and ensure compliance. No alternative mitigations were identified.

VII. Metrics

The metrics proposed address overall plant safety. The regular monitoring and accountability for actions to address performance provide great value in controlling core damage frequency risk.

The accountability metrics related to this risk include the following:

- The DCPP PRA model is regularly updated to ensure risk threshold and margin is maintained.
- The DCPP Reliability and Safety indicator industry metric measures overall safety and reliability performance with a comparison to all plants in the U.S. Some of the specific components of this indicator are capability factor, forced loss rate, and safety system availability.

VIII. Next Steps

All regulatory required improvement actions have been implemented[8] in compliance with state and federal regulations to ensure that a core damaging event is effectively managed with minimal risk. PG&E performed an updated assessment in 2017 for the Nuclear Operations and Safety – Core Damaging Event risk. During this process, PG&E reviewed key risk drivers and their potential impacts, evaluated the effectiveness of existing mitigating activities, and considered additional mitigations for addressing any possible gaps in our controls. The result of this assessment was PG&E has determined that current controls are adequately managing this risk.

As the NRC is requiring additional seismic evaluations and continues to evaluate additional BDB requirements (identified as Tier 2 and 3 equipment and process impacts), DCPP will continue to evaluate the core damaging event risk and need for mitigations based on the evaluation.

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[8] Completed mitigations include:

- Beyond Design Basis regulatory requirements:
  - Seismic, Flooding, and Tsunami studies
  - FLEX equipment procured and available for fast installation
  - Staffing and communication studies to support emergent BDB strategies
  - Upgrade Spent Fuel Pool Instrumentation
  - Install Reactor Cooling Pump Seal

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 13
HYDRO SYSTEM SAFETY – DAMS

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2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 13
HYDRO SYSTEM SAFETY – DAMS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Hydro System Safety – Dams.
IN SCOPE	Failure of a Pacific Gas and Electric Company (PG&E)-owned high consequence dam as a result of a flood, seismic event, or seepage.
OUT OF SCOPE	Events that do not result in a failure of a high consequence dam or failures that are primarily caused by drivers other than flood, seismic, or seepage.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data, and subject matter expert (SME) input.

This chapter discusses the risk drivers associated with a dam failure event, the potential range of consequences, the controls in place to prevent a dam failure, and mitigations intended to reduce the risk. This risk is titled Hydro System Safety – Dams (HSS-D).

To support the Risk Assessment and Mitigation Phase (RAMP), PG&E performed quantitative analyses of the three primary drivers of a dam failure – flood, seismic, and seepage. The overall likelihood of a catastrophic failure of one of PG&E's 20 highest consequence dams is estimated to be one failure every 140 years.

The consequences are evaluated using the standard RAMP modeling methodology described in Chapter B and resultant risk outcomes are converted into a Multi-Attribute Risk Score (MARS).

PG&E has controls in place to maintain safety under the Dam Safety Program (DSP). Controls include:

- Routine observations by trained Hydro operations and maintenance (O&M) personnel;
- Regular inspections by qualified engineers in PG&E's Facility Safety Program;
- Regular regulatory inspections by the Federal Energy Regulatory Commission (FERC) and California's Department of Water Resources' Division of Safety of Dams (DSOD);
- Five-year Independent Consultant Safety Inspections in accordance with Chapter 18 of the Code of Federal Regulations (18 CFR) Part 12D; and
- Engineering evaluations of dam stability, seismicity, spillway design capacity, and other design and operational issues as conditions and engineering guidelines evolve.

Based on the results of the bow tie analysis, PG&E proposes mitigations to address the seepage, seismic, and flood drivers. These mitigations are titled seepage mitigation projects, spillway remediations, seismic retrofit, and Low Level Outlet (LLO) refurbishments and are proposed for select dams within the 20 highest consequence dams. The mitigations are quantitatively evaluated to determine Risk Spend Efficiency (RSE) in addressing the three key risk drivers. Based on a thorough alternatives analysis, the proposed mitigations reduce the HSS-D RAMP risk by an estimated 1.5 percent.

The operational risk model development for this filing has developed a foundation for adding risk to PG&E's quantitative toolkit for managing the hydro portfolio. Continued refinement of the model inputs and expansion to include more dams will augment PG&E's dam safety program.

II. Risk Assessment

A. Background

The HSS-D risk is defined by PG&E as a large PG&E-owned dam failure that is located in PG&E territory with the potential to cause significant safety and environmental damage.

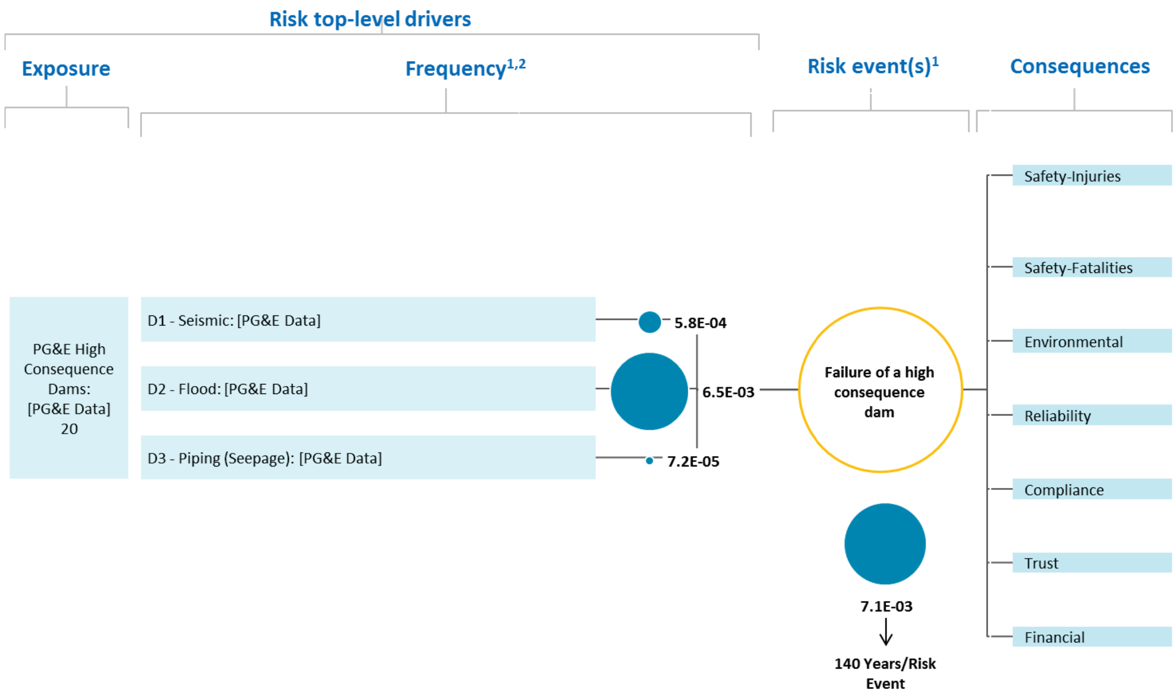
There are approximately 87,000 dams in the United States (U.S.), many of which are over 100 years old. Of these millions of aggregated years of dam operations in the U.S., there have been 47 catastrophic failures, some of which resulted in significant loss of life. More recently, dam safety incidents at Oroville (2017), Lake Delhi (2010), Taum Sauk (2005), and Folsom (1995) demonstrate that even without loss of life a significant event at a dam can result in loss of trust in a company, major regulatory changes, and financial impact to the entire industry.

To appropriately address and acknowledge the inherent risks of owning and operating a dam, PG&E added the HSS-D risk to PG&E's risk register. Due to the potentially catastrophic impact of a dam failure, this risk has been designated as an Enterprise-level risk overseen by the Safety and Nuclear Operations committee of PG&E's Board of Directors.

PG&E's DSP maintains the safety of its 169 dams, protecting the public and company's assets through overall management of dam safety risks. 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, including installation of hazard warning signs through the hydro system as well as prevention, preparedness, education, and outreach activities through a comprehensive public outreach program.

Power Generation used the bow tie methodology, as shown in Figure 13-1, to develop a quantitative risk model specific to the failure of PG&E's 20 highest consequence dams. This model uses a combination of PG&E-specific data, industry data, and SME input, to gain a better understanding of the risk drivers and consequences for a dam failure. Figure 13-1 lists risk drivers in order of appearance within the model.

Figure 13-1 : Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson and Binomial distributions.

B. Exposure

PG&E's hydro facilities carry high inherent consequences in the unlikely event of a catastrophic failure. The DSP implements measures to manage and reduce the risks of owning and operating PG&E's dams. To develop a reasonable list of dams for RAMP, PG&E's dam safety experts screened dams in the portfolio for potential impacts of dam failure based on the number of structures within each dam's failure inundation zone, the dam height, and the impounded reservoir volume to determine which dams would have the highest consequences from catastrophic failure. This resulted in a list of 20 dams that are termed as the high consequence dams; 18 of which meet the FERC high hazard classification.
Two dams, Upper Bear and Lower Bear dams, meet the FERC significant hazard classification which is limited to the criteria of the probable loss of human life and the impacts on economic, environmental, and lifeline interests. Lower Bear dam is considered one of PG&E's high consequence dams due to meeting the storage capacity criterion. Upper Bear dam is included due to the expectation that it will result in a cascading failure of Lower Bear dam in the event of a catastrophic failure. Since PG&E's dams are currently evaluated for safety using

well-established regulatory driven deterministic approaches, the list of PG&E's high consequence dams was limited to an initial 20 dams to ensure a manageable scope of analysis for this RAMP filing. Additional dams are planned for inclusion in future RAMP filings.

The 20 highest consequence dams provide a representative sample of the dams in PG&E's portfolio and include three types of dams:

- Earthfill – Homogenous and zoned earthen embankment dams:
  - Belden, Butt Valley, Crane Valley, Lake Almanor, Lake Tabeaud, Pit 1 Forebay
- Rockfill – Concrete-faced rockfill dams (CFRD):
  - Bucks Lake, Courtright, Fordyce, Main Strawberry, Relief, Salt Springs, Spaulding No. 3, Upper Bear, Wishon, Lower Bear
- Concrete – Concrete gravity and concrete arch dams:
  - Chili Bar, Scott, Spaulding No. 1, Spaulding No. 2

C. Drivers and Associated Frequency

The HSS-D risk model uses data from a variety of sources independent to each driver to inform the bow tie assessment. The drivers are not dependent on each other as the contributors to each driver do not play a role in the other drivers. The data, and PG&E's experience, suggests that the risk drivers that could result in catastrophic failure of an individual dam occur very rarely making the probability of a hydro dam failure event from any one of these causes to also be very rare. Cumulatively, the frequency of one of PG&E's 20 high consequence dam failure from the drivers is once per 140 years.

The drivers are:

D1 – Seismic: Due to the nature of seismic events, the precise size, location, and timing of earthquakes cannot be predicted. However, seismic risk can be evaluated and refined to ensure dams and associated structures are robust. 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 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. The aggregate evaluation of the portfolio of 20 dams resulted in an average likelihood that one seismic event with the potential to cause dam failure could occur every 1724 years, or 5.80×10^{-4} events per year. The seismic driver is attributable to 8 percent of the overall frequency of a failure of a high consequence dam.

D2 – Flood: Flooding typically occurs as a result of heavy precipitation or snowmelt; however, 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 used historic flow data that PG&E maintains for each dam to develop index-level flood frequency data for each dam that was then used to estimate the frequency of the flood that exceeds each dam's capacity to safely pass a flood event. The analyses resulted in an average likelihood of 6.48×10^{-3} dam failures due to flood per year, or one flood every 154 years causing dam failure. The flood driver is attributable to 91 percent of the overall frequency of a failure of a high consequence dam.

D3 – 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 progressive, catastrophic dam failure. For the earthfill dams, the estimated frequency of such failures is conservatively based on 50 percent of the average failure rate of earthfill dams due to all causes.[1] 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 excessive seepage than earthfill dams and the analysis of this phenomenon supports this conclusion. Concrete dams rarely, if ever, fail due to excessive internal seepage and, as a result, these dams do not contribute to the frequency of the seepage driver. The seepage initiating event frequency was determined to be 7.22×10^{-5}

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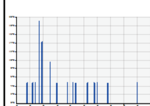
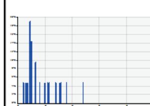
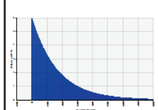
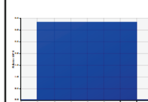
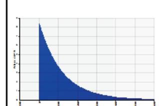
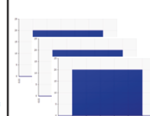
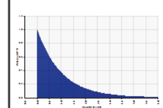
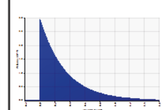
1 Costa, J. E. (1985). ''Floods from dam failures.'' U.S. Geological Survey, Open-File Rep. No. 85-560, Denver, 54. Reported that of all dam failures as of 1985, 34 percent were caused by overtopping (water height exceeding dam height), 30 percent due to foundation defects, 28 percent from piping and seepage, and 8 percent from other modes of failure. Costa (1985) also reports that for earth/embankment dams only, 35 percent have failed due to overtopping, 38 percent from piping and seepage, 21 percent from foundation defects; and 6 percent from other failure mode.

dam failure events per year, or one event every 13,854 years. The seepage driver is attributable to 1 percent of the overall frequency of a failure of a high consequence dam.

D. Consequences

The model inputs to each consequence are described with their respective consequence attribute below in Figure 13-2. In the figure, there is an explanation of the data sources used for each of the consequence attributes and the resultant tail average outcomes and MARS values.

Figure 13-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PG&E Data	PG&E Data	SME Input	SME Input	SME Input	PG&E Data	SME Input
Consequence Distributions	Samples directly from Injury values from high consequence dam data 	Samples directly from fatality values from high consequence dam data 	5% value=$10M 95% value=$500M (Exponential) 	Range=0-30,000 Customer Min (Uniform) 	5% value=$1M 95% value=$350M (Exponential) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Restoration costs: Ave=$1B (Exponential)  + Property damage: 5% value=$1.7M 95% value=$1B (Exponential) 
Outcome-TA-NU[1]	2.37	1.25	$12,165,012	1,087	$8,589,205	1.16%	$97,031,861
Outcome-TA-MARS[2]	0.65	34.15	1.22	0.00	0.86	5.80	58.22
						MARS Total	100.89

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** To calculate the frequency of injuries, the Dekay-McClelland[2] empirical method was used to calculate the estimated likelihood of fatality as described below. The method does not actually give a value for injury, but based on the National Oceanic and Atmospheric Administration flood data for California, a ratio of 1.87 injuries per fatality was determined and used to estimate injury counts at each dam. This distribution of injuries is sampled directly in the model. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of 2.37 injuries per year.

2 Dekay, Michael L., and Gary H. McClelland, "Predicting Loss of Life in Cases of Dam Failure and Flash Flood," 1993.

- **Safety – Fatalities (SF):** Fatality severity distribution was a result of applying the results of the Dekay-McClelland empirical method with the variables of population at risk (PAR), force of water (Fd), and warning time (Wt) defined by 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. 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 operational risk model for the quantity of fatalities occurring in the event of dam failure. The injury distribution is a ratio of the fatality calculation as described in the SI section. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of 1.25 fatalities per year.
- **Environmental (E):** Impact to the environment due to a high consequence dam failure is expressed in U.S. dollars and is expressed as an exponential distribution with a 5th percentile value of $10,000,000 by best estimate of the SME and the 95th percentile value of $500,000,000 is evaluated using SME judgment. Factors considered for determining the distribution values 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. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of $12 million per year.
- **Reliability (R):** The impact to the electric grid resulting from dam failure is expected to be negligible because in many cases the generation can be replaced quickly so the lower bound for reliability is no loss of power. The upper bound is set to 30,000 customer-minutes because the power provided by some dams is necessary to ensure regional grid stability. These values were determined through SME input based on PG&E information. This does not include any potential loss of reliability due to physical electric transmission equipment damaged as a consequence of the dam failure. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of 1,087 customer minutes per year.
- **Compliance (C):** The compliance impact is expressed as an exponential distribution with a 5th percentile value of $1,000,000 which is the expected cost to conduct a study on the entire PG&E hydro portfolio to evaluate the extent of the condition that led to the originating failure. The 95th percentile value of the distribution is $350,000,000, which includes the estimated cost to implement a new compliance program on all PG&E dams. These valuations do not include information from the

events at Oroville Dam because the consequences of the event have not been fully realized. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of $8.6 million per year.

- **Trust (T):** Trust is evaluated in the model as a function of injuries and fatalities resulting from dam failure and is expressed in percent change in brand favorability. As dam events are infrequent, the annualized injuries or fatalities are relatively low as compared to some more frequent events, thus the impact to trust resulting from the failure of a high consequence dam is relatively small. However, the Oroville Dam incident has shown that this type of event impacts trust in all dam operators. As the events of Oroville Dam are recent and response to the incident is ongoing, information from this event could not be used in calculating trust for this RAMP filing. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of 1.16 percent change in brand favorability per year.
- **Financial (F):** The financial impact reflects the cost of restoring a dam and the property damage resulting from the failure. The restoration costs were determined to have an exponential distribution with an average of $1,000,000,000 by best estimate of the SME. Property damage is also expressed as an exponential distribution with a 5th percentile value of $1,700,000 based on the lowest estimate for property damage which was determined by multiplying the number of structures within the inundation zone by average home prices for each high consequence dam. The 95th percentile value of the distribution is based on the failure of Lake Almanor which, through the same means as finding the 5th percentile value, was found to result in the most costly damage to structures, roads, and bridges and result in $1,000,000,000 in damage. Based on these inputs, the tail average model results across the 2017-2022 time periods show an average value of $97 million per year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

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:

- Implementation of PG&E's DSP as described in Section I, above, to protect the public and the company's assets through overall management of dam safety risks;
- 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 the status of PG&E's hydro assets; and
- Defining the responsibilities and authority of the Chief Dam Safety Engineer (CDSE) to be accountable for achieving dam safety with support from PG&E's senior leadership.

Controls currently in place that address overall dam safety including the HSS-D RAMP risk drivers of flood, seepage, and seismic include:

C1 – Hydro Operations and Maintenance: 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 of twice annually to once every three years, 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 facilities 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. Work performed by the facilities safety engineers is under the supervision of PG&E's CDSE. To augment internal inspection efforts, 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.

C3 – FERC and DSOD Inspections: FERC and DSOD engineers inspect PG&E's dams collaboratively with PG&E engineers at an interval of annually to every three years, depending on DSOD and FERC hazard classification. PG&E receives official reports from the inspections that include documented observations, recommendations, or requirements to address identified issues. 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 Potential Failure Modes Analysis (PFMA) that takes a comprehensive look at ways a dam could fail and guides monitoring and 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, as described in *Section II. Risk Assessment A. Background*, implements measures to reduce the risks of owning and operating a dam and the expectations of the DSP are prescribed by FERC. PG&E also goes beyond FERC's expectations for an Owner's DSP by employing an independent panel of experts titled the Dam Safety Advisory Board to audit the DSP and to advise on dam safety issues as requested. In addition, for complicated 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.

Mitigation projects currently planned for the 20 highest consequence dams are grouped into the following four Mitigation Plans: Seepage Mitigation Projects, Seismic Retrofit, Spillway Remediation and Improvement Projects, and LLO Maintenance and Improvement Projects. The mitigation projects are all targeted to maintain the risk of dam failure at the inherent level. Due to the dynamic conditions the dams are subject to, there is potential that additional mitigation projects will be necessary to ensure the HSS-D risk is appropriately maintained. The following mitigations either commenced or were continued in 2016.

M1 – Seepage Mitigation Projects: Excessive seepage through CFRD and earthfill dams can lead to a potential piping of finer grained materials through a dam with graded materials. For rockfill dams this seepage 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. Seepage mitigations included in this filing are on rockfill dams only as there are no seepage mitigation projects planned for earthfill dams in the 20 high consequence dams. Seepage mitigation projects address the dam seepage 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. The two primary methods are common both in the industry and to PG&E and are proven methods that are effective at reducing seepage. The 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. The effectiveness of the work will be measurable through visual inspection of flow through the downstream toe of dams and downstream flow instrumentation.

M1a – Fordyce Dam: A major seepage mitigation project commenced on Fordyce dam in 2016 and 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. This is a major and expensive resolution that is justified due to the ineffectiveness of past repairs and is expected to limit the need for future repairs for leakage for an extended duration. As 2016 was the first year of the project, both expense and capital was used to prepare for the project with a significant ramp up in capital costs expected in 2018.

M2 – Spillway Remediations: Dam Spillway remediation includes improvements to spillway walls, chutes, gates, and operators. This mitigation 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. The incident at Oroville dam in 2017 resulted in significant erosion downstream of the main and emergency spillways. Forensic analyses of the event is underway at the time of writing this mitigation summary and in parallel, PG&E is evaluating its facilities with similar features based on FERC and DSOD requests and as an industry best practice. PG&E participated in the development of the industry best practice through its members on the National Hydropower Association's Hydraulic Power Committee. Pending results of the forensic evaluation and PG&E's spillway evaluations may necessitate additional spillway mitigations that could increase future work planned for this mitigation. Successful implementation of this mitigation is measurable through operational testing and demands and inspections listed above as controls.

M2c – Salt Springs Dam: Seals on all 13 radial gates at Salt Springs have been identified as needing replacement and the gates require painting to prevent corrosion. These issues were identified during an inspection of the facility, leading to the need for this work. Completing these projects will prevent gate deterioration that could render the gate inoperable during a flood, increasing the likelihood of a dam failure. Early project scoping and planning expense began in 2016 for this mitigation with planned increases in capital and expense costs in the next three years.

M3 – Seismic Retrofit: PG&E has completed numerous seismic retrofit projects on hydro assets. Seismic hazard studies that are updated on a 10-year cycle may drive additional mitigations not yet identified at the time of this filing. Presently, there is one seismic retrofit planned for the Crane Valley Dam intake tower, which is scheduled to commence in 2019.

M4 – Low Level Outlet Refurbishments: Pit 1 LLO and radial gate retrofit, initiated as part of a FERC recommendation, Relief Dam LLO bevel gear replacements, and dredging at Spaulding Dam will improve the reliability of the LLOs at these three dams. Note that this mitigation ends prior to the 2020 RAMP timeframe and is thus not included in modelling, but described here as the work is being performed to mitigate the risk. Although LLOs will not directly mitigate the three major drivers, maintaining reliable operation of these features is critical to relieving the water loading on a dam during or after a seismic or internal seepage event to potentially prevent a failure.

M4a – Pit 1 Forebay: An upstream dive inspection of the Pit 1 radial gates and LLO identified a broken stem on the LLO between radial gates 4 and 5, which requires retrofit to restore functionality of the LLO. Side seal leakage on two radial gates was also identified as well as debris blockage. These retrofits will be determined acceptable upon satisfactory completion of the work and follow-up inspection.

M4b – Relief Dam: The three 30-inch knife gate valve assemblies at the Relief Dam LLO have failing bevel gears. Vendor analysis has not been able to determine the cause of the premature and concurrent failure of all of the bevel gears. PG&E has determined that the best course of action is to replace the bevel gears with a custom design with larger thrust roller bearings rather than the current design with needle thrust bearings.

M4c – Spaulding Dam: The intake structure to the Spaulding Dam LLO has significant debris buildup that has the potential to obstruct the LLO valve and the instream flow release valve. Removal of the debris, particularly after the significant rains seen in 2017, will help to ensure continued flow control through the LLO if it is required.

The Controls listed above are being maintained as flat for the purposes of this RAMP filing. PG&E is continuously evaluating its DSP and will enhance controls as opportunities arise using new technologies, updated analysis methodologies, changes to the physical environment, and lessons are learned from the industry. Mitigations commenced in 2016 are included in the Table 13-1 below to show the ongoing cost. Additional mitigations that began in 2017-2019 are described in the next section. The LLO projects are currently estimated to end by December 2019, so they are described here and in the next section but will not be modeled in the RAMP filing.

Table 13-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Hydro O&M[1,2]	D1, D2, D3	GRC	45	–
C2	Facility Safety Inspections[1,2]	D2, D3	GRC	2,141	–
C3	FERC and DSOD Inspections[1,2]	D2, D3	GRC	254	–
C4	Part 12 D Inspections and Follow-up[1,2]	D1, D2, D3	GRC	1,882	–
C5	DSP[1,2,3]	D1, D2, D3	GRC	6,460	–
M1	Seepage Mitigation Projects	D3	GRC	115	404
M2	Spillway Remediation and Improvement Projects	D2	GRC	6	–
M3	Seismic Retrofit	D1	GRC	–	–
M4	LLO Refurbishments	D2, D3	GRC	3	221
TOTAL Expense vs. Capital				**10,906**	**625**

Notes:

[1] Hydro O&M expenses only covers charges to Facility Safety and not entire O&M budget.

[2] Expenses are for entire hydro asset portfolio and not divided to only the 20 high consequence dams.

[3] DSP expenses includes the expenses for C1, C2, C3 and C4 as the DSP encompasses these controls.

IV. Current Mitigation Plan (2017-2019)

No specific changes to controls are planned in the 2017-2019 time period and so are not discussed again in this section. PG&E will continuously evaluate its DSP and will enhance those controls as opportunities arise. To determine mitigations for 2017-2019, PG&E considered all ongoing and planned work for the top 20 highest consequence dams and evaluated all work that mitigated the RAMP drivers and grouped the projects into the same four mitigations described in Section III. This section describes further work in the mitigations that are applicable to the 2017-2019 timeframe.

M1 – Seepage Mitigation Projects: Multiple seepage mitigation projects will begin and continue through 2017-2019.

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 will begin 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 will be addressed by removing and replacing damaged sections of spalled concrete. This multi-year project began in

January 2017 and is expected to continue through 2022. 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 and is being remediated through identical methods. Due to the remote location of Relief Dam, work performed on the dam will have to be supplied through helicopter support; the cost outlook of this project accounts for that. Work began in January 2017 and is estimated through December 2021.

M1d – Courtright Dam: Cracks and spalling of various concrete joints are present in the Courtright Dam face as a result of compression caused by dam settlement. Remediation of Courtright Dam will include addressing cracks and removal and replacement of the spalled concrete sections. The work is expected to begin and end in 2017.

M2 – Spillway Remediation and Improvement Projects: As stated in the previous section, PG&E continues to engage with regulators and the industry in the combined response to the incident at Oroville Dam. The projects below are in the current 2017-2019 plans and do not include a response to Oroville Dam due to its ongoing nature. PG&E expects the spillway remediation scope particularly to expand in the coming years as the industry responds to the incident.

M2a – Scott Dam: Multiple projects are planned at Scott Dam to remediate spillways. Most of the remediations were recommended in the most recent 18 CFR Part 12 Independent Safety Consultant Inspection report. In response to the recommendations, PG&E plans to modify one radial gate hoist for remote operation and modify all radial gates to allow them to be raised to 13 feet to minimize reservoir levels during storm flows. A second radial gate hoist with an isolated power supply is also planned to provide radial gate operation redundancy. The slide gates are planned to be recoated and refurbished due to identified corrosion and deformations. The mitigations will increase the reliability and function of the spillway to operate as planned during a flood event. Spillway gates not operating properly during a flood event have the potential consequence of increasing the likelihood of failure during the flood events.

M2b – Belden Dam: During excavation work to replace a pipe, cracking was found along the base of a wall panel on the Belden Spillway. 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; (2) construct a reinforced concrete retaining wall with an anchor block element and vertical post-tensioned corrosion protected anchors. To determine which method will best address the spillway base cracking, PG&E plans in 2018 to further evaluate the conditions. Implementation of the selected alternative will begin with design in 2019 and construction in 2020. Temporary remediations were constructed in 2016 consisting of concrete blocks with tiebacks to support the wall.

M2c – Salt Springs Dam: The seals on all 13 radial gates at Salt Springs are planned to be replaced and the gates painted by 2019.

M3 – Seismic Retrofit: The seismic retrofit planned for the Crane Valley Project intake tower will begin in 2019.

M3a – Crane Valley Intake Tower: The intake tower at Crane Valley services both the powerhouse and the LLO. It was identified during the 2014 18 CFR Part 12D Independent Consultant Safety Inspection at the Crane Valley Project that the intake tower had not been evaluated using current seismic analysis methods. After performing an updated analysis, PG&E identified that the intake tower is vulnerable to a brittle shear failure at either the construction joint near elevation 3321 feet or at elevation 3333 feet above the location where the diagonal struts connect to the main tower. Success of the project will ensure that updated analyses do not reveal continued vulnerability to failure under the designed for seismic event.

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 will restore reliable operation of the LLOs at these three dams. Note that this mitigation ends prior to the 2020 RAMP timeframe and is thus not included in modelling, but described here as the work is being performed to mitigate the risk.

M4a – Pit 1 Forebay: All issues identified in the previous section are scheduled for completion by 2019. These retrofits will be determined acceptable upon satisfactory completion of the work and follow up inspection.

M4b – Relief Dam: Replacement of the bevel gears described in the previous section will have completed by the end of 2017.

M4c – Spaulding Dam: Dredging at Spaulding Dam will be completed by the end of 2017.

M4d – Lake Almanor: There are five operating LLO gates at the Lake Almanor Tower, however all five have been observed to have difficulties operating. Work is planned to begin and end in 2017 to disassemble the gates and either replace degraded components or clean the components and reassemble the gate and ensure appropriate operation.

Table 13-2, below, shows the costs of mitigations planned for 2017-2019. Control work, as it is planned to be flat, is not repeated from Table 13-1 but does continue throughout this time period.

Table 13-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1	Seepage Mitigation Projects	2016	2022	D3	609 (C) – (E)	4,750 (C) –(E)	4,100 (C) – (E)
M2	Spillway Remediations	2015	2022	D2	440 (C) 682 (E)	1,395 (C) 775 (E)	1,267 (C) 1,727 (E)
M3	Seismic Retrofits	2019	2020	D1	– (C) – (E)	– (C) – (E)	500 (C) – (E)
M4	LLO Refurbishments	2014	2019	D2, D3	390 (C) 477 (E)	2,083 (C) – (E)	100 (C) – (E)
TOTAL Expense and Capital by Year					**1,439 (C) 1,159 (E)**	**8,228 (C) 775 (E)**	**5,967 (C) 1,727 (E)**

V. Proposed Mitigation Plan (2020-2022)

For inclusion in the HSS-D operational risk model, PG&E considered all work planned work in 2020-2022 for the top 20 highest consequence dams and evaluated the work's impact on mitigating the RAMP drivers. The projects that directly reduced risk of the three RAMP drivers were compiled into the following same RAMP Mitigations: M1 Seepage Mitigation, M2 Spillway Remediation, and M3 Seismic Retrofit.

M1 – Seepage Mitigation Projects: Multiple seepage mitigation projects will begin and continue through 2020-2022.

M1a – Fordyce Dam: The major seepage mitigation project commenced on Fordyce dam in 2016 will continue through 2023. Significant capital investment on this project is planned for 2021-2023 as geomembrane installation continues and completes.

M1b – Main Strawberry Dam: This multi-year project began in January 2017 and is expected to continue through 2022. 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: Work began in January 2017 and is estimated through December 2021. Costs are projected to decrease year over year as flying in supplies becomes less necessary towards completion of the project in 2021.

M2 – Spillway Remediation and Improvement Projects: Two of the previously discussed spillway projects are expected to continue into the 2020-2022 timeframe.

M2a – Scott Dam: Slide gate work will finish in 2022 with painting of the gates.

M2b – Belden Dam: Belden dam capital costs are expected to increase significantly in 2020 as the design to address the deflected chute wall will have been selected and all work on the chute will begin and end in 2020.

M3 – Seismic Retrofit: The seismic retrofit planned for the Crane Valley Project intake tower will continue in 2020.

M3a – Crane Valley Intake Tower: The seismic retrofit work will increase significantly with most of the work planned at the tower to occur in 2020. Completion of the retrofit is also scheduled for 2020.

Table 13-3, below, summarizes the mitigations, associated drivers, and expected value-risk spend efficiency and tail average-risk spend efficiency (TA RSE) per million dollars calculated with the operational risk model, and associated estimated costs for each year covered by the 2020 General Rate Case.

Table 13-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1	Seepage Mitigation Projects	0.0045	0.0004	2016	2022	D3	3,848-4,253 (C) – (E)	17,100-18,900 (C) – (E)	11,828-13,073 (C) – (E)
M2	Spillway Remediations	0.692	0.069	2015	2022	D2	4,750-5,250 (C) – (E)	– (C) – (E)	95-105 (C) – (E)
M3	Seismic Retrofits	0.474	0.047	2019	2020	D1	1,425-1,575 (C) – (E)	– (C) – (E)	– (C) – (E)
TOTAL PROPOSED PLAN RSE: 0.1573 **TOTAL Expense and Capital by Year**							**10,023-11,078 (C) – (E)**	**17,100-18,900 (C) – (E)**	**11,923-13,178 (C) – (E)**

VI. Alternatives Analysis

After assessing all of the mitigations, PG&E has two Alternative plans to the proposed mitigation plan. Alternative Plan 1 was created considering a high amount of resources are available. Alternative Plan 2 was created based on minimizing the cost. The plans are comprised of re-evaluations of the mitigations previously proposed with these two concepts and address the same drivers as the originally proposed plans. As some mitigations did not have higher resource allocation versions or non-mandated version, the proposed plans remained as a component of the Alternative plan. Table 13-4 explains the layout of the plans and provides the calculated RSE for the set of mitigation with each plan. The Alternative plans are described in detail in the subsections below.

Table 13-4: Mitigation List

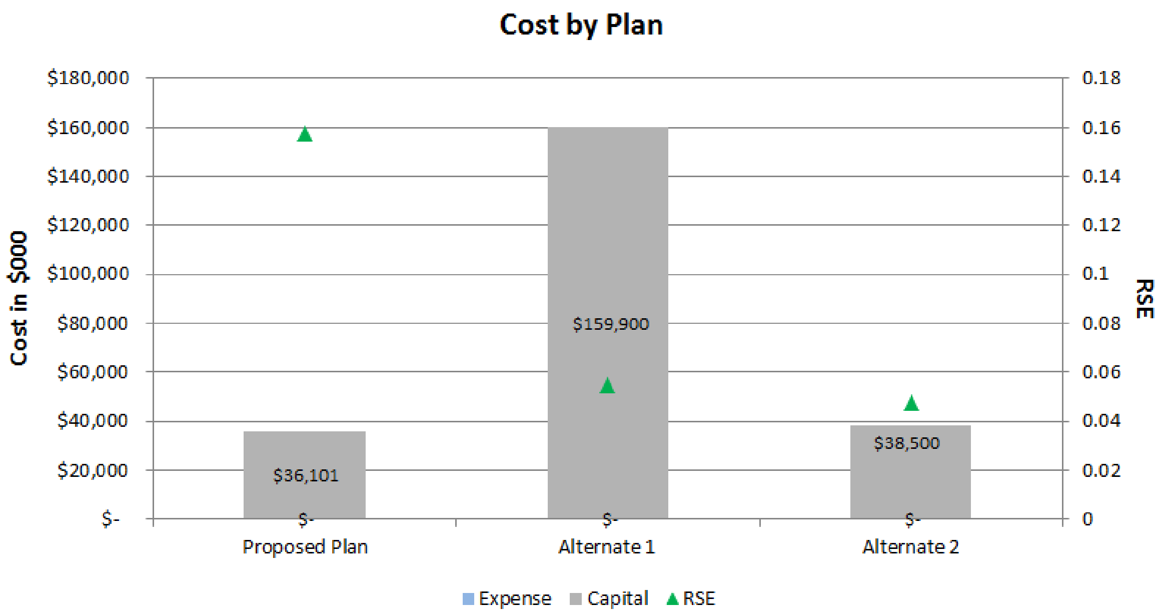
#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1	Seepage Mitigation Projects	0.0045	0.0004	X			WP 13-2
M2	Spillway Remediations	0.6920	0.0692	X	X		WP 13-9
M3	Seismic Retrofits	0.4741	0.0474	X	X	X	WP 13-14
M4	LLO Refurbishments[1]	N/A	N/A	X	X		WP 13-17
AM1	Seepage Mitigation Projects Alternative – Geomembrane Liners	0.0013	0.0001		X		WP 13-2
AM2	Seepage Mitigation Projects Alternative – Status Quo	0.0005	0.0001			X	WP 13-2
AM3	Spillway Remediation Alternative – Minimum Mandated	0.1861	0.0186			X	WP 13-9
AM4	LLO Alternative – Operation Without refurbishments[1]	N/A	N/A			X	WP 13-17

Notes:

[1] Mitigation is not evaluated for RSE or included in the tables below as it is not included in the model due to completion prior to 2020

Figure 13-3 below-compares the 2020-2022 cost and TA RSE of the Proposed Plan, Alternative 1 Plan, and Alternative 2 Plan.

Figure 13-3: Alternatives by Cost and RSE Score



Costs and RSE details of both Alternative plans are provided below in Tables 13-5 and 13-6 below.

A. Alternative Plan 1

This Alternative considers potential work that could be done if a very high amount of resources, including both workforce and financial resources, were available. This Alternative has been analyzed and found undesirable as the mitigation effectiveness is equivalent but the cost is significantly increased. There is a long-term benefit as the geomembrane liner installation is expected to last longer than standard concrete restoration work, but the very high cost of installation is still not expected to result in a commensurate spend efficiency.

M2 – Spillway Remediation and Improvement Projects: Dam spillway remediations include improvements to spillway walls, chutes, gates, and operators. This mitigation ensures spillways and necessary components in the spillway are available to control flow, particularly during high dam level or other high water flow events including the flood risk driver.

M3 – Seismic Retrofit: The seismic retrofit planned for the Crane Valley Project intake tower will begin in 2019 and end in 2020. No Alternatives for this work can be identified, as such, it remains in all plans.

M4 – LLO Refurbishments: Pit 1 LLO and radial gate retrofit, Relief Dam LLO bevel gear replacements, and dredging in Spaulding Dam will restore reliable operation of the LLOs at these three dams. Note that this mitigation ends prior to the 2020 RAMP timeframe and is thus not included in modelling, but described here as the work is being performed to mitigate the risk. The current work plan goes beyond the regulator mandated work scope and thus is included in the high allocation work plan. Note that this mitigation will complete prior to the 2020-2022 RAMP timeframe so it is not included in Table 13-5 but would be performed in this Alternative.

AM1 – Seepage Mitigation Projects Alternative – Geomembrane Liners: The first identified alternative is to install geomembrane liners on all dams currently needing face work for leakage mitigation. This is already being done at Fordyce. Geomembrane liner installation has a higher long-term reliability than standard concrete restoration work, however the results of the originally proposed projects have the same mitigation effectiveness in the short-term and are a normal industry practice for performing concrete dam restoration. This option is not desirable due to the very high costs of implementation for equivalent foreseeable seepage mitigation.

Table 13-5 provides the RSE and costs associated with Alternative Plan 1 which is based on a high allocation of resources.

Table 13-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M2	Spillway Remediation	0.692	0.069	2015	2022	D2	4,750-5,250 (C) – (E)	– (C) – (E)	95-105 (C) – (E)
M3	Seismic Retrofit	0.474	0.047	2019	2020	D1	1,425-1,575 (C) –(E)	– (C) – (E)	– (C) – (E)
AM1	Seepage Mitigation Alternative – Geomembrane Liners	0.0013	0.0001	2016	2022	D3	11,400-12,600 (C) – (E)	64,600-71,400 (C) – (E)	45,600-50,400 (C) – (E)
TOTAL ALTERNATIVE PLAN 1 RSE: 0.0546 **TOTAL Expense and Capital by Year**							**17,575-19,425 (C) – (E)**	**64,600-71,400 (C) – (E)**	**45,695-50,505 (C) – (E)**

B. Alternative Plan 2

The second alternative plan is to only perform minimum work where possible in each mitigation versus the proposed projects. This alternative is not a proactive approach to safety, which is a key principle of PG&E’s strategy. This approach also has the undesirable effect of possibly eroding the trust that regulators place in PG&E and will likely lead to more substantial repairs being needed in the future. Financial estimates are also questionable due to the uncertainty of future inspections that may result in mandated work or potential fines for not accountably addressing degradation.

M3 – Seismic Retrofit: The seismic retrofit planned for the Crane Valley Project intake tower will begin in 2019 and end in 2020. No Alternatives for this work can be identified, as such, it remains in all plans.

AM2 – Seepage Mitigation Projects Alternative – Status Quo: The proposed plan maintains the status quo for all four dams with only the Fordyce Dam leakage reduction being performed, since it is work that has already been committed to the FERC and DSOD. Since there are increasing trends of seepage at all of these dams, not addressing the seepage will increase the risk of excessive seepage at any of the four dams. It is unlikely that the increased seepage will lead to a failure over that period of time, but the anticipated increased seepage levels will make the need for future work more urgent and potentially more costly depending on how quickly they worsen, with the inevitable need to perform repairs in the foreseeable future. Costs provided do not reflect potential fines or regulator-ordered actions. This alternative is not desirable due to the negative consequences being significantly worse than addressing the leakage as planned. Benefits to this alternative are that money is not spent and may be repurposed.

AM3 – Spillway Remediation Alternative – Minimum Mandated: This alternative only performs the spillway remediation at Belden as PG&E has already made a regulatory commitment to complete the project. This does not perform the work listed above for Scott Dam or Salt Springs Dam, thus reducing the mitigation exposure from 3 to 1 high consequence dam. While this may be an acceptable alternative, continued deterioration of these structures could lead to a situation where the facilities can't operate properly during a flood event, thus increasing the risk of a catastrophic failure. Not maintaining the spillways will erode both public and regulator trust in PG&E.

AM4 – LLO Refurbishments – Operation without refurbishments: The currently evaluated alternative is to not implement further refurbishments on the LLOs. This is not a desirable alternative due to several projects are already being implemented, and it will not address operability issues that are key to reducing the risks associated with being able to lower reservoirs in emergency situations. There is also potential for DSOD to issue notice of violations or noncompliances and requirements to repair the LLOs. Note that this mitigation will complete prior to the 2020-2022 RAMP timeframe so it is not included in Table 13-6 but would be performed in this Alternative.

Table 13-6 provides the RSE and costs associated with Alternative Plan 2 which is based on minimizing spend.

Table 13-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M3	Seismic Retrofit	0.474	0.047	2019	2020	D1	1,425-1,575 (C) – (E)	– (C) – (E)	– (C) – (E)
AM2	Seepage Mitigation Projects Alternative – Status Quo	0.0005	0.0001	2016	2022	D3	2,850-3,150 (C) – (E)	16,150-17,850 (C) – (E)	11,400-12,600 (C) – (E)
AM5	Spillway Remediation Alternative – Minimum Mandated	0.1861	0.0186	2015	2020	D2	4,750-5,250 (C) – (E)	– (C) – (E)	– (C) – (E)
TOTAL ALTERNATIVE PLAN 2 RSE: 0.0473 TOTAL Expense and Capital by Year							9,025-9,975 (C) – (E)	16,150-17,850 (C) – (E)	11,400-12,600 (C) – (E)

VII. Metrics

Seepage metrics for the mitigations will be evaluated on an individual dam basis. This is due to the design of each dam being application-specific and not generic, so downstream toe flow will be based on environmental and operational conditions of each dam.

Spillway remediations and LLO refurbishments can be evaluated for effectiveness by responding to operational testing and demands and passing inspections. LLOs are typically required to be exercised annually, but it is up to each licensee to determine the timing of the testing. As opening an LLO can present hazards to the public and the downstream environment, dam operations will exercise an LLO when it is reasonable to do so. Testing spillways and spillway components is based on several factors including dam level. It is expected that a spillway will only be operated during a high flow condition or during regular testing.

Mitigations that change design, such as seismic, cannot be reasonably measured for effectiveness.

Proposed accountability metrics in Table 13-7 below include the following, related to the proposed mitigations and drivers mitigated:

Table 13-7: Proposed Accountability Metrics

Mitigation	Associated Driver #	Proposed Metric	Targets
See page Mitigation	D3	Downstream Toe Flow	Evaluated on an individual dam basis
Spillway Remediations	D2	Operational testing and demands, Inspection Findings and Follow-up	Evaluated on an individual dam basis
Seismic Retrofits	D1	None	Will become part of the design and unmeasurable
LLO Refurbishments	D2, D3	Operational testing and demands, Inspection Findings and Follow-up	Evaluated on an individual dam basis

VIII. Next Steps

The risk quantification effort has improved Generation's capability to apply risk reduction value to our planned work. Throughout the process, ideas for further ways to apply risk analysis techniques and apply risk earlier in the planning process were discovered and are desirable. These developments will best be obtained by improving on inputs to the RAMP operational risk model as well as including more dams in the model.

The HSS-D model has significant potential to achieve a higher granularity and ensure reliable and insightful results. This includes incorporation of further risk methodologies undergoing development in the hydro industry into the model which will increase speed and accuracy when making risk informed decisions regarding mitigations planned for PG&E's hydro assets, and expanding the model to include all PG&E-owned dams to ensure the highest RSE.

The incident at Oroville Dam is also precedent setting and potentially industry-changing. As this occurred in February 2017, regulatory and industry causal analyses are ongoing and actions to prevent the event at other dams are still being determined. Incorporating the event and responses to the Oroville incident into a comprehensive operational risk model and operational plan would be beneficial.

It is also desirable to achieve accurate quantification through applying lessons learned in this process and implementing and enhancing risk-informed models providing input to the RAMP process. More accurate quantification by including more dams and additional data relating to each dam will better represent the inherent dam safety risk while justifying continued spend on relatively small impacts to the baseline risk. This is necessary to ensure PG&E's dams are well-maintained, failure is prevented, and trust and compliance is foundational.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 14
CONTRACTOR SAFETY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 14
CONTRACTOR SAFETY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Contractor Safety
IN SCOPE	High and medium risk work[1] activities performed by contractors.
OUT OF SCOPE	Low risk work[2] activities performed by contractors.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, Bureau of Labor Statistics (BLS), United States (U.S.) Utility Industry data, Contractor Occupational Safety and Health Administration (OSHA) recordable data, and subject matter expert (SME) input.

Contractor Safety risk is 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. The safety of contractors working for Pacific Gas and Electric Company (PG&E or Company) is one of PG&E's Enterprise Risks. The mitigation of this risk is key to PG&E's mission as well as necessitated by regulations, financial considerations and operational capabilities. The costs of not mitigating contractor safety include injuries, illnesses, fatalities, fines, and delays or disruptions in work flow. PG&E had a monthly average of approximately 2,000 contract companies with approximately 24,000 contract employees in 2016.[3] Their work included high risk exposures, such as high voltage, hazardous materials, heavy equipment and fall hazards. Successful mitigation of Contractor Safety risk will ensure that PG&E is in regulatory compliance and has a workforce that is healthy, equipped and able to meet the needs of its customers.

In 2014, PG&E began implementing an enterprise Contractor Safety Program to reduce the potential for injury or illness to PG&E's contract employees. PG&E's contract companies have experienced on average 149[4] OSHA recordable injuries/illnesses and two serious injuries or fatalities per year over the past four years (2012-2016), making Contractor Safety one of the top risks for the Company.

In 2017, PG&E's Safety and Health organization used the bow tie methodology to develop a probabilistic operational risk model specific to Contractor Safety. In developing the model, PG&E used a combination of PG&E-contractor specific data,

1 Defined by SAFE-3001S: Contractor Safety Standard, Appendix A.

2 Defined by SAFE-3001S: Contractor Safety Standard, Appendix A.

3 See "2016 Site Tracker – Annual Report" showing average number of contract employees per month.

4 Serious Injuries and Fatalities Contractor 2012-2016.

industry data, and SME judgement to gain a better understanding of the risk drivers associated with this risk and where to target new mitigations.

The primary drivers of this risk include overexertion and bodily reaction, contact with objects and equipment, and falls/slips.

PG&E's current controls[5] set the foundation for compliance with the Contractor Safety Program, and are designed to comply with requirements established by OSHA and California Public Utilities Commission (CPUC).

PG&E has concluded that the best way to reduce the Contractor Safety risk is through Contractor Safety Program Process Improvement; Governance; Knowledge; and Tools and Technology. PG&E estimates that focusing on this mitigation plan will result in a 48 percent risk reduction.

The primary metric for measuring risk reduction is for 80 percent of PG&E's prime contractors to have an "A" grade in ISNetworld (ISN) by the end of 2022.

As next steps, PG&E will monitor progress of this primary metric and other Contractor Safety metrics, including the risk outcome of these mitigations. Through focus on continuous improvement, PG&E will seek to identify additional opportunities to reduce risk in this area.

II. Risk Assessment

A. Background

The Contractor Safety risk is 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.

PG&E's historical approach to contractor safety was to require contractors to follow all federal, state and local safety regulations, such as those established by the Federal Occupational Safety and Health Administration and the California Occupational Safety and Health Administration.

Following a contractor fatality at the Kern Power Plant in 2012, the CPUC opened an Order Instituting Investigation (OII). The OII resulted in the development and implementation of an enterprise Contractor Safety Program.[6]

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5 Current controls discussed/outlined in Section III of this chapter.

6 CPUC Decision 15-07-014, July 23, 2015, pages 10-12. "Kern OII Settlement Agreement."

Under the Contractor Safety Program, PG&E utilized ISN, a service provider specializing in the contractor safety qualification process, to assess the safety record of contractor companies. Since PG&E's adoption of ISN, over 1,000 prime contractor companies[7] and almost 1,000 subcontractor companies[8] have been assessed against the program's safety pre-qualification criteria. This process evaluates a contractor's companywide historical safety performance and validates that a contractor's written safety programs meet OSHA regulatory compliance requirements. In addition, each PG&E Line of Business (LOB) has established a LOB specific Contractor Oversight Procedure[9] in alignment with the Corporate Contractor Safety Standard which establishes PG&E's requirements for managing medium and high risk work activities performed by contractors.

As PG&E reviewed contractor safety incident investigation findings and program compliance assessment results, PG&E identified opportunities to improve risk mitigation beyond the current controls. The most significant opportunity focuses on pre-qualification requirements, including the review of newly-formed contractor companies (companies that have been in business less than three years) and contractor companies that have experienced significant high-growth over a short time period (20 percent personnel growth within a single quarter). The mitigations proposed in this plan are intended to address these and other drivers to this risk.

PG&E's Safety and Health organization used the bow tie methodology to develop a quantitative risk model specific to Contractor Safety risk. The risk bow tie in Figure 14-1 below is an illustrative representation of the analysis performed, depicting the exposure and drivers and how they contribute to the likelihood of injury, illness or fatality as a consequence of this risk event.

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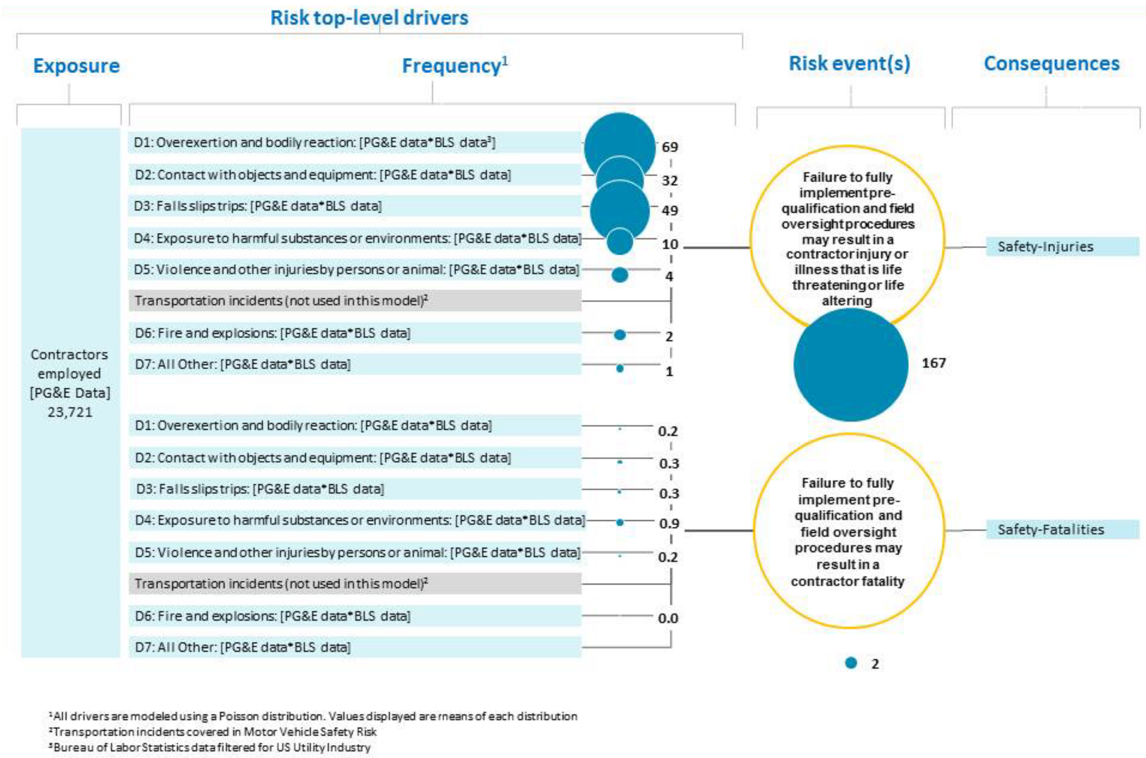
7 A "prime contractor" is any supplier performing work or delivering services under a contract with PG&E.

8 Subcontractors are any suppliers performing work or delivery services for PG&E under the contract with a PG&E prime contractor.

9 LOB Contractor Safety Oversight Procedures are based on the SAFE-3001S: Contractor Safety Standard and provides guidelines on how each LOB is to implement the requirements outlined in the Standard within their individual LOBs.

Figure 14-1: Risk Bow Tie



B. Exposure

PG&E identified that the population exposure for the Contractor Safety risk is approximately 24,000 individual contract employees (combining prime contractors and subcontractors) on average per month.

C. Drivers and Associated Frequency

The drivers for the Contractor Safety risk are categorized into eight categories by the BLS "Occupational Injury and Illness Classification Manual" (OIICM). Please note that transportation incidents were excluded from this analysis as these are discussed in the stand alone Motor Vehicle Safety risk chapter.

The model was populated with OSHA recordable incident data for PG&E contractors for the years 2015 and 2016[10] and from PG&E's third party

10 See "2015 Site Tracker – Annual Report" and "2016 Site Tracker – Annual Report."

contractor safety management database, ISN.[11] The injuries and fatalities data in the model use BLS U.S. Utility Industry data for years 2011 through 2015.[12]

- **D1 – Overexertion and Bodily Reaction:** Includes bending, climbing, crawling, bodily reaction and exertion, overexertion in holding and carrying, overexertion in lifting/lowering, overexertion in pulling or pushing, repetitive placing, grasping, repetitive use of tools, typing or key entry. Roughly 41 percent of reported total injuries and roughly 10 percent of reported total fatalities were from overexertion and bodily reaction; this is equivalent to 69 injuries and 0.2 fatalities per year.
- **D2 – Contact With Objects and Equipment:** Includes being caught in or compressed by equipment, caught or crushed in collapsing equipment, contact with objects and equipment, jarred by tool, equipment, rubbed or abraded by foreign material, stepped on object, struck against moving object, struck against stationary object, struck by falling or flying object. Roughly 19 percent of reported total injuries and roughly 17 percent of reported total fatalities were from contact with objects and equipment; this is equivalent to 32 injuries and 0.3 fatalities per year.
- **D3 – Falls Slips Trips:** Includes fall down stairs or steps, fall from ladder, fall from nonmoving vehicle, fall onto or against objects, fall to floor, walkway, or other, fall to lower level, slip, trip, loss of balance. Roughly 29 percent of reported total injuries and roughly 16 percent of reported total fatalities were from falls slips trips; this is equivalent to 49 injuries and 0.3 fatalities per year.
- **D4 – Exposure to Harmful Substances or Environment:** Includes contact with electrical current, contact with hot or cold object, contact with skin or other exposure, exposure to noise, inhalation of substance. Roughly 6 percent of reported total injuries and roughly 46 percent of reported total fatalities were from exposure to harmful substances or environment; this is equivalent to 10 injuries and 0.9 per year.
- **D5 – Violence and Other Injuries by Persons or Animal:** Includes assaults and violent acts by people, assaults by animals, venomous bites or stings or insect related incidents. Roughly 2 percent of reported total injuries and roughly 10 percent of reported total fatalities were from exposure to violence and other injuries by persons or animal, this is equivalent to 4 injuries and 0.2 fatalities per year.
- **D6 – Fire and Explosion:** Includes fire and explosion related injuries such as burns (chemical and electrical), welder’s flash, heatstroke. Less than

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11 PG&E began collecting contractor safety data using the ISN database beginning in May 2015.

12 This data set includes years 2011-2015 as BLS statistics provide more data on these drivers in terms of number, type and frequency. The ISN data set for PG&E contractors is limited to 2015-2016 and does not provide specific injury types and frequency per each of these drivers. See footnote 16.

1 percent of reported total injuries and less than 1 percent of reported total fatalities were from exposure to fire and explosion, this is equivalent to 2 injuries and close to 0.0 fatalities per year.

- **D7 – All Other:** Includes tendonitis, carpal tunnel, sprains, hearing disorders, dermatitis. Less than 1 percent of reported total injuries and less than 1 percent of reported total fatalities were from exposure to all other drivers, this is equivalent to 1 injury and close to 0.0 fatalities per year.

D. Consequences

The range of consequences and the attributes that help describe the tail average risks and the associated Multi-Attribute Risk Score (MARS) are shown in Figure 14-2. Consequences that can potentially result from a Contractor Safety risk event include injuries and fatalities. In Figure 14-2, there is an explanation of the data sources used for each of the consequence attributes and the resultant tail average outcomes and MARS values.

Figure 14-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PG&E and BLS Data	PG&E and BLS Data	NA	NA	NA	NA	NA
Consequence Distributions	All injuries The driver frequencies of this model already quantifies injuries, therefore there are no additional calculation steps in this section	All fatalities The driver frequencies of this model already quantifies fatalities, therefore there are no additional calculation steps in this section					
Outcome-TA-NU[1]	190.22	4.75					
Outcome-TA-MARS[2]	51.93	129.55					
						MARS Total	181.48

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI)**: The driver frequencies of this model already quantifies injuries, therefore, the total number of the events is equal to the total number of contractor injuries. The outcome of the model from these inputs show the tail average value is ~190 injuries per year. Expected value is 167 injuries per year – see Figure 14-2.

- **Safety – Fatalities (SF)**: The driver frequencies of this model already quantifies fatalities, therefore, the total number of the events is equal to the total number of contractor fatalities. The outcome of the model from these inputs show the tail average value is ~5 fatalities per year. Expected value is 2 fatalities per year – see Figure 14-2.
- **Environmental (E):** This consequence is not applicable, as there were no environmental impacts included in the data set of past incidents.
- **Reliability (R)**: This consequence is not applicable, as there was no reliability impacts included in the data set of past incidents.
- **Compliance (C):** Consequence is not included since costs are assumed to be embedded in the current Contractor Safety Program.
- **Trust (T):** This consequence is not applicable, as there was no trust impacts included in the data set of past incidents.
- **Financial (F):** Consequence is not included since costs associated with contractor injuries, illnesses and fatalities are subsumed by the contractor.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

There are controls currently in place to manage the risk drivers for Contractor Safety risk. These controls are included within the components of the Contractor Safety Program. Each of the controls described in this section address all risk drivers for Contractor Safety risk. They began in 2015 and were fully implemented by December 31, 2016.

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. Previous to the Contractor Safety Program enhanced contract terms and conditions control, safety was addressed in general terms and conditions, which lacked specific safety expectations for all contractors performing medium and/or high risk work.

C2 – Contractor Safety Pre-Qualification: The Contractor Safety program's pre-qualification process establishes criteria[13] for contractors to qualify in order to perform work for PG&E based on historical companywide safety and health performance.

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13 See SAFE-3001S, Attachment 1.

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.

C4 – Contractor Safety Plans: Safety plans are developed by the contractor, reviewed and approved by PG&E prior to commencing high risk work. These plans are required to address the Scope of Work (SOW)[14] 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 prior to beginning medium and/or high risk work activities.

C5 – Contractor Hazard Analysis: Contractors perform a job hazard analysis 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.

C6 – LOB Contractor Safety Oversight: The Lines of business provide oversight of the contractors 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. Beginning in October 2017, PG&E will utilize a software solution, SafetyNet®, on smart phones and tablets to capture observation information. 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 Corrective Action Program (CAP). These compliance assessments focus on PG&E work that utilize 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 140 Contractor Safety Program compliance

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14 A SOW contains a detailed description of service, project or program work activities.

assessments across all applicable LOBs 2017 year-to-date[15] and the Contractor Safety team is on track to exceed its target of 160 assessments by year end 2017.

C8 – Corrective Action Program for contractor issues: CAP provides employees with a process to document contractor performance related issues. Issues are then assessed for risk and evaluated for possible corrective actions. Any resulting corrective actions are tracked to completion. For contractor issues, PG&E can generate reports by CAP item type to determine the volume and type of CAP issues that are identified related to contractor safety. Additionally, Corporate Contractor Safety team compliance assessments utilize CAP to address assessment findings.

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[16] are entered into each contractor's ISN account and factor into each contractor's pre-qualification status. These evaluations focus on areas such as subcontractor safety oversight, utilizing equipment appropriately, and timely reporting of safety incidents to PG&E.

Table 14-1: Risk Controls and 2016 Recorded Costs

#	Control/Mitigation	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)[A]	2016 Recorded Capital ($000)[B]
C1	Enhanced Standard Contract Terms and Conditions	All Drivers	General Rate Case (GRC)	–	–
C2	Contractor Safety – Pre-Qualification	All Drivers	GRC	–	–
C3	Contractor Safety Standard and LOB Contractor Oversight Procedures	All Drivers	GRC	–	–
C4	Contractor Safety Plans	All Drivers	GRC	N/A	–
C5	Contractor hazard analysis	All Drivers	GRC	N/A	–
C6	LOB Contractor Safety Oversight	All Drivers	GRC	N/A	–
C7	LOB Compliance Assessments	All Drivers	GRC	688	–
C8	CAP for contractor issues	All Drivers	GRC	–	–
C9	Contractor Safety Post Job Safety Performance Review	All Drivers	GRC	264	–
TOTAL Expense and Capital				**952**	**–**

15 See "2017 CSI Assessments Tracker" for validation of assessments year-to-date.

16 See "TLine Post-Job Contractor Performance Appraisal" as an example.

IV. Current Mitigation Plan (2017-2019)

PG&E plans to address gaps in the current controls with the mitigations described below for2017-2019. These mitigations will focus primarily on further managing this risk by enhancing the pre-qualification management process, and improving contractor safety planning, training and work oversight. Each of the mitigations address all of the drivers. Mitigations with expense costs contain embedded costs associated with existing resources, or costs that reside outside of the Safety and Health organization.

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 (five-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 make the CAP for use by contractors. 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 – ISNetworld (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 – 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 Job Safety Analysis (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).

Table 14-2: Risk Mitigations and 2017-2019 Estimate Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1B	SIF Incident Governance and Oversight	2017	2017	All Drivers	– (C) – (E)	– (C) – (E)	– (C) – (E)
M2	Contractor Safety Officer Criteria	2018	2018	All Drivers	– (C) – (E)	– (C) 4 (E)	– (C) – (E)
M3	CAP Issues Criteria	2019	2022	All Drivers	– (C) – (E)	– (C) – (E)	– (C) – (E)
M4	ISNetworld Company Rapid Growth Tracking	2017	2017	All Drivers	– (C) 15 (E)	– (C) – (E)	– (C) – (E)
M5	Contractor Blocking Automation	2018	2018	All Drivers	– (C) – (E)	– (C) – (E)	– (C) – (E)
M6	OSHA Programs Training Requirements	2018	2018	All Drivers	– (C) – (E)	– (C) 5 (E)	– (C) – (E)
M7	Standardized Safety Plan and JSA Templates	2017	2017	All Drivers	– (C) 62 (E)	– (C) – (E)	– (C) – (E)
M8	PG&E Specific Hazards Communication Process	2019	2019	All Drivers	– (C) – (E)	– (C) – (E)	– (C) 3 (E)
TOTAL Expense and Capital by Year					**– (C) 77 (E)**	**– (C) 9 (E)**	**– (C) 3 (E)**

V. Proposed Mitigation Plan (2020-2022)

In addition to the data analysis performed using the model, Safety and Health evaluated potential program and process improvements, referenced benchmarking studies involving other industries and peer utilities that are considered to have best practices in contractor safety performance and how each of these practices relates to the drivers for this risk.[17] Through the results of the analysis and the insight gained from reviewing those companies' programs and contractor safety management processes, PG&E determined that to reach a similar level of performance in contractor safety, the Company would need to implement a mitigation plan to strengthen the governance and oversight of contractors, increase the knowledge base for identifying and mitigating hazards, and implement process improvement and technology solutions to close risk exposure gaps.

17 See "2016_ISN_US_Utilities Safety Performance" page 2. PG&E is letter "I" (India), second quartile. See "2017-CASE STUDY-Southern Company." See "Contractor Safety Benchmarking_Big 3."

PG&E's Proposed Mitigation Plan from 2020 through 2022 for the Contractor Safety risk includes the mitigation categories shown below.[18] These mitigations expand on PG&E's existing controls and mitigations, and position PG&E to continue reducing the Contractor Safety risk. Based on the model analysis for each of the drivers, there is a potential for 48 percent reduction in the risk score from the proposed mitigations.

M9 – Contractor Governance: The purpose of this mitigation is to develop a procedural framework for managing PG&E processes and program requirements, with the goal of reducing contractor injuries through greater compliance with these requirements. This mitigation provides the structure, information and organization needed for contractors to improve their work planning and enhances how PG&E monitors and provides feedback on their performance. Its focus is on safety planning and increased PG&E oversight of contractor work by increasing safety observations and providing detailed performance feedback to the contractors. This mitigation is in addition to existing processes, procedures and standards. PG&E expects that this mitigation will reduce risk by providing standardized procedures across the enterprise, greater oversight, detailed evaluation, performance reviews, and auditing. This mitigation is expected to be implemented by 2022.

M10 – Contractor Knowledge: The purpose of this mitigation is to provide additional training and knowledge assessment of the program requirements for PG&E employees and contractors to support the reduction of injuries and fatalities resulting from contractor operations. With a focus on standardizing required training and orientation, this mitigation provides consistent support to educate employees and contractors on the Contractor Safety Program requirements and how to effectively recognize and mitigate hazards. This mitigation is in addition to any existing enterprise trainings and standards. PG&E anticipates that this mitigation will reduce risk by providing increased knowledge and specified instruction from SMEs. This mitigation will be developed starting in 2020 and be implemented by 2022.

M11 (A-C) – Contractor Process Improvements: The purpose of this mitigation is to address program gaps in order to mitigate the risk exposures for a contractor related serious safety incident. With a focus on improving work methods and programs, the mitigations strengthen current evaluation, training and planning processes. Five process improvement efforts were identified and separated into three categories (A, B & C).[19]

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18 For purposes of model development, PG&E bundled initiatives into the mitigations listed. For specific initiative details, see "ContractorSafety_ModelInputTemplate_050217."

19 For purposes of model development, PG&E bundled initiatives into the mitigations listed. For specific initiative details, see "ContractorSafety_ModelInputTemplate_050217."

The five process improvement areas are:

1. Establish SOW training to improve alignment between the written SOW and the work actually being performed;
2. Implement supplier safety incentives across all portfolios to incentivize safe work performance;
3. Review of contractors Department of Motor Vehicle incident record and specify driver training required by PG&E;
4. Require Work/Hold Permits for critical work activities; and
5. Establish a tracking process for contract change orders.

The three categories are:

- Mitigation M11 A: Includes all five of the process improvement mitigations;
- Mitigation M11 B: Includes all five of the process improvements mitigations except for the SOW enhancements; and
- Mitigation M11C: Includes Supplier Safety Incentives and Requirements for Work/Hold permits.

This mitigation provides controls for the safe execution of work. This mitigation goes beyond any existing continuous improvement efforts currently in place and is expected to be implemented by 2022.

M12 – Tools and Technology: The purpose of this mitigation is to provide tools and technology to support the reduction of contractor injuries resulting from contractor operations. With a focus on effectively utilizing the ISN database, this mitigation provides information technology (IT) solutions to contractors in performing their tasks for program compliance. This mitigation is in addition to existing utilization of ISN.

The following strategies are included in this mitigation:[20]

1. Validate and track insurance certificates for medium and high risk contractors in ISN;
2. Utilize ISN's individual badge feature to verify contractor employee training and qualifications at the job site;
3. Require contractors to implement a Drug and Alcohol (D/A) Testing Program and track the program in ISN; and
4. Establish a tool for capturing Contractor Near-hits and Good-Catches.

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20 For purposes of model development, PG&E bundled initiatives into the mitigations listed. For specific initiative details, see "ContractorSafety_ModelInputTemplate_050217."

PG&E proposes that this mitigation will reduce risk by maximizing the utilization of existing tools and identifying new technology. The proposed plan was developed based on benchmarked practices, after consulting with SMEs from each LOB, and then validated through the Contractor Safety risk model. This mitigation is expected to be implemented by 2022.

Exposure reduction benefits associated with each of the four mitigations (Governance, Knowledge, Process Improvements, and Tools and Technology) are qualitative in nature and based on a combination of SME judgement and existing data collected from multiple sources. Through the Risk Assessment and Mitigation Phase (RAMP) process, SME assumptions were analyzed using the contractor safety risk model and validated through the impact analyses submitted by the LOBs for Contractor Safety's proposed mitigations.

For instance, the data used to quantify the Risk Spend Efficiency (RSE) values displayed in the sections below, include PG&E employee OSHA recordable data classified according to the nature of injury definitions the causal factors of workplace safety events included in the BLS OIICM, and contractor injury and fatality data for years 2015 and 2016 from the ISN database. The Proposed Mitigation Plan outlined in Table 14-3 was selected because of the potential return on investment identified in the model, providing the greatest risk reduction through the most effective use of resources. Table 14-3 included below summarizes the mitigation, associated drivers, RSE, and associated estimated costs for each year covered by the 2020 GRC.

Table 14-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M9	Contractor Governance	55.17	37.64	2017	2022	D1-D5	– (C) 1,179 – 1,303 (E)	– (C) 1,120 – 1,238 (E)	– (C) 1,120 – 1,238 (E)
M10	Contractor Knowledge	379.25	258.74	2017	2022	D1-D5	– (C) 35 - 38 (E)	– (C) – (E)	– (C) 35 - 38 (E)
M11A	Contractor Process Improvements-A	71.55	48.60	2020	2022	D1-D5	– (C) 243 - 268 (E)	– (C) 241 – 266 (E)	– (C) 241 – 266 (E)
M11B	Contractor Process Improvements-B	17.03	11.61	2019	2022	D1-D5	– (C) 102 - 113 (E)	– (C) 102 - 113(E)	– (C) 102 - 113 (E)
M11C	Contractor Process Improvements-C	13.05	8.89	2019	2022	D1-D5	– (C) 147 - 163 (E)	– (C) 128 - 141 (E)	– (C) 128 - 141 (E)
M12	Tools and Technology	315.52	215.26	2017	2022	D1-D5	– (C) 47 - 52 (E)	– (C) 47 - 52 (E)	– (C) 47 - 52 (E)
Proposed Mitigation Plan TA RSE: 62.7 TOTAL Expense and Capital by Year							**– (C) 1,753 - 1,937 (E)**	**– (C) 1,638 - 1,810 (E)**	**– (C) 1,673 - 1,848 (E)**

VI. Alternatives Analysis

After assessing all of the mitigations, PG&E developed two alternative plans in addition to the Proposed Mitigation Plan. PG&E considered that there may be some challenges implementing possible contractual changes required by the proposed plan. Therefore, Alternative Plan 1 was created by removing M11B, the SOW development improvements mitigation strategy from the Contractor Process Improvements mitigation,[21] because of potential feasibility constraints.[22] Similarly, Alternative Plan 2 was created based on same possible constraints considered in Alternative Plan 1, in addition to removing M11C, the DMV records review as obtaining the records could lead to delays in contract negotiations and union concerns over employee privacy, and also removes the development of a process for tracking contract "Change Orders" at the close-out of projects given implementation constraints. All plans are shown in summary below in Table 14-4 and in detail in Tables 14-5 and 14-6, respectively.

Table 14-4: Mitigation List

#	Mitigation	TA RSE (Units/$M) Tail Average Risk Spend Efficiency Score (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M9	Contractor Governance	55.17	37.64	X	X	X	WP 14-15
M10	Contractor Knowledge	379.25	258.74	X	X	X	WP 14-2
M11A	Contractor Process Improvements-A	71.55	48.60	X	X	X	WP 14-10
M11B	Contractor Process Improvements-B	17.03	11.61	X			WP 14-10
M11C	Contractor Process Improvements-C	13.05	8.89	X	X		WP 14-10
M12	Tools and Technology	315.52	215.26	X	X	X	WP 14-6

Figure 14-3 below shows the breakdown both cost and RSE of the Proposed Plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE. The Proposed Plan, Alternative Plan 1, and Alternative Plan 2, have an RSE of 62.7, 65.9 and 71.1, respectively. The Proposed Plan was chosen over Alternative Plan 1 and Alternative Plan 2 as it implements the complete program with the greatest risk reduction to mitigate hazards.

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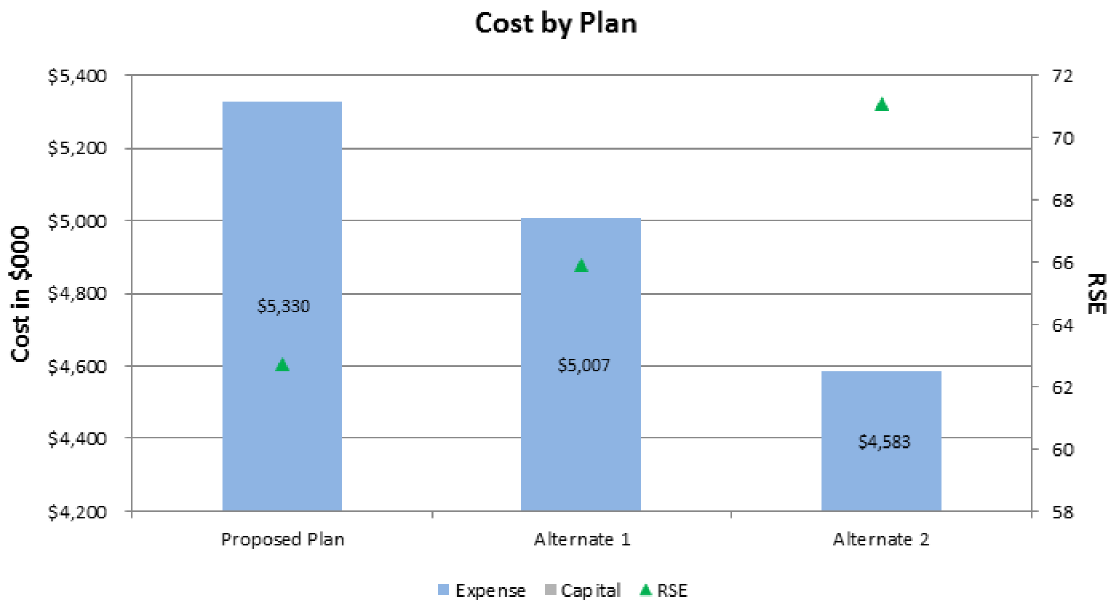
21 See workpaper "14 Contractor Safety – PI Mitigation Summary."

22 Determining known and unknown restrictions are based on SME judgement.

Figure 14-3: Alternatives by Cost and RSE Score



A. **Alternative Plan 1**

Alternative Plan 1 removes SOW development improvements strategy (M11B) from the Contractor Process Improvements mitigation. The SOW enhancements could be placed on hold given contract negotiation feasibility constraints. The other three mitigations (Governance, Knowledge, Tools and Technology) for Contractor Safety remain the same.

PG&E did not choose this as an alternative plan as removing this initiative from the mitigation plan in its entirety would not produce the desired reduction in risk and the feasibility of this strategy was not certain. Alternative Plan 1 was not chosen.

Table 14-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M9	Contractor Governance	55.17	37.64	2017	2022	D1-D5	– (C) 1,179 - 1,303 (E)	– (C) 1,120 - 1,238 (E)	– (C) 1,120 - 1,238 (E)
M10	Contractor Knowledge	379.25	258.74	2017	2022	D1-D5	– (C) 35 - 38(E)	– (C) – (E)	– (C) 35 - 38 (E)
M11A	Contractor Process Improvements-A	71.55	48.60	2020	2022	D1-D5	– (C) 243 - 268 (E)	– (C) 241 – 266 (E)	– (C) 241 – 266 (E)
M11C	Contractor Process Improvements-C	13.05	8.89	2019	2022	D1-D5	– (C) 147 - 163 (E)	– (C) 128 - 141 (E)	– (C) 128 - 141 (E)
M12	Tools and Technology	315.52	215.26	2017	2022	D1-D5	– (C) 47 - 52E)	– (C) 47 - 52 (E)	– (C) 47 - 52 (E)
Alternative Plan 1 TA RSE: 65.9 **TOTAL Expense and Capital by Year**							**– (C) 1,651 - 1,824 (E)**	**– (C) 1,536 - 1,697 (E)**	**– (C) 1,571 - 1,735 (E)**
Note: RSE changes in Alternative Plan 1 are due to reduced total costs of the Contractor Process Improvements mitigation.									

B. Alternative Plan 2

Alternative Plan 2 in addition to the removal of SOW Enhancements (M11B), removes the DMV records review as obtaining the records could lead to delays in contract negotiations and union concerns over employee privacy, and also removes the development of a process for tracking contract "Change Orders" at the close-out of projects (M11C) given implementation constraints. The other three mitigations (Governance, Knowledge, Tools and Technology) for Contractor Safety remain the same.

PG&E did not choose this as an alternative plan because the other three mitigations (Governance, Knowledge, Tools and Technology) could better achieve the desired risk mitigation results and the feasibility of this strategy was not certain. Alternative Plan 2 was not chosen.

Table 14-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M9	Contractor Governance	55.17	37.64	2017	2022	D1-D5	– (C) 1,179 - 1,303 (E)	– (C) 1,120 - 1,238 (E)	– (C) 1,120 - 1,238 (E)
M10	Contractor Knowledge	379.25	258.74	2017	2022	D1-D5	– (C) 35 - 38(E)	– (C) – (E)	– (C) 35 - 38 (E)
M11A	Contractor Process Improvements-A	71.55	48.60	2020	2022	D1-D5	– (C) 243 - 268 (E)	– (C) 241 – 266 (E)	– (C) 241 - 266 (E)
M12	Tools and Technology	315.52	215.26	2017	2022	D1-D5	– (C) 47 - 52 (E)	– (C) 47 - 52 (E)	– (C) 47 - 52 (E)
Alternative Plan 2 TA RSE: 71.1 **TOTAL Expense and Capital by Year**							**– (C) 1,504 - 1,661 (E)**	**– (C) 1,408 - 1,556 (E)**	**– (C) 1,443 - 1,594 (E)**
Note: RSE changes in Alternative Plan 1 are due to reduced total costs of the Contractor Process Improvements mitigation.									

VII. Metrics

PG&E will utilize three metrics which will track compliance with the program requirements, number of contractor serious injuries and fatality events, and percentage of prime contractors in ISN with an “A” grade.

Table 14-7: Metrics

Mitigation	Associated Driver #	Metric	Targets
Contractor Conformance Findings	D1-D7	% of Assessments that Include Non-Conformance Findings	0 – 5% of total assessments
Contractor SIF Events	D1-D7	# of Contractor Serious Injuries & Fatalities	Track Only
Prime Contractor ISN Grade	D1-D7	% of “A” Grade Prime Contractors	80% of “A” grade Prime Contractors

VIII. Next Steps

While PG&E’s knowledge of the Contractor Safety risk has improved significantly through the work done following the first RAMP process, it still has more to do to better capture and analyze contractor injury, illness and fatality data. Additional mitigations/initiatives will be developed from this analysis to continue to drive the expected reductions in contractor injuries and fatalities. As PG&E gathers more data through ISN, obtaining larger data sets of contractor injury, safety incident and fatality information, the ability to determine whether existing controls and the proposed mitigations have been effective in reducing risk will improve.

Finally, in addition to improvements to the overall Contractor Safety Program, PG&E plans to enhance data collection process by further exploring ISN's capabilities and benchmarking with peer utilities to expand capability through new tools and techniques.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 15
EMPLOYEE SAFETY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 15
EMPLOYEE SAFETY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES

I. Executive Summary

RISK NAME	Employee Safety
IN SCOPE	PG&E employees.
OUT OF SCOPE	Public Safety, Contractor Safety and Motor Vehicle Safety
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E internal data, Workers Compensation Claims, Bureau of Labor Statistics (BLS) injury and fatality data for the U.S. Utility Industry, and subject matter expert (SME) input.

Employee Safety risk is the failure to identify and mitigate occupational exposures that may result in an employee injury or illness that is fatal, life threatening or life altering. Employee Safety risk has been on Pacific Gas and Electric's (PG&E) risk register since 2013, and is one of PG&E's highest priority Enterprise Risks. The mitigation of this risk is key to PG&E's mission and necessitated by regulations, financial considerations and operational capabilities. The costs of not mitigating employee safety include injuries, illnesses, fatalities, fines, and delays or disruptions in work flow. PG&E had an average of approximately 24,000 employees in 2016 exposed to this risk and many whose work includes high risk exposures, such as high voltage, hazardous materials, heavy equipment, and fall hazards. Successful mitigation of Employee Safety risk will ensure that PG&E is in regulatory compliance and has a workforce that is healthy, trained, equipped, and able to meet the needs of its customers.

Through the Risk Assessment and Mitigation Phase (RAMP) process, PG&E Safety and Health adopted the risk bow tie methodology to develop a quantitative model and identified seven key drivers responsible for Employee Safety (injury or fatality) events: (1) Overexertion, (2) Contact with Objects and Equipment, (3) Falls/Slips, (4) Exposure to Harmful Substances or Environments, (5) Violence and Other Injuries by Persons or Animal, (6) Fire and Explosions, and (7) All Other Events.

Current controls for this risk include multiple PG&E and regulatory safety programs and procedures. Mitigations underway support existing programs by understanding the root cause of serious injuries and fatalities, such as the Serious Injury and Fatalities Incident Investigation Review, and the Musculoskeletal Program. Other current mitigations set the foundation for future development and integration of the safety program, such as Job Hazard Analysis, Learning Organization, and the Enterprise Safety Communication Plan. These programs require continued investment to ensure sustainability in the transition to the Safety Management System (SMS).

The risk quantification effort undertaken as part of the RAMP process has provided a first step toward using a data driven statistical model to evaluate safety risk investments and guide changes to PG&E's investment planning process for the creation of the SMS. These programs require continued investment to ensure sustainability in the transition to the SMS and further development of the risk assessment process.

At the direction of the Board of Directors and Senior Leadership, PG&E is implementing an Enterprise Safety Management System (ESMS) that will apply to all aspects of PG&E's business. This structure addresses safety across a comprehensive set of dimensions including safety culture, occupational health and safety, process safety, asset and environmental management. A component of the ESMS, the SMS, provides a uniform approach to safety, ensuring governance and process consistency and rigor and will be developed and implemented in concert with the ESMS (See Safety Culture).

The SMS is being assembled from existing safety work either in place or now underway within the company's various lines of business. The plans are structured to provide a strategic framework for deploying each individual safety initiative throughout the enterprise.

II. Risk Assessment

A. Background

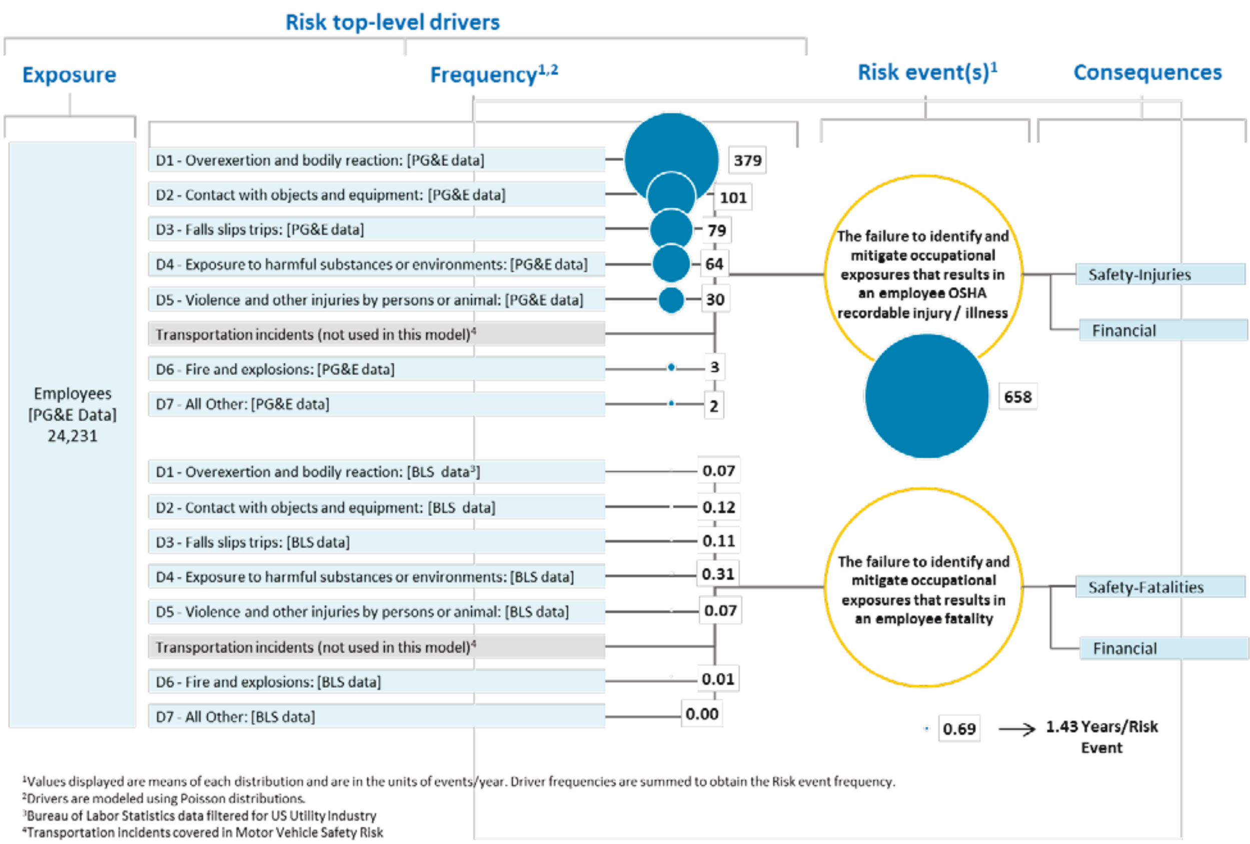
The Enterprise Risk for Employee Safety is the failure to identify and mitigate occupational exposures that may result in an employee injury or illness that is fatal, life threatening or life altering. PG&E's historical approach to employee safety risk mitigation were safety programs that were siloed into the Lines Of Business (LOB) and focused on compliance with federal, state and local safety regulations, such as those established by the Federal Occupational Safety and Health Administration (Fed/OSHA) and the California Occupational Safety and Health Administration (Cal/OSHA). The incident investigation and accident investigation process was focused on causal factors, which lead to an inadvertent emphasis on assigning blame and a safety culture that was reactive, concentrated on lagging indicators, and did not promote communication between the LOBs, and between employees and management.

The One PG&E Occupational Health and Safety Plan (as described in Safety Culture) and the SMS were developed using the company's Integrated Planning Process to identify and reduce risk, and coordinate a proactive and consolidated approach to Employee Safety.

Corporate Safety and Health used the bow tie methodology to develop a quantitative risk model specific to Employee Safety risk. The risk bow tie in

Figure 15-1 below illustrates the analysis of the exposure and shows how the drivers contribute to the likelihood of injury, illness or fatalities.

Figure 15-1: Risk Bow Tie



B. Exposure

PG&E measured the risk exposure as the average number of employees during 2016 (≈24,000).

C. Drivers and Associated Frequency

Injuries – PG&E OSHA Log Incidents From Years 2006 Through March 2017

The drivers for the Employee Safety risk are categorized into eight categories by the Bureau of Labor Statistics (BLS) "Occupational Injury and Illness Classification Manual." According to PG&E's historical OSHA[1] incident data, for the period 2006 to March 2017, PG&E experienced 7,365 employee workplace injuries which equates to an average of 658 workplace injuries per year over the

1 PG&E OSHA 300A.

11.2-year timeframe (excluding transportation incidents discussed in the Motor Vehicle Safety risk chapter).

Fatalities – BLS Incidents From Years 2011 Through 2015

During the period 2003-2016, PG&E incurred six fatalities. In order to evaluate a larger sample size, PG&E utilized BLS U.S. Utility Industry fatality data for years 2011 through 2015 in the employee safety risk model to calculate fatality distribution frequencies. This rate was approximately 0.69 fatalities per year. Again, transportation incidents were excluded as these are discussed in the Motor Vehicle Safety risk chapter.

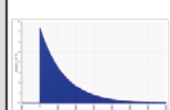
- **D1 – Overexertion and Bodily Reaction**: Includes bending, climbing, crawling, bodily reaction and exertion, overexertion in holding and carrying, overexertion in lifting/lowering, overexertion in pulling or pushing, repetitive placing, grasping, repetitive use of tools, typing or key entry. Overexertion injuries account for roughly 58 percent of reported total PG&E injuries; this is equivalent to 379 injuries and 0.07 fatalities per year (based on BLS data).
- **D2 – Contact With Objects and Equipment**: Includes being caught in or compressed by equipment, caught or crushed in collapsing equipment, jarred by tool, equipment, rubbed or abraded by foreign material, stepped on object, struck against a moving object, struck against a stationary object, struck by a falling or flying object. Contact with objects and equipment account for roughly 15 percent of reported total PG&E injuries; this is equivalent to 101 injuries and 0.12 fatalities per year (based on BLS data).
- **D3 – Falls, Slips and Trips**: Includes fall down stairs or steps, fall from ladder, fall from nonmoving vehicle, fall onto or against objects, fall to floor, walkway, or other, fall to lower level, slip, trip, loss of balance. Falls, slips and trips account for roughly 12 percent of reported total PG&E injuries; this is equivalent to 79 injuries and 0.11 fatalities per year (based on BLS data).
- **D4 – Exposure to Harmful Substances or Environment**: Includes contact with electrical current, contact with hot or cold object, contact with skin or other exposure, exposure to noise, inhalation of substances. Exposure to harmful substances account for roughly 10 percent of reported total PG&E injuries and; this is equivalent to 64 injuries and 0.31 fatalities per year (based on BLS data).
- **D5 – Violence and Other Injuries by Persons or Animal**: Includes assaults and violent acts by people, assaults by animals, venomous bites or stings or insect related incidents. Violence and other injuries by persons or animal account for roughly 5 percent of reported total PG&E injuries; this is equivalent to 30 injuries and 0.07 fatalities per year (based on BLS data).

- **D6 – 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 less than 1 percent of reported total PG&E injuries; this is equivalent to 3 injuries and 0.01 fatalities per year (based on BLS data).
- **D7 – All Other**: Includes tendonitis, carpal tunnel, sprains, hearing disorders, and dermatitis. This driver accounts for less than less than 1 percent of reported total PG&E injuries; this is equivalent to 2 injuries and 0.00 fatalities per year (based on BLS data).

D. Consequences

The range of consequences and the attributes that help describe the tail average risks and the associated MARS are shown in Figure 15-2 below. Consequences that result from an Employee Safety risk event include injuries and fatalities, and financial impacts. In Figure 15-2, there is an explanation of the data sources used for each of the consequence attributes and the resultant tail average outcomes and MARS values.

Figure 15-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PG&E Data	BLS Data	NA	NA	NA	NA	PG&E Data
Consequence Distributions	All injuries The driver frequencies of this model already quantifies injuries, therefore there are no additional calculation steps in this section	All fatalities The driver frequencies of this model already quantifies fatalities, therefore there are no additional calculation steps in this section					Average Medical + Indemnity costs: $13,460/incident (Exponential) 
Outcome-TA-NU[1]	702.89	2.39					$9,766,683
Outcome-TA-MARS[2]	191.89	65.26					5.86
						MARS Total	263.01

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** The driver frequencies of this model already quantifies injuries, therefore, the total number of the events is equal to the total number of employee injuries. The outcome of the from these inputs show the tail average value is ~703 injuries per year.

- **Safety – Fatalities (SF)**: The driver frequencies of this model already quantify fatalities using BLS data; therefore, the total number of the events is equal to the total number of employee fatalities. The outcome of the model from these inputs show the tail average value is ~2 fatalities per year.
- **Environmental (E):** This consequence is not applicable. The events in the analysis would have minor to negligible environmental impacts.
- **Reliability (R):** This consequence is not applicable. The events in the analysis have negligible impact on the ability to provide service to PG&E customers.
- **Compliance (C):** Included in the financial consequence, see Financial below.
- **Trust (T):** This consequence is not applicable. Public trust is addressed in asset-based risk assessments.
- **Financial (F):** The risk score is quantified using PG&E 2016 workers compensation claims data with estimated costs assigned to each claim. The analysis uses the workers compensation data to reflect OSHA claim dollars so that the employee safety risk only quantifies the injuries and fatalities that are OSHA recordable events, recognizing that the workers compensation data reflects all claims from 2016, including those that are not OSHA recordable. (i.e., Workers compensation claims may not have been an OSHA recordable incident or vice versa). The calculated average for these data is $13,460 per claim. The outcome of the model from these inputs show the tail average value is $9,766,683.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

The controls in this section are primarily programmatic in nature. They provide the infrastructure to support strengthening compliance and safety culture. Each control addresses all drivers.

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 utilize the Standards to develop and/or revise work methods and procedures.

C2 – Corrective Action Program (CAP): CAP is a companywide program that provides employees with an electronic process to identify and document hazardous or unhealthy conditions. These can be submitted anonymously. The submittals are assessed by teams of professionals, assigned to appropriate SMEs and tracked to completion. CAP provides PG&E employees another tool to raise concerns or identify hazards and ensures the concerns are reviewed, tracked and addressed.

C3 – Employee Knowledge and Skills Assessments (Including Academy Training): 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 – Safety Observation Program: LOB supervisory and corporate Safety Specialists conduct worksite observations using checklists developed in the Guardian system (PG&E's Safety Observation database tool) as part of the Serious Injury and Fatality (SIF) Program implementation. The SIF Program was implemented to identify high risk work activities (known as SIF Exposure Factors), the personnel potentially exposed and those Protection Measures necessary to prevent a SIF incident. As part of the SIF Program implementation, teaching materials and a Field Guide were developed to provide guidance to Supervisory personnel and the workers performing the high-risk tasks. Safety observations, performed in the field, are defined as an interaction with a Leader and one or more employees where safety systems, conditions and behaviors are observed and documented.

C5 – Personal Protective Equipment (PPE) requirements: This standard outlines the requirements for the selection and use of PPE. It applies to all employees exposed to hazards that are not adequately controlled by engineering or administrative controls.

C6 – Safety Leadership Development (SLD): Between 2014-16, PG&E completed 433 six-day SLD workshops that included approximately 1,100 supervisors and superintendents involved in high hazard operations. The workshops taught these leaders how to identify and control safety exposures through behavioral techniques. After the workshops, a certified PG&E safety leadership coach met with the management participants in the field to observe and coach them. In 2014-16, PG&E completed approximately 3,200 coaching sessions. In 2016, PG&E revised the SLD Program to reach Crew Leads, the Officers and Directors responsible for this span of control, and transferred delivery of the program to HR's series of Leadership and Employee Development programs.

Table 15-1: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	PG&E Safety and Health Compliance Standards	All Drivers	GRC	161	–
C2	Corrective Action Program (CAP)	All Drivers	GRC	630	–
C3	Employee knowledge and skills assessments (including Academy training)	All Drivers	GRC	26,331	–
C4	Safety Observation Program	All Drivers	GRC	284	–
C5	Personal Protective Equipment (PPE) requirements	All Drivers	GRC	7,500	–
C6	Safety Leadership Development (SLD)	All Drivers	GRC	5,703	–
TOTAL Expense and Capital				**40,609**	**–**

IV. Current Mitigation Plan (2017-2019)

The current mitigations are focused on addressing high frequency occurrences such as: Safety Observation Tool (M3) and Musculoskeletal Program (M6), and on setting the foundation for future development of the One PG&E Occupational Health and Safety Plan. Forward looking initiatives, such as ESMS Planning (M1), Job Hazard Analysis (M4), and Safety Leadership Development (M10) are setting the groundwork for the full implementation of an ESMS.

M1A – Safety Management System (SMS) – Planning: As preparation for implementation of an 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, and utilize the Learning Teams to assist in developing recommendations.

M3 – Safety Observation Tool: PG&E is implementing the new 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 database of 500 million completed observations and includes algorithms to provide predictive injury analysis and dashboards. It contains algorithms that help improve 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 Occupational Health and Safety Plan, which is agreed-upon by the senior management team, to establish shared accountability, ownership and commitment.

M6 – Musculoskeletal Program: 64 percent of the injuries during the last three years are musculoskeletal disorders, 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.

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 of 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 (SLD): 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 a process called Learning Teams. This mitigation is an enhancement of control C6.

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.

The mitigations above are planned and authorized for years 2017 through 2019 and are expected to be in place as controls prior to 2020. Table 15-2 summarizes these costs over this period.

Table 15-2: 2017 to 2019 Mitigation Work and Associated Cost

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1A	Safety Management System (SMS) Planning	2017	2021	All	– (C) 1,500 (E)	– (C) 1,500 (E)	– (C) 1,500 (E)
M2	Serious Injury and Fatalities Incident Investigation Review	2017	2022	All	– (C) 2,094 (E)	– (C) 2,094 (E)	– (C) 2,094 (E)
M3	Safety Observation Tool	2017	2022	All	– (C) 300 (E)	– (C) 300 (E)	– (C) 300 (E)
M4	Job Hazard Analysis	2016	2022	All	– (C) 1,983 (E)	– (C) 2,053 (E)	– (C) 2,053 (E)
M5	Safety Plan	2017	2022	All	– (C) 222 (E)	– (C) 222 (E)	– (C) 222 (E)
M6	Musculoskeletal Program	2016	2022	All	10,000 (C) 4,027 (E)	10,000 (C) 4,027 (E)	10,000 (C) 4,027 (E)
M7	Benchmarking	2017	2022	All	– (C) 322 (E)	– (C) 322 (E)	– (C) 322 (E)
M8	Enterprise Safety Communication Plan	2017	2022	All	– (C) 322 (E)	– (C) 322 (E)	– (C) 322 (E)
M9	Learning Organization	2016	2022	All	– (C) 3,800 (E)	– (C) 3,100 (E)	– (C) 3,100 (E)
M10	Safety Leadership Development (SLD)	2017	2022	All	– (C) 2,310(E)	– (C) 1,680 (E)	– (C) 1,680(E)
M11	Injury Management	2016	2022	All	– (C) 483 (E)	– (C) 483 (E)	– (C) 483(E)
M12	Health and Wellness	2017	2022	All	– (C) 2,255 (E)	– (C) 2,255 (E)	– (C) 2,255 (E)
TOTAL Expense and Capital by Year					**10, 000 (C)** **19,618(E)**	**10,000 (C)** **18,358(E)**	**10,000 (C)** **18,358(E)**

V. Proposed Mitigation Plan (2020-2022)

PG&E is implementing a companywide SMS, and plans to continue this implementation in the 2020 – 2022 time period.

M1B – SMS 5 Year Implementation: The SMS establishes the guidelines (minimum requirements) and sets a foundation to manage PG&E's safety-related systems, policies, and procedures and includes a process for continuous improvement to drive performance and risk reduction (see Safety Culture chapter). Moving to an SMS will help PG&E manage assets and processes to reduce the safety risks for all stakeholders, foster continuous learning and continuous improvement, and help connect the behavior of employees and contractors to the desired safety culture. This system is fundamental to understanding and addressing how risks and obligations are identified and managed across the company. The SMS is foundational to the safety effort going forward and because of the continuous improvement component, the effectiveness of the mitigation increases as the process is implemented. Therefore the risk spend efficiency was not the primary reason to select this mitigation. The implementation timeline of 2021 was determined after assessment of the current state of the safety program and taking into account the scope and complexities of the organization, and available resources. This is an enhancement and application of M1A.

Table 15-3: PG&E ESMS and SMS Target Implementation Roadmap

Target Date	Milestone
Complete Q4 2016	Initial ESMS Policy Approved[2] and subsequent ESMS draft by Lloyds' Register
Complete Q1 2017	Third-party gap assessment relative to draft ESMS standard by line of business
Complete Q1 2017	Internal gap assessment of draft ESMS relative to recognized ESMSs such as ANSI-Z10, ISO 45001, etc. and recognized asset, environmental and security management systems
Q4 2017	ESMS manual approved; Identification of ESMS standard elements applicable to specific areas of the business, including the SMS within Corporate Safety
Q1 2018	ESMS and SMS governance processes in place
Q2 2018	Line-of-Business action plans developed and approved
Q3 2018 to Q4 2021	Implementation of action plans within the ESMS and SMS framework
Ongoing	Continual improvement and evolution of the ESMS and SMS

2 SAFE-01.

Table 15-4: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	SMS 5 Year Implementation	0.15	0.14	2017	2021	All	– (C) 1,425-1,575 (E)	– (C) 1,425-1,575 (E)	– (C) – (E)
Proposed Mitigation Plan TA RSE: 0.15 **TOTAL Expense and Capital by Year**							**– (C)** **1,425-1,575 (E)**	**– (C)** **1,425-1,575 (E)**	**– (C)** **– (E)**

VI. Alternatives Analysis

Safety and Health assessed all identified mitigations and how each relates to the drivers for Employee Safety risk. This analysis provided two alternative implementation options to the proposed plan for the integrated SMS. The Proposed Mitigation Plan targets an implementation completion in year 2021.

Alternative Plan 1 allows an additional year, for SMS implementation with completion in year 2022. This spreads out the impact of system implementation, requiring a less acute focus of staff time and resources, but delays the benefits of a fully implemented SMS.

Alternative Plan 2 keeps the 2021 implementation timeline, but depends on an investment in information technology (such as software, mobile devices, and electronic databases) for implementation instead of fully focusing the efforts of organization. This option would divert resources from personnel development to cover capital expenses. The resultant end product with this Alternative plan would function more as an ‘add on’ program. While this is initially more efficient, it would not have the efficacy of the Proposed Mitigation Plan.

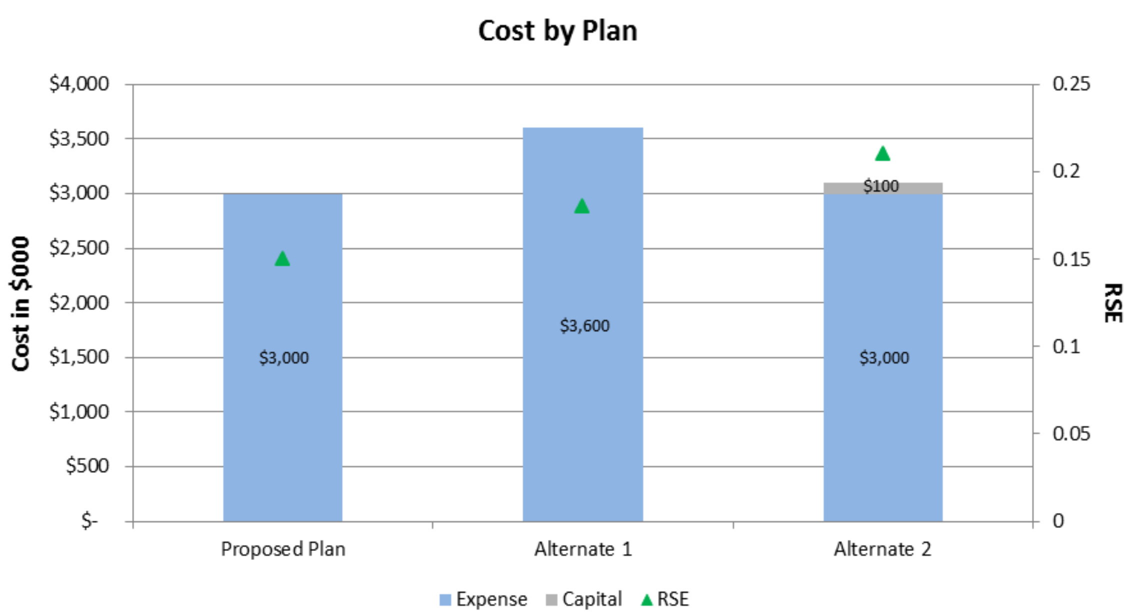
Analysis and exposure reduction benefits associated with each of the three mitigations are qualitative and based on SME best judgement.

Table 15-5: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1B	SMS 5 year implementation	0.15	0.14	x			WP 15-2
M1C	SMS 6 year implementation	0.18	0.16		x		WP 15-2
M1D	SMS 5 year implementation and IT solution	0.21	0.19			x	WP 15-2

Figure 15-3 below shows the breakdown of the Proposed Plan, Alternative Plan 1, and Alternative Plan 2 based on cost and Risk Spend Efficiency (RSE).

Figure 15-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

Alternative Plan 1 adds an additional year to the implementation of the SMS (six year period). Extending the timeline, while still addressing the risk drivers, is not required for the development of the program or establishing the foundation for successful implementation. Given the clear necessity for SMS implementation and lacking any reason to support delayed implementation, the Alternative Plan 1 with an extended timeline was not chosen.

Table 15-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	SMS 6 year implementation	0.18	0.16	2017	2022	All	– (C) 1,140-1,260 (E)	– (C) 1,140-1,260 (E)	– (C) 1,140-1,260 (E)
Alternative Plan 1 TA RSE: 0.18 **TOTAL Expense and Capital by Year**							**– (C) 1,140-1,260 (E)**	**– (C) 1,140-1,260 (E)**	**– (C) 1,140-1,260 (E)**

B. Alternative Plan 2

Alternative Plan 2 includes an off the shelf IT solution to replace staff-based SMS implementation over a five year period. This would be a programmatic add-on instead of a fundamental shift that was tailored and developed to address PG&E operations and risks. This option does not effectively develop or deploy an effective SMS. For this reason, Alternative Plan 2 was not chosen.

Table 15-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	SMS 5-year implementation and IT solution	0.21	0.19	2017	2021	All	45-55 (C) 1,425-1,575 (E)	45-55 (C) 1,425-1,575 (E)	– (C) – (E)
Alternative Plan 2 TA RSE: 0.21 **TOTAL Expense and Capital by Year**							**45-55 (C) 1,425-1,575 (E)**	**45-55 (C) 1,425-1,575 (E)**	**– (C) – (E)**

VII. Metrics

Development and implementation of an SMS includes the utilization of leading indicators as metrics of safety performance. These metrics will include: Job Hazard Analysis, Employee and Supervisor Training, Safety Observations, Program Audits, and Near-hit Reporting. These metrics are leading indicators in an SMS framework because they provide for evaluation of system performance prior to an incident.

Current outcome and accountability metrics used to track the Employee Safety risk include but are not limited to the following:

Table 15-8: Proposed Metrics

Mitigation	Associated Driver # and Consequence	Metric	Targets
SMS	All	SIF Timely Corrective Actions Completion (percent)	85 percent (2017)
SMS	All	SIF: Effectiveness of Corrective Actions	0.313 (2017)
SMS	All	# of Employee Serious Injuries & Fatalities	track and trend only
SMS	All	DART Rate	track and trend only
SMS	All	Lost Workday Case Rate	0.435 (2017)
SMS	All	OSHA Injury Rate	track and trend only

VIII. Next Steps

PG&E has evolved its strategic thinking through the RAMP process, SMS development, and the One PG&E Occupational Health and Safety Plan, so the Employee Safety mitigation efforts are shifting focus to risk-based prioritization, and the identification and evaluation of essential safeguards (leading indicators). Opportunities remain to improve data capture and program evaluation, specifically in the development and deployment of these leading indicators, such as SMS audits. Gap analysis will be conducted to determine LOB readiness for SMS compliance. LOB specific action plans will be developed to close performance gaps. Leading and lagging indicators, will be developed and used to monitor the progress of the action plans.

The immediate next steps are the publication and establishment of the SMS and the One PG&E Occupational Health and Safety Plan. Following publication, additional gap assessments will be conducted to further the risk assessment process, and quantify and develop LOB specific action plans. The implementation of the action plans will address deficiencies and bring operations and programs into alignment with the SMS. The continual improvement cycle of the SMS ensures an ongoing process of risk assessment and analysis. Additional mitigations and corrective actions will be developed from these risk assessments and analyses to continue to drive reductions in frequency of events. The ongoing process of audits and program evaluation, and the implementation and refinement of the SMS, will help PG&E to identify and reduce Employee Safety risk throughout the enterprise.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 16
MOTOR VEHICLE SAFETY

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 16
MOTOR VEHICLE SAFETY

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Motor Vehicle Safety (MVS)
IN SCOPE	Registered vehicles requiring a driver's license (commercial and non-commercial) operated on Company business – including personal vehicles and rental vehicles; use of vehicles with Pacific Gas and Electric Company (PG&E) logos (at any time); motor vehicle incidents; driving on roads, public streets, and highways.
OUT OF SCOPE	Motorized equipment, off-road vehicles, off-road driving, unique or specialized vehicles, non-staff augmentation contractors, and other drivers.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, National data from the U.S. Department of Transportation Bureau of Transportation Statistics and National Highway Traffic Safety Administration (NHTSA), and Subject Matter Expert (SME) input.

According to the Bureau of Labor Statistics, driving is one of the highest risk activities of many professions.[1] While PG&E's injury and fatality rates are not as high as the national average, over the last three years, PG&E has experienced one death and 87 Occupational Safety and Health Administration (OSHA) incidents related to motor vehicle incidents, making this risk one of the top risks for the Company.[2]

In 2017, PG&E used the risk bow tie assessment methodology to develop a probabilistic operational risk model specific to the MVS risk. This model's inputs and outputs are presented in this chapter. The model uses a combination of PG&E-specific data, industry data, and SME judgment to gain a better understanding of the risk drivers associated with the risk and where to target new mitigations.

The purpose of this chapter is to present PG&E's proposed mitigation plan for the MVS risk for 2020 through 2022, and the probabilistic operational risk model developed and utilized to assess mitigations. The MVS risk assessment analyzes and evaluates risk drivers which may result in a PG&E employee or general public injury or fatality, and mitigations that can reduce the risk.

Through the Risk Assessment and Mitigation Phase (RAMP) process, PG&E was able to objectively evaluate its ability to reduce the MVS risk and concluded that mitigations "Deploy Vehicle Safety Technology (VST) in Personal Vehicles," "Driver Selection Program" and "Motor Vehicle Safety Management System" are best able to reduce the

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1 https://www.bls.gov/news.release/pdf/cfoi.pdf.

2 An OSHA recordable incident is an occupational (job-related) injury or illness that requires medical treatment beyond first aid, or results in work restrictions, death or loss of consciousness. OSHA recordable rate is calculated as OSHA recordable times 200,000 divided by employee hours worked.

probability of MVS incidents. PG&E calculates that these mitigations will reduce the MVS Risk overall by 7.4 percent. PG&E also learned that if technologies and tools are developed in the future with risk reduction capabilities similar to the inputs modeled for Alternative Plan 1, these tools and technologies should be evaluated, and adopted if warranted based on the evaluations.

Areas for continued model development are risk reduction quantification for process improvements and emerging tools and technologies. Modeling data for PG&E's process improvement mitigations is subjective, and thus often less reliable than risk reduction data for tools and technologies that have been commercially available for some time. During the early development stages of new tools and technology, risk reduction data is qualitative, and based largely on SME judgment. As tools and technologies become more common in the market place, data becomes more available. The MVS system will enable PG&E to continually improve management of this risk at an increasingly quantitative level, including assessing alternatives as they emerge and data becomes available.

II. Risk Assessment

A. Background

MVS risk is 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.

According to the Bureau of Labor Statistics, driving is one of the highest risk activities of many professions, and based on the Bureau of Transportation Statistics, the average fatality rate and injury rate, respectively from 2007 through 2015 for drivers were 1.16 and 78 per 100 million miles driven.[3] PG&E has a motor vehicle carrier license, maintains a fleet of over 9,000 vehicles and employs 3,700 commercial drivers. PG&E has developed several controls to manage risk and compliance associated with its motor vehicle fleet and the motor vehicle carrier license ranging from license requirements for drivers to training on safe driving practices. In addition, PG&E rents vehicles for various operational needs, and employees use personal vehicles for company business. PG&E has developed controls for all employees that may drive for business, such as the "Phone Free Driving Standard."

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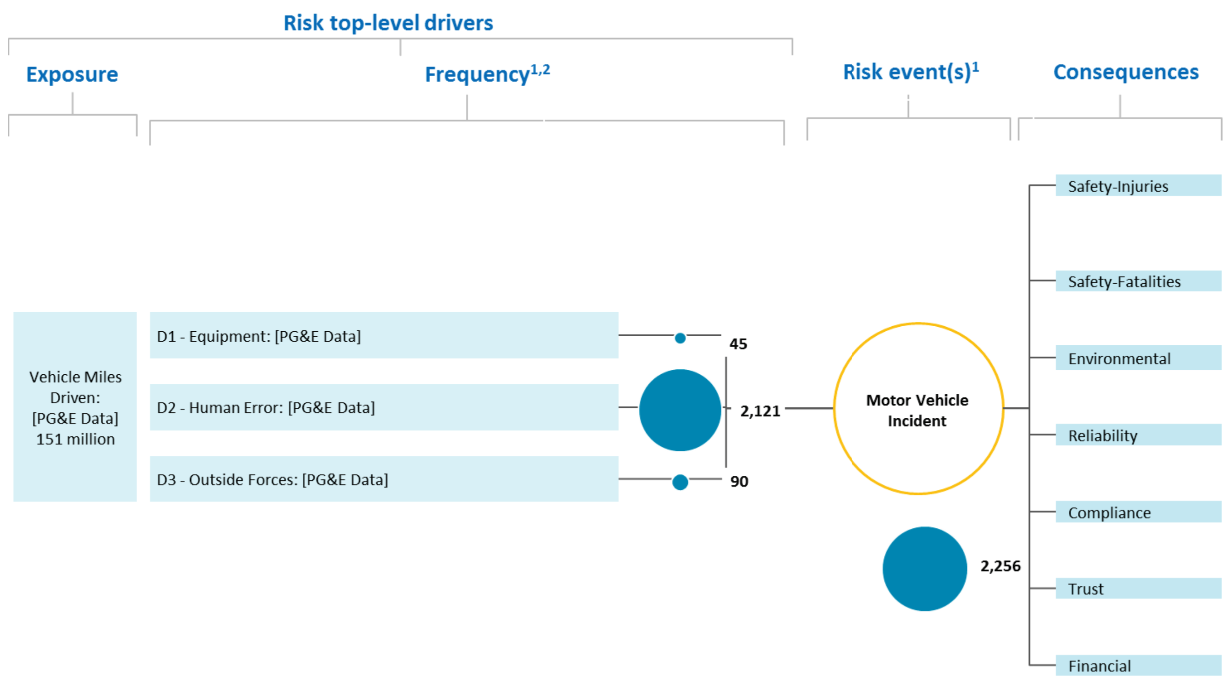
3 https://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_02_17.html.

MVS was added to the Safety and Health (formerly Safety and Shared Services) risk register in 2015, and identified as a top risk for Safety and Health in 2016. In 2017, the MVS risk was moved to a top risk for the Company.

Mitigation plans were developed and implemented following a bow tie analysis in 2016, and expanded in 2017. As a result of the safety impact associated with this risk, MVS risk was selected to go through the RAMP process.

The risk bow tie shows the exposure and frequency drivers for the risk, as well as the probability of a risk event related to each risk driver. The risk event, at the center of the bowtie, is defined as a motor vehicle incident. Based on the model inputs for frequency, this risk event is likely to occur approximately 1,494 times for every 100 million miles driven. The risk bow tie diagram is a representation of how the RAMP model utilizes PG&E historical mileage and incident data, and national mileage and incident data to calculate an exposure and frequency distribution for the bow tie risk drivers.

Figure 16-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson distributions.

B. Exposure

Being in a motor vehicle creates exposure to this risk. PG&E uses miles driven as a measure of exposure, and uses the number of events per 100 million vehicle miles driven as a measure of risk relative to exposure. This unit of risk is used by the Bureau of Transportation Statistics and Federal Highway Administration (FHWA), and allows PG&E to utilize national data, and to compare performance with that of other companies.[4,5] PG&E estimates 151 million miles will be driven by employees in 2017, with a calculated compound annual growth rate of 2.5 percent per year based on 2014-2016 data. The mileage is made up of 69 percent PG&E-owned vehicles, 23 percent employee-owned vehicles, and 8 percent rental vehicles.

C. Drivers and Associated Frequency

Based on PG&E's accident data and national data provided by the Bureau of Transportation Statistics, the primary drivers for MVS include Equipment, Human Error, and Outside Forces.[6] As a part of RAMP, each risk driver was evaluated for contribution to incidents. Both PG&E data and national data were used to develop weightings for each risk driver.[7] The drivers are:

- **D1 – Equipment:** Equipment failures are incidents due to the failure of the vehicle, or part of the vehicle such as, flat tires and brake failures. Evaluation of national data indicates that 2 percent of incidents are caused by equipment failure resulting in an estimate of 45 events.
- **D2 – Human Errors:** Human errors are incidents resulting from human mistakes for reasons such as internal and external distractions, driving too fast, overcompensation, and non-performance errors such as sleep. Evaluation of national data indicates human errors account for 94 percent of MVS incidents or an estimate of 2,121 events.
- **D3 – Outside Forces:** Outside forces are incidents related to factors outside the driver's control such as roadway design, and atmospheric conditions such as slick roads. Evaluation of national data indicates that 4 percent of incidents are caused by outside forces, or an estimate of 90 events.

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4 https://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_02_17.html.

5 https://safety.fhwa.dot.gov/local_rural/training/fhwasa1109/app_c.cfm.

6 https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/812115.

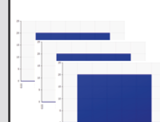
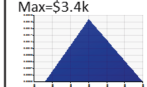
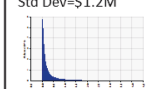
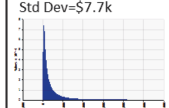
7 https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/812115;2015 PGE Motor Vehicle Incident Report; 2016 PGE Motor Vehicle Incident Report.

Incidents may result from a single risk driver, or a combination of risk drivers. For example, weather (Outside Force) can create hazardous conditions, to which the automobile driver fails to reasonably respond by slowing down (Human Error). However, PG&E did not model the effect of multiple drivers for this RAMP.

D. Consequences

The range of consequences and the attributes that help describe the tail average risks and the associated Multi-Attribute Risk Score are shown in Figure 16-2. There is an explanation of the data sources used for each of the consequence attributes. Note that not all consequences are applicable to the MVS risk.

Figure 16-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	PG&E Data	PG&E and US DOT[3] Data	NA	NA	NA	PG&E Data and SME Input	PG&E Data
Consequence Distributions	19.6 injuries per 100 millions miles / 1494 crashes per 100 million miles ➔Mean=0.01315 (Poisson) 	1.2 fatalities per 100 million miles / 1494 crashes per 100 million miles ➔Mean=0.00078 (Poisson) 				Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=6-9% Severe=2.5-6% Low=0-2.5% (Uniform) 	Claims (Triangular) Likelihood=83% Min=$2.3k; Ave=$2.8k; Max=$3.4k  + Settlements (Lognormal) Likelihood=2.6% Ave=$0.4M Std Dev=$1.2M  + Repairs (Lognormal) Likelihood=65% Ave=$3.0k Std Dev=$7.7k 
Outcome-TA-NU[1]	41.90	4.58				8.82%	$56,297,585
Outcome-TA-MARS[2]	11.44	124.97				44.11	33.78
						MARS Total	**214.30**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units
[3]US Department of Transportation

- **Safety Injuries (SI):** Based on 2015 and 2016 PG&E incident reports, the PG&E incident rate is 1,494 incidents per 100 million miles.[8] PG&E OSHA recordable injuries from motor vehicle incidents reports from years 2014 through 2016 are an average of 19.64 per 100 million miles.[9] (To

8 015 PGE Motor Vehicle Incident Report; 2016 PGE Motor Vehicle Incident Report; MVS-01-20170314 – Data from MVS emails.xlsx.

9 15 - EMPSAFE - 02 - OSHA Only 2006-2017 Injuries-updated 6-14-17_v2.xlsx; MVS-01-20170314-Data from MVS emails.xlsx.

compare, the national average from years 2007 through 2015 is 78 injuries per 100 million miles.) The PG&E values produce an average injury per incident rate of 0.01315. Based on these inputs, the tail average model worst case results across the 2017-2022 time periods are 41.90 injuries a year.

- **Safety Fatalities (SF):** PG&E had one fatality related to motor vehicle incidents over the 2014 through 2016 timeframe, or 0.22 fatalities per 100 million miles. The national average from years 2007 through 2015 is 1.16 fatalities per 100 million miles. The consequence input is quantified using Bureau of Transportation Statistics average fatality rate from years 2007 through 2015.[10] This data is collected in a national database which is inclusive of all data elements that characterize fatal crashes on U.S. public roadways. These elements include FHWA and NHTSA definitions of fatality type, collision type, collision location, and type of person involved in the fatal crash. PG&E relied on national data for fatalities rather than PG&E data due to the statistical limitations of the data set. Using the national data set with the PG&E's incident rate per 100 million miles, an average fatality per incident rate of 0.00078 is calculated. Based on these inputs, the tail average model worst case results across the 2017-2022 time periods are 4.58 fatalities a year.
- **Environmental (E):** The unit of measure used for environmental consequences is U.S. dollars. Based on review of claims and settlements related to motor vehicle incidents from years 2012 through 2016, and PG&E regulatory fines and penalties, PG&E has experienced little to no environmental costs associated with this risk.
- **Reliability (R):** Reliability is measured in customer outage minutes. PG&E has reviewed motor vehicle incidents from 2012 through 2016, and has determined that outages due to PG&E motor vehicle incidents are negligible.
- **Compliance (C):** The unit of measure used for compliance consequences is U.S. dollars. Based on review of claims and settlements related to motor vehicle incidents from years 2012 through 2016, and PG&E regulatory fines and penalties, PG&E has experienced few, if any, regulatory fines and penalties associated with this risk. Additionally, fines and penalties are below-the-line items that are not included in the RAMP filing.
- **Trust (T):** Events are dependent upon safety outcomes, both injury and fatality, and categorized as: low, severe, and high. This methodology was used across all risks.[11] For this risk, PG&E assumed approximately

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10 https://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_02_17.html.

11 Refer to Chapter B, Risk Model Overview, for the trust consequence calculation details.

half of the impact based on frequency and familiarity of vehicle incidents relative to other safety events. This results in a high severity bounds of 6-9 percent, severe bounds of 2.5-6 percent, and a low bound of 0-2.5 percent. Based on these inputs, the tail average model worst case results across the 2017-2022 time periods show an average value of a 9 percent change a year.

- **Financial (F):** PG&E used incident logs and claims, settlements, and repair records from years 2012 through 2016 to establish probability distributions to use for the financial impacts. Claims are modeled using an 83 percent likelihood of a claim based on 1723 historical claims in 2085 incidents. Claims are modeled using a triangular distribution with a minimum, average, and maximum value based on historical data. Settlement impacts are modeled using a likelihood of a settlement of 2.6 percent based on historical PG&E data. The settlement impact is modeled using a lognormal distribution with the historical mean and standard deviation as input. Next the financial impact of repairs is modeled. The likelihood of a repair impact is 64.6 percent and is also modeled with a lognormal distribution using historical PG&E mean and standard deviation values. Based on these inputs, the tail average model worst case results across the 2017-2022 time periods is $56 million a year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls and mitigations described in this section address one or more drivers of the MVS Risk. Table 16-1 below summarizes the controls, mitigations and 2016 recorded costs associated with each control and mitigation. Controls and mitigations with expense costs listed as 0 in Table 16-1 are costs embedded in existing resources, or that do not reside in Corporate Safety. Controls and mitigations with capital costs listed as 0 in Table 1 do not have recorded capital costs. These controls are focused in three areas: driver training and qualifications, driver fitness, and vehicle maintenance. Many of the controls focus on training drivers to recognize hazards which include outside forces. PG&E does not consider training to recognize outside forces as a control for the outside forces risk driver. PG&E has no controls specific to the outside forces risk driver.

The following controls address Human Error (see risk driver D2 above). These controls focus on skills and qualifications for drivers to prevent human errors due to limited skills and knowledge. Many of these controls also meet regulatory requirements.

C1 – Commercial Driving School: This course (EQIP-0006) is recommended for those employees that are required to obtain a commercial driver's license (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.

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) motor vehicle incidents.

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.

The following controls address Human Error (see risk driver D2 above), focusing on driver mental and physical fitness to drive.

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, and 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 (Department of Transportation (DOT) and Gas Employees): All DOT covered employees are subject to the following categories of drug testing managed by the DOT Compliance Team per 49 CFR parts 40, 199, 382, and 14 CFR part 120:

- Post-accident Drug Testing
- Random Drug Testing
- Drug Testing resulting from Reasonable Suspicion and/or Reasonable Cause
- Return to Duty Drug Testing
- Follow-up Drug Testing

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.

The following controls are intended to limit incidents caused by Equipment Failure (see risk driver D1 above.)

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 – Driver Visual Inspection Report (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.

There were five mitigations that began in 2016 and were completed in 2016. Two of these five mitigations, VST Program and VST Program Standardized Reporting, are foundational for additional mitigations in 2017 through 2019. All of these mitigations address the Human Error risk driver and provide data to further assess the risk.

M1 – 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.

M2A – Vehicle Safety Technology Program: VST is Global Positioning System (GPS) based. The tool provides real-time, audible feedback to the driver when risky behaviors occur, such as speeding, hard acceleration and hard braking. This mitigation was completed in 2016.

M3 – 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. This is used by the driver and by the Company to assess performance improvements over time. This mitigation was completed in 2016.

M4 – 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.

M5 – 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.

Table 16-1: Risk Controls and Mitigations 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Cost Recovery Source	2016 Recorded Expense ($000) [A]	2016 Recorded Capital ($000) [A]
C1	Commercial Driving School	D2	GRC	–	–
C2	Driver Qualification	D2	GRC	–	–
C3	Smith Driving	D2	GRC	–	–
C4	Distracted Driving	D2	GRC	–	–
C5	Smith Driving Course	D2	GRC	–	–
C6	Defensive Driving -The Critical 5	D2	GRC	–	–
C7	Vehicle Tie Down Equipment Training	D2	GRC	–	–
C8	Reasonable Suspicion Supervisor Training	D2	GRC	–	–
C9	DMV Employer Pull Notice Program	D2	GRC	51	–
C10	Fitness for Duty Training	D2	GRC	–	–
C11	Phone Free Driving Standard	D2	GRC	–	–
C12	Company Pool Vehicle Standard	D2	GRC	–	–
C13	Commercial Driver's Fatigue Management Procedure	D2	GRC	–	–
C14	Drug/Alcohol Testing program (DOT and Gas Employees)	D2	GRC	161	–
C15	"How Am I Driving" hotline reporting and Supervisor review	D2	GRC	220	–
C16	Preventative Maintenance On Time Performance and Monitoring	D1	GRC	–	–
C17	Driver Visual Inspection Report (DVIR) and Audit	D1	GRC	322	–
M1	MVS Standard	D2	GRC	–	–
M2A	Vehicle Safety Technology Program	D2	GRC	–	–
M3	Vehicle Safety Technology Program standardized reporting	D2	GRC	14	–
M4	Driving Expectations & New Laws	D2	GRC	–	–
M5	Standardized Employee Motor Vehicle Training Requirements	D2	GRC	–	–
TOTAL Expense and Capital				**768**	**–**

Note A: Controls and Mitigations with expense costs listed as – are costs embedded in existing resources, or that do not reside in Corporate Safety. Controls and Mitigations with capital costs listed as – do not have recorded capital costs.

IV. Current Mitigation Plan (2017–2019)

The focus of PG&E's mitigations for years 2017 through 2019 are on the Human Error risk driver (D2), which is the source of for 94 percent of motor vehicle incidents. These mitigations were selected through a review of alternatives with SMEs. There are four mitigations planned between years 2017 and 2019. Of these four mitigations, three expand upon the VST Program and VST Program Standardized Reporting mitigations initiated and completed in 2016: "Implement Driver Accountability," "2017 Vehicle Safety Technology Install and Activate" and "Revise license verification process for non-DOT Covered Drivers." The remaining mitigation is an additional control to further ensure drivers have the minimum qualifications.

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. This mitigation was completed in 2017, and is now a control.

M7 – Implement Driver Accountability: Use VST and Driver Check 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. This mitigation was completed in 2017, and is now a control. This control will be expanded as PG&E installs VST in more vehicles.

M2B – 2017 and 2018 Vehicle Safety Technology Install and Activate: This mitigation is an expansion of mitigation M2 from 2016. PG&E will Install and activate VST in 2,000 vehicles in 2017, and the rest of the fleet in 2018. See M2A in Section III for more information about VST.

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 control C9, DMV Employer Pull Notice Program. The expected impact is to ensure that drivers on the road have the appropriate license and are compliant with California laws. This mitigation is expected to be complete, and become a control, by the end of 2019.

Table 16-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000) [A]	2018 Estimate ($000) [A]	2019 Estimate ($000) [A]
M6	Training acknowledgement for valid license	2017	2017	D2	– (C) 40 (E)	– (C) 3 (E)	– (C) 3 (E)
M7	Implement Driver Accountability	2017	2017	D2	– (C) 16 (E)	– (C) 16 (E)	– (C) 16 (E)
M2A	2017 and 2018 Vehicle Safety Technology Install and Activate	2017	2018	D2	1,676[B] (C) 2,027[B] (E)	1,251[B] (C) 2,460[B] (E)	– (C) 2,460[B] (E)
M8	Revise License Verification Process for Non-DOT Covered Drivers	2017	2019	D2	– (C) 386 (E)	– (C) 336 (E)	– (C) 336 (E)
TOTAL Expense and Capital by Year					**1,676 (C)2,469 (E)**	**1,251 (C) 2,815 (E)**	**– (C) 2,815 (E)**

Note A: Mitigations with capital costs listed as – do not have recorded capital costs.
Note B: These mitigations include costs covered by Transportation Services.

V. Proposed Mitigation Plan (2020–2022)

PG&E performed an assessment of all mitigations considered and how each relates to the drivers for MVS Risk. PG&E's proposed mitigations fall into two groupings:

- Tools and Technology – utilization of existing and emerging tools and technology to help drivers improve driving habits, alert drivers of pending risks, and minimize impacts from incidents; and
- Process Improvements – increased utilization and aggregation of data and systems to provide PG&E insights and direction to further reduce risk.

The Proposed Mitigation Plan consists of the "Deploy Vehicle Safety Technology in Personal Vehicles" tools and technology mitigation, and the "Driver Selection Program" and "Motor Vehicle Safety Management System" process improvement mitigations. These mitigations expand on PG&E's existing controls and mitigations, and position PG&E to make continual improvements to reduce the MVS risk. Based on the risk model output, the Proposed Plan is anticipated to reduce the risk by 7.4 percent compared to the baseline, and has the most favorable risk spend efficiency. This is the optimal plan when considering what tools and technologies are currently available. Mitigations not selected are the tools and technologies "Emerging Incident Reduction Technology" and "Emerging Impact Reduction Technology" mitigations. These mitigations are based on proxy data used to illustrate potential risk reduction based on tools and technologies PG&E is either currently using, or proposing to use. As these tools are developed and become commercially available, PG&E will assess their actual risk reduction potential. Mitigations included in the Proposed Plan are listed below.

M9 – Deploy Vehicle Safety Technology in Personal Vehicles: This mitigation will deploy VST in personal vehicles, possibly in the form of a cellphone application. This mitigation will provide similar information to the drivers and PG&E as M2, but will rely on a different hardware and, or software solution. The technology will provide real time feedback, such as an alarm, to employees about their driving habits while driving personal vehicles for company business. By alerting employees of potentially dangerous habits, such as hard breaking and hard acceleration, employees can modify their driving habits. In addition, VST will provide PG&E data on employee driving habits while on company business. This information will be used to provide employees feedback, context (relative to other drivers) and coaching. By improving driving habits, employees reduce the risk of human error. PG&E estimates that this technology will reduce the risk of incidents caused by human errors from PG&E drivers by 50 percent. PG&E assumes 50 percent of human errors are due to PG&E drivers, and 50 percent are due to other drivers. This means that this mitigation will reduce incidents from human error by

25 percent overall. This is based on a consultant report,[12] CNA Driver Performance article,[13] and SME opinion.

PG&E estimates the costs for this mitigation to be in the range of $487,000-539,000 in capital, and $1,962,000-2,170,000 in expense over the RAMP time period.[14] Costs for this mitigation are based on Davis Instruments.[15] The Tail Average Risk Spend Efficiency (TA RSE) for this mitigation is 6.5.[16]

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 on the VST mitigation and license verification process. It utilizes multiple data sources to develop driver criteria. PG&E will work with drivers to improve individual and overall Company driving performance. Corrective action will depend on specific circumstance, and may include training, driving restrictions and alternative transportation. This will reduce injuries associated with motor vehicle incidents resulting from human error. Like the VST mitigation above, PG&E estimates that this technology will reduce the risk of incidents caused by PG&E driver human errors by 50 percent, or 25 percent overall. This is based on CNA Driver Performance article,[17] and SME opinion.

PG&E estimates the costs for this mitigation to be in the range $231,000-255,000 in expense over the RAMP time period.[18] Costs are for internal resources within Safety and Health. The TA RSE for this mitigation is 277.8.[19]

M13 – Motor Vehicle Safety Management System: Implement comprehensive MVS Programmatic Management System. This mitigation provides a systematic approach to managing vehicle safety that allows for continual improvement. The systematic approach drives analysis of vehicle safety, such as periodically assessing emerging technologies and identifying and incorporating new data sources into the Driver Selection program, and establishes improvement plans based on PG&E performance

12 Davies Consulting Alternatives Analysis v2 2016-08-23.pdf.

13 CNA Driver Performance.pdf.

14 Workpaper WP 16-9.

15 Davis Instruments Cost Estimates Email.msg.

16 Workpaper WP 16-9.

17 CNA Driver Performance.pdf.

18 Workpaper WP 16-2.

19 Workpaper WP 16-2.

data, benchmarks and other external data. The system establishes assessment and corrective action of improvement plans. PG&E projects that this will result in incremental improvement on a continual basis, and identify opportunities for significant increases or "breakthroughs." Further, this mitigation will be important to establishing and sustaining a risk tolerance level for the MVS risk.

PG&E projects that this mitigation will result in a modest incremental risk reduction of 2 percent in affected risk drivers—equipment failures, and human error, and impact reduction in injuries and fatalities. PG&E did not make assumptions for significant breakthroughs. Significant breakthroughs identified by this mitigation will result in new future mitigations.

PG&E estimates the costs for this mitigation to be in the range $93,000-$102,000 in expense over the RAMP time period.[20] Costs are for internal resources within Safety and Health. The TA RSE for this mitigation is 118.7.[21]

Table 16-3 is a list of the proposed mitigations described above, the associated costs and RSEs for each mitigation.

<u>Table 16-3: Proposed Mitigation Plan and Associated Costs</u>

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M9	VST in Personal Vehicles	6.5	4.9	2020	2022	D2	487 – 539(C) 740 - 818 (E)	– (C) 611 – 676 (E)	– (C) 611 – 676 (E)
M10	Driver Selection Program	277.8	210.8	2020	2022	D2	– (C) 77 - 85 (E)	– (C) 77 - 85 (E)	– (C) 77 - 85 (E)
M13	MVS Management System	118.7	82.7	2020	2022	D1, D2, SI, SF	– (C) 31 - 34 (E)	– (C) 31 - 34 (E)	– (C) 31 - 34 (E)
Proposed Mitigation Plan TA RSE: 32.7 **TOTAL Expense and Capital by Year**							**487 - 539 (C)** **848- 937 (E)**	**– (C)** **719 - 795 (E)**	**– (C)** **719 -795)**

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20 Workpaper WP 16-2.

21 Workpaper WP 16-2.

VI. Alternatives Analysis

PG&E also assessed two additional mitigations that were not selected for the Proposed Plan. These mitigations were included in the motor vehicle safety risk model and are described below.

M11 – Emerging Incident Reduction Technology: Implement new and/or emerging vehicle safety technology as it becomes commercially available for incident reduction. This mitigation anticipates advances in technology, similar to back-up cameras and lane drift detection that can be used to reduce the frequency of injuries. These technologies are primarily focused on incidents resulting from human errors. Some of these technologies will become standard equipment for vehicles, and will be adopted by PG&E through turnover of the PG&E fleet. This mitigation assumes a new technology is developed, or existing technology demonstrates advancement that has a similar risk reduction value as VST. Under these circumstances, PG&E will retrofit vehicles to expedite implementation. However, current technologies on the market, such as back-up cameras, do not have the same risk reduction capabilities as VST.[22]

PG&E estimates the costs for this mitigation to be in the range $1.3 million to $1.4 million in capital over the RAMP time period. Costs were estimated based on typical costs to retrofit a vehicle with a back-up camera. No maintenance costs were estimated over the RAMP time period. The TA RSE for this mitigation is 37.3.

M12 – Emerging Impact Reduction Technology: Implement new and, or emerging vehicle safety technology as it becomes commercially available for impact reduction. This mitigation anticipates advances in technology, similar to airbags that can be used to reduce the severity of injuries. Some of these technologies will become standard equipment for vehicles, and will be adopted by PG&E through turnover of the PG&E fleet. This mitigation assumes a new technology is developed that has a similar risk reduction value as airbags. However, no emerging technologies on the market today meet these criteria. Under these circumstances, if a new technology meeting the criteria above emerges, PG&E will retrofit vehicles to expedite implementation.

A study by Road Injury Prevention and Litigation Journal showed an injury reduction of about 20 percent when airbags were coupled with seatbelts, and about 5 percent reduction in fatalities when coupled with seatbelts compared to seatbelts alone.[23] PG&E used these values for risk reduction effectiveness as proxy for future impact reduction advances.

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22 Workpaper WP 16-9.

23 http://www.usroads.com/journals/p/rilj/9709/ri970902.htm.

PG&E estimates the costs for this mitigation to be in the range $8.6 million to $9.5 million in capital over the RAMP time period. No maintenance costs were estimated over the RAMP time period. Costs were estimated based on typical costs PG&E was able to find to retrofit, or replace a vehicle with an airbag. The TA RSE for this mitigation is 1.4.

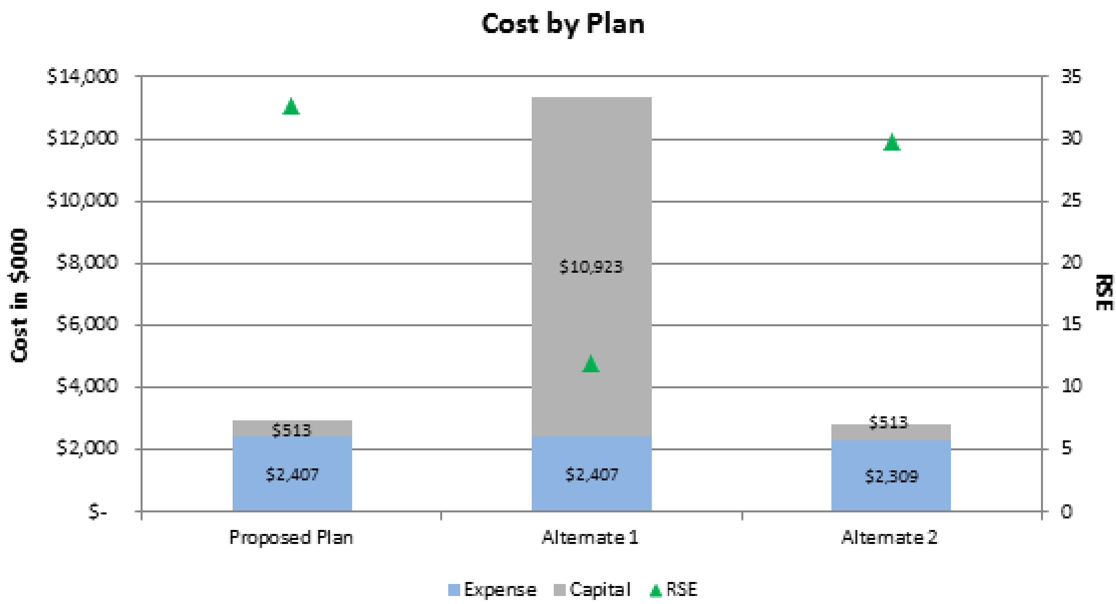
After assessing all of the mitigations, PG&E has two alternative plans to the proposed mitigation plan. Plan 1 was created based on adding additional tools and technologies as they become available, and based on modeling has similar risk reduction as VST. Plan 2 was created based on a combination of resource limitations, and ability to leverage other programs to achieve the process improvement mitigations within the Proposed Mitigation Plan. Both plans are shown below in Tables 16-5 and 16-6, respectively. Table 16-4 lists all the mitigations considered for adoption in the RAMP time period.

Table 16-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)Expected Value Risk Spend Efficiency Score (Units/1$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M9	VST in Personal Vehicles	6.5	4.9	X	X	X	WP 16-9
M10	Driver Selection Program	277.8	210.8	X	X	X	WP 16-2
M11	Emerging Incident Reduction Technology	37.3	28.3		X		WP 16-9
M12	Emerging Impact Reduction Technology	1.4	0.9		X		WP 16-9
M13	MVS Management System	118.7	82.7	X	X		WP 16-2

Figure 16-3 below shows the breakdown of the Proposed Mitigation Plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE. The Proposed Mitigation Plan has the most favorable RSE, and at an estimated cost of $2.9 million is the second most economical. Alternative Plan 1 has the highest risk reduction, but is also the most costly at $13.3 million and has the lowest RSE. The RSE and total cost of $2.8 million of Alternative Plan 2 are similar to, but slightly lower than, those of the Proposed Mitigation Plan.

Figure 16-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

Alternative Plan 1 consists of two additional Tools and Technologies mitigations not part of the Proposed Plan. These additional mitigations are:

- **M11 – Emerging Incident Reduction Technology:** Implement new or emerging vehicle safety technology as it becomes commercially available for incident reduction;
- **M12 – Emerging Impact Reduction Technology:** Implement new or emerging vehicle safety technology as it becomes commercially available for impact reduction.

Alternative Plan 1 assumes that the additional Tools and Technologies mitigations will become commercially available and will have an RSE that is comparable to other mitigation alternatives. Under these circumstances, these tools and technologies may warrant implementation. While there are various technologies that are being developed and will reduce motor vehicle incidents, they currently do not meet these criteria. At such a time as tools and technologies meet these criteria, PG&E would retrofit its fleet with the technology as warranted. PG&E will adopt many of these technologies through fleet turnover. For these reasons, Alternative Plan 1 was not chosen.

Table 16-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$ M)	EV RSE (Units/$ M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000) [A]	2021 Estimate ($000) [A]	2022 Estimate ($000) [A]
M9	VST in Personal Vehicles	6.5	4.9	2020	2022	D2	487 – 539 (C) 740 - 818 (E)	– (C) 611 - 676 (E)	– (C) 611 - 676 (E)
M10	Driver Selection Program	277.8	210.8	2020	2022	D2	– (C) 77 - 85 (E)	– (C) 77 - 85 E)	– (C) 77 - 85 (E)
M11	Emerging Incident Reduction Technology	37.3	28.3	2020	2022	D2	1,283 - 1,418 (C) – (E)	– (C) – (E)	– (C) – E)
M12	Emerging Impact Reduction Technology	1.4	0.9	2020	2022	SI, SF	8,550 - 9,450 (C) – (E)	– (C) – (E)	– (C) – (E)
M13	MVS Management System	118.6	82.7	2020	2022	D1, D2, SI, SF	– (C) 31 - 34 (E)	– (C) 31 - 34 (E)	– (C) 31 - 34 (E)
Alternative Plan 1 TA RSE: 11.9 TOTAL Expense and Capital by Year							**10,320 - 11,407 (C) 848 - 937 (E)**	**– (C) 719 - 795 (E)**	**– (C) 719 - 795 (E)**
Note A: Mitigations with expense costs listed as – are costs embedded in existing resources, or that do not reside in Corporate Safety. Mitigations with capital costs listed as – do not have recorded capital costs.									

B. Alternative Plan 2

Alternative Plan 2 consists of the same mitigations as the Proposed Mitigation Plan except that it assumes that the Process Improvement mitigation: Implement comprehensive MVS programmatic management system will not be implemented. The resources necessary to implement this mitigation will be contributed to an overall budget reallocation.

The MVS risk is unique from the Employee Safety risk, and requires different knowledge to manage. However, the Employee Safety mitigation – Safety Management System (SMS), may be leveraged to perform some aspects of this MVS Process Improvement mitigation. As this likely could not be done without increasing the resources needed to implement the Employee Safety SMS mitigation, there would be little value in expanding the scope of the Employee Safety SMS mitigation instead of implementing the MVS process. For these reasons, Alternative Plan 2 was not chosen.

Table 16-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver # and Consequence	2020 Estimate ($000)[(a)]	2021 Estimate ($000)[(a)]	2022 Estimate ($000)[(a)]
M10	VST in Personal Vehicles	6.5	4.9	2020	2022	D2	487 - 539 (C) 740 - 818 (E)	– (C) 611 - 676 (E)	– (C) 611 - 676 (E)
M11	Driver Selection Program	277.8	210.8	2020	2022	D2	– (C) 77 - 85 (E)	– (C) 77 - 85 (E)	– (C) 77 - 85 (E)
Alternative Plan 2 TA RSE: 29.7 **TOTAL Expense and Capital by Year**							**487 - 539 (C)** **817 - 903 (E)**	**– (C)** **688 - 761(E)**	**– (C)** **688 - 761(E)**

VII. Metrics

Current outcome metrics used to track the MVS risk include the following:

- **Preventable Motor Vehicle Incident (PMVI) Rate:** A "Preventable" incident is one where the PG&E driver could have, but failed to take reasonable steps to prevent the incident. This measures the total number of PMVIs for which the driver could have reasonably avoided, per 1 million miles driven.
- **Serious Preventable Motor Vehicle Incident (SPMVI) Rate:** This measures the total number of confirmed serious preventable motor vehicle incidents (SPMVIs) for which the driver could have reasonably avoided, per 1 million miles driven. A serious MVI is one where one or more of the following conditions occur: injuries that require immediate treatment away from the scene of the incident, a vehicle is towed, or vehicle damage exceeds $5,000.
- **Driver's Check Rate:** This measures the total number of Driver Check complaint calls received per 1 million miles driven by vehicles included in the Driver Check program.
- **Hard Brake Rate:** The total number of hard braking events (>=8 mph per second decrease in speed) per thousand miles driven in a given period. This metric is generated through VST, and is a leading indicator.
- **Hard Acceleration Rate:** The total number of hard acceleration (>=7 mph per second increase in speed) per thousand miles driven in a given period. This metric is generated through VST, and is a leading indicator.
- **Maximum Speed:** The total number of speed events (>=80 mph) per thousand miles driven in a given period. This metric is generated through VST, and is a leading indicator.

Table 16-7 includes the proposed accountability metrics related to the proposed mitigations an*d* drivers mitigated.

Table 16-7: Proposed Metrics

Mitigation	Associated Driver #	Proposed Metric	Targets
VST in Personal Vehicles	D2	Initial metrics will be deployment of VST to employees who drive personal vehicles for business. Once VST has been deployed, PG&E will track overall and individual data. See "Hard Brake Rate above as an example.	Targets will be designed following establishment of a baseline.
Driver Selection Program	D2	This mitigation assimilates data and metrics from several different sources and uses these data and metrics to establish driving criteria for PG&E employees that drive PG&E vehicles and personal vehicles for business. PG&E will monitor these various data and metrics and communicate and coach employees to improve performance. Driving behaviors following communications and coaching at the individual and company level will be monitored to see if these actions result in improved performance. These metrics are leading indicators. PG&E will also track incident rates, a lagging metric, to ensure the mitigation is reducing incidents.	Targets will be designed following establishment of a baseline.
MVS Management System	D1, D2, SI, SF	The systematic management of vehicle safety will rely on existing metrics and measures, and incorporate new data from audits, assessments, benchmarks and external data sources. Metrics will be designed to ensure the management system is being implemented as designed.	Targets will be established following design of the management system and controls to support the system.

VIII. Next Steps

The risk quantification effort undertaken as part of the RAMP process has improved PG&E's ability to quantify and compare diverse mitigations on a relative basis. This is a substantial change from prior alternative assessments conducted for the MVS risk. The primary factor limiting the ability to quantify different mitigations is the availability of data. There is substantial PG&E and published data regarding frequency of incidents, risk drivers and consequences (injuries, fatalities, and costs). However, there is limited data available to assess the impact of tools, technology and processes. Much of the available data is limited to subject matter expertise and indirect correlation used to measure cause and effect.

PG&E proposes to implement the tools and technology, and process improvement mitigations that are supported by the risk model considering modeling limitations. The proposed mitigations have the most reliable data, and most favorable outlook for managing the MVS risk. These mitigations will reduce the MVS risk, generate new and additional data for use in performing future risk analyses, and provide PG&E with processes to continually improve risk reduction.

Completion of the process improvement mitigations for years 2020 through 2022, contributes to the overall desired future state for the MVS risk. These processes coupled with risk modeling capabilities will allow PG&E to establish and sustain a risk tolerance for the MVS risk.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 17
LACK OF FITNESS FOR DUTY PROGRAM AWARENESS

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 17
LACK OF FITNESS FOR DUTY PROGRAM AWARENESS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Lack of Fitness for Duty Program Awareness (FFD Awareness)
IN SCOPE	PG&E people leader observations that may indicate a PG&E employee has an underlying physical, psychological, or cognitive medical condition that impairs his or her ability to work safely, including reasonable suspicion for drug and, or alcohol use.
OUT OF SCOPE	The scope of the FFD Awareness risk does not include contract employees, workers' compensation and performance management issues, nor does it include work processes, tools, materials hazard identification, and emergency situations.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, and subject matter expert (SME) judgement.

The FFD Awareness risk is defined as PG&E people leaders[1] failing to identify and act upon observed behaviors which indicate an employee may be unable to work safely. These behaviors could point to a reasonable suspicion of drug or alcohol use, or to a physical, psychological, or cognitive medical condition. An employee working while unfit for duty could result in an injury or fatality to themselves, a fellow PG&E employee or a member of the public.

This risk was added to PG&E's risk register in 2015; and in 2017, PG&E used the risk bow tie assessment methodology to develop a probabilistic risk model to understand the drivers for the FFD Awareness risk and to target new mitigations. The model uses a combination of PG&E-specific data and SME best judgement. As the risk is dependent upon people leaders observing and acting upon employee behaviors, the single driver of the risk is Fitness for Duty (FFD) events with an adverse outcome. This driver can be divided into two sub-drivers: Supervisor Effectiveness and Undetected Behaviors.

The risk model reinforced that training has the greatest impact on reducing the risk of unaware or ineffective people leaders. This assumes that once trained, people leaders will timely and effectively utilize the FFD Program.

The current controls and mitigations in place include voluntary training, supervisor check-list and instructions, field observations by Safety Specialists and employee wellness programs. Whereas, the proposed mitigation plan focuses on mandatory training for people leaders, a short term disability plan (known as the Voluntary Plan) provides a financial safety net for employees to take time off regardless of tenure, and

1 People leaders refers to directors, managers, superintendents, and supervisors.

enhanced immediate access to healthcare through on-site telemedicine kiosks and clinics.

The risk assessment effort undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process highlights the need to capture more data points from incident investigations and a FFD database to better quantify whether FFD concerns were present leading up to the risk events. As a result, the proposed plan will also include a mechanism for capturing information from incident investigations to quantify whether there was a FFD component involved.

II. Risk Assessment

A. Background

Lack of FFD Awareness is the inability of people leaders to identify and act upon observed behaviors that raise FFD concerns, which may result in a serious injury or fatality.

FFD Awareness has been on PG&E's risk register since 2015. However, the effectiveness of the FFD Program has been under review since 2012. At that time FFD was part of the Employee Assistance Program (EAP). In 2012, PG&E hired a consultant to review the EAP. Regarding FFD, the consultant found: instructions to PG&E people leaders lacked clear guidelines for when and how to make FFD referrals, people leaders held a mistaken belief FFD was limited to situations involving alcohol and/or drug abuse, and people leaders tended to avoid dealing with issues until the situation reached a crisis stage. Around the same timeframe, findings from a separate, unrelated investigation of a single motor vehicle incident were issued that echoed the consultant's conclusions. The convergence of these two sets of findings provided the impetus to transfer management of FFD from EAP to the Integrated Disability Management (IDM) Department. As a result, in late 2014, lack of people leader awareness of the FFD program was noted as a risk during a Human Resources risk identification workshop. This risk has been evaluated and refreshed on annual basis since then. In 2015, during PG&E's integrated planning process, the risk was transferred to the Safety and Health organization. The risk was assessed qualitatively based on SME judgement after analyzing calls made to the FFD Program Manager. In 2015, a Registered Nurse was hired to manage the FFD program. With professional clinical expertise in place, the program was revised to take a more proactive approach to managing the FFD program.

In 2016, the FFD Program Manager released new guidance documents,[2] developed five minute meeting materials, revised the Supervisor's Guide and Checklist, and instituted a voluntary training curriculum. Additionally, to help measure the effectiveness of the voluntary training, the Program Manager began tracking each referral to determine if the caller had taken the voluntary training and whether the referral was a proper FFD referral or was a situation unrelated to FFD.

In 2017, greater emphasis was placed on data quantification in alignment with the RAMP process objectives. The FFD Awareness risk assessment included the development of a tail average consequence scenario by a team of PG&E IDM organization SMEs, which included the FFD Program Manager.

The FFD Awareness risk was evaluated using a risk bow tie assessment and quantitative analysis model that predicts tail average outcomes and calculates mitigation RSE values in addition to MARS. Figures 17-1 below displays the bow tie analysis. This analysis shows the progression of the exposure and drivers as they contribute to the likelihood of the FFD Awareness risk event and the resulting consequences. This model considers people leader effectiveness in observing, reacting to and reporting employee behaviors that may indicate an employee is not physically or psychologically fit for duty. For those behaviors that go undetected, it shows how many result in an adverse outcome such as an employee injury, or an injury to a member of the public.

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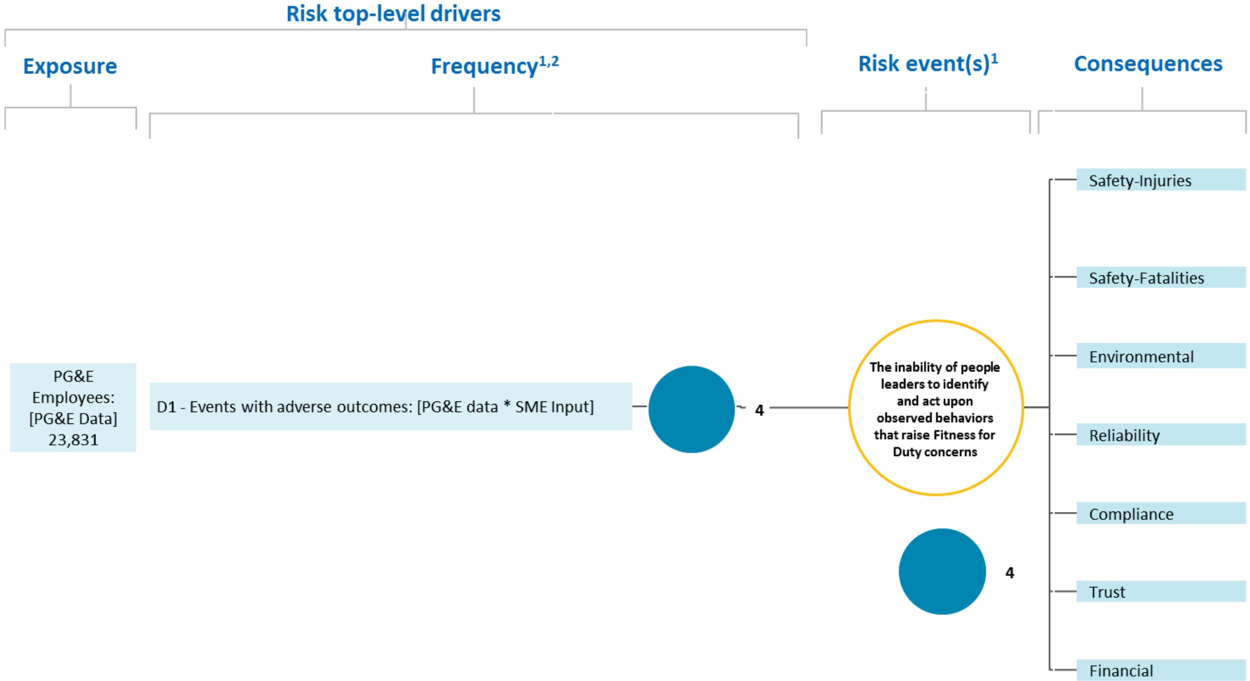
2 Guidance documents include: FFD Procedures, revised Supervisor's Guide and Checklist, and Five Minute Meeting material.

Figure 17-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Driver modeled using Beta, Triangular, and Binomial distributions.

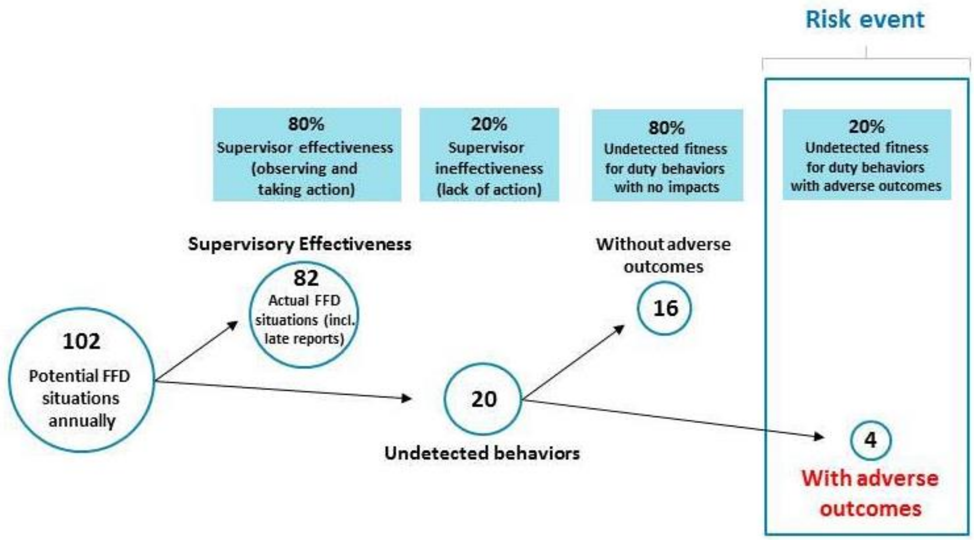
B. Exposure

During 2016, PG&E had an average of approximately 24,000 employees, some whose work may include high risk exposures, such as high voltage, high pressure, hazardous materials, heavy equipment, and fall hazards. The inability of employees in this group to perform safely may result in adverse outcomes such as an employee injury, or an injury to a member of the public. The FFD Program is an essential tool for people leaders to assure PG&E has a healthy and productive workforce, which benefits all stakeholders. People leader observations are an important part of effectively utilizing the program and reducing the exposure.

C. Drivers and Associated Frequency

The risk bow tie shown in Figure 17-1 above is the current representation of how the RAMP model calculates a frequency distribution for both undetected and thus unobserved FFD behaviors that result in an event with an adverse outcome. Figure 17-2 illustrates the adverse outcomes calculation shown in the risk bow tie model above.

Figure 17-2: Fitness for Duty Awareness Driver Overview



1. Based on historical Fitness for Duty observations over the past two years (2015 and 2016) and SME-informed estimates

Based on data gathered, which tracked the appropriateness and timeliness of FFD referrals and gauged people leader awareness of the FFD program, and incorporating SME best judgement, people leaders' effectiveness in observing, reacting to and reporting FFD concerns was rated at 80 percent. This means that 80 percent of people leaders would either contact the FFD Program Manager directly, or report concerns to their supervisor, their Human Resources Business Partner, or their Labor Relations Specialist who in turn would refer them to the FFD Program Manager. Put another way, SME best judgment determined that 20 percent of people leaders would either not be aware of their duty to observe, or would not react and report the behaviors to anyone due to lack of knowledge about the FFD Program, due to neglect, or due to assigning a low priority to reporting the observed behavior(s).

As indicated in Figure 17-1 the single driver for the FFD Awareness Risk, is:

- **D1 – FFD Events with Adverse Outcomes:** For those employee behaviors that go undetected approximately one in five, or 20 percent, result in an event with an adverse outcome such as an employee injury, or an injury to member of the public. This equates to a frequency of 20 undetected behaviors and 4 events per year based on the annual average of identified FFD situations, including late reports.

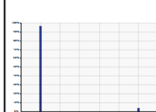
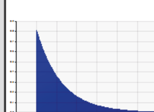
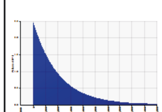
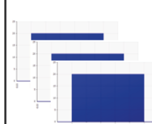
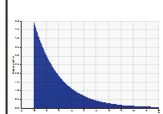
This driver can be further broken out further into two sub-driver categories as follows:

- **Supervisory Effectiveness:** The effectiveness of people leaders with the duty to observe, react and report employee behaviors that may indicate an employee is not physically, psychologically, or cognitively fit for duty, including reasonable suspicion of drug/alcohol use. This sub-driver has an estimated frequency of 80 percent.
- **Undetected Behaviors:** For those employee behaviors that go undetected, how many result in an event with an adverse outcome such as an employee injury, or an injury to member of the public. This second sub driver has an estimated frequency of 20 percent, which means one in five undetected behaviors are expected to result in an adverse outcome.

D. Consequences

The range of consequences and the attributes that help describe the tail average risks and the associated MARS are shown in Figure 17-3 below. Below in the table, there is an explanation of the data sources used for each of the consequence attributes.

Figure 17-3: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	SME Input	SME Input	NA	SME Input	SME Input	PG&E Data and SME Input	SME Input
Consequence Distributions	10% value=0 90% value=1 (Exponential) ➔Mean=0.407 (Poisson) 	10% value=0 90% value=0.1 (Exponential) ➔Mean=0.0407 (Poisson) 		10% value=0 90% value=3*60min (Exponential) 	10% value=$0 90% value=$100k (Exponential) 	Dependent on Safety outcomes. If there are any fatalities= High severity brand favorability change If there are injuries without fatalities, 50/50 chance of Low or Severe High severity=0.6-1% Severe=0.3-0.6% Low=0-0.3% (Uniform) 	10% value=$2.5k 90% value=$5M (Exponential) 
Outcome-TA-NU[1]	5.03	1.17		770	$427,741	0.87%	$21,402,624
Outcome-TA-MARS[2]	1.37	31.82		0.00	0.04	4.35	12.84
						MARS Total	**50.43**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** The employee injuries risk score is quantified using subject matter expertise judgement to define a 10th percentile chance of zero and a 90th percentile chance of 1 injury per incident associated with undetected and thus unaddressed fitness for duty situations. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average of 5.03 injuries per year.

- **Safety – Fatalities (SF):** The employee fatalities risk score is quantified using subject matter expertise judgement to define a 10th percentile chance of zero and a 90th percentile chance of 0.1 fatalities per incident associated with undetected and thus unaddressed fitness for duty situations. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average of 1.17 fatalities per year.

- **Environmental (E):** This consequence is not applicable. Impacts to the environment associated with the average worst case scenario are assumed to be negligible.

- **Reliability (R):** The reliability risk score is quantified using subject matter expertise judgement to define 10th percentile chance of zero and a 90th percentile chance of 180 minutes per incident associated with undetected and thus unaddressed fitness for duty situations. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average is 770 minutes (12.8 hours) per year.

- **Compliance (C):** The compliance risk score is quantified using subject matter expertise judgement to define 10th percentile chance of zero and a 90th percentile chance of $100,000 costs per incident associated with undetected and thus unaddressed fitness for duty situations. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average is $427,741 per year.

- **Trust (T):** The risk score is quantified using anticipated percentage change in brand favorability tied to safety impacts. The default values used for trust bounds are based on a Gas Operations: Transmission Pipeline – Rupture with Ignition event as described in Chapter B-Modeling chapter. However, for this risk, the trust bounds are quantified using subject matter expertise judgement to define high severity bound of 0.6-1 percent, severe bound of 0.3-0.6 percent, and a low bound of 0-3 percent. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average is 0.87 percent change in brand favorability per year.

- **Financial (F):** The financial risk score is quantified using subject matter expertise judgement to define 10th percentile chance of $2,500 and a

90th percentile chance of $5,000,000 costs per incident associated with undetected and thus unaddressed fitness for duty situations. Considering the reported incidences and potential undetected incidences, the outcome of the model from these inputs show the tail average is $21,402,624 per year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls and mitigation described in this section improves people leader effectiveness and addresses the risk driver. Table 17-1 below summarizes the controls and associated 2016 recorded costs. The controls can be categorized into three groups: Training and Communication; Employee Wellness; and, Benefit Plans and Policies. Many controls have benefits which extend beyond FFD Program Awareness. For instance, improved access to information about PG&E benefit plans and onsite clinical medical services, employee health screenings, health coaching and other wellness programs all contribute to overall employee wellbeing which in turn benefits all stakeholders by helping to ensure a healthy, safe and productive workforce.

C1 – 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:

- Compliance and Ethics and Code of Conduct training,
- FFD Cross Program Manager Training, Cross training,
- Voluntary FFD situational awareness training for leaders, and
- A quarterly process to communicate new or changing issues during Risk and Compliance Committees (RCC) meetings.

C2 – Employee Wellness: Employee wellness controls promote access to medical services and other programs which are designed to improve the overall wellness of the employee population. These controls allow employees to proactively self-address medical issues so they remain FFD. There are eight Wellness controls:

- Drug and Alcohol Testing Requirements for Safety Sensitive Positions
- Employee Assistance Program
- Employee Health Screenings
- Industrial Athlete Program
- Medical History Interview (Post-Offer)
- Office Worker Safety and Health Program
- Wellness Outreach
- Peer Volunteer Program

C3 – Benefit Plans and Policy: Benefit Plans and Policy controls act to improve employee access to benefit plan information and provide a one stop shop for help in choosing which benefit suits their needs such that employees can readily address medical concerns in order to stay FFD. Some of the controls ensure proper administration of benefits which ensures proper and prompt delivery of benefits. Three additional mitigations were implemented in 2016 and are summarized below in Table 17-1.

M1 – Amending Benefit Plans: Includes implementation of third party administration of benefit program offerings (long-term disability, stay at work, return to work, and leaves of absence). This mitigation is being expanded with the implementation of the Voluntary Plan.

M2 – Identify and Track Population to Receive FFD Training (Expand to Temporary Supervisors); Measure Training Completion: Includes planning for mandatory FFD training implementation for all people leaders. This control is being expanded with the implementation of mandatory FFD training and course refresher and training planned for 2020.

M3 – Redesign Time Off Policy for Management and Union Employees (Vacation, Sick, Short-Term Disability, Etc.) Inclusive of the Voluntary Plan: Includes union communications regarding adoption of the redesigned time off policy including the voluntary plan.

The 2016 recorded costs for controls and mitigations are summarized in Table 17-1.

Table 17-1: Risk Controls and Mitigations 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Training and Communication	D1	GRC	266	–
C2	Employee Wellness	D1	GRC	10,903	–
C3	Benefit Plans and Policy	D1	GRC	75,656	–
M1	Amending benefit plans	D1	GRC	N/A	–
M2	Identify and track population to receive FFD training (expand to temporary supervisors); measure training completion	D1	GRC	46	–
M3	Redesign time off policy for management and union employees (vacation, sick, short term disability, etc.) inclusive of the voluntary plan	D1	GRC	322	–
TOTAL Expense and Capital				**87,193**	**–**

IV. Current Mitigation Plan (2017–2019)

In addition to the controls and mitigations listed above, as part of the integrated planning process risk evaluation, the following mitigations were identified and are planned and authorized for years 2017–2019. The planned mitigations address the risk driver, seek to reduce exposure, and will be in place as controls prior to the RAMP mitigation timeframe of 2020–2022. These mitigations are already being implemented by PG&E at no additional cost through 2019 by leveraging existing resources.

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. This is a new mitigation starting in 2017 and will be implemented and ongoing in 2018. This mitigation improves people leader awareness of the FFD Program.

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 is a new mitigation for 2017 and will be continue in subsequent years. This mitigation improves the ability to measure the effectiveness of changes to the FFD Program since it was removed from EAP.

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.

Table 17-2 shows costs for mitigations M4-M6 which are embedded in other activities, and therefore no costs are shown.

Table 17-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M4	Observations – FFD trained Field Safety Specialists observations	2017	2018	D1	– (C) – (E)	– (C) – (E)	– (C) – (E)
M5	Enhanced FFD metrics	2017	2019	D1	– (C) – (E)	– (C) – (E)	– (C) – (E)
M6	FFD data sources review	2017	2017	D1	– (C) – (E)	– (C) – (E)	– (C) – (E)
TOTAL Expense and Capital by Year					**– (C)** **– (E)**	**– (C)** **– (E)**	**– (C)** **– (E)**
Note: Costs listed as – are embedded in existing resources.							

V. Proposed Mitigation Plan (2020–2022)

To maximize potential risk reduction, the Proposed Mitigation Plan includes all mitigations considered except M8 – Instructor led FFD for new leaders.[3] Of the mitigations included in the Proposed Plan, mandatory training to improve people leader effectiveness (M7) provides the greatest RSE benefit as indicated in Table 17-3 below. The following mitigations are included in the Proposed Plan:

M7 – Knowledge, Mandatory Fitness for Duty Training All People Leaders: Development and implementation of mandatory FFD Training for all people leaders including Web Based Training provided for new hires within 90 days with triennial refresher training. This mitigation, once implemented, contributes to improved people leader FFD Program awareness.

M9 – Process Improvements, Redesigned Time-Off Policy and Voluntary Plan: Implementation of redesigned time-off policy inclusive of the Voluntary Plan will provide an adequate financial safety net for all employees, improve and/or maintain the health of the workforce through improved case management and clinical advocacy for employees to assure quality of care and fitness to return-to-work. Employees are eligible at date of hire.

M10 – Tools and Technology, Set Number of Telemedicine Kiosks Available to PG&E Employees: Establish a set number of Telemedicine kiosks available to PG&E employees. The telemedicine kiosks are expected to reduce adverse outcomes associated with FFD behaviors that are not observed and thus unaddressed, as employees will have immediate access to health care services.

M11 – Tools and Technology, Set Number of On-Site Clinics Available to PG&E Employees: Establish a set number of on-site clinics available to PG&E employees. The on-site clinics will are expected to reduce adverse outcomes associated with FFD behaviors that are not observed and thus unaddressed, as employees will have immediate access to health care services.

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3 PG&E's Learning Academy is currently reviewing and restructuring the New Leader Curriculum and as a result, M8 – Instructor led FFD training for new leaders is not included in the Proposed Plan.

Table 17-3 is a list of the proposed mitigations described above, the associated costs, and RSE for each mitigation.

Table 17-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$ M)	EV RSE (Units/$ M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M7	Knowledge – mandatory training	6.40	4.21	2017	2020	D1	– (C) 220-243 (E)	– (C) – (E)	– (C) – (E)
M9	Process Improvements - Redesigned time off policy and Voluntary Plan	1.99	1.33	2017	2022	D1	– (C) 38 -42 (E)	– (C) 38 -42 (E)	– (C) 38 -42 (E)
M10	Tools and Technology -Kiosks	0.40	0.26	2017	2022	D1	95-105 (C) 134-148(E)	95-105 (C) 135 -150 (E)	95-105 (C) 137 -151 (E)
M11	Tools and Technology - Clinics	0.04	0.03	2017	2022	D1	– (C) 3,860 -4,266(E)	– (C) 4,297 -4,749 (E)	– (C) 4,519 –4,994 (E)
Proposed Mitigation Plan TA RSE: 0.29. TOTAL Expense and Capital by Year							**95 -105 (C) 4,252 -4,699 (E)**	**95 -105 (C) 4,470-4,941 (E)**	**95 -105 (C) 4,694 -5,187 (E)**

VI. Alternatives Analysis

PG&E evaluated two additional mitigation plan alternatives as part of the RAMP process as summarized below. Alternative 1 changes the Proposed Plan by adding M8 - Instructor led FFD training for new leaders taught by the FFD Program Manager (described below) and eliminating M10 – Tools and Technology, Set number of Telemedicine kiosks available to PG&E employees. Alternative 2 changes the Proposed Plan by adding M8 – Instructor led FFD training for new leaders taught by the FFD Program Manager. The mitigations contained in the proposed and Alternative plans are shown below in Table 17-4.

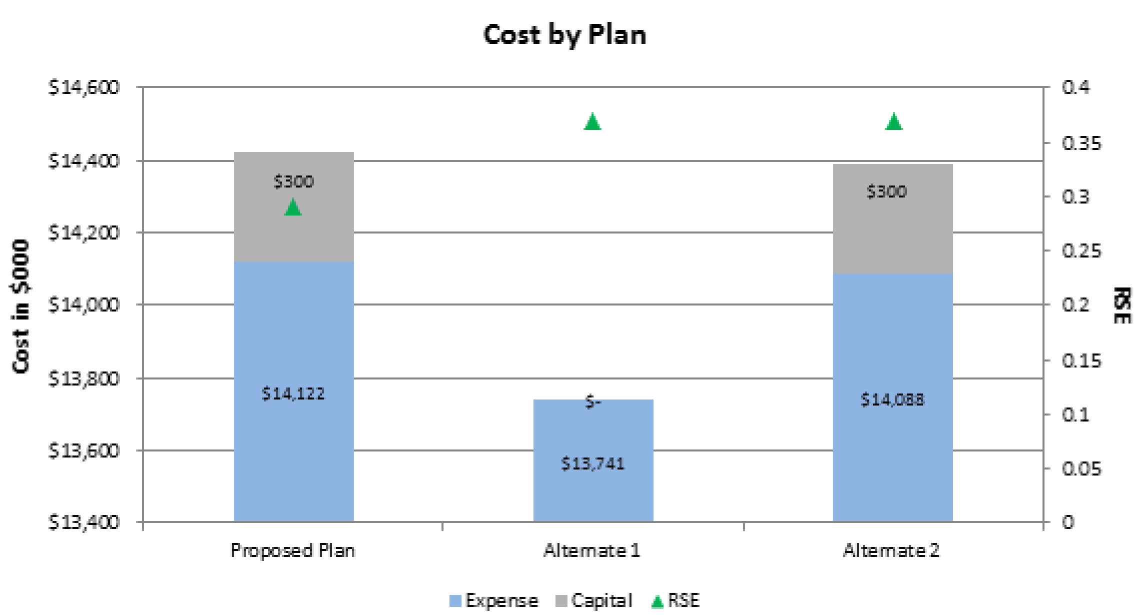
M8 – Instructor-Led FFD Training for New Leaders: FFD Program Manager to provide in person training to new leaders. Allowing the FFD Program Manager to teach the FFD module during New Leadership Training will allow new leaders to gain a more thorough understanding of the role people leaders play in the FFD Program. This mitigation once implemented, contributes to improved people leader FFD Program awareness.

Table 17-4: Mitigation List

#	Mitigation	TA RSE (Units/$M)Tail Average Risk Spend Efficiency Score (Units/1$M)	EV RSE (Units/$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M7	Knowledge – mandatory training	6.40	4.21	X	X	X	WP 17-2
M8	Knowledge – instructor led training	48.88	32.13		X	X	WP 17-2
M9	Process Improvements - Redesigned time off policy and Voluntary Plan	1.99	1.33	X	X	X	WP 17-12
M10	Tools and Technology-Kiosks	0.40	0.26	X		X	WP 17-7
M11	Tools and Technology - Clinics	0.04	0.03	X	X	X	WP 17-7

Figure 17-4 shows the comparison of the Proposed Mitigation Plan, Alternative Plan 1, and Alternative Plan 2 based on cost and RSE. The Proposed Mitigation Plan, Alternative Plan 1, and Alternative Plan 2 have RSEs of 0.29, 0.37, and 0.37 respectively. The Proposed Plan was chosen over Alternative Plan 1 and Alternative Plan 2 because of the restructuring of the New Leader Curriculum, as described in Section IV.

Figure 17-4: Alternatives by Cost and RSE Score



A. Alternative Plan 1

Alternative Plan 1 includes M8 – Instructor led FFD training for new leaders taught by the FFD Program Manager and removes continued installation of the M10 – Telemedicine Kiosks from the Tools and Technology mitigations. Alternative Plan 1 was created based on a strategy that including the FFD Program Manager as an instructor for in-person new leader training would improve new leader awareness of their duty to observe, react, and report FFD concerns. The Telemedicine Kiosks were removed from Alternative Plan 1 based on information indicating telemedicine kiosks previously installed were not seeing the same level of usage as onsite clinics.

Even though the mitigation of M8 provided the best reduction in risk, as a result of the restructuring of the New Leader Curriculum, as described in Section IV, this plan was not chosen.

Table 17-5: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M7	Knowledge – mandatory training	6.40	4.21	2017	2020	D1	– (C) 220–243 (E)	– (C) – (E)	– (C) – (E)
M8	Knowledge – instructor led training	48.88	32.13	2018	2020	D1	– (C) 15 –16 (E)	– (C) 15 –16 (E)	– (C) 15 –16 (E)
M9	Process Improvements-Redesigned time off policy and Voluntary Plan	1.99	1.33	2017	2022	D1	– (C) 38–42 (E)	– (C) 38–42 (E)	– (C) 38–42 (E)
M11	Tools and Technology - Clinics	0.04	0.03	2017	2022	D1	– (C) 3,860–4,266 (E)	– (C) 4,297–4,749 (E)	– (C) 4,519–4,994 (E)
Alternative Plan 1 TA RSE: 0.37 TOTAL Expense and Capital by Year							**– (C) 4,133–4,567 (E)**	**– (C) 4,350–4,807 (E)**	**– (C) 4,572–5,052 (E)**

B. Alternative Plan 2

Alternative Plan 2 includes all the elements of Alternative Plan 1 plus the continued installment of M10 - Telemedicine Kiosks for additional locations that do not have sufficient employee populations to justify an onsite clinic. The telemedicine kiosks are a cost effective way of improving employee access to healthcare services.

Alternative Plan 2 was not chosen because of the restructuring of the New Leader Curriculum, as described in Section IV, and kiosk usage and adoption data indicating that the installation of Telemedicine Kiosks at additional locations would not be of further benefit.

Table 17-6: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M7	Knowledge – mandatory training	6.40	4.21	2017	2020	D1	– (C) 220–243(E)	– (C) –(E)	– (C) –(E)
M8	Knowledge – instructor led training	48.88	32.13	2018	2020	D1	– (C) 15–16 (E)	–(C) 15–16 (E)	–(C) 15–16 (E)
M9	Process Improvements-Redesigned time off policy and Voluntary Plan	1.99	1.33	2017	2022	D1	– (C) 38 - 42 (E)	– (C)	– (C)
M10	Tools and Technology Kiosks	0.40	0.26	2017	2022	D1	95–105 (C) 134–148(E)	95–105 (C) 135–150 (E)	95–105 (C) 137–151 (E)
M11	Tools and Technology - Clinics	0.04	0.03	2017	2022	D1	– (C) 3,860 – 4,266(E)	– C) 4,297– 4,749 (E)	– (C) 4,519 – 4,994 (E)
Alternative Plan 2 TA RSE: 0.37 **TOTAL Expense and Capital by Year**							**95-105 (C) 4,267– 4,715 (E)**	**95-105 (C) 4,447– 4,915 (E)**	**95-105 (C) 4,671– 5,161 (E)**

VII. Metrics

Current outcome metrics and accountability metrics used to track the FFD Awareness risk include the following:

Table 17-7: Proposed Metrics

Mitigation	Associated Driver #	Metric	Targets
Training - FFD Training All People Leaders	D1	Percent of referrals to the FFD program deemed proper FFD situations: Percentage of employee of referrals deemed proper FFD situations by the FFD Program Manager in collaboration with the Labor Relations Specialist and/or HRBP. Percent of referrals to the FFD program reported late: Percentage of employee of referrals to FFD Program reported more than six months after observed behavior	Track and trend (targets TBD)
Process - Redesigned Time Off Policy and Voluntary Plan	D1	Workforce Unavailable due to Health (Company): Percentage of full-time employees unavailable for work either due to long-term or short-term health reasons. (A healthier employee population helps reduce the occurrence of FFD situations supervisors would need to detect).	Target: 6.9 percent (2017)

VIII. Next Steps

The effort undertaken as part of the RAMP process highlights the need to capture more data points from incident investigations and the FFD database to better quantify whether FFD concerns were present leading up to risk events.

In support of ongoing FFD Program improvement and FFD Awareness risk reduction, additional mitigations are being considered and include: continued evaluation of FFD awareness performance to determine if mandatory people leader, and in-person new leader or new hire training participation is proving effective in reducing the risk; evaluation of consolidating FFD refresher training and Department of Transportation reasonable suspicion training; including crew leads and foremen in mandatory fitness for duty training; and evaluation of the inclusion of FFD contributing factors as part of the incident investigation formal process.

Continued improvements to the success of the FFD program support a PG&E workforce capable of working safely and productively, which benefits all stakeholders and is a critical component for achieving the Company's commitment to employee and public safety.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT MITIGATION PHASE
CHAPTER 18
CYBER ATTACK

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT MITIGATION PHASE
CHAPTER 18
CYBER ATTACK

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Cyber Attack
IN SCOPE	A cyber attack that results in a loss of operational control or loss of company data (customer, employee, and/or business information)
OUT OF SCOPE	Nuclear, Diablo Canyon Power Plant (DCPP)[1]
DATA QUANTIFICATION SOURCES	Assessment informed by Pacific Gas and Electric Company (PG&E or the Company) data, Industry data (Verizon and Advisen), and subject matter expert (SME) judgment

Cyber-attack risk is 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, business, and electric operations.

The cyber-attack risk originates from adversaries that actively attempt to compromise PG&E systems for their own purposes. Attackers are constantly innovating, requiring PG&E to continuously adapt in order to defend against cyber attacks. Cyber-attack risk has been on PG&E's risk register since 2013. It is also an enterprise-level risk due to the potentially catastrophic consequences to safety and reliability of a successful cyber attack on PG&E's operational systems.

The following two core risk events are fundamental to cyber-attack risk for any utility, including PG&E:

1) Attacks on information technology with the objective of obtaining unauthorized access to data; and
2) Attacks on operational technology (OT) with the objective of disabling PG&E's ability to control the delivery of gas and electricity to our customers.

Both risk events generally result from four primary drivers that indicate potential deficiencies in a computing or operational environment:

- Governance – relates to executive leadership, framework management, policies, procedures, and roles and responsibilities;
- Business Process – includes risk assessments, controls and oversight;

1 DCPP is not in scope for this risk. DCPP must comply with cyber security protocols that are aligned with the Nuclear Regulatory Commission's (NRC) Cyber Security Directorate.

- Systems and Infrastructure – encompasses protection of data storage and transfer, monitoring and diagnostics, and resolving obsolete or end-of-life technology; and
- People and Culture – includes awareness and training, employee engagement, and acquisition and development of specialized skillsets.

The core risk events and their associated drivers are addressed by existing controls and proposed mitigations. Controls and mitigations for the loss of operational control focus on preventing and reducing the impact of such events. The consequences of a loss of control event could include compromises to the integrity of operational assets, manipulation of those assets to cause malfunctions, degraded availability, and unplanned outages. Similarly, controls and mitigations for preventing and reducing the impact of data loss events are also deployed throughout the enterprise. The consequences of such events include the loss of the ability to ensure that sensitive information remains confidential, which in turn may lead to unauthorized access and theft of that information.

PG&E's controls and mitigations conform to programs aligned with the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF). The NIST CSF establishes the basic premises of an effective cybersecurity program. PG&E has adopted this framework to enable a standardized, objective approach for developing PG&E's programs to reduce cyber-attack risk.

Through the risk assessment undertaken as part of the Risk Assessment and Mitigation Phase (RAMP) process, PG&E confirmed the direction of its cybersecurity program in fulfilling its mission to deliver and maintain an integrated program to safeguard PG&E's digital assets. The modeling effort also reaffirmed PG&E's current understanding of risk drivers and consequences, as reflected in the mitigation programs for 2017-2019 and the proposed mitigation plan for the RAMP period of 2020-2022.

The next steps toward improving PG&E's understanding and analysis for cyber-attack risk include researching best practices on obtaining event data specific to OT systems and seeking better sources of information regarding data-loss risk. Industry agreement on the mapping of metrics to specific controls is another objective.

II. Risk Assessment

A. Background

The risks of cyber attack to PG&E's gas and electric distribution and transmission systems continue to increase. Cyber-attack incidents among all utilities have increased from a confirmed total of 3 in 2012 to 66 in 2015, the last year for which figures are publicly available. Along with the increase in incidents, threat intelligence indicates that cyber attacks have also become more ingenious and complex.

PG&E's cybersecurity program must protect against data security risks common to all companies, such as the risk of unauthorized disclosure of customer information. Additionally, PG&E must protect against risks to its operational systems that govern the flow of gas and electricity. Attacks on these systems could interrupt gas or electric service to PG&E's customers, and may potentially result in incidents that have catastrophic consequences, including injuries or deaths. As options for access and control become more complex, cybersecurity becomes more important for the overall safety of the PG&E operating environment.

PG&E's vision for cybersecurity takes the aforementioned factors into account. PG&E's goal is to have a cutting-edge program that employs the best professionals and leverages top-tier capabilities to safeguard its gas and electric system and protect sensitive information.

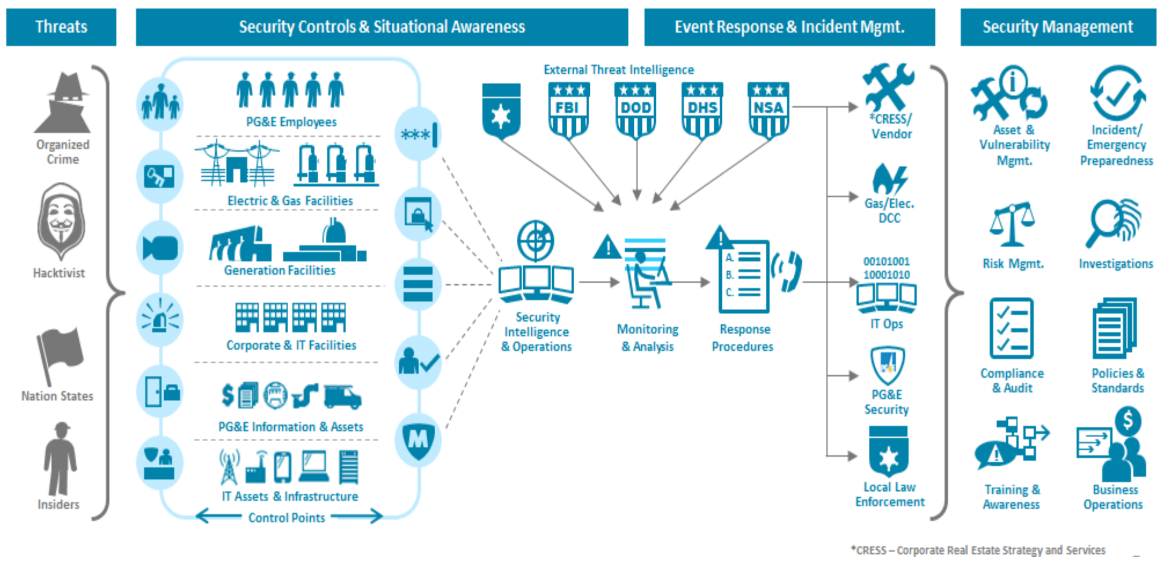
The mission of the PG&E cybersecurity organization is to deliver and maintain an integrated program that safeguards PG&E's digital assets by the following:

- Identifying our cyber-attack risks and defining mitigation strategies to ensure the safety of PG&E's customers, employees and contractors; and
- Building, deploying and operating effective security technologies and processes.

PG&E implements this vision through an increased focus on cyber-attack risk management, improved protective technologies, and insourcing its Cyber Security Intelligence and Operations Center (SIOC).

Figure 18-1 below illustrates the PG&E cybersecurity program's vision and mission. It indicates the source of threats, the assets that are targets for attacks, protective control points, and the role of the round-the-clock PG&E cybersecurity operations center which detects and combats attacks.

Figure 18-1: Security Strategy



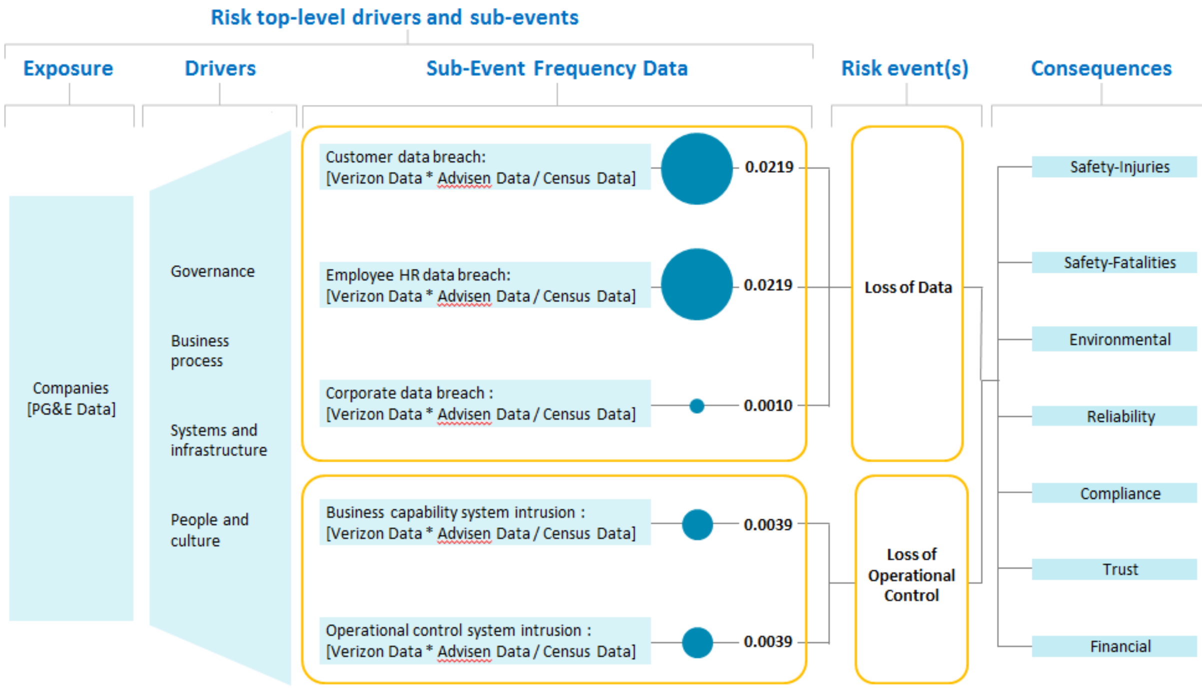
A cyber attack is a coordinated malicious attack that is purposefully targeted at PG&E's core business functions, resulting in a loss of control over information and systems used for gas, electric and business operations. Two categories of risk events are fundamental to cyber-attack risk:

- Attack on information technology with the aim of obtaining unauthorized access to data; and
- Attack on operational technology with the intent of crippling PG&E's ability to control the flow of gas and electricity to our customers.

When considering the safety impact of a cyber attack, the consequences of loss of control over operational technology are considered. Safety-related events stem primarily from a loss of operational control and not from data loss events. While there have been relatively few loss of control events in the industry, if an event occurred the consequences could have very high safety impacts. In addition to safety consequences, a successful cyber attack would also have impacts on system reliability, incur added costs to respond to a cyber attack, and cause loss of public trust in PG&E.

Figure 18-2 below is the visual representation of the risk bow tie which shows how inputs were represented in the risk model. Due to the unique nature of cyber-attack risk, the model looks at five sub-risk event types: customer data breach, employee data breach, corporate data breach, loss of operational control, and system intrusion. These five sub-risk event types are then grouped further to identify the Company's top two concerns: loss of data and a loss of operational control. This chapter speaks primarily to these two top concerns.

Figure 18-2: Risk Bow Tie



[1]All drivers are modeled using a Poisson distribution. Values displayed are means of each distribution.

B. Exposure

PG&E is exposed to potential cyber attack through its computer systems and networks. In the modeling effort, exposure was defined to be the Company in its entirety. This definition is necessary to compare to industry data reported on a per company basis. Within the Company, however, there are several likely points of potential intrusion such as the following:

- Computing systems or services accessible from untrusted networks. (Systems and Infrastructure)
- Computing systems or services owned or managed by third parties. (Business Process and People and Culture and Governance)
- Computing systems or services that are not maintained (for example, not being updated and/or using outdated operating systems). (Systems and Infrastructure)
- Malicious insiders (addressed more specifically through insider-threat risk). (People and Culture)
- Employees and contractors not engaging in good security practices. (People and Culture and Business Processes and Governance)

- The effectiveness of protective technologies such as firewalls, data loss prevention, anti-spam and anti-phishing filters, etc. (Systems and Infrastructure)

This is not an exhaustive list and exposure is hard to define. While the measurement of exposure is understood in a qualitative manner, it is difficult to quantify. For example, while counting the number of systems accessible from untrusted networks owned or managed by third parties or not maintained in a timely manner provides a rough notion of exposure, the fact remains that it only takes a vulnerability in one system to permit a cyber attack to happen. Moreover, protective technologies are designed to prevent attacks. It is not possible to measure attacks that don't occur. At best, it would be possible to measure indicators of cyber-attack attempts, but these would not be true cyber attacks. Analysis of the results of the bow tie analysis framework should take all the aforementioned factors into account.

C. Drivers and Associated Frequency

In modeling this risk, PG&E distilled the potential drivers of a cyber attack into four primary drivers. Due to the broad range and complexity of potential drivers to a cyber attack, these four categories consolidate all the drivers into their most fundamental level.

D1 – **Governance** – relates to executive leadership, framework management, policies, procedures, and roles and responsibilities. Poor governance could lead to a cyber attack through the lack of clear policies. For example, if the Company did not have a policy to disallow plugging in USB devices into the network this could introduce malicious software into PG&E's systems.

D2 – **Business Processes** – includes risk assessments, controls, oversight, and incident response. Business process could lead to a cyber attack through lack of controls or oversight. As an example, if the Company lacked a process to handle or identify vulnerabilities it could increase PG&E's exposure to a cyber attack.

D3 – **Systems and Infrastructure** – encompasses protection of data storage and transfer, monitoring and diagnostics, and resolving obsolete or end-of-life technology. Cyber attacks most often target individual systems directly. As a consequence, poorly maintained or outdated equipment can increase the exposure to a cyber attack.

D4 – **People and Culture** – includes awareness and training, employee engagement, and acquisition and development of specialist skillsets. Ultimately, people are the first line of defense for cyber attacks. Phishing emails are a common method of getting individuals to take actions that facilitate an attack.

A company culture of clicking email links without questioning the validity of the content or sender could increase the chance of a cyber attack.

As discussed in Sections III and IV, each of the risk drivers above are addressed by multiple mitigations.

While these drivers help to inform our mitigations, only the sub-risk events' relative frequency of events were used as inputs to the model due to constraints on available data. The data used in the model was comprised of Verizon and Advisen data on the frequency of cyber incidents among like size companies and used to inform our baseline risk. The Utility breaches from 2014, 2015 and 2016 in the Verizon Data Breach Investigation Reports[2] indicate yearly data breach frequencies range from 7 to 80 events per year and operational control breaches range from 0 to 7 events per year. The Advisen[3] loss data is used to estimate a compound annual growth rate of events and the percentage breakdown of data breach events into the various sub-risk events.

D. Consequences

The range of consequences and the attributes that help describe the expected value and tail average risks and the associated multi-attribute risk score are shown below in Figure 18-3. The data available to establish consequence distributions for cyber attack risk are rare and generally unobtainable, therefore, for this risk, SME is used. Figure 18-3 shows that generally the 5th and 95th percentile values were given by the SMEs to describe the consequence impacts if a specific sub-risk event were to occur.

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2 Verizon Data Breach Investigation Report: http://www.verizonenterprise.com/verizon-insights-lab/dbir/2016.

3 https://www.advisenltd.com/data/loss-data.

Figure 18-3: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	SME Input	SME Input	SME Input	SME Input	SME Input	SME Input	SME Input
Customer data breach						Min:4%; Max:20% (Uniform)	5%:$5M; 95%:$50M → Mean: $19.50M (Exponential)
Employee HR data breach						Min:1%; Max:3% (Uniform)	5%:$5M; 95%:$80M → Mean: $29.17M (Exponential)
Corporate data breach			5%:$0; 95%:$50k → Mean: $16,110 (Exponential)	5%:0; 95%:60k → Mean:19,332 (Exponential)	N/A	Min:4%; Max:15% (Uniform)	5%:$5M;95%:$100M → Mean: $35.61M (Exponential)
Business capability system intrusion			N/A	N/A	N/A	Min:1%; Max:3% (Uniform)	5%:$5M;95%:$50M → Mean: $19.50M (Exponential)
Operational control system intrusion	5%:0; 95%:60 → Mean: 19.33 (Exponential)	5%:0; 95%:3 → Mean: 0.97 (Exponential)	5%:$0; 95%:$4.6M → Mean: $1.48M (Exponential)	5%:0; 95%:840M → Mean: 270.65M (Exponential)	5%:$70k; 95%:$25M → Mean: $8.10M (Exponential)	Min:15%; Max:40% (Uniform)	5%:$500k;95%:$5B → Mean: $1.95B (Exponential)
	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Outcome-TA-NU[1]	0.76	0.04	$61,580	11,507,908	$333,081	4.48%	$92,154,455
Outcome-TA-MARS[2]	0.21	1.04	0.01	28.77	0.03	22.40	55.29
						MARS Total	107.75

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

- **Safety – Injuries (SI):** Safety-related events stem exclusively from loss of operational control and not from data loss events. Events involving loss of operational control have been few in number, causing the data set for such events to be extremely small. Attackers may have incentives not to execute attacks that they otherwise could perform (for example, retaliation by nation-state actors could result). As a consequence, we expect such events to be fairly rare. The tail average outcome resulted in 0.76 injuries per year.
- **Safety – Fatalities (SF):** Safety-related events stem exclusively from loss of operational control and not from data loss events. Events involving loss of operational control have been few in number, causing the data set for such events to be extremely small. Attackers may have incentives not to execute attacks that they otherwise could perform (for example, retaliation by nation-state actors could result). As a consequence, we expect such events to be fairly rare. The tail average outcome resulted in 0.04 fatalities per year. Additionally, fatalities would be most likely to occur for gas control systems and very unlikely for electric control

systems. Thus the likelihood of fatalities for electric control systems would be even less than the likelihood of injuries.

- **Environmental (E):** Environmental incidents are extremely unlikely to result from data loss events. While they could result from events where there is a loss of operational control, those events have been few in number. Attackers may have incentives not to perform attacks that they otherwise could perform, as noted in the Safety attribute. As a result, PG&E expects such events to be rare. The tail average outcome resulted in an environmental impact of $62,000 per year.
- **Reliability (R):** Reliability events would result exclusively from a loss of operational control. Events involving loss of operational control have been few in number. While attackers may have incentives not to execute attacks that they otherwise could perform (for example, retaliation by nation-state actors), they may also have incentives to execute such attack as part of a larger agenda (also often involving nation-state actors). As a consequence, PG&E expects such events to be fairly rare, but not as rare as safety-related events. The tail average outcome resulted in a reliability impact of 11.5 customer minutes a year.
- **Compliance (C):** Most compliance issues are independent of cyber attacks or potential cyber attacks. Moreover, compliance is no guarantee against cyber attacks, nor does it prevent some vulnerabilities that could be exploited (for example, weaknesses in operating systems or applications). The tail average outcome resulted in a $333,000 per year in possible compliance impacts per year.
- **Trust (T):** The impacts of a cyber attack on PG&E's ability to maintain public confidence in its ability to deliver electric and gas services safety, reliably, and securely are likely to be extensive. This would be true both for a loss of operational control and for a loss of data. A data loss event would also erode customers' confidence in PG&E's ability to protect their personal information. Trust is defined by SME input with a minimum and maximum range for each sub-risk event. The tail average outcome from these inputs resulted in a 4.48 percent change per year in brand favorability.
- **Financial (F):** Costs to recover from a cyber attack are expected to be substantial, including attack containment, evaluation, remediation of previously unknown vulnerabilities, recovery, root cause analysis, and possible engagement of external resources to assist in response and recovery functions. This would be the case both for a loss of operational control and for a data loss event. The tail average outcome resulted in a $92 million per year financial impact.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Each of the controls and mitigations described in this section manages one or more drivers of the cyber-attack risk. Controls and mitigations are organized in programs aligned with the NIST CSF, which establishes the basic premises of an effective cybersecurity program and is recognized as industry best practice. PG&E has adopted this framework to enable a standardized, objective approach for developing our programs to reduce cyber-attack risk. The major programs (also referred to as domains) of the NIST CSF discussed in this chapter are: Identify, Protect, Detect, and Respond.

The majority of mitigation programs for 2016 focused on deployment of detective technologies, the inclusion of technologies to identify threats, and the creation of a round-the-clock security operations center to improve threat intelligence and response. The programs are constructed to contain both controls and mitigations.

C1 – Identify: Activities that develop the organizational understanding to manage cyber-attack risks to systems, assets, data, and capabilities. Understanding the business context, the resources that support critical functions and the related cyber-attack risks enables the organization to focus and prioritize its mitigation efforts, thereby putting resources where the most risk reduction will be gained.

C2 – Protect: Activities that develop and implement the appropriate safeguards to ensure delivery of critical infrastructure services, supporting the ability to limit or contain the impact of a cyber-attack event, reducing both the frequency and consequence of cyber attacks.

C3 – Detect: Activities that identify the occurrence of a potential cybersecurity event, enabling timely discovery of a cyber attack and reducing the potential consequence of the cyber attack.

C4 – Respond: Activities that enable effective evaluation of a potential cyber-attack event, and containment of the impact of a cyber attack again reducing the potential consequence of a cyber attack.

Table 18-1 below summarizes associated 2016 recorded costs associated with each control.

Table 18-1: Risk Controls and Mitigations 2016 Recorded Costs

#	Controls and Mitigations	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Identify	All Drivers	GRC TO GT&S	6,177 (E) 1,199 (E) 2 (E)	9,035 (C) 295 (C) 496 (C)
C2	Protect	All Drivers	GRC TO GT&S	2,383 (E) 47 (E) 1 (E)	9,249 (C) – (C) – (C)
C3	Detect	All Drivers	GRC TO GT&S	2,784 (E) 88 (E) – (E)	2,674 (C) – (C) – (C)
C4	Respond	All Drivers	GRC TO GT&S	935 (E) 20 (E) – (E)	2,908 (C) – (C) 711 (C)
TOTAL Expense and Capital				**13,636 (E)**	**25,368(C)**

IV. Current Mitigation Plan (2017-2019)

Mitigations for the years 2017-2019 are also aligned with the NIST CSF—Identify, Protect, Detect, and Respond programs. Because of previous investments in Identify, Detect, and Respond, a majority of expenditures in 2017 are focused on protective technologies and processes. This trend is maintained for the 2017-2019 time period and is consistent with PG&E's use of cyber-attack mitigation and control programs. Each mitigation within the NIST CSF programs addresses all key risk drivers: governance, business process, systems and infrastructure, and people and culture discussed above.

M1A – Identify: The Identify mitigation program is composed of six projects: Third-Party Risk Management; Critical Application Security Monitoring; Identity and Access Management (IAM) Product Enhancements; Next Generation Endpoint Security; Priority Applications Integration; and Vulnerability Management improvements.

- **Third-Party Risk Management:** The organization will implement an integrated vendor risk management system that enables PG&E to improve upon current labor-intensive third-party risk management processes and support new programs. The system will provide a central repository for all vendor risk assessments, including responses to questionnaires, assessment reports, assessment communications, and evidence. Customization provides all LOBs optimal visibility into their respective vendors' assessment status and risk profiles. This mitigation includes workflow configuration, data validation, integration processes, and training and awareness.
- **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. The project will leverage potential

application logs as well as Information Technology asset management and other data. Logging from high-criticality applications will be prioritized for onboarding.

- **IAM Product Enhancements:** Expand the capabilities of the IAM solutions to support cloud identity management, developer security Operations, database integrations, cloud access security, DOE 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.
- **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. The project evaluates technology controls and the role of policy and procedure controls in the endpoint strategy.
- **Priority Applications Integration:** Systems will be evaluated for risk of inappropriate logical access, particularly systems critical for Sarbanes-Oxley (SOX) compliance and systems critical for compliance with regulatory requirements for the custody of Customer Energy Usage Data.
- **Vulnerability Management:** Develop and implement a comprehensive solution for vulnerability and patch management process across all PG&E lines of business (LOB). The solution may include governance, tools, and/or workflows.

M2A – Protect: The Protect program is comprised of these projects: Application Integration; Auto Cloud Security; (Operational Data Network (ODN)) Security Improvements; Cloud Security Training; Customer Information Protection; Enterprise Password Vault; Gas Supervisory Control and Data Acquisition (SCADA) Network; and Catalog Privileged Accounts and Access to Critical Systems.

- **Application Integration:** Expands 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. Users will be granted access based only on the privileges required to do their job, and no more. Role-based access ensures that customers' personally identifiable information and corporate data are not lost due to incorrect user access.
- **Auto Cloud Security:** Designs and implements a collection of processes and tools for applications, computers, and storage and network deployment on the cloud in order to mitigate the risk of data stored in the cloud. The project also deploys capabilities to continuously test, detect, measure, and incrementally improve security to reduce risk.
- **ODN Security Improvements:** This is a multi-year project that will extend beyond 2019 into the 2020-2022 period. The first year will establish core security technologies and test their compatibility with OT devices. This will enable the development of technology architecture and designs to deploy in future years at Distribution Control Centers, transmission substations, distribution substations, and customer service centers. Technology deployed will address threats from a cyber

attack, allowing a response to an identified cyber attack to create separation zones to limit the impact of an attack and maintain substation automation to the rest of the territory.

- **Cloud Security Training:** Obtains security training courses for employees on 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 to expose development teams to security best practices in secure system development, operations, configuration management, vulnerability management, and data loss prevention.
- **Customer Information Protection:** Develops and implements a data security governance program to address and manage compliance and legal requirements to ensure that sensitive data is protected in alignment with the PG&E data classification framework, policies and standards. The organization will deploy technology to discover where sensitive information resides, and assess the health of the controls in place. Where controls are lacking, remediation measures will be identified and implemented in phases based on risk.
- **Enterprise Password Vault:** Provides complex passwords for the systems a user needs to access. This will reduce the risk of security incidents due to the use of common passwords.
- **Gas SCADA Network:** This is a mitigation completed in multiple phases, addressing asset management, network protection (segregation, reduce single point of failure), security monitoring, and technology evaluation and planning for operating system upgrades. Parts of this mitigation are dependent on the Security Analytics and Advanced Monitoring project.
- **Catalog Privileged Accounts and Access to Critical Systems:** Secures the enterprise network through 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.

M3A – Detect: The Detect Program is comprised of the following projects: Mobile Threat Detection; Security Analytics and Advanced Monitoring Phase III; Security Analytics Enhancements; and Security Monitoring Capability Extension.

- **Mobile Threat Detection:** Implements comprehensive threat protection for Bring Your Own Device and Corporate-Owned Personally Enabled devices against mobile network, device, and application related cyber attacks. Also implemented will be a solution that monitors mobile devices in real time to detect known and unknown threats, analyzes any deviations from baseline behavior, and responds immediately.
- **Security Analytics and Advanced Monitoring Phase III:** Enhances cybersecurity monitoring technology, algorithms, tools, and processes to use improved techniques for discovery, logging, analysis, detection, and alerting. These enhancements will include different or improved statistical analysis, machine learning, or other forms of analytics and advanced monitoring.

- **Security Monitoring Capability Extension:** Accommodates organic growth in security monitoring of systems, of system attributes, and log retention. Accommodating this growth requires the addition of storage, network capacity, software licensing, and hardware.

M4A – Respond: The Respond Program is comprised of two projects: Advanced Persistent Threats (APT) Detection and Analysis Enhancement; and eDiscovery Capacity and Resilience Improvement.

- **APT Detection and Analysis Enhancement:** Improves event analysis and accelerates the detection of attacks coming from APT by extending the length of time that security event logs are retained. This will 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.
- **eDiscovery Capability and Resilience Improvement:** Increases the capacity of the tool currently used for eDiscovery, and creates space for data backups from the tool. The system is used to investigate and respond to suspicious cyber activity. Increasing capacity will increase system resiliency when responding to a cyber attack.

Table 18-2 shows the associated costs for 2017-2019, based on the bundle of work under each domain.

Table 18-2: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1A	Identify	2017	2019	All Drivers	6,817 (C) 1,158 (E)	4,737 (C) 815 (E)	4,737 (C) 815 (E)
M2A	Protect	2017	2019	All Drivers	10,912 (C) 3,953 (E)	13,406 (C) 5,067 (E)	13,616 (C) 5,167 (E)
M3A	Detect	2017	2019	All Drivers	1,468 (C) 427 (E)	6,055 (C) 1,303 (E)	6,775 (C) 1,302 (E)
M4A	Respond	2017	2019	All Drivers	3,605 (C) 516 (E)	– (C) 42 (E)	– (C) 42 (E)
TOTAL Expense and Capital by Year					**22,802 (C) 6,054 (E)**	**24,198 (C) 7,227 (E)**	**25,128 (C) 7,326 (E)**

The mitigation programs listed above will address the four drivers, as discussed above, and more specifically they are expected to support the following objectives.

- The improved ability to isolate systems and networks affected by control failures, thus reducing their impact considerably (system infrastructure); and
- Better control over the use of confidential and sensitive data to ensure that only authorized individuals are able to access those categories of data (business process, people and culture and governance).

In 2017, improvements in network situational awareness and asset configuration management are being implemented with the goal of quicker root cause analysis and better estimation of recovery times in the event of a cyber attack on gas distribution or transmission control systems. In addition, improvements in identity and access management started in previous years will be completed to ensure that PG&E employees and contractors have only the access they need to do their jobs. The mitigation program to comprehensively protect customer information begins in 2017 and will continue into subsequent years.

In 2018 and 2019, improvements in network protection, including protection of field devices, are to be implemented. Additional improvements in asset configuration management are also scheduled. These changes are intended to enable better localization of any control failures that could occur from a cyber attack on gas distribution or transmission control systems, thus reducing their duration and impact. Even so, threats continue to evolve and protective and detective practices must evolve as well to effectively counter those threats. Given the dynamic nature of cybersecurity and, in particular, cyber threats, impacts and mitigations must be re-evaluated at least yearly. The customer information protection mitigation program will also continue in order to advance improvements in preventing unauthorized access to customer data. In addition, as cloud computing becomes more important at PG&E, mitigation initiatives are planned to reduce the risks to data stored in the cloud.

V. Proposed Mitigation Plan (2020-2022)

The proposed mitigations below are a continuation of the mitigations listed above in 2017-2019. Consistent with previous years, cyber-attack risk mitigations for 2020-2022 are organized into four programs that organize mitigation projects to extend and improve controls in groupings that are in alignment with the NIST CSF. Similar to the previous section, each of the programs address all of the drivers of Governance, Business Process, Systems and Infrastructure, and People and Culture. Additionally, it is important to recognize the fluidity of these programs, which will be reprioritized as the threat landscape changes. Detailed descriptions of each of the four programs follow below.

M1B – Identify: The Identify program is comprised of five projects: Citizen Developer Models; Third-Party Security and Risk Management; IAM Product Enhancements; Enhance Cyber Reporting; and Future Generation Endpoint Security Program.

- **Citizen Developer Models:** To secure the enterprise network the organization will identify and catalog individual users in all LOBs with significant critical PG&E logical and/or physical assets. The organization will ensure that common standards, repositories, version control, testing standards, testing tools, and integration with agile code pipelines are developed and implemented. These models will enable each LOB to perform some of its own application development services. Citizen developer models will also support the use of consistently secure coding practices across multiple development organizations, thereby reducing the risk of insecure code.

- **Third-Party Security and Risk Management:** This project will implement an integrated vendor risk management system that will enable PG&E to improve upon current labor-intensive third-party risk management processes, as well as supporting new programs. The system will provide a central repository for all vendor risk assessments. Customization will provide all LOBs optimal visibility into their respective vendors' assessment status and risk profiles. This mitigation includes workflow configuration, data validation, integration process and training and awareness. The improved business processes and repository of records provided by the initiative will permit a better understanding of the cybersecurity risks that vendors may present to PG&E.
- **IAM Product Enhancements:** This initiative expands the capabilities of the IAM solutions to support cloud identity management, developer security operations, high risk database integrations, cloud access security, DOE Part 810 export controls, unstructured high risk data access management, and segregation of duties. It includes extending on-premise IAM solutions to cloud and enterprise mobility. The capabilities enabled by this project will improve the quality of access control and reduce the risk of inappropriate access across multiple environments, including public cloud environments.
- **Enhance Cyber Reporting:** This project will permit cybersecurity analysts to spend more time responding to high-impact incidents, and less time on mundane administrative tasks. The current process to respond to an event requires labor-intensive steps to investigate the event, identify the event as an incident, perform forensics on the system, and upload event data so the proper response can be executed. This mitigation will assist analysts in identifying and responding to security events in a more efficient and timely manner. Timely response to cyber-attack events reduces the risk of higher impact to PG&E systems and data.
- **Future Generation Endpoint Security Program:** Aims to leverage technology improvements in the ability to detect, alert, prevent or block unwanted or malicious activity on endpoint computing devices. Unwanted activity might include unwanted system changes, code execution or network traffic. Endpoint computing devices might include computers, portable devices, or operational devices. The technology might leverage machine learning, behavioral analytics, or other techniques that improve protection effectiveness and value. The program would evaluate the computing environment, threat landscape, mitigation landscape available at the time to determine the best approach.

M2B – Protect: Through the following nine initiatives, PG&E will develop and implement safeguards to ensure delivery of critical infrastructure services.

- **ODN Security Improvements:** This project will implement technology to allow isolation of control failures caused by a cyber attack to create separation zones to limit the impact and maintain substation automation to the rest of the territory.

These improvements will reduce the reliability risk from the Integrated Planning cyber-attack failure scenario to a tolerable level by implementing access controls at remote sites, as well as securing the electric distribution system.

- **Gas SCADA Network Protection:** This project will address observations made by Gas Operations cybersecurity risk assessments. It is a mitigation in multiple phases, addressing asset management, network protection, security monitoring, technology evaluation and planning for operating system upgrades both before and during the RAMP period. Benefits include:
    - Enhanced situational awareness
    - Improved detection and response capabilities
    - Better preparation for future operational technologies
- **Customer Information Protection:** This set of projects will develop and implement a data security governance program that addresses and manages compliance and legal requirements to ensure that sensitive data is protected in alignment with the PG&E data classification framework, policies and standards. Technology will be deployed to discover sensitive information, and assess the health of the controls in place to protect that information. Where controls are lacking, remediation will be implemented in phases based on risks being mitigated. This initiative will reduce the risk of unauthorized access to data, malicious insider behavior, or other data breaches.
- **Smart Grid Security:** This project will advance the development and standardization of cybersecurity policies, procedures, and practices for the smart grid architecture and Advanced Metering Infrastructure (AMI). The project will ensure efficiencies in deploying new devices on the AMI network. It will also provide a real-time view of the state of the network, including the presence of rogue devices and malicious traffic. Strengthening the governance around network segmentation and hardening the perimeter will also be needed as additional stakeholders leverage the AMI network. Centralized governance will provide for consistent interactions among all stakeholders that use the AMI network to ensure effective security oversight.
- **Application Integration for Access Management:** To mitigate the risk of users having inappropriate access to high-risk applications, the project will expand role-based access controls to restrict workforce and third-party access to only the functions and data required to complete tasks or other job functions. The components of this initiative—application integration, third-party account integration, and control of user access based on roles and responsibilities—will reduce the risk of inappropriate access to high-risk data.
- **Patch Automation:** This project will deploy technology that enables a single, integrated patch management and automation solution to improve automation of patching for high and medium risk non-critical systems. The application of patches across all PG&E systems is labor-intensive and time-consuming. This program will automate the patching of critical and high impact systems. This mitigation will reduce time and labor spent on applying patches which equates to cost savings as well.

- **Automate Cloud Security:** This initiative will mitigate cyber threats to high- and medium-risk data stored in the cloud. Actions to accomplish this objective will include designing and implementing processes and tools to ensure that applications and data in the cloud are secure. This project will also enable the ability to continuously test, detect, measure and incrementally improve controls to reduce risk. This effort will ensure that cloud services utilized by PG&E adhere to PG&E's security requirements. This initiative would obtain the necessary tools and services to ensure that cloud environments used by PG&E are secure.
- **Catalog Privileged Accounts and Access to Critical Systems:** To secure the enterprise network, this project will identify and catalog individual users with access to significant critical PG&E logical and/or physical assets. Users with privileged access or access to both physical and logical critical systems will also be identified. The project will also provide additional monitoring and validation of user access to prevent and detect potential incidents.
- **Network Access Control (NAC):** The goal of this project is to implement NAC across PG&E's corporate network. Implementation of a NAC solution will enable PG&E to identify and permit access from only trusted devices to PG&E's network. It would also enable the ability to direct untrusted devices to a guest network to mitigate the risk they pose to devices that possess a higher level of trust.

M3B – Detect: The projects that comprise the mitigations in Detect are: Identity Analytics; Enterprise User and Entity Behavior Analytics; Security Analytics and Advanced Monitoring Phase III; Security Analytics and Advanced Monitoring Enhancements; Security Monitoring Lifecycle; and Security Monitoring Capacity Extension.

- **Identity Analytics:** This project will implement tools to monitor user and administrator activity. By monitoring these activities, the system learns the level of access required to perform specific job functions. It will then suggest an access profile that reduces access that is not needed to perform job functions. This capability will reduce the chance of granting excessive access to an individual, and reduces the risk of insider threats. These tools will also improve the efficiency of onboarding employees, maintaining and removing access credentials, and the ability to manage credentials for systems that are critical for SOX compliance.
- **Enterprise User and Entity Behavior Analytics:** This project will correlate user activity with other entities such as managed and unmanaged endpoints, applications (including cloud, mobile and other on-premise applications), networks, and external threats. Such correlation will identify intentional and unintentional insider actions that violate data usage policies. Tools deployed for this purpose will also proactively identify and enable an effective response to incidents in which data is sent outside PG&E with malicious intent (for example, data theft) by establishing a baseline of expected behaviors within a job function and flagging deviations from that baseline for further review.
- **Security Analytics and Advanced Monitoring Phase III:** The PG&E Threat Intelligence organization will continue to build out the SIOC. In this phase, the SIOC

will integrate and consolidate cybersecurity and physical security day-to-day operations by insourcing security analytics. The organization will obtain additional software licenses and add capacity to perform analytics with existing tools. The mitigation includes plans to add new tools with monitoring, detection, and analytics capabilities. Furthermore, this initiative will develop human process workflows that incorporate the security analytics into day-to-day operations. PG&E previously engaged a vendor for security event analysis, but the services provided by the vendor did not enable a holistic view of both cyber and physical security. Insourcing is an opportunity to improve the quality of security event detection and analysis, thereby enabling PG&E to detect more events, gain deeper insight into the events, and respond to them more quickly and more effectively. Activities planned for this phase also will improve collaboration between cybersecurity and physical security personnel and systems to improve the effectiveness of both functions.

- **Security Analytics and Advanced Monitoring Enhancements:** This set of projects will enhance cybersecurity monitoring technology, algorithms, tools, and processes to use improved techniques for discovery, logging, analysis, detection, and alerting. These enhancements will include different and improved statistical analysis, machine learning, or other forms of analytics and advanced monitoring to improve the effectiveness and efficiency of security analytics and monitoring in detecting cyber attacks.
- **Security Monitoring Lifecycle:** To maintain PG&E's monitoring capabilities, this mitigation will replace or upgrade obsolete security monitoring hardware or software with supported and relevant technology as technology ages. This may include replacing one or more technology platforms. Obsolete systems increase security risk, as they can cease to function, operate poorly, or increase operating cost. Vendor license terms can also be modified over time, necessitating changes to maintain valid licenses.
- **Security Monitoring Capacity Extension:** This set of activities will maintain and support sufficient security monitoring capacity through the addition of storage, network capacity, software licensing, and hardware (virtual or physical). Existing and anticipated growth will mandate additional monitoring capacity to sustain existing business capabilities. Moreover, expanding the scope of systems logged and monitored and retaining logs over longer periods of time will improve monitoring and alerting capabilities and reduce blind spots.

M4B – Respond: The Respond mitigation includes three projects: Optimize Cyber Response and Incident Reports; Enhance Cybersecurity Labs and Forensics; and Cyber Response Automation.

- **Optimize Cyber Response:** This project will enable security analysts to analyze and identify security incidents more effectively. A large number of events coming from multiple sources may need to be examined and cross-referenced in order to identify a security incident. Tools to automate the identification of incidents from events across multiple systems will reduce the time required for security analysts to perform the tasks needed to determine the appropriate response actions. Thus, security analysts can focus on responding to events more quickly. Timely event response can lessen the impact of an event. This project will deploy technology that will aggregate events from disparate systems to determine if a cybersecurity incident has occurred. Typical systems that report events include anti-virus, firewalls, and data loss prevention agents. Operational systems can also report potential security events.

- **Enhance Cybersecurity Labs and Forensics:** PG&E will procure and build an in-house test lab to evaluate and configure monitoring and cybersecurity forensics tools. The lab would include systems that are representative of common PG&E environments. The mitigations enable testing of current forensics, monitoring, detection and alerting tools. These tools need to be tested for compatibility, to avoid outages of information technology or OT systems, as well as enabling the tools to be optimized before they are deployed in a real-time environment.
- **Cyber Response Automation:** Response automation will apply technologies that can identify common cyber incidents, quarantine an affected system or computer, and begin remediation. Timely response to events can reduce the impact of a security incident to PG&E systems. Response automation will provide effective incident mitigation to return a system or computer back to normal operations without waiting for a security analyst to respond. This allows security analysts to investigate and determine the root causes of more complex events, and allows the system or computer to return to service sooner.

Table 18-3 summarizes the mitigations' associated drivers and associated estimated costs for each year. The Risk Spend Efficiency (RSE) metric is not applied to the cyber-attack risk because of the complex and innovative nature of the attack methods which make estimating risk reduction a challenge.

Table 18-3: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Identify	N/A	N/A	2020	2022	All Drivers	1,953 (C) 525 (E)	3,000 (C) 2,135 (E)	2,600 (C) 1,150 (E)
M2B	Protect	N/A	N/A	2020	2022	All Drivers	15,624 (C) 4,093 (E)	14,000 (C) 4,540 (E)	13,585 (C) 6,036 (E)
M3B	Detect	N/A	N/A	2020	2022	All Drivers	5,673 (C) 1,335 (E)	4,200 (C) 1,869 (E)	4,940 (C) 2,470 (E)
M4B	Respond	N/A	N/A	2020	2022	All Drivers	2,976 (C) 642 (E)	3,000 (C) 777 (E)	2,210 (C) 1,050 (E)
TOTAL Expense and Capital by Year							**26,226 (C) 6,595 (E)**	**24,200 (C) 9,321 (E)**	**23,335 (C) 10,706 (E)**

VI. Alternatives Analysis

While assessing all of the mitigations for cyber-attack risk, PG&E developed two alternative plans to the proposed mitigation plan. Alternative Plan 1 increases the scope and cost of mitigation programs while Alternative Plan 2 decreases scope and cost. Both plans are shown in Tables 18-4 and 18-5.

Alternative Plans 1 and 2 incorporate all four of the mitigation programs, with specific projects within the programs changing either pace and scope for each alternative. To maintain consistency with the previous sections of this discussion, this section presents each alternative on a program-by-program basis, with the two alternatives being directly compared within each program.

Table 18-4: Mitigation List

#	Mitigation	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M1B	Identify	X			WP 18-2
M2B	Protect	x			WP 18-6
M3B	Detect	x			WP 18-13
M4B	Respond	X			WP 18-18
M1C	Identify		X		WP 18-2
M2C	Protect		X		WP 18-6
M3C	Detect		X		WP 18-13
M4C	Respond		X		WP 18-18
M1D	Identify			X	WP 18-2
M2D	Protect			X	WP 18-6
M3D	Detect			X	WP 18-13
M4D	Respond			X	WP 18-18

Table 18-5 below illustrates the key changes in our alternatives. Each alternative is a more of or less of approach and the chart below details which of the projects would actually change in each program.

Table 18-5: Alternative Plans

Proposed Mitigation Program	Alternative One	Alternative Two
Identify *($11.4 million Proposed Over RAMP Period)*	Increase scope of IAM Product Enhancements from high-risk systems to high- and medium-risk systems. Would have reduced risk for medium-risk systems as well as high-risk system but with increased execution risk because of greater scope. Increases cost by approximately $1 million.	Reduce scope of Enhanced Cyber Reporting, giving employees fewer tools to identify cyber-attack events. Reduces cost by approximately $0.33 million.
Protect *($57.9 million Proposed Over RAMP Period)*	Increase scope of Patch Automation to cover non-critical systems as well as critical systems. Expand Automate Cloud Security to migrate low-risk data in addition to medium- and high-risk data. Total increased cost of approximately $9.5 million.	Eliminate NAC project, increasing risk of unauthorized devices connecting to PG&E networks. Reduces cost by approximately $6 million.
Detect *($20.5 million Proposed Over RAMP Period)*	Increase scope of Security Monitoring Lifecycle and Security Monitoring Capability Extension to deploy additional, potentially unproven technologies. Total increased cost of approximately $4.1 million.	Reduce scope of Security Analytics and Advanced Monitoring Enhancements, deploying fewer technologies. Reduces cost by approximately $5.6 million.
Respond *($10.7 million Proposed Over RAMP Period)*	Increase scope of Enhance Cybersecurity Labs and Forensics to permit more tools to be evaluated for compatibility with the PG&E environment and for effectiveness. Increases cost by approximately $1 million.	Reduce scope of Enhance Cybersecurity Labs and Forensics, reducing lab testing capacity and requiring triage to test only upgrades to critical tools. Decreased cost of approximately $.9 million.

A. Alternative Plan 1

Below are the mitigations considered for Alternative Plan 1.

M1C – Identify: This alternative would have increased the amount spent on IAM Product Enhancements by approximately $1 million during the RAMP period, while retaining proposed spending for all other projects in this mitigation program.

This additional spend would expand the scope of IAM Enhancements and further expand the capabilities of the proposed solution to include medium-risk database integrations and medium-risk data access management of unstructured data. This would have reduced risk across high and medium systems compared to targeting only high-risk systems. PG&E chose not to implement this scope in our proposed scenario in order to utilize lessons learned during deployment of enhancements to only high-risk systems, thus enabling more efficient deployment among lower-risk systems after the RAMP period (post-2022).

M2C - Protect: The first alternative scenario would have increased the scope of the Patch Automation project by approximately $7.6 million and the Automate Cloud Security project by approximately $1.9 million while retaining the same scope for the other projects in the proposed mitigation program. The changes that were considered for the two projects are described in more detail in the following paragraphs.

- **Patch Automation** – The increase in spending for this project would have allowed deployment of a single patch management and automation solution. In the current environment we have multiple patch management solutions that support different operating systems. Moving to a single patch management solution could have improved automation of patching for all non-critical systems, expanding the scope of this project. This alternative would have covered non-critical systems that can be used to launch attacks against more critical systems. PG&E does not recommend this alternative for the 2020-2022 RAMP period because the increased costs would not provide a significant reduction in risk for safety-critical systems.
- **Automate Cloud Security** – The increase in spending for this project would have expanded the scope of the project by mitigating low-risk data in addition to high- and medium-risk data stored in the cloud. We don't recommend this alternative because the resulting risk reduction would be minimal compared to the investment required.

M3C – Detect: This alternative would have increased the amount spent on Security Monitoring Lifecycle by approximately $2.15 million and Security Monitoring Capability Extension by approximately $2 million while retaining proposed spending for all other projects in this mitigation program.

Increasing spend for these programs would have allowed PG&E to deploy emerging yet unproven technologies and would most likely have led to replacing the existing technology platform for this purpose. Any such platform could offer additional tools and capabilities to reduce the impact of cyber risk. However, immature technologies also introduce the risk of incorrect categorization of cyber events as potential cyber attacks. Because of the probability of this additional risk, PG&E recommends this type of scope expansion in the future, when emerging technologies have had the opportunity to mature.

M4C – Respond: This alternative would have increased the amount spent for the project to Enhance Cybersecurity Labs and Forensics by approximately $1 million, while retaining proposed spending for all other projects in this mitigation program.

This alternative would have included more systems that could have been tested in the lab for compatibility and effectiveness with new monitoring tools. The

RAMP proposal focuses on systems that are critical to safety or are otherwise common in the PG&E environment. This alternative would have expanded the scope to systems that are not common but still perform key business functions. PG&E's evaluation was that this expansion of scope did not meaningfully reduce the security or reliability impacts of cyber-attack risk and could be explored at a later time.

Table 18-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1C	Identify	N/A	N/A	2020	2022	All Drivers	1,953 (C) 525 (E)	3,000 (C) 2,135 (E)	3,600 (C) 1,150 (E)
M2C	Protect	N/A	N/A	2020	2022	All Drivers	15,624 (C) 7,843 (E)	14,000 (C) 7,790 (E)	13,585 (C) 8,536 (E)
M3C	Detect	N/A	N/A	2020	2022	All Drivers	6,848 (C) 1,635 (E)	5,200 (C) 2,399 (E)	5,490 (C) 2,970 (E)
M4C	Respond	N/A	N/A	2020	2022	All Drivers	3,082 (C) 892 (E)	3,300 (C) 952 (E)	2,330 (C) 1,150 (E)
TOTAL Expense and Capital by Year							**27,507 (C) 10,895 (E)**	**25,500 (C) 13,276 (E)**	**25,005(C) 13,806 (E)**

B. Alternative Plan 2

Below are the programs proposed for Alternative Plan 2.

M1D – Identify: This alternative would have reduced spending on the Enhance Cyber Reporting project during the RAMP period by approximately $330,000, while retaining proposed spending for all other projects in this mitigation program.

Considering potential restraints on funding, PG&E examined what could be reduced in this program. The Enhance Cyber Reporting project was identified as the only project in this mitigation program that could have been reduced with minimal impact to cyber-attack risk. Reducing Enhanced Cyber Reporting would have given employees fewer tools to identify cyber events and cyber attacks efficiently and consistently. This would require the employees to make up for the lack of automation by spending more effort on routine and administrative tasks not reducing the impact of a cyber-attack risk event and possibly increasing the impact of such an event.

M2D – Protect: This alternative would have eliminated the NAC project by approximately $6 million while retaining proposed spending for all other projects in this mitigation program.

This alternative was considered because of the complexity of NAC deployment. Eliminating NAC would have allowed unauthorized devices greater opportunity to compromise PG&E systems by allowing direct access to our corporate network resulting in an increased risk of cyber attack. The NAC project is designed to reduce that risk by directing devices not meeting PG&E security requirements to a guest network with minimal access to PG&E systems. Eliminating a NAC deployment would eliminate this capability. Thus, PG&E does not recommend this alternative because it would have relinquished an opportunity to substantially reduce cyber-attack risk.

M3D – Detect: This alternative would have reduced proposed spending for Security Analytics and Advanced Monitoring Enhancements Phase III by approximately $5.6 million while retaining proposed spending for all other projects in this mitigation program.

The justification for this alternative would have been to reduce costs and provide more time for the Security Analytics and Advanced Monitoring Phase III project to mature in order to obtain efficiencies in later deployments. However, delaying this project would have also prevented PG&E from leveraging new capabilities that could have improved the likelihood of detecting advanced cyber attacks.

M4D – Respond: This alternative would have reduced proposed spending for the project to Enhance Cybersecurity Labs and Forensics by approximately $.9 million, while retaining proposed spending for all other projects in this mitigation program.

This alternative would have decreased the capacity of the lab compared to the RAMP proposal, thus allowing PG&E to test only upgrades to critical tools and not evaluate new tools and technologies except on a best-effort basis. This alternative would have resulted in delays in applying updates to tools not deemed critical, reducing forensic response capabilities and potentially increasing the impact of a cyber-attack risk event. Additionally, this alternative would have delayed evaluations of emerging tools and technologies resulting in slower adoption and delayed risk mitigations thereby also increasing the impact of a cyber-attack risk event.

Table 18-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1D	Identify	N/A	N/A	2020	2022	D1,D2,D3,D4	1,953 (C) 450 (E)	3,000 (C) 2,030 (E)	2,600 (C) 1,000 (E)
M2D	Protect	N/A	N/A	2020	2022	D1,D2,D3,D4	13,764 (C) 3,593 (E)	12,000 (C) 3,840 (E)	13,585 (C) 5,036 (E)
M3D	Detect	N/A	N/A	2020	2022	D1,D2,D3,D4	4,743 (C) 1,185 (E)	3,200 (C) 1,659 (E)	2,340 (C) 1,770 (E)
M4D	Respond	N/A	N/A	2020	2022	D1,D2,D3,D4	2,632 (C) 642 (E)	2,700 (C) 701 (E)	2,030 (C) 1,050 (E)
TOTAL Expense and Capital by Year							**23,092 (C) 5,870 (E)**	**20,900 (C) 8,230(E)**	**20,555 (C) 8,856 (E)**

VII. Metrics

Proposed accountability metrics include the following, related to the proposed mitigations and drivers mitigated:

The publicly available metrics that measure the cyber-attack risk are as follows:

- Vulnerability Ticket Management – shows the high severity vulnerability ticket average age which measures the average amount of time in days of all currently open high-severity tickets.
- Phishing Click Through Rate – rate at which the organization clicks on links in internally-generated test phishing emails.

The metrics in this section are currently in use. These metrics are being revised and will be reassessed at the end of 2017 for future use or replacement. They are indicators of the overall risk and not necessarily of each mitigation's effectiveness.

VIII. Next Steps

The next steps toward improving PG&E's understanding and analysis for cyber-attack risk include researching best practices on obtaining event data specific to OT systems, such as those that govern electric and gas control systems, and industry agreement on the mapping of metrics to specific controls. There are challenges to obtaining this data however. As an example, the category of cyber-attack threats known as APT, specifically relevant to utilities, incorporates stealth by its very nature, thus making it impossible to gather data on potential attacks of this type. All known APT attacks are suspected to have support from nation states, which find it advantageous to maintain their attack capabilities in reserve. There is more data relating to attacks that cause a loss of information but, even in those attacks, victims often do not disclose information publicly in an attempt to limit legal liabilities. Currently, metrics focus on the day-to-day operations of protective systems or on compliance and, to this point, have not been correlated with the probability of events.

As discussed, cyber-attack risk is distinctive among risks to PG&E because that risk is actively exploited by adversaries applying ever-increasing levels of skill to attempt to breach PG&E systems and data. Legacy systems, particularly operational technology, are especially difficult to secure because standard approaches such as frequent patching and updates may sometimes conflict with imperatives to maintain the availability and reliability of the gas and electric systems. The cybersecurity program must balance these imperatives and, in appropriate situations, implement alternative controls to compensate for challenges in deploying standard controls. Operational technology systems may have a particularly large impact on the safety of the gas and electric systems. Ensuring the security of customer data is also important, requiring measures to be taken to protect against data loss. In addition, the program must protect innovative technologies such as cloud computing, SmartMeter™ devices, distributed generation, the Internet of Things, and future platforms not yet envisioned. Innovations in technology combined with innovation by our adversaries will require continual improvements in the PG&E cybersecurity program, requiring a risk-informed program that is recognized as a leader among utilities.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 19
INSIDER THREAT

PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 19
INSIDER THREAT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Insider Threat
IN SCOPE	The three elements of an insider threat which differentiate it from other risks are individuals with: (1) authorized access, (2) knowledge of Pacific Gas and Electric Company (PG&E or Company), and (3) malicious intent.
OUT OF SCOPE	Out of scope risks include but are not limited to: external threat actors, individuals who gain unauthorized access to PG&E, workforce misconduct which lacks malicious intent. Although these situations are out of scope for the insider threat risk there are interdependencies between these types of situations and insider threat. Therefore, insider threat, security, and workforce conduct stakeholders closely collaborate to ensure the most qualified resources are directed toward each risk.
DATA QUANTIFICATION SOURCES	Reports of actual incidents, PG&E employee conduct and security investigations records, Federal Bureau of Investigation (FBI) active shooter data, subject matter expert (SME) judgement, industry, academic, and market research

The insider threat risk is the potential for employees or non-employee workers (NEWs)[1] with current or previously authorized access to PG&E's assets to use their access and knowledge with intent to negatively affect PG&E or its customers.

Insider threat has been identified as an enterprise risk since 2015. If the insider threat risk transpired at PG&E, it could impact the safety of the public, employees, or NEWs through a workplace violence incident or by disrupting utility services leading to outages, accidents, hazardous conditions, or environmental harm.

According to the United States (U.S.) Department of Homeland Security, the insider threat risk is "complex and dynamic," requiring critical infrastructure owners and operators to "recognize the nuances and breadth of this threat in order to develop appropriate risk-based mitigation strategies."[2] It is currently not feasible to quantitatively model the insider threat risk because there is no definitive model of human behavior through which one can estimate outcomes with high specificity. Due to the scope, breadth, and ambiguous nature of the risk, it is neither easily measurable nor observable. These limitations on quantitative modeling do not preclude a rigorous

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1 A non-employee worker is anyone who performs work for PG&E Corporation or its controlled subsidiaries, including Pacific Gas and Electric Company (collectively, PG&E), but is not a PG&E employee. NEWs include: contractors, consultants, independent contractors, and/or staff augmentation suppliers' temporary agency workers.

2 Department of Homeland Security, "National Risk Estimate: Risks to U.S. Critical Infrastructure from Insider Threat."

assessment of the risk. Subject matter expertise and the judgement of a diverse, experienced team are required to assess the risk and prioritize work.

PG&E's Corporate Security Department established an enterprise-wide, holistic Insider Threat Program. The program proactively identifies and mitigates insider threat risks to PG&E's workforce, customers, assets, and systems. The team advises other owners of related mitigations and controls on insider threat risk reduction through proactive engagement and assistance. PG&E anticipates making investments in additional risk-based mitigations as the program matures and the threat evolves over time.

The proposed mitigation plan makes investments in internal threat intelligence, data, and analytics capabilities. This proposed mitigation is the most effective way to manage the insider threat risk. The expected benefits of the proposed mitigation are advance detection of anomalies which may not be identified using more traditional security measures. This is the proposed mitigation because it scales easily and it is flexible enough to address the full spectrum of the insider threat. It also leverages previous investments in Cybersecurity and creates opportunities for cross-functional integration.

Because insider threat risks are neither easily measurable nor observable, PG&E will focus the metrics on the capability to prevent, detect, mitigate, and respond to the threat. PG&E already has advanced expertise which is relevant to this risk. Human Resources, Legal, Compliance and Ethics, operational lines of business, Cybersecurity, and Corporate Security stakeholders already contribute various controls and mitigations and apply judgment in the management of workforce related issues. The Insider Threat Program will harness this expertise and lead the development of the capability to manage this risk.

II. Risk Assessment

A. Background

All types of organizations are exposed to the potentially harmful actions of malicious insiders. Insiders are any trusted individuals with access to and/or knowledge of an organization. People with access and knowledge are among the most important assets of any organization. They form the institutional reservoir of human capital that allows an organization to consistently meet its objectives. But insiders are also uniquely positioned to cause disproportionate harm.

There are confounding features of the insider threat problem which complicate efforts to analyze the risk quantitatively, as is standard practice with some financial, technology, or engineering risk problems. The application of the Multi-Attribute Risk Score (MARS) model to the insider threat risk highlighted the following limitations of the modeling approach.

It is currently not feasible to quantitatively model the insider threat risk *ex-ante*, because there is no definitive model of human behavior through which one can estimate outcomes with high specificity. Insiders may act alone or be influenced (or coerced) by unknown external adversaries. Individuals with malicious intentions have the ability to adapt their behavior to avoid detection or maximize their impacts. Exposure is a function of the workforce profile, knowledge and access of individuals, and the criticality of accessible data, assets, or systems. It is not practical to distill these factors into quantifiable model inputs. Furthermore, these factors are not uniform over time or across PG&E. The cause-and-effect relationships between these variables cannot currently be quantified with any certainty, particularly at the scale of the enterprise.

Due to the scope, breadth, and ambiguous nature of the risk it is currently not practical to statistically model the insider threat risk in an *ex-post* manner. Employee conduct and investigations records can be insightful, but it would be misleading to assume these data paint a full picture of the insider threat risk. Avoided incidents do not show up in any data. The most consequential incidents occur very infrequently and may not be represented in the existing data. This may lead risk analysts to discount high-consequence incidents relative to those which are more easily measured. Conduct data are also likely to understate insider risk because some instances may go undetected or unreported at the enterprise level. According to Carnegie Mellon University Software Engineering Institute (CMU CERT), a leading insider threat research center, the majority of insider threat actions are never discovered.[3] It is not straightforward to differentiate general misconduct from insider threats. Each instance of misconduct is unique but insider incidents have three elements: exploitation of: (1) access, (2) knowledge, and demonstration of (3) malicious intent. All of these elements are highly subjective in nature and can only be determined upon the successful resolution of an investigation. If determined, these elements are not easily represented through quantitative data inputs.

The inability to quantify the cause-and-effect relationships and mitigation effectiveness does not preclude a rigorous assessment of the problem and potential solutions. Assessing the insider threat risk at PG&E requires SME judgement and functional expertise.

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3 https://insights.sei.cmu.edu/insider-threat/2010/10/interesting-insider-threat-statistics.html.

The following examples of actual external incidents demonstrate the nuances and breadth of the risk.

- Recently, a UPS employee killed three coworkers in the company's San Francisco facility before killing himself.[4]
- In 2012, a backup diesel generator at the San Onofre Nuclear Generating Station was inappropriately maintained, leading to an investigation of possible sabotage.[5]
- That same year, upon learning of his imminent termination, an employee of an oil and gas company remotely reset the company's network servers to factory settings resulting in serious disruptions to eastern U.S. business operations for thirty days.[6]
- In 2010, a former network administrator for the City of San Francisco was convicted for locking out the city's computer network for 12 days, leading to disruptions in law enforcement and administrative operations.[7]
- During 2006, two traffic engineers working for the City of Los Angeles discretely altered the programming of the traffic signals at four key intersections as part of a labor dispute resulting in several days of additional, wide-spread traffic disruptions.[8]

Each case shows how a worker with access, knowledge, and malicious intent can cause significant harm to an organization, its people, or the public. The impacts can be severe in the rare circumstance that a member of the workforce exploits a trusted position to act maliciously. These examples also illustrate the diversity of the risk.

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4 https://www.usnews.com/news/us/articles/2017-06-23/gunman-in-california-ups-shooting-targeted-co-workers-for-slayings.

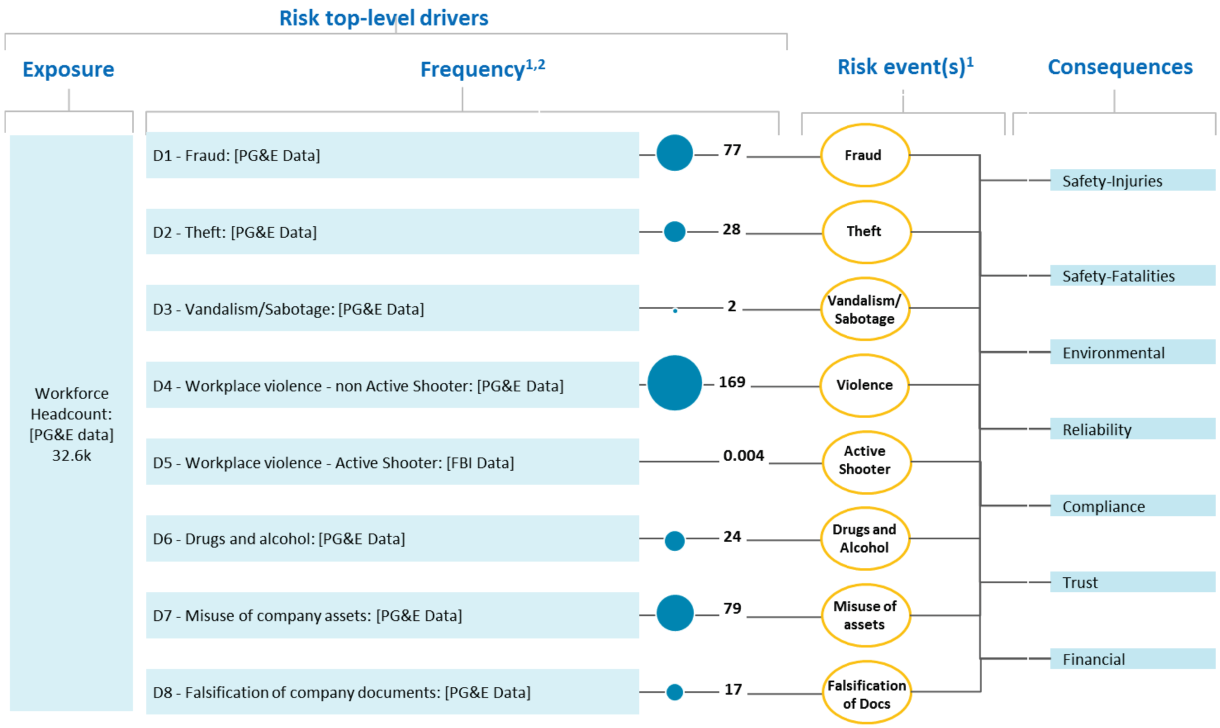
5 http://www.nti.org/gsn/article/fears-over-california-reactors-vulnerability-sabotage-mount/.

6 https://www.justice.gov/usao-sdwv/pr/enervest-computer-attack-draws-four-year-federal-sentence.

7 https://www.infoworld.com/article/2653004/misadventures/why-san-francisco-s-network-admin-went-rogue.html.

8 http://latimesblogs.latimes.com/lanow/2009/12/engineers-who-hacked-in-la-traffic-signal-computers-jamming-traffic-sentenced.html.

Figure 19-1: Risk Bow Tie



[1]Values displayed are means of each distribution and are in the units of events/year. Driver frequencies are summed to obtain the Risk event frequency.
[2]Drivers are modeled using Poisson distributions.

B. Exposure

Exposure is a function of the workforce profile, knowledge and access of individuals, and the criticality of accessible data, assets, or systems. The known factors of exposure are: (1) the workforce profile, (2) knowledge and access of individuals, and (3) the criticality of accessible data, assets, or systems. There could be unknown factors of exposure, yet to be identified. At the time of this analysis, PG&E's workforce consisted of approximately 25,000 current employees and 8,000 NEWs. These numbers do not include former employees and NEWs, which also contribute to exposure. It is not practical to distill these known factors into model inputs.

C. Drivers and Associated Frequency

PG&E conduct and investigation data were used as inputs to the model, but high-consequence incidents such as a workplace violence active shooter and a high-consequence insider sabotage incident were not represented in the data set. PG&E used other external data sources to represent these aspects of the risk. Also, Insiders may commit acts without direct safety consequences, but have meaningful financial impacts such as fraud and theft.

The FBI produced information about active shooters in workplaces.[9] These Federal data were scaled down from national scope to the size of the PG&E workforce and used as inputs to the analysis. They were used to estimate a frequency and consequence for the active shooter workplace violence scenario within PG&E. From a statistical perspective, the workplace violence active shooter incident at PG&E has a very low probability, but would have a very high impact. Despite the low probability, it is possible this type of incident could be experienced at PG&E. A similar incident has occurred at another California investor-owned utility. This is the tragic 2011 shooting incident involving a Southern California Edison employee who killed two and wounded two at his workplace before taking his own life.[10] The individual exploited his employee credentials to enter and move freely through the secured facility, simultaneously targeting specific individuals and interacting casually with others who were apparently unaware of what was unfolding.[11] Despite the very low probability of occurrence, the risk is significant and PG&E, along with every other organization, continues to be exposed to the potential for this type of violent act.

The brief definitions of the following general drivers are intended to be illustrative. The Employee Code of Conduct and any applicable company policies, standards, or procedures apply to any particular situation. The frequencies used in the model estimated from the available data from PG&E investigation reports and an estimate of the percentage of the incidents that may lead to adverse consequences. All driver frequencies are derived with this data except for the Active Shooter driver which is discussed separately.

- **D1 – Fraud:** fraud is any deceptive action intended to result in personal or financial gain. The frequency estimated from PG&E data for this driver is 77 incidents per year.
- **D2 – Theft:** theft means stealing company property or assets. The frequency estimated from PG&E data for this driver is 28 incidents per year.
- **D3 – Vandalism/Sabotage:** means the intentional destruction, disruption, or degradation of company systems, assets, property, facilities or operations. The frequency estimated from PG&E data for this driver is 2 incidents per year.

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9 https://www.fbi.gov/file-repository/activeshooterincidentsus_2014-2015.pdf/view.

10 http://articles.latimes.com/2011/dec/17/local/la-me-shooting-follow-20111218.

11 http://www.pasadenastarnews.com/2011/12/19/gunman-in-irwindale-shooting-was-reprimanded-day-of-attack/.

- **D4 – Workplace Violence – Non Active Shooter:** means the acts or threats of physical violence, intimidation, harassment or coercion, stalking, and similar activities, without the instance of an active shooter. The frequency estimated from PG&E data for this driver is 169 incidents per year.
- **D5 – Workplace Violence – Active Shooter:** means the instance of a person engaged in killing or attempting to kill others in a confined or populated area with the use of a firearm. Fortunately, PG&E has not experienced an insider driven workplace violence active shooter event and therefore cannot estimate a frequency of this occurring from company data. To supplement, the FBI produced information about active shooters in workplaces. These Federal data were scaled down from national scope to the size of the PG&E workforce and used as inputs to the analysis. They were used to estimate a frequency and consequence for the active shooter workplace violence scenario within PG&E. From a statistical perspective, the workplace violence active shooter incident at PG&E has a very low probability, but would have a very high impact. Despite the low probability, it is possible this type of incident could be experienced at PG&E. The frequency derived from industry data resulted in a value of 0.004 incidents per year.
- **D6 – Drugs and Alcohol:** means the use of drugs, alcohol, or other controlled substance that violates the employee code of conduct and/or impairs a person's ability to perform their work safely and efficiently. The frequency estimated from PG&E data for this driver is 24 incidents per year.
- **D7** – **Misuse of Company Assets:** means using company assets, systems, funds, equipment, or other property inconsistently with the employee code of conduct, company policies, standards, or procedures. The frequency estimated from PG&E data for this driver is 79 incidents per year.
- **D8 – Falsification of Company Documents:** means deliberately altering, omitting, or inaccurate completion of records. The frequency estimated from PG&E data for this driver is 17 incidents per year.

While employee conduct and investigations records can be insightful, it would be misleading to assume these data paint a full picture of the insider threat risk. Avoided incidents do not show up in any data. The most consequential incidents occur very infrequently and may not be represented in the existing data.

D. Consequences

For the purposes of evaluating the consequence impacts, PG&E gathered various sources of information to first develop and then validate the reasonableness of these assumptions. These sources of information include reports of actual incidents, both within PG&E and more broadly across the United States, PG&E employee conduct and security investigation records, FBI active shooter data, and SME judgement.

One example of an insider incident is well-planned sabotage against utility assets or critical systems which could disrupt energized gas or electric assets through physical or logical access resulting in hazardous conditions, environmental harm, and/or extended customer outages. In 1997 a three-and-a-half hour outage in downtown San Francisco Mission Substation impacting 126,000 customers was attributed to insider sabotage.[12] The attacker used a key to enter a PG&E substation and operate 39 switches to stop power flow. The incident was used as a benchmark to estimate the potential magnitude of an insider sabotage incident.

The 2013 Metcalf substation attack offers another example of a possible insider attack. The attack did not cause any customer electrical outages but it did stress the operation of the bulk electric system and cause the California Independent System Operator (CAISO) to issue a Flex Alert.[13] If the conditions had been different on the day of the attack, it could have led to an extended outage involving hundreds of thousands of customers. The attack resulted in $15.4 million in direct restoration costs with approximately $200 million more in additional indirect costs through not only thousands of hours of productive time from first responders, PG&E staff, and public officials but also upgrades to substations beyond Metcalf. As of today, it is not known who attacked Metcalf, but the evidence demonstrates that the attacker had knowledge of substation equipment, conducted advance planning, and understood the criticality of that particular site. The possibility that the attack was committed by a knowledgeable insider cannot be ruled out. The financial consequences of this incident were used in the model.

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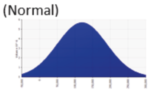
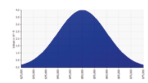
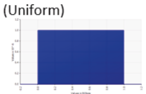
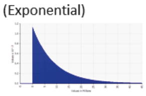
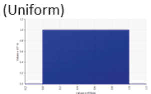
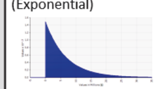
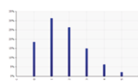
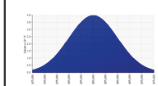
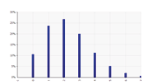
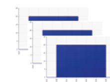
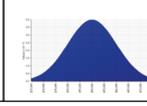
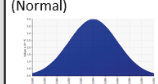
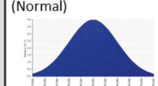
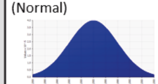
12 http://www.nytimes.com/1997/10/25/us/blackout-in-san-francisco-sabotage-is-seen.html.

13 http://www.caiso.com/Documents/Flex-Alert-UrgentConservationNeededNow-SantaClara-SiliconValleyApr16_2013.pdf.

Figure 19-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	SME Input and FBI	SME Input and FBI	SME Input	SME Input	SME Input	SME Input and FBI	SME Input and ACFE
Fraud							Ave:$120k;Std Dev:$70k (Normal) 
Theft							Ave:$50k; Std Dev:$10k (Normal) 
Vandalism/Sabotage			Min: $0; Max: $1M (Uniform) 	Ave: $8.8M (Exponential) 	Min: $0; Max: $1M (Uniform) 		Ave:$6.7M (Exponential) 
Workplace violence - non Active Shooter	Ave: 0.01 (Poisson) 					If there are any fatalities= High severity brand favorability change. If there are injuries without fatalities, 50/50 chance of Low or Severe	Ave:$50k; Std Dev:$10k (Normal) 
Workplace violence - Active Shooter	Ave: 3.5 (Poisson) 	Ave: 2.25 (Poisson) 				High severity=12-20% Severe=5-12% Low=0-5% (Uniform) 	Ave:$900k; Std Dev: $200k (Normal) 
Drugs and alcohol							Ave: $50k; Std Dev:$10k (Normal) 
Misuse of company assets							Ave: $50k; Std Dev:$10k (Normal) 
Falsification of company documents							Ave: $50k; Std Dev:$10k (Normal) 
Outcome-TA-NU[1]	4.44	0.10	$2,522,794	53,811,877	$2,522,794	11.36%	$63,416,081
Outcome-TA-MARS[2]	1.21	2.70	0.25	134.53	0.25	56.80	38.05
						MARS Total	**233.79**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

Figure 19-2 shows the range of consequences and the attributes that help describe the expected value and tail average risks and the associated MARS. An explanation of the assumptions used for each of the consequence attributes distributions is detailed below.

- **Safety – Injuries (SI):** FBI, "Active Shooter Incidents in the United States in 2014 and 2015" were applied with an average 3.5 injuries per incident. The incident data were scaled down from the population of the U.S. to the size of the PG&E workforce. The Poisson distribution was used. The workforce size used in this analysis is approximately one ten-thousandth the size of the U.S. population in 2015, leading to a very low frequency of active shooter injuries for PG&E. For non-active shooter incidents, it is assumed that there are no fatalities and one out of every one hundred workplace violence incidents with no active shooter produces an injury. With these inputs, the tail average outcome is 4.44 injuries per year.

- **Safety – Fatalities (SF):** FBI, "Active Shooter Incidents in the United States in 2014 and 2015" were applied with an average of 2.25 fatalities per incident. These data were scaled down from the population of the U.S. to the size of the PG&E workforce. The Poisson distribution was used. The workforce size used in this analysis is approximately one ten-thousandth the size of the U.S. population in 2015, leading to a very low frequency of active shooter fatalities for PG&E. With these inputs, the tail average outcome is 0.10 fatalities per year.
- **Environmental (E):** There could be environmental remediation costs associated with a sabotage incident. Lacking any other data source, PG&E's assumed a uniform distribution with environmental consequences up to $1 million. With this input, the tail average outcome is $2.5 million per year.
- **Reliability (R):** Sabotage incidents, such as an insider disrupting energy delivery could have significant reliability impacts. Although, most incidents would be minor, severe incidents are possible; albeit with a very low frequency. The exponential distribution was selected with a 95th percentile worst case of up to 26 million customer minutes based on the 1997 SF Mission Substation incident, leading to an average of 8.8 million customer minutes. The tail average outcome is 54 million customer minutes per year.
- **Compliance (C):** Sabotage incidents, such as an insider leaking protected information or tampering with the grid would have significant compliance impacts. Lacking any other data source, PG&E's assumed a uniform distribution with compliance consequences up to $1 million. With this input, the tail average outcome is $2.5 million per year.
- **Trust (T):** Trust is evaluated in the model as a function of injuries and fatalities resulting from the risk event occurring, and is expressed in percent change in brand favorability. The values used for this risk is based on the standard parameters discussed in the model Chapter B and result in a tail average outcome of 11.4 percent change in brand favorability.
- **Financial (F):** Insider incidents may have financial impacts based on the productive hours spent on incident response, remediation costs, new proposed upgrades, and similar activities. For fraud, PG&E assumed median losses of $120,000 per U.S. incident based on a report from the Association

of Certified Fraud Examiners.[14] For Vandalism/Sabotage, the exponential distribution was selected with a 95th percentile worst case of up to $20 million in direct remediation costs based PG&E experience from the Metcalf incident, leading to an average of $6.7 million. For a workplace violence active shooter incident, PG&E assumed a normal distribution of financial impacts from productive time costs with an average of $900 thousand with a $200 thousand standard deviation. For all other incidents, PG&E assumed a normal distribution of productive time costs with an average of $50 thousand with a $10 thousand standard deviation. These inputs resulted in a tail average outcome of $63 million per year.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Through 2016, there are numerous controls distributed throughout many departments across the enterprise. These disparate capabilities are not designed to mitigate insider threat but do play an indirect role in insider threat risk reduction. For example, the Compliance and Ethics helpline is well established and provides a method for anyone at any time to report concerning issues, anonymously if they choose, without fear of retaliation. The primary purpose of the helpline is not directly related to insider threat, but it indirectly supports mitigation of this risk.

Other controls include Security capabilities (e.g., general security and policies, contract guard force, Cybersecurity activities, investigation resources, and incident response plans), and non-security activities such as human resources processes (e.g., Employee Assistance Program, Fitness for Duty, background investigations, employee exit procedures, compensation and incentives, discipline standards, etc.), and legal functions. This portfolio of existing controls is focused on protecting the workforce, responding to general misconduct, and securing the enterprise. PG&E has recognized an opportunity to better coordinate these disparate controls and make investments in additional, more targeted mitigations, to reduce the insider threat risk.

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14 Association of Certified Fraud Examiners, “Report to the Nations on Occupational Fraud and Abuse, 2016 Global Fraud Study,” p. 7.

IV. Current Mitigation Plan (2017-2019)

Table 19-1: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1	Insider Threat Program Governance	2017	2019	All	0 (C) 40 (E)	0 (C) 100 (E)	0 (C) 200 (E)
M2	Business Process Development	2017	2019	All	0 (C) 40 (E)	0 (C) 100(E)	0 (C) 200 (E)
M3	Risk and Threat Assessment	2017	2019	All	0 (C) 40 (E)	0 (C) 100 (E)	0 (C) 200 (E)
M4	Training Awareness and Communications	2017	2019	All	0 (C) 40 (E)	0 (C) 100 (E)	0 (C) 200 (E)
M5A	Internal Threat Intelligence, Data, and Analytics Strategy	2017	2019	All	1,100 (C) 690 (E)	1,100 (C) 750 (E)	1,100 (C) 850 (E)
TOTAL Expense vs. Capital by Year					**1,100 (C) 850 (E)**	**1,100 (C) 1,150 (E)**	**1,100 (C) 1,650 (E)**

As the enterprise owner for insider threat, PG&E Corporate Security Department established a holistic Insider Threat Program in 2016. The program proactively identifies and mitigates insider threat risks to PG&E's workforce, customers, assets, and systems. The team advises other owners of related mitigations and controls on insider threat risk reduction through proactive engagement and assistance. The program will reduce the risk through prevention, advance detection, heightened awareness, prioritized effort, and more effective response.

PG&E established five mitigations under a holistic program after extensive research, consultation, and planning. Technology is a necessary program element, but non-technical activities provide the means to address the full spectrum of the risk. These five mitigations allow more complete coverage of the nineteen technical practices recommended by CMU CERT.[15] Gartner says insider threat risk reduction requires a mix of technical and non-technical detection methods, risk assessment, and prevention.[16] According to Forrester Research, "insider threats are not a technology problem," and recommends ten specific steps which combine technology and human processes.[17] These five technical and non-technical mitigations together create a comprehensive program consistent with industry practice. The program and the threat will evolve and PG&E anticipates guiding these mitigations over time to optimize their effectiveness.

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15 Carnegie Mellon University, Software Engineering Institute, "Common Sense Guide to Mitigating Insider Threats 4th Edition," December 2012.

16 Litan, Avivah and Perry Carpenter, Gartner, "Best Practices for Managing Insider Security Threats, 2016 Update," August 24, 2016.

17 Blakenship, Joseph, Forrester Research, "Hunting Insider Threats," July 20, 2016.

M1 – Insider Threat Program Governance are the activities which constitute the high level structure of the program, set standards for consistent application, and create frameworks for planning and decision making.

M2 – Business Process Development is the activities to manage business initiatives and improve processes to better mitigate insider threats. These activities also provide documented standards for other stakeholders as they execute the processes.

M3 – Risk and Threat Assessment enables risk-based prioritization of resources and decision-making to balance the possibility of adverse outcomes against business requirements.

M4 – Training, Awareness, and Communications enable executive vision and intent to permeate the organization, fostering a company culture that is still familiar to employees, but better attuned to risk and anomalous behavior.

M5A – Internal Threat Intelligence Data and Analytics Strategy plans, implements, operates and maintains proactive, data-driven, identity-centric security capabilities as well as enhancements of existing security platforms across the organization.

V. Proposed Mitigation Plan (2020-2022)

Table 19-2: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M5B	Internal Threat Intelligence , Data and Analytics Strategy	N/A	N/A	2020	2022	All	1,100 (C) 650 (E)	1,100 (C) 650 (E)	1,100 (C) 650 (E)
TOTAL Expense and Capital by Year							**1,100 (C) 650 (E)**	**1,100 (C) 650 (E)**	**1,100 (C) 650 (E)**

Table 19-2 summarizes the mitigation, associated drivers, and associated estimated costs for each year covered by the 2020 General Rate Case. The Risk Spend Efficiency (RSE) metric is not applied to the insider threat risk because the risk is neither measurable nor observable.

The proposed mitigation plan (M5B) is to make additional investments in internal threat intelligence, data, and analytics capabilities. This proposed mitigation is the most effective way to manage the insider threat risk.

The internal threat intelligence, data, and analytics mitigation is the development, acquisition and integration of internally available information from a variety of sources into enterprise security analytics software platforms. The security analytics platforms continuously process high volumes of data using advanced analytics and produce actionable outputs that help analysts better prioritize investigative and response activities. The anticipated result is increased visibility across the enterprise, leading to a more proactive security posture. The mitigation is complementary to the security monitoring or perimeter controls approach.

The expected benefits of the proposed mitigation are advance detection of anomalies which may not be identified using more traditional security measures. This mitigation is not static. It will enable the company's capability to evolve along with security technologies and external threat actors.

This mitigation was selected as the proposed mitigation because internal intelligence, data, and analytics capabilities: (1) scale easily to the enterprise level; (2) can be configured for line-of-business specific situations; (3) can be adapted as the threat evolves; and (4) are flexible enough to address all the drivers of insider threat. This proposed mitigation builds on the authorized mitigations in progress from 2017-2019. This proposed mitigation is part of a comprehensive, holistic approach and is highly consistent with insider threat mitigations at organizations with more experience mitigating this risk. This mitigation also leverages previous IT investments and creates opportunities for further Corporate Security and Cybersecurity integration. The capability provided by this proposed mitigation is complementary to Cybersecurity's strategy because it relies on existing tools and resources, but uses them in new ways. This is a benefit because, according to Forrester Research, twenty four percent of data breaches originate through current or former members of the workforce.[18]

VI. Alternatives Analysis

The alternatives to the proposed mitigation are to broadly implement more traditional security measures across the enterprise. These measures would be similar to those which already exist at highly protected facilities, such as airports. These measures certainly make it more difficult for a person to conduct harmful actions. They may reduce insider threat risk in some specific situations. But they cannot address the full spectrum of the insider threat risk and cannot be adapted over time. PG&E may implement very specific, targeted applications of these alternative mitigations, if they have potential to reduce localized risks. But after extensive research, consultation, and planning, PG&E determined they are not the most effective enterprise strategy to reduce the insider threat risks.

M7 – Enhanced Threat Detection at access control points (e.g., metal detector, trace detection, etc.).

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18 Adams, Jennifer, Forrester Research Webinar, "Forrester Data Deep Dive: Security Outlook In A Time of Rising Threats," September 25, 2017.

M8 – Armed Guards positioned at facility entry points, and/or roving in certain critical facilities.

M9 – Personal Article (and/or Vehicle) Inspection, randomized or comprehensive, at facility entry points.

M10 – Dual Factor Authentication for all physical access points including office environments.

M11 – Ballistic Protections in company vehicles and/or in customer service office service windows.

M12 – Safe Rooms entails the implementation of full-strength safe rooms throughout facilities to protect workforce in the case of a workplace violence incident.

Table 19-3: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M5B	Internal Threat Intelligence, Data, and Analytics Strategy	N/A	NA	x			WP 19-2
M7	Enhanced Threat Detection	NA	NA		x		WP 19-8
M8	Armed Guards	NA	NA		x		WP 19-4
M9	Personal Article and/or Vehicle Inspection	NA	NA		x		WP 19-10
M10	Dual Factor Authentication	NA	NA		x		WP 19-6
M11	Ballistic Protections	NA	NA			x	WP 19-12
M12	Safe Rooms	NA	NA			x	WP 19-14

A. Alternative Plan 1

Table 19-4: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M7	Enhanced Threat Detection	NA	NA	2020	2022	D1,D4,D7, D8	25,000 - 50,000 (C) 1,000 - 2,000 (E)	25,000 - 50,000 (C) 1,000 - 2,000 (E)	25,000 - 50,000 (C) 1,000 - 2,000 (E)
M8	Armed Guards	NA	NA	2020	2022	D1,D4,D7, D8	0 (C) 50,000 - 95,000 (E)	0 (C) 50,000 - 95,000 (E)	0 (C) 50,000 - 95,000 (E)
M9	Personal Article and/or Vehicle Inspections	NA	NA	2020	2022	D1,D4,D7, D8	500 - 1,000 (C) 5,000 - 10,000 (E)	500 - 1,000 (C) 5,000 - 10,000 (E)	500 - 1,000 (C) 5,000 - 10,000 (E)
M10	Dual Factor Authentica tion	NA	NA	2020	2022	D3,D4,D6	2,000 - 4,000 (C) 1,000 - 2,000 (E)	2,000 - 4,000 (C) 1,000 - 2,000 (E)	2,000 - 4,000 (C) 1,000 - 2,000 (E)
TOTAL Expense and. Capital by Year							**27,500 - 55,000 (C) 57,000 - 109,000 (E)**	**27,500 - 55,000 (C) 57,000 - 109,000(E)**	**27,500 – 55,000 (C) 57,000 -- 109,000 (E)**

Alternative Plan 1 consists of increasing the protection levels of the physical security perimeter. This would be accomplished by incorporating highly conspicuous physical security enhancements over time applied consistently across the enterprise. The individual mitigations in this alternative include enhanced threat detection at access control points, armed guards at entry points, personal article and personal vehicle inspections, and dual factor authentication at all physical access points.

These highly conspicuous security measures applied consistently across the company would be intended to deter and detect potential security threats. The expected benefits would be to reduce the frequency of unauthorized physical intrusions and the use or possession of dangerous or unauthorized materials or weapons on company property. It would also restrict and better control movement within company facilities, reduce unauthorized access by anyone lacking proper credentials, including members of the workforce.

This alternative was not selected because it does not address all the drivers of insider threat risk. Also, it does not easily scale to the enterprise level, cannot be re-configured for line-of-business specific use cases, cannot be adapted as the insider threat evolves, and is not flexible enough to address all the drivers of insider threat. Risk reduction benefits would be limited to unauthorized physical intrusion and carrying of hazardous or unauthorized materials through entry points, primarily reducing frequency of theft or violence-related drivers of the risk. Other contributing factors to the decision to forgo this alternative during the 2020-2022 period are the high lifecycle costs, invasiveness of the measures, and a lack of fit with company culture and brand. These mitigations, if implemented consistently across all facilities, would be highly disruptive to day to day business and utility operations. Furthermore, this perimeter-centric approach has limited effectiveness for threats which originate from persons with authorized access. Its value in reducing the full spectrum of insider threat risk drivers would be limited.

B. Alternative Plan 2

Table 19-5: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/$M)	EV RSE (Units/$M)	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M11	Ballistic Protections	NA	NA	2020	2022	D1,D8	5,000 - 15,000 (C) 1,000 - 2,500 (E)	5,000 - 15,000 (C) 1,000 - 2,500 (E)	5,000 - 15,000 (C) 1,000 - 2,500 (E)
M12	Safe Rooms	NA	NA	2020	2022	D1,D8	5,000 - 15,000 (C) 1,000 - 2,500 (E)	5,000 - 15,000 (C) 1,000 - 2,500 (E)	5,000 - 15,000 (C) 1,000 - 2,500 (E)
TOTAL Expense and Capital by Year							**10,000 - 30,000 (C) 2,000 - 5,000 (E)**	**10,000 - 30,000 (C) 2,000 - 5,000 (E)**	**10,000 - 30,000 (C) 2,000 - 5,000 (E)**

Alternative Plan 2 consists of implementation throughout the company of ballistic protections for certain applications (such as vehicles and customer service offices) and the installation of full-strength safe rooms within occupied buildings. The mitigations would be designed to protect the company workforce from an armed person intent on violence.

This alternative, if broadly implemented, offers some defenses-in-depth beyond just the physical security perimeter. Under certain limited circumstances, the mitigations could potentially reduce the consequences of a workplace violence incident.

However, the failure to address risk drivers beyond violence, eliminate it from consideration to address the insider threat risk. This alternative does not easily scale to the enterprise level, cannot be re-configured for line-of-business specific use cases, cannot be adapted as the insider threat evolves, and is not flexible enough to address all the drivers of insider threat. Also the lifecycle costs and operational disruptions would be prohibitive. The fundamental design and use of company vehicles and workspace is inconsistent with implementation of ballistic protections. There would be significant degradation of functionality assets and space-use conflicts. This would lead to loss of use, increased maintenance costs, and business disruptions. Most importantly, this alternative was not selected because it reduces risk by lowering the consequences of a workplace violence incident in progress. Reducing frequency through advance detection and proactive intervention is the preferred approach for risks with safety-related impacts.

VII. Metrics

Since insider threat risks are neither measurable nor observable in a way which can be easily applied to a quantitative model, the risk metrics focus instead on PG&E's capability to prevent, detect, mitigate, and respond to the threat. The program activities will be measured against a capability maturity framework. The framework measures eight programmatic elements, each with specific attributes which can be objectively evaluated against defined criteria (rated one through five) in order to determine a maturity level. The higher numbers imply greater maturity. Since the risk and its mitigations are very complex and dynamic, the capability maturity framework provides an actionable way to organize the work and see progress over time.

VIII. Next Steps

PG&E will continue to develop the organizational capabilities to proactively manage the insider threat risk. The mitigations currently in progress during 2017-2019 create the foundation for a comprehensive program which not only integrates technology, but also facilitates the cross-functional business processes necessary to manage the full spectrum of the risk.

Since insider threat risks are neither easily measurable nor observable, PG&E will focus metrics on the capability to prevent, detect, mitigate, and respond to the threat. The capability maturity framework will allow PG&E to address the full spectrum of this broad risk through realistic and achievable mitigations. PG&E has high confidence that the authorized and proposed mitigations will reduce risk, although risk reduction cannot be determined quantitatively. PG&E will rigorously assess the risk and all of the unique variations across the enterprise. Quantitative information will be applied where feasible, but there is no comprehensive information which fully represents the breadth and complexity of this human-centric, cross-cutting risk.

PG&E will continue to build a program which harnesses the advanced expertise, knowledge, and judgement which already exists across the enterprise. The Insider Threat program will not only facilitate technical mitigations, but also will facilitate the working relationships with internal experts such as Law, Human Resources, Compliance and Ethics, Cybersecurity, and the operational lines of business. The program will facilitate relationships and leverage the expertise of external parties such as Federal and local law enforcement, the intelligence community, the research community, and security technology vendors. PG&E's current and proposed mitigations are designed to improve the capabilities of the enterprise to prevent, detect, and respond to insider threats. A capability development approach is the most effective enterprise strategy to address this dynamic, enterprise-wide risk.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 20
RECORDS AND INFORMATION MANAGEMENT

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 20
RECORDS AND INFORMATION MANAGEMENT

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES

I. Executive Summary

RISK NAME	Records and Information Management.
IN SCOPE	This risk assessment only applies to the impact of records on top company safety risks identified in the Pacific Gas and Electric Company (PG&E or the Company) 2017 Risk Assessment and Mitigation Phase (RAMP) filing.
OUT OF SCOPE	This assessment does not apply to any risk outside the top company safety risks identified in the PG&E 2017 RAMP filing.
DATA QUANTIFICATION SOURCES	Assessment informed by PG&E data, industry data, and subject matter expert (SME) input.

The Records and Information Management (RIM) risk has been on PG&E's risk register since 2013. The risk of not having an effective records and information management program may result in the failure to construct, operate and maintain a safe system and lead to property damage and/or loss of life. Tragically, PG&E has previously experienced such a major event within the last 10 years, as evidenced by the San Bruno accident. The inability to find records and information in a timely manner undermined the public's trust in PG&E as a safe pipeline operator.

Probabilistic modeling of the RIM risk as part of the RAMP process identifies it as a sub-driver of 12 of the major Lines of Business (LOB) asset and operational safety risks identified in RAMP. This makes the RIM risk an important cross-cutting safety risk for the Company. RIM risk is managed by the Enterprise Records and Information Management (ERIM) Department.

PG&E is actively addressing this risk through a variety of controls and mitigations. The mitigation plan for 2020-2022 reflects the most risk reduction and highest Risk Spend Efficiency (RSE) of all the plans considered. This plan also allows the Company to achieve Information Governance Maturity Model (IGMM) Level 3 maturity in the most expeditious manner to lower the RIM risk.

Going forward, the ERIM department will increase PG&E's ability to identify records related issues by analyzing data trends from Corrective Action Program (CAP) reports, notices of violations (NOV), and Internal Audit (IA) findings as well as working with the incident reporting teams to add RIM as an explicit risk driver in post-incident assessment. The CAP was rolled out enterprise-wide in mid-2017, ensuring a broad and diverse pool of information going forward. It is anticipated that trending this enterprise-wide data will provide additional insights into the RIM risk. Likewise, additional insights are anticipated from monthly reviews by the ERIM department of NOVs and IA findings with the intent to analyze the risk drivers for RIM-related issues.

II. Risk Assessment

A. Background

The RIM risk has been tracked on PG&E's risk register since 2013. The risk of not having an effective records and information management program may result in the failure to construct, operate and maintain a safe system and lead to property damage and/or loss of life. A lack of records availability may also have additional negative consequences after a catastrophic event occurs, such as what occurred after the tragic accident in San Bruno.

RIM risk is managed by the ERIM department. In 2015, PG&E's senior leadership identified records management as one of the Company's Enterprise Risks. The ERIM program was established to promote greater program maturity and to provide strategy for records and information management that addresses this Enterprise Risk and supports PG&E's safety culture.

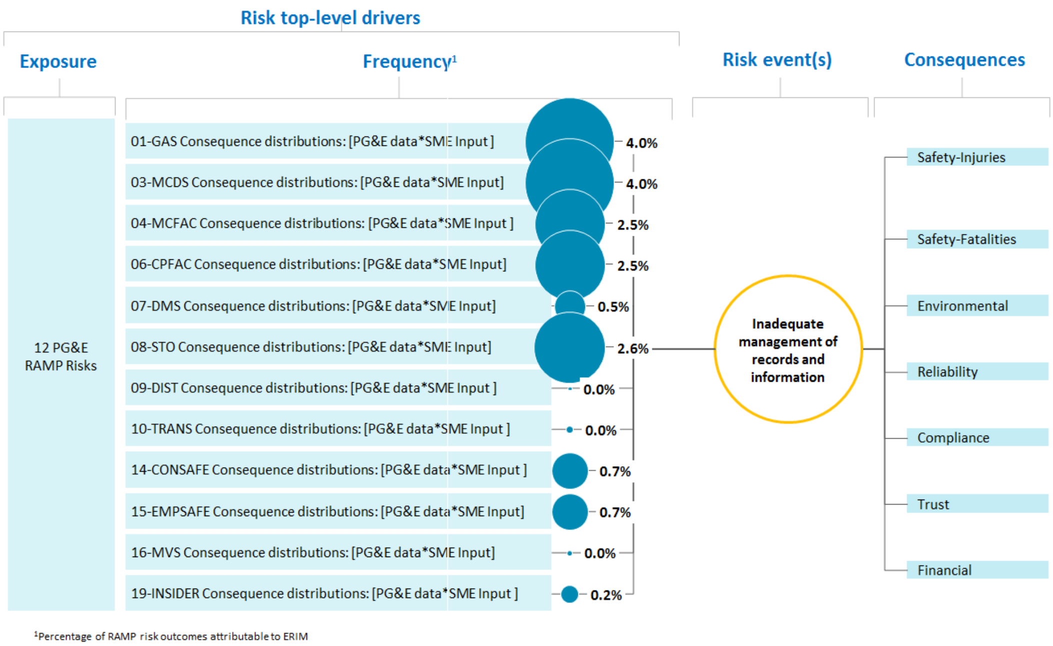
In 2017, the ERIM department used the bow tie risk assessment methodology to identify the key drivers and controls to be used for developing a quantitative risk model specific to the RIM risk. This model is presented in this chapter and uses a combination of PG&E-specific data, industry data, and SME's judgement to gain a better understanding of the risk drivers associated with the risk and where to target new mitigations.

B. Exposure

The RIM risk model is cross-cutting in that it is designed to aggregate the potential contribution of RIM risk events from 12 stand-alone or asset and operational safety RAMP risks for which the RIM risk is a precursor. Other risks may have a RIM risk as a precursor to an event but are not part of the scope of the RIM risk for this filing; however, the drivers, controls, and mitigations presented throughout this chapter would generally apply to those other risks as well.

Figure 20-1 below provides a visual representation of the risk bow tie for the RIM risk as presented in the RIM risk model. The exposure is comprised of the 12 asset and operational safety PG&E RAMP risks that have a potential for a RIM risk event as a root cause along with the resulting frequencies that are described in Subsection C, below.

Figure 20-1: Risk Bow Tie



C. Drivers and Associated Frequency

The ERIM department uses the IGMM developed by the Association of Records Managers and Administrators (ARMA) to measure the maturity of its program. A mature program is more effective in mitigating a RIM risk because it is characterized by defined policies and procedures and the implementation of processes specifically intended to improve information governance and recordkeeping. For this reason, PG&E aligned its sub-drivers to the framework of the IGMM by incorporating the ARMA principles.[1] PG&E believes two primary ARMA principles that would lead to a RIM risk event include the following:

D1 – Records Availability: The failure to maintain records and information in a manner that allows the timely, efficient and accurate retrieval of that information to support informed decision making.

D2 – Records Integrity: The inability to maintain records and information managed or generated by the organization in a manner providing a reasonable and suitable guarantee of accuracy and authenticity may result in inaccurate information for critical decision making.

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1 For education and resources on the Generally Accepted Recordkeeping Principles, visit www.arma.org/principles.

These drivers of a RIM event are precursors to the 12 asset and operational safety RAMP risk events shown in Figure 20-1 above. RIM risk is embedded into the likelihood of each of the 12 asset and operational safety RAMP risks. The potential frequency is driven by insufficient or inaccurate data for decision making stemming from the RIM risk. At this time, PG&E does not have Company or industry data on the frequencies of these sub-drivers and has made a number of assumptions to model a reasonable frequency for purposes of this filing. These assumptions are described in the remaining parts of this sub-section.

The first step to define the frequencies was to obtain the relevant drivers of the 12 asset and operational safety RAMP risks where the RIM Risk could be a sub-driver. Table 20-1 below includes all 12 asset and operational safety RAMP risks'—drivers that could be initiated by a RIM risk sub-driver. The second column of this table includes the associated frequency proportioned to each risk. These inputs were derived by meeting with the SMEs for each LOB risk and asking the question "Could inadequate records (maintenance, inspection, etc.) availability or integrity be a root cause to this driver?"

The second step of calculating the frequency was to determine the percentage allocation of the underlying frequencies presented in the second column of Table 20-1 that are attributable to a RIM risk sub-driver. Since PG&E does not have sufficient internal or external data specific to its two RIM risk sub-drivers, additional assumptions needed to be made in the RIM risk model. The ERIM department used data obtained from Gas Operations, CAP, Severe Injuries or Fatalities (SIF) events, and SME judgment to develop additional assumptions.

For simplicity and until further data can be obtained, PG&E determined both of the RIM risk drivers of D1 – Record Availability and D2 – Records Integrity equally contribute to the 12 asset and operational safety RAMP risks in Figure 20-1, therefore both were combined into a single RIM risk model assumption, to determine the minimum and maximum proportion of drivers attributable from RIM Risk. Each RAMP risk used in the risk assessment was evaluated by identifying the number of known incidents involving a RIM risk sub-driver within each LOB, the frequency and impact of the risk, and the type of records involved. This resulted in the creation of three frequency ranges, that for ease of understanding, we will refer to as "high," "medium," and "low." Table 20-1 below provides the resulting frequency ranges assigned to the 12 RAMP risks. The percentages represent the frequency of the individual LOB risk events caused by the RIM risk.

Table 20-1: RIM Frequency Attributes

RAMP Risk	Proportion of RAMP Risk Related to RIM Risk	Proportion of Drivers or Equivalent Attributable to RIM		Average Driver Frequency Attributable to RIM (Bow Tie %)	Post Event Financial Consequences Attributable to RIM	Proportion of EV MARS From Each Asset Risk
		Min	Max			
STO-Natural Gas Storage Well Failure – Loss of Containment With Ignition at Storage Facility	64.79%	2.640%	5.263%	2.6%	2.0%	1.6%
CPFAC-Compression and Processing (C&P) Failure – Release of Gas With Ignition at Manned Processing Facility	62.82%	2.640%	5.263%	2.5%	0.6%	2.1%
MCFAC-Measurement and Control (M&C) Failure – Release of Gas With Ignition at M&C Facility	62.82%	2.640%	5.263%	2.5%	3.0%	1.4%
MCDS-Measurement and Control (M&C) Failure – Release of Gas With Ignition Downstream	100.00%	2.640%	5.263%	4.0%	2.4%	1.8%
DMS-Release of Gas With Ignition on Distribution Facilities – Non-Cross Bore	12.73%	2.640%	5.263%	0.5%	1.5%	1.5%
GAS-Transmission Pipeline Rupture With Ignition	100.00%	2.640%	5.263%	4.0%	32.3%	63.9%
DIST-Distribution Overhead Conductor Primary	0.43%	1.310%	2.630%	0.0%	0.8%	2.7%
TRANS-Transmission Overhead Conductor	1.41%	1.310%	2.630%	0.0%	7.2%	0.9%
INSIDER-Insider Threat	23.74%	0.012%	1.300%	0.2%	0.9%	2.3%
MVS-Motor Vehicle Safety	2.00%	0.012%	1.300%	0.0%	0.8%	1.3%
CONSAFE-Contractor Safety	100.00%	0.012%	1.300%	0.7%	0.0%	4.9%
EMPSAFE-Employee Safety	100.00%	0.012%	1.300%	0.7%	9.6%	13.7%

The “high” range was developed using Gas Operations data. The data indicated that one of 19 over pressurization events were related to inadequate records. This became the basis for the high-end of the frequency range of 5.263 percent (=1/19). The low end of this range was determined by taking the mid-point between 0 percent and the high end, 5.263 percent. Since this range was developed by using data from Gas Operations, it was applied to the Gas LOB risk events.

The “low’” range was calculated by looking at both SIF and CAP data. The higher end of the range was calculated by dividing 50 percent of the reported SIFs events over the past 10 years that mentioned records, by the number of SIF incidents over that same period (1.3% = 7/530) (50 percent was an assumption used to capture the potential that the SIF event may have mentioned records, but records were not the cause of the event). The low end of the range was developed by taking these same SIF events over the number of CAP records (0.012% = 7/58,191) for that same period.

The "medium" range was established by using the range between the "high" range and the "low" range. It was applied to the Electric Operations LOB risks due to these risks being ranked high in RAMP probabilistic modeling.

The product of the underlying frequencies and the RIM frequency attributes in Table 20-1 resulted in the RIM risk frequencies shown in Figure 20-1 above. The frequency ranges are initial assumptions that will be updated as PG&E's ERIM program matures and as we are able to implement a more consistent capture of RIM risk in post-event analysis. This may result in the frequency increasing as additional data from multiple sources is collected and analyzed.

D. Consequences

An event involving unavailable or inaccurate records and/or information is likely to have an impact on the 12 asset and operational safety RAMP risks which in turn have an impact on Safety, Reliability, Trust, Environmental, and Compliance, and Financial consequences. With the exception of the financial consequence, the distributions from the asset and operational safety risks were aggregated to determine the consequences for the RIM risk. For the financial consequence, post event severity consequences were modeled based on internal and external case studies as shown in Figure 20-2.

Figure 20-2: Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source							PG&E Data
Post Event Consequence Multiplier	Aggregation of inputs from associated RAMP risks						Aggregation of inputs from associated RAMP risk and post financial consequences: 01-GAS = 32.3% 03-MCDS = 2.4% 04-MCFAC = 3.0% 06-CPFAC = 0.6% 07-DMS = 1.5% 08-STO = 2.0% 09-DIST = 0.8% 10-TRANS = 7.2% 14-CONSAFE = 0.0% 15-EMPSAFE = 9.6% 16-MVS = 0.8% 19-INSIDER = 0.9%
Outcome-TA-NU[1]	9.55	0.08	$ 25,300	694,510	$ 571,626	0.4%	$ 18,831,850
Outcome-TA-MARS[2]	2.61	2.17	0.00	1.74	0.06	1.94	11.30
						MARS Total	**19.81**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

RIM risk is a sub-driver to other RAMP risks. Therefore, PG&E aggregated inputs from the other RAMP risks using the assumptions as described in sub-Section C above. As a result, a discussion regarding the modeling for the specific consequence outcomes is not applicable, except in the case of financial consequences. An event caused in part by a RIM risk would add financial consequences above and beyond what is included in the 12 asset and operational safety RAMP risks due to records discovery efforts.

- **Safety – Injuries (SI):** The RIM risk model aggregated a baseline tail average of 9.55 injuries per year resulting in a contribution of 2.61 Multi-Attribute Risk Score (MARS) units from this consequence category.
- **Safety – Fatalities (SF):** The RIM risk model aggregated a baseline tail average of 0.08 fatalities per year resulting in a contribution of 2.17 MARS units from this consequence category.
- **Environmental (E):** Environmental consequences are measured in U.S. dollars per year for expected financial impact due to environmental damage. The RIM risk model aggregated a baseline tail average of $25,300 environmental costs per year resulting in a contribution of 0.00 MARS units from this consequence category.
- **Reliability (R):** Reliability consequences are measured in customer outage minutes expected from a risk event. The RIM risk model aggregated a baseline tail average of 694,510 customer outage minutes per year resulting in a contribution of 1.74 MARS units from this consequence category.
- **Compliance (C):** Compliance consequences are measured in U.S. dollars per year for potential amount of regulatory scrutiny and orders that could be expected to result from the risk event. The RIM risk model aggregated a baseline tail average of $571,626 compliance costs per year resulting in a contribution of 0.06 MARS units from this consequence category.
- **Trust (T):** Trust consequence is measured in brand favorability reduction per year. The RIM risk model aggregated a baseline tail average of 0.4 percent brand favorability reduction per year resulting in a contribution of 1.94 MARS units from this consequence category.
- **Financial (F):** Financial consequences are measured in U.S. dollars per year. The RIM risk model aggregated the financial consequences in the same way as all other consequence categories but also includes post severity consequences above and beyond what is included in the 12 asset and operational safety RAMP risks due to records discovery efforts. This resulted in a baseline tail average of $18,831,850 per year, resulting in a contribution of 11.30 MARS units from this consequence category. PG&E

considered the following when developing its financial consequence assumptions:

– Post event severity consequences were modeled based on internal and external case studies. The results are shown in the "Financial" column of Figure 20-2 above. Due to its similarity, the tragic San Bruno accident served as the case study for the Gas Transmission Pipeline risk. There was a significant added expense to identify and produce records after the event, which led to a higher percentage of added financial consequences overall for the event. For the remaining LOB risks, industry benchmark data related to the cost of discovery formed the basis for the case study used to calculate added financial consequences. The percentages for these risks represent the additional financial consequences anticipated for an event involving the records availability and integrity sub-drivers with post-event records and information discovery.

– Penalties and fines were purposely excluded from the financial consequences discussed above. While these can be a consequence of RIM caused events and result in substantial additional costs, they are treated as a shareholder expense and excluded from the model. An example of this was the Carmel explosion, which had records deficiencies and resulted in $35.2 million in related fines. These costs were not included in our modeling of financial consequences for RAMP.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

The goal of the ERIM program is the continued maturing of PG&E's records and information management program. This will be achieved by completing initiatives and projects on ERIM's roadmap that are designed to increase the program's maturity level as measured by the ARMA IGMM principles with the intent of ultimately achieving IGMM Level 3 maturity across all LOBs by 2022. This level is characterized by defined RIM policies and procedures and the implementation of RIM processes specifically intended to meet legal, regulatory and business requirements. At this level, the key basic components of a sound RIM program are in place and are expected to be minimally compliant.

Prior to and during 2016, the ERIM department implemented various controls to mitigate the RIM risk as part of its roadmap. For ease of understanding and to align to the framework of the IGMM, the control activities have been bundled according to the ARMA principles used to measure program maturity and are described below:

C1 – Accountability-Related Controls: These controls involve the oversight of the ERIM program including the management of its policy and standards. These activities include:

- **Integrated Project Planning** – Promote successful adoption and sustainability of ERIM projects/initiatives by supporting change management and using effective PG&E project management strategies. The ERIM department has incorporated PG&E's project management and change management framework into all its projects starting in 2015 to ensure projects are rolled out effectively.
- **RIM Governance** – Management of a governance strategy and controls to govern various information-driven processes throughout the enterprise. This includes the reporting to the Compliance and Ethics Committee (consisting of Officers at Senior Vice President or above level) to ensure program visibility to PG&E's executive leadership. ERIM's director is also a member of the Compliance and Ethics Leadership Team, which allows for coordination between the ERIM Program and the Compliance and Ethics Program. ERIM also uses the LOB Champions (consisting of Vice President and Senior Director representatives) to provide oversight and champion program implementation within the LOBs. This governance is ongoing.

C2 – Transparency-Related Controls: These controls are related to the documentation of business processes and activities. These mitigations include:

- **Financial Reporting –** Management of major work categories and ongoing financial program support and reporting for expenses related to the ERIM program.
- **Companywide Training –** Annually updating the Records and Information Management Training (CORP-9041WBT) required of all employees and non-employees[2] and the development of additional training specific to implementing the ERIM program for LOBs.
- **Gas Monitoring and Continuous Improvement –** Implementation of a records field monitoring plan for the Gas organization to identify and address any observed ERIM program gaps.
- **Regulatory Reporting and Support –** Provide support for regulatory filings. In 2016, provided support for the 2017 General Rate Case (GRC). Successfully filed direct and rebuttal testimony as well as responded to data requests.

C3 – Compliance-Related Controls: These controls involve verification of compliance with applicable laws and other regulations issued by binding authorities, as well as the ERIM program's policy and standards. These activities include:

- **Integrated Planning for ERIM –** Identifying and documenting ERIM's five-year plan and resources for supporting the increase in program maturity; development and management of the ERIM compliance program; developing strategies, and identifying and tracking RIM related legal and regulatory requirements and risks.

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2 The target audience for this training includes contractors with a LAN ID or unescorted badge access to facilities that contain records. On a case-by-case basis, non-employees are excluded from this training requirement based on a narrow criteria and evaluation as to the presence of reduced records risk by enforcing the training.

C4 – Retention-Related Controls: These controls involve maintaining records and non-records for an appropriate time, taking into account legal, regulatory, fiscal, and operational requirements. These controls include:

- **Centralized Physical Records Management (PRM) (Off-Site Storage) –** Centralized off-site storage operations has been established for inactive physical records to promote more consistent management and protection of physical records.

Various mitigations began in 2016 which continue through 2019. For ease of understanding and to align to the framework of the IGMM, these have been bundled according to the ARMA principles used to measure program maturity. These principles set forth the characteristics of an effective and mature RIM program. These are M1A through M6A. We have included these in the table below since there are costs recorded from 2016 related to these mitigations.

M1A – Accountability-Related Mitigations: These mitigations supplement existing controls discussed in C1 above. These activities include:

- **Metric Reporting –** Reporting and monitoring program metrics that align with the IGMM principles to demonstrate our progress toward program maturity. In 2016, established ERIM program metrics and Business Plan Review reporting for ERIM. The metrics reporting is an ongoing control.

M2 – Transparency-Related Mitigations: These mitigations supplement existing controls discussed in C2 above. These activities include:

- **ERIM Policy and Standards** – Published the ERIM Policy and eight Standards. Through the ERIM policy and standards, build awareness of requirements, roles and responsibilities for governing the identification, control, management, retrieval, retention, and disposition of records and non-records at PG&E. The annual review and update of these is an ongoing control.

M3A – 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. These activities include:

- **Compliance Plan –** Development of the strategy and action items supporting the implementation of the ERIM program's Policy and Standards within the LOBs.
- **Auditing Plan –** Established an annual audit plan within the ERIM program and conducted by ERIM employees to evidence compliance with the Enterprise Records Retention Schedule (ERRS), ERIM Policy and Standards. This includes establishing a response, reporting and mitigation plan for RIM-related NOVs as well as partnering

with the Compliance and Ethics Liaisons[3] to document monitoring and tracking. The auditing plan was implemented in 2016 and is an ongoing control.

- **Achieve IGMM Level 3 Maturity in Gas Operations –** This control involves ongoing work to achieve and demonstrate IGMM Level 3 by April 2018 for Gas Operations and the implementation of remedies as scheduled in order to comply with the Gas Transmission Recordkeeping OII. In 2016, this includes: the completion of 38 field office readiness assessments; rolling out the Gas Monitoring program (previously described in C2) and completing 11 visits; and updating the ERRS for compliance with CPUC's General Order 112 F.

- **Gas: Map Business Processes:** Developed records process maps for Gas Operations to ensure that the required level of authenticity and chain of custody can be applied to its records and information and to demonstrate compliance with the information governance policy. In 2016, completed the following:

  – Developed records recommendations for Gas Qualifications Department for the mapped processes:

    a) Operator Qualifications for employees and contractors

    b) Welding Qualifications

    c) Plastic Qualifications for employees and contractors

  The maintenance and updating of records process maps is an ongoing control.

- **Storage of Nitrates Negatives:** Safely manage nitrate negatives to ensure long-term access to valuable PG&E records and historical assets. In 2016, a storage solution was developed.

M4A – Retention-Related Mitigations: These mitigations supplement existing controls discussed in C4 above. These activities include:

- **Enterprise Record Retention Schedule –** Development and publication of an enterprise-wide retention schedule. The schedule aligned with legal and regulatory obligations promoting the retention of records for the appropriate amount of time. The regular review and update of this schedule is an ongoing control.

- **Corporate Archives –** Maintain centralized enterprise-wide archives for PG&E to aid in identifying and retaining records with historical value. The archives were established in 2016 and their maintenance is now an ongoing control.

M5A – Protection-Related Mitigations: These mitigations involve providing an appropriate level of security controls for records and non-records that are internally classified for security purposes as Public, Internal, Confidential, and Restricted. The ERIM department also has developed mitigations specific to records classified as Vital, as these records are essential to business continuity. These activities include:

[3] The Compliance and Ethics Liaisons are a manager-level body that champion and support compliance and ethics efforts throughout PG&E’s LOB. Please refer to the Compliance and Ethics Liaisons Charter, Corporation Standard: GOV-1010S.

- **Migrate Fossil and Renewable Drawings to Documentum –** This mitigation involved the migration of Fossil and Renewable engineering drawings from shared drives to Documentum to improve the ability to retrieve records and protect them. As Documentum is a Tier One system, this migration also ensured that vital records would be available in the event of an emergency or interruption of service.
- **Vital Records, Business Continuity and Disaster Recovery –** This mitigation included documentation of an Enterprise-wide Records Inventory capturing details for over 12,000 records categories containing over 1,000 vital records and certified by 350 internal leaders. Maintenance of this records inventory is an ongoing control.
- **Physical Records Cleanup –** The identification, indexing and relocation of inactive physical records to Iron Mountain to ensure a consistent and secure environment for ongoing storage for the remainder of the record's retention period. This effort includes restoring damaged records to ensure the records remain available and protected. In 2016, this work involved remediation at four pilot sites.
- **Enterprise Shred Services –** The implementation of an all shred strategy and deployment across PG&E using industry best practices to provide confidential document destruction services on a regularly scheduled time and as-needed basis, thereby allowing for a reasonable level of protection for the destruction of records and information classified as Confidential or Restricted. In 2016, finalized and executed the shred supplier contract and the operational transition plan.
- **Engineering Records Unit (ERU) Decentralization and the Migration of the Engineering Library System (ELS) –** The decentralization of the ERU was achieved by migrating and cleaning legacy data from the ELS to Documentum including relocating paper records to a safer, more compliant centralized location to improve the ongoing protection of those records.

M6A – Availability Related Mitigations: These mitigations involve maintaining records and information in a manner that allows for timely, efficient, and accurate retrieval of records. These activities include:

- **Records Inventory and Certification –** Developed the Enterprise Records Inventory to identify and document record categories for all LOBs including identifying attributes of the records categories such as vital records, security classifications, storage locations, record owners, and security and retention requirements. The regular maintenance of this records inventory is an ongoing control.
- **Scanning Operations –** A cost effective enterprise program for scanning that aligns the minimum required image quality of documents with ERIM standards. The scanning strategy was being developed in 2016.
- **Legacy Indexing –** Indexing legacy records formerly managed by the PG&E Corporate Record Center and other off-site storage sites to better identify the contents of boxes and improve our ability to identify records for retrieval from offsite storage.

- **Physical Records Manager (PRM) Tool Simplification –** Improvement of the functionality and user experience of the PRM tool which is used to manage sending and retrieving off-site records as well as retention and legal hold. This tool allows anyone at PG&E to identify and retrieve physical records stored at the off-site storage vendor Iron Mountain.

Three mitigations, M4A – M6A, began in 2016 which are continuing work through the 2020 GRC period. We have included these in Table 20-2 below since there are costs recorded from 2016 related to these mitigations.

M7A – Implement Records and Information Management 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. In 2016, some of the specific activities associated with this mitigation were:

- Piloted the Kazeon tool to crawl through and evaluate metadata associated with unstructured content stored in a pilot group of departments resulting in the identification of 70 percent duplication.
- Establishing File Plan and Taxonomy model – Developed the enterprise taxonomy with five LOBs. It includes 15 content types and 45 attributes.
- SAP Migration – This initiative migrated records currently stored in WebDocs, Email, SAP OpenText and DMS, SharePoint, Share Drives, and various drawing management tools. In 2016, the SAP code review and associated testing was completed. The code was readied for deployment.

M8A – EDMS Migration: Migrated the Enterprise Data Management System (EDMS) and FileNet systems (legacy systems which are scheduled to sunset) into Documentum to improve efficient and accurate retrieval of needed information. Completed the following activities in 2016:

- Web user interface functional testing was completed.
- Code deployed to quality assurance and user acceptance testing started.
- Performance team conducted shake out testing and peak load testing.
- Migrated 9.7 million at-risk records from EDMS containing fossil and renewable drawings, hydro water rights, power gen drawings, etc.

M9A – Electronic Records Cleanup: Using Kazeon to perform data analytics to identify duplicates and obsolete content for future disposition, and applying retention to records contained in unstructured environments. In 2016, hosted informational meetings to explain the phases of the project and obtained approval to crawl files with the Finance and Risk, Human Resources, Power Generation, and Customer Care LOBs. In addition, some initial crawls were performed with the Power Generation LOB.

Table 20-2 summarizes 2016 recorded costs associated with each control.

Table 20-2: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source[4]	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Accountability Related Controls	All Drivers	GRC	274	–
C2	Transparency Related Controls	All Drivers	GRC	583	–
C3	Compliance Related Controls	All Drivers	GRC	187	–
C4	Retention Related Controls	All Drivers, F	GRC	931	–
M1A	Accountability Related Mitigations	All Drivers	GRC	593	190
M2	Transparency Related Mitigations	All Drivers	GRC	62	–
M3A	Compliance Related Mitigations	All Drivers	GRC	1,214	–
M4A	Retention Related Mitigations	All Drivers, F	GRC	254	–
M5A	Protection Related Mitigations	All Drivers, F	GRC	8,459	21
M6A	Availability Related Mitigations	D1, F	GRC	5,558	–
M7A	Implement Records and Information Management Governance for Content in Unstructured Data Repositories	All Drivers, F	GRC	3,985	1,741
M8A	EDMS Migration	All Drivers, F	GRC	2,039	2,635
M9A	Electronic Records Cleanup	All Drivers, F	GRC	1,006	–
TOTAL Expense and Capital				**25,145**	**4,587**

IV. Current Mitigation Plan (2017-2019)

In addition to the controls and mitigations listed above, the risk assessment identified further needs to reduce the risk to a tolerable level. Those additional work activities are the mitigations documented in this section for the years 2017-2019. PG&E identified these mitigations below by using the ERIM program roadmap to achieve IGMM Level 3 maturity. The focus of these mitigations will be to continue to strengthen and enhance the strides that we made in 2016 and previous years in the areas of records accountability, transparency, compliance, retention, protection, disposition, integrity, and availability. As in Section III above, these mitigations were bundled according to the ARMA principles for measuring information governance program maturity.

M1B – Accountability-Related Mitigations: These mitigations supplement or are enhancements to existing controls discussed in C1 of Section III above. These activities include:

- **Metric Reporting –** Reporting and monitoring program metrics that align with the IGMM principles to demonstrate progress toward program maturity, including the

4 Certain mitigations and controls specific to Gas Operations involved costs that were funded by PG&E's shareholders.

development of an online dashboard for immediate access to program status. This is an enhancement to metric reporting work that was established in 2016 and is discussed in M1A of Section III above. The online dashboard was made available in 2017 and further improvements are anticipated for 2018.

M3B – Compliance-Related Mitigations: These mitigations supplement or are enhancements to existing controls discussed in C3 of Section III above. These activities include:

- **Compliance Plan:** This is continuation of the work that was begun in 2016 and is further discussed in M3A of Section III above. It is anticipated that the compliance plan will be finalized and implemented in 2017. The ongoing monitoring will be a control.
- **Achieve IGMM Level 3 Maturity in Gas Operations:** This is continuation of work that began in 2016 and earlier and is further discussed in M3A of Section III above. It is anticipated that this work will be operationalized and become a control by 2018.
- **Storage of Nitrates Negatives:** This is continuation of work that began in 2016 and is discussed in M3A of Section III above. It is anticipated that the building and construction of a permitted and environmentally safe storage facility will be completed in 2018 and the continuing management of the storage for nitrate negatives will be an ongoing control.

M4B – Retention Related Mitigations: These mitigations supplement or are enhancements to existing controls discussed in C4 of Section III above. These controls include:

- **Enterprise Record Retention Schedule Annual Update –** Annual review and update of retention requirements based on all aspects of ERRS. The update will align the ERRS with any changes or updates to the legal and regulatory obligations addressing the retention of records. It will also be updated to capture any changes to records categories reflected in the most recent version of the Enterprise Records Inventory or in retention periods dictated by business need. This is the operationalization of the ERRS development work that was performed in 2016 and is discussed in M4A of Section III above. This ERRS will be evaluated on an annual basis and the scope of work determined. We anticipate that as the schedule matures, there will be less frequent updates needed.

M5B – Protection-Related Mitigations: These mitigations supplement or are enhancements to existing mitigations discussed in M5A of Section III above. These mitigations include:

- **Migrate Fossil and Renewable Drawings to Documentum –** This is continuation of work that began in 2016 and is discussed in M5A of Section III above. It is anticipated to be completed by 2018.

- **Legacy Documentum Records Reconciliation With Taxonomy –** Index existing legacy electronic records and map their location to the new taxonomy to improve the retrieval of records. This work is scheduled to begin in 2019.
- **System Retirements –** Incorporate ERIM program requirements for retention and disposition into the Information Technology (IT) system retirement process to prevent the loss of records and content subject to Legal Hold that are stored in systems that are being retired. This development work is anticipated to begin in 2018 and implementation and operationalization occurring in 2019.
- **Vital Records, Business Continuity and Disaster Recovery –** Manage records classified as vital records by testing the method of retrieval of vital records to ensure that they remain available in the event of an emergency or interruption of service. Availability testing will also ensure that these vital records are stored in a Tier 1 or Tier 2 system, which is prioritized for restoration. This is the operationalization of the vital records identification work that was performed in 2016 and discussed in M5A of Section III above. This work will be ongoing on an annual basis.
- **Physical Records Cleanup –** This continues work that was begun in 2016 and discussed in M5A of Section III above. In 2017, this work involves 150 sites. Another 150 sites are projected to be completed in 2018.
- **Enterprise Shred Services –** This continues work that was begun in 2016 and discussed in M5A in Section III above. The enterprise wide deployment is expected to be completed in 2017. The annual management of the shred services becomes an ongoing control from this point forward.
- **Gas: Support Safety and Enforcement Division (SED) Records Audits –** In order to support SED records audits, identify, develop and execute remediation plan for migration of records stored in other electronic 'off-line' data storage devices such as floppy/hard disks, CDs/DVDs, USB drives, and external hard drives. This work is scheduled to begin in 2018.
- **Engineering Records Unit Decentralization and the Migration of the Engineering Library System –** This includes the continuation of the work that was begun in 2016 and is discussed in M5A of Section III above. It is anticipated to be completed in 2017.

M6B – Availability-Related Mitigations: These mitigations supplement or are enhancements to existing mitigations discussed in M6A of Section III above. These mitigations include:

- **Mobile Content Delivery –** Evaluate, select and deploy mobile content management tools and allow external access for PG&E users. Pilot in 2018 for small user group, license and implementation.
- **Records Information Rights Management (Documentum) –** Enable document rights management in Documentum, to improve the ability to retrieve electronic records. This applies to records in Documentum only, involving infrastructure work

to configure the server, and install, and configure the software product. This work is scheduled to begin in 2018 and be completed by 2019.

- **Scanning Operations –** This is a continuation of work that was begun in 2016 and is discussed in M6A of Section III above. The implementation of the strategy will be completed in 2017 with ongoing scanning operations becoming a control.
- **Gas: Support Certifications (PAS 55/ISO 55001, RC 14001) –** Validate Gas records stored in offsite repositories in support of maintaining existing certifications. This work is scheduled to begin in 2018 and become an ongoing control.

M10 – 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. This included:

- **Disposition Strategy and Implementation –** Formulate a strategy for applying disposition to records and non-records that have met retention and are no longer subject to the San Bruno legal hold or other applicable legal hold. Once the San Bruno legal hold is lifted, implement the strategy and begin awareness and change management campaign. This mitigation began in 2017 and is expected to be ongoing over several years.

M11 – Integrity Related Mitigations: These mitigations improve the integrity of records and information to support authenticity and reliability. These mitigations include:

- **Electronic Signature Generic Integration –** Create an enterprise integration service from PG&E to an electronic signature (e-sign) vendor to route the documents to external customers for signatures. This control will apply the required level of authenticity and chain of custody to these documents. This work is scheduled to begin and be completed in 2018.
- **Legacy Indexing –** This is continuation of work that began in 2016 and is discussed in M6A of Section III above. It is anticipated that this work will be operationalized and become a control by 2019.
- **Physical Records Management Tool Simplification –** This is continuation of the work that was begun in 2016 and is discussed in M6A of Section III above. It is anticipated to be completed in 2019

In addition to the mitigations we have completing before 2020, we have six mitigations, M7B – M14A, that run into the 2020 GRC period, and are explained below.

M7B – Implement Records and Information Management Governance for Content in Unstructured Data Repositories: This is continuation of work from 2016 that was discussed in M7A of Section III above. In the years 2017-2019, the following is planned to be performed:

- Execution of usability testing of records management classification and organization schema prior to configuration;
- Creation of maintenance and governance procedures for the schema rules;

- Enterprise adoption of records management tools such as Documentum, SharePoint, and Outlook;
- Standardization of file plans to support effective search and e-Discovery compliance;
- Application of the record retention categories to Documentum; and
- Continuation of the e-Strategy governance work around eliminating storage of records in shared drives, personal storage table (pst) files, etc.

M8B – EDMS Migration: This mitigation is a continuation of the work that began in prior years and is discussed in M8A of Section III above. During the years 2017-2019, the work associated with this mitigation involves completing the full migration of content from EDMS and indexing records within Documentum. This will lead to migrating/re-indexing records identified through analysis that originated from EDMS to the new instance of Documentum configured with the Enterprise Taxonomy.

M9B – Electronic Records Cleanup: This mitigation is continuation of work that was begun in 2016 as discussed in M9A of Section III above involving the assessment of unstructured content repositories within LOBs (e.g., SharePoint, file shares, email). In the years, 2017-2019, work will continue with all LOBs to complete analysis and disposition, and will begin to analyze the remaining LOBs. It will lead to the identification of records within those unstructured repositories and manage them consistent with ERIM policy and standards. This includes utilizing Kazeon and other analytic tools for analysis, categorization and migration of unstructured content to an approved records repository.

M12A – Preservation Strategy and Implementation: This mitigation operationalizes PG&E's governance for eDiscovery requests. It involves the creation of a governance model and center of excellence with representation from affected departments, such as ERIM, Legal, Cyber Security, IT, etc. The governance committees will promote alignment and efficient management for the ongoing support of regulatory and litigation response. In addition, the governance committees will provide input on current technology tools, future investment to support legal hold, defensible disposition strategy and eDiscovery needs. This mitigation supports records retention. Preliminary work on this effort begins in 2017.

M13A – Implement Records and Information Management 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 (CC&B), etc., to dispose of records and information that are no longer needed. This mitigation begins in 2018, and for the years 2018 and 2019 will focus on developing the strategy for establishing the records lifecycle management capabilities for the following enterprise systems:

- SAP
- CC&B
- Mobile Apps
- Bentley ProjectWise
- GIS (top 20)

M14A – Map Work Processes That Generate Records: This mitigation maps records to work processes to identify when a record is generated and document in the work process the identification of the final version of the record and its ultimate storage to reduce potential ambiguity for record retrieval. This mitigation is a PG&E business requirement (GOV-7101S). Not performing this mitigation is not an option.

- In the 2017-2019 timeframe, this effort involves:
  - Mapping records categories in the Enterprise Records Inventory to legal and regulatory requirements; and
  - Determining existing LOB Quality Assurance (QA)/Quality Control (QC) processes for compliance with legal and regulatory requirements as well as identifying related controls and testing those controls.

Table 20-3 summarizes the mitigation estimated costs for the years 2017-2019.

Table 20-3: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver and Consequence	2017 Estimate ($000)[5]	2018 Estimate ($000)[5]	2019 Estimate ($000)
M1B	Accountability Related Mitigations	2017	2019	All Drivers	– (C) 24 (E)	1,600 (C) 505 (E)	– (C) 129 (E)
M3B	Compliance Related Mitigations	2016	2019	All Drivers	200 (C) 985 (E)	– (C) 2,013 (E)	– (C) 1,149 (E)
M4B	Retention Related Mitigations	2017	2019	All Drivers, F	– (C) 235 (E)	– (C) 869 (E)	– (C) 129 (E)
M5B	Protection Related Mitigations	2016	2019	All Drivers, F	– (C) 8,928 (E)	700 (C) 8,741 (E)	1,200 (C) 8,828 (E)
M6B	Availability Related Mitigations	2016	2019	D1, F	1,291 (C) 6,343 (E)	1,700 (C) 5,287 (E)	1,250 (C) 3,091 (E)
M10	Disposition Related Mitigations	2017	2019	All Drivers, F	– (C) 2,943 (E)	– (C) 2,460 (E)	– (C) 856 (E)
M11	Integrity Related Mitigations	2017	2019	D2	– (C) – (E)	– (C) 300 (E)	– (C) – (E)
M7B	Implement Records and Information Management Governance for Content in Unstructured Data Repositories	2016	2022	All Drivers, F	3,315 (C) 1,570 (E)	2,850 (C) 6,357 (E)	4,050 (C) 5,264 (E)
M8B	EDMS Migration	2016	2020	All Drivers, F	416 (C) 624 (E)	– (C) 2,789 (E)	– (C) 751 (E)
M9B	Electronic Records Cleanup	2016	2022	All Drivers, F	– (C) 2,047 (E)	– (C) 1,569 (E)	– (C) 1,745 (E)
M12A	Preservation Strategy and Implementation	2017	2021	All Drivers, F	– (C) 71 (E)	1,950 (C) 880 (E)	1,950 (C) 688 (E)
M13A	Implement Records and Information Management Governance for Content in Structured Data Repositories	2018	2022	All Drivers, F	– (C) – (E)	– (C) 26 (E)	– (C) 27 (E)
M14A	Map Work Processes That Generate Records	2017	2022	D2	– (C) 247 (E)	– (C) 400 (E)	– (C) 569 (E)
TOTAL Expense and Capital by Year					**5,222 (C) 24,017 (E)**	**8,800 (C) 32,196 (E)**	**8,450 (C) 23,226 (E)**

V. Proposed Mitigation Plan (2020-2022)

As mentioned in previous sections, the goal of the ERIM program is the continued maturing of PG&E's records and information management program with the intent of ultimately achieving IGMM Level 3 maturity across all LOBs by 2022. This will be achieved by completing initiatives and projects on ERIM's roadmap. In this roadmap, there are the following mitigations for the 2020-2022 timeframe:

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5 Certain mitigations and controls specific to Gas Operations involved costs that were funded by PG&E's shareholders.

- Implement Records and Information Management Governance for Content in Unstructured Data Repositories
- EDMS Migration
- Electronic Records Cleanup
- Preservation Strategy and Implementation
- Implement Records and Information Management Governance for Content in Structured Data Repositories
- Map Work Processes That Generate Records
- Enterprise Search

These mitigations formed the basis of the proposed plan as well as the alternatives considered in Section VI. The following are the reasons this proposed plan was selected:

- The RSE score is the highest of all the plans considered over the same time period. (Proposed Plan = 0.1134; Alternative 1 = 0.1059; Alternative 2 = 0.0901.)
- Similarly, the risk reduction achieved by this plan is the highest of all the plans considered by the completion of the 2020 GRC period. (Proposed plan approx. 40 percent; Alternative 1 approx. 30 percent; Alternative 2 approx. 20 percent.)
- This plan will allow the company to achieve IGMM Level 3 maturity in the most expeditious manner to quickly lower the RIM risk. (Proposed plan by 2022; Alternative 1 by 2024; Alternative 2 by 2032.)

The proposed plan will lower the RIM risk by approximately 40 percent with a tail average MARS reduction of 0.1134 units per million dollars spent.

The proposed recommendation involves the following mitigations which are part of ERIM's roadmap and many of which are the completion of efforts that originated in the prior years:

M7C – Implement Records and Information Management Governance for Content in Unstructured Data Repositories: This mitigation continues the work that was begun in 2016 and discussed in M7A of Section III and M7B of Section IV above. In the years 2020-2022, it will involve:

- Migrate content and records from file shares to SharePoint and/or Documentum;
- Evaluate and Select email integration capability with Documentum for ERIM; and
- Add storage to address digitalization of paper records and organic growth.

M8C – EDMS Migration: This mitigation completes the migration of the EDMS and FileNet systems (legacy systems which are scheduled to sunset) into Documentum and was discussed in M8A of Section III and M8B of Section IV above. This effort is scheduled to be completed in 2020 with no additional work anticipated in future years.

M9C – Electronic Records Cleanup: This mitigation continues the work that was begun in 2016 and discussed in M9A of Section III and M9B of Section IV above. In the years 2020-2022, this mitigation completes the assessment of content repositories within all LOBs and high-risk records are identified and secured.

M12B – Preservation Strategy and Implementation: This mitigation continues work that was begun in 2018 and is discussed in M12A of Section IV above. In the years 2020-2022, this mitigation implements tools for the automation of records and information retrieval to improve timeliness, efficiency, and cost for eDiscovery requests. It is anticipated that the majority of this work will be completed in 2020 with some remaining work being finalized in 2021.

M13B – Implement Records and Information Management Governance for Content in Structured Data Repositories: This mitigation continues work that was begun in 2018 and is discussed in M13A of Section IV above. In years 2020-2022, this mitigation will establish the records lifecycle management capabilities (including in-place retention management, in-place disposition management, and disposition workflow for non-Documentum records) for the following enterprise system:

- SAP
- CC&B
- Mobile Apps
- Bentley ProjectWise
- GIS (top 20)

M14B – Map Work Processes that Generate Records: This mitigation continues work that was begun in 2017 and is discussed in M14A of Section IV above. It is a PG&E business requirement (GOV-7101S) and not performing this mitigation is not an option. In the years 2020-2022, completes and operationalizes the work that begun in the previous years including:

- Completing the mapping of compliance records to the records inventory;
- Finalizing the identification of existing LOB QA/QC processes for regulations as well as if controls and testing are in place and aiding in the development of these where there are gaps; and
- Continuing to track, analyze, report, and remediate findings.

M15 – Enterprise Search: This mitigation implements a web-based tool to search across multiple unstructured data repositories to increase the timely, efficient, and accurate identification and retrieval of records and information. This involves the evaluation, selection and implementation of the tool. Work on this mitigation is not anticipated to begin until 2020.

Table 20-4 summarizes the mitigations' associated drivers, RSE, and associated estimated costs for each year.

Table 20-4: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M7C	Implement Records and Information Management Governance for Content in Unstructured Data Repositories	0.0677	0.0408	2016	2022	All Drivers, F	2,708 - 2,993 (C) 2,257 - 2,495 (E)	475 - 525 (C) 1,813 - 2,004 (E)	475 - 525 (C) 3,182 - 3,517 (E)
M8C	EDMS Migration	0.1313	0.0761	2016	2020	All Drivers, F	– (C) 589 - 651 (E)	– (C) – (E)	– (C) – (E)
M9C	Electronic Records Cleanup	0.1508	0.0959	2016	2022	All Drivers, F	– (C) 1,608 - 1,777 (E)	– (C) 2,648 - 2,927 (E)	– (C) 2,666 - 2,947 (E)
M12B	Preservation Strategy and Implementation	0.0775	0.0458	2017	2021	All Drivers, F	2,993 - 3,308 (C) 710 - 785 (E)	– (C) 109 - 121 (E)	– (C) – (E)
M13B	Implement Records and Information Management Governance for Content in Structured Data Repositories	0.0707	0.0403	2018	2022	All Drivers, F	2,280 - 2,520 (C) 633 - 700 (E)	1,140 - 1,260 (C) 583 - 644 (E)	1,425 - 1,575 (C) 1,677 - 1,854 (E)
M14B	Map Work Processes that Generate Records	0.8194	0.4007	2017	2022	D2	– (C) 516 - 570 (E)	– (C) 232 - 257 (E)	– (C) 212 – 234 (E)
M15	Enterprise Search	0.2531	0.1210	2020	2022	D1, F	– (C) 53 - 58 (E)	190 - 210 (C) 285 - 315 (E)	190 - 210 (C) 285 - 315 (E)
PROPOSED PLAN TA RSE: 0.1134 TOTAL Expense and Capital by Year							**7,981 - 8,821 (C) 6,366 - 7,036 (E)**	**1,805 - 1,995 (C) 5,670 - 6,268 (E)**	**2,090 - 2,310 (C) 8,022 - 8,867 (E)**

VI. Alternatives Analysis

After assessing all of the mitigations, the ERIM Department considered two alternative plans to the proposed mitigation plan.

Alternative plan 1 was created based on the need to lower annual costs in conjunction with a higher risk tolerance during the 2020 GRC period. This plan was considered under the assumption the Company could tolerate a higher level of risk for the RIM risk assuming the benefits of the lower annual costs would offset and support risk reduction efforts in other areas.

Alternative plan 2 was created based on similar premises by assuming the company could tolerate a higher RIM risk level than in both the recommended plan and alternative plan 1, with the understanding that the resulting cost savings would be greater and could be directed to other efforts. This plan involved using less automation and leveraging manual processes.

Both plans are shown below in Table 20-5, Table 20-6, and Table 20-7. Table 20 -5 below summarizes the mitigation and RSE for the proposed plan, alternative plan 1, and alternative plan 2.

Table 20-5: Mitigation List

#	Mitigation	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M7C	Implement Records and Information Management Governance for Content in Unstructured Data Repositories	0.0677	0.0408	X			WP 20-2
M8C	EDMS Migration	0.1313	0.0761	X			WP 20-8
M9C	Electronic Records Cleanup	0.1508	0.0959	X			WP 20-13
M12B	Preservation Strategy and Implementation	0.0775	0.0458	X			WP 20-18
M13B	Implement Records and Information Management Governance for Content in Structured Data Repositories	0.0707	0.0403	X			WP 20-23
M14B	Map Work Processes that Generate Records	0.8194	0.4007	X	X	X	WP 20-29
M15	Enterprise Search	0.2531	0.1210	X			WP 20-34
M16	Implement Records and Information Management Governance for Content in Unstructured Data Repositories - Alternative 1	0.0590	0.0355		X		WP 20-2
M17	EDMS Migration - Alternative 1	0.1276	0.0725		X		WP 20-8
M18	Electronic Records Cleanup - Alternative 1	0.1247	0.0793		X		WP 20-13
M19	Preservation Strategy and Implementation - Alternative 1	0.0751	0.0439		X		WP 20-18
M20	Implement Records and Information Management Governance for Content in Structured Data Repositories - Alternative 1	0.0643	0.0367		X		WP 20-23
M21	Enterprise Search - Alternative 1	0.1849	0.0884		X		WP 20-34
M22	Implement Records and Information Management Governance for Content in Unstructured Data Repositories - Alternative 2	0.0348	0.0209			X	WP 20-2
M23	EDMS Migration - Alternative 2	0.0576	0.0331			X	WP 20-8
M24	Electronic Records Cleanup - Alternative 2	0.0933	0.0588			X	WP 20-13
M25	Implement Records and Information Management Governance for Content in Structured Data Repositories - Alternative 2	0.0267	0.0152			X	WP 20-23
M26	Enterprise Search - Alternative 2	0.0759	0.0363			X	WP 20-34

The same mitigations as in the proposed plan formed the basis for those considered in the alternative plans. These were:

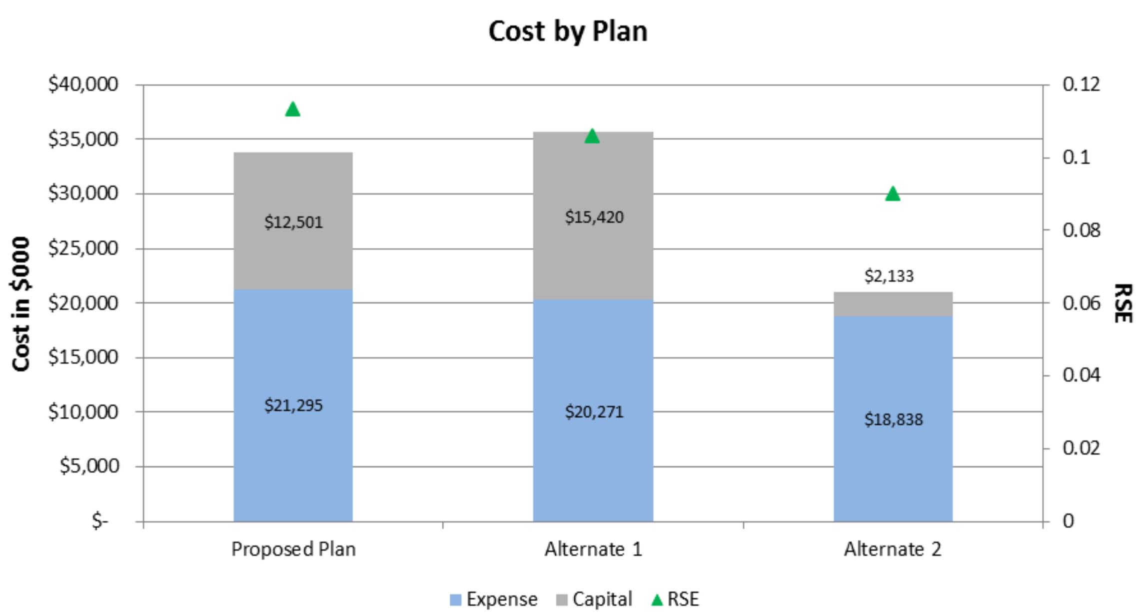
- Implement Records and Information Management Governance for Content in Unstructured Data Repositories
- EDMS Migration

- Electronic Records Cleanup
- Preservation Strategy and Implementation
- Implement Records and Information Management Governance for Content in Structured Data Repositories
- Map Work Processes that Generate Records
- Enterprise Search

The differences between the above listed mitigations in alternative plan 1 versus the proposed plan are discussed in more detail Subsection A below. Similarly, the differences between the above listed mitigations in alternative plan 2 versus the proposed plan are discussed in more detail in Subsection B below.

Figure 20-3 below is a graphical representation of the proposed plan, alternative plan 1, and alternative plan 2 based on cost and RSE.

Figure 20-3: Alternatives by Cost and RSE Score



A. Alternative Plan 1

This alternative mitigation bundle proposed for the RIM risk involves the same mitigations as in those identified for the proposed mitigation plan in Section V above but extends that work over a longer period of time (2022-2024) based on a need to lower annual costs in conjunction with a higher risk tolerance during the 2020 GRC period. As a result, this alternative plan extends each of the mitigations by one to two years with the exception of Mitigation 14B – Map Work Processes that Generate Records. This mitigation is required to be completed as originally proposed due to a compliance commitment.

The following are identified changes by mitigation:

- **M16:** Implement Records and Information Management Governance into Unstructured Data Repositories – Alternative 1
  - Extends M7C in Section V above to 2024
- **M17:** EDMS Migration – Alternative 1
  - Extends M8C in Section V above to 2022.
- **M18:** Electronic Records Cleanup – Alternative 1
  - Extends M9C in Section V above to 2024.
- **M19:** Preservation Strategy and Implementation – Alternative 1
  - Extends M12B in Section V above to 2022.
- **M20:** Implement Records and Information Management Governance into Structured Data Repositories – Alternative 1
  - Extends M13B in Section V above to 2024.
- **M14B:** Map Work Processes that Generate Records
  - No change: Required to be completed as originally proposed due to a compliance commitment
- **M21:** Enterprise Search – Alternative 1
  - Extends M15 in Section V above to 2024.

The following are the benefits and risks of this alternative mitigation bundle:

- **Benefits**
  - Addresses the same drivers.
  - Involves completing the same scope of work over an extended period of time.
  - Reduced annual resource costs.

- **Risks**
  - The risk reduction is accomplished over a longer period of time. This would mean the organization and the Company would tolerate a greater risk for an extended period of time.
  - Delayed achievement of IGMM Level 3 program maturity across PG&E until 2024.
  - Extending the mitigations over an extended period of time will result in higher costs due to inflation.

Due to the higher costs of this plan versus the proposed plan during the 2020 GRC period and additional costs anticipated for the years 2023 and 2024, this alternative mitigation bundle was not chosen. Despite the reduced annual costs per mitigation, the overall costs of the mitigation bundle during the 2020 GRC period was greater than the proposed plan with additional costs anticipated in outer years. Additionally, achievement of IGMM Level 3 program maturity across PG&E is delayed until at least 2024.

Table 20-6 summarizes the mitigations; associated drivers, RSE, and associated estimated costs for each year covered by the 2020 GRC for alternative plan 1.

Table 20-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (units/ $M)	EV RSE (units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M16	Implement Records and Information Management Governance for Content in Unstructured Data Repositories - Alternative 1	0.0590	0.0355	2016	2024	All Drivers, F	2,879 - 3,182 (C) 3,090 - 3,415 (E)	2,261 - 2,499 (C) 2,223 - 2,457 (E)	1,264 - 1,397 (C) 3,012 - 3,329 (E)
M17	EDMS Migration - Alternative 1	0.1276	0.0725	2016	2022	All Drivers, F	– (C) 976 - 1,078 (E)	– (C) 602 - 665 (E)	– (C) 472 - 522 (E)
M18	Electronic Records Cleanup - Alternative 1	0.1247	0.0793	2017	2024	All Drivers, F	– (C) 1,206 - 1,333 (E)	– (C) 1,604 - 1,773 (E)	– (C) 1,605 - 1,774 (E)
M19	Preservation Strategy and Implementation - Alternative 1	0.0751	0.0439	2017	2022	All Drivers, F	1,492 - 1,649 (C) 494 - 546 (E)	1,492 - 1,649 (C) 502 - 555 (E)	1,492 - 1,649 (C) 511 - 565 (E)
M20	Implement Records and Information Management Governance for Content in Structured Data Repositories - Alternative 1	0.0643	0.0367	2018	2024	All Drivers, F	760 - 840 (C) 226 - 250 (E)	1,140 - 1,260 (C) 401 - 444 (E)	1,615 - 1,785 (C) 941 - 1,040 (E)
M14B	Map Work Processes that Generate Records	0.8194	0.4007	2017	2022	D2	– (C) 516 - 570 (E)	– (C) 232 - 257 (E)	– (C) 212 - 234 (E)
M21	Enterprise Search - Alternative 1	0.1849	0.0884	2020	2024	D1, F	– (C) 26 - 29 (E)	127 - 140 (C) 216 - 239 (E)	127 - 140 (C) 190 - 210 (E)
ALTERNATIVE PLAN 1 TA RSE: 0.1059 TOTAL Expense and Capital by Year							**5,131- 5,671 (C) 6,534- 7,221 (E)**	**5,020 - 5,548 (C) 5,780 - 6,390 (E)**	**4,498 - 4,971 (C) 6,943 - 7,674 (E)**

B. Alternative Plan 2

The second alternative mitigation bundle involves the same mitigations as in Section V above, but with less automation and in lieu of manual processes. Each of the mitigations has been modified to reduce or eliminate the amount of automation with the exception of Mitigation 14B – Map Work Processes that Generate Records, which is required to be completed as originally proposed due to a compliance commitment.

The following are identified changes by mitigation:

- **M22:** Implement Records and Information Management Governance into Unstructured Data Repositories
  - Do not integrate with Documentum

- Exclude streaming video
- Manage records within existing e-mail tool
- Remove customization
- Manually manage records in Documentum

- **M23:** EDMS Migration
  - Do not automate business processes to address documents not yet migrated or are in the process of migration.
- **M24:** Electronic Records Cleanup
  - Rely on LOBs to perform cleanup manually without support from Kazeon analytics.
- Preservation Strategy and Implementation
  - Do not implement.
- **M25:** Implement Records and Information Management Governance into Structured Data Repositories
  - Implement simplified retention rules
- **M14B:** Map Work Processes that Generate Records
  - No change: Required to be completed as originally proposed due to a compliance commitment.
- **M26:** Enterprise Search
  - Enable search capabilities in existing unstructured data systems but do not implement an overall enterprise search tool.

The following are the benefits and risks of this alternative plan 2 mitigation bundle:

- **Benefits**
  - Reduced annual IT costs; however, the LOBs must dedicate significantly more resources to complete ERIM program implementation work resulting in minimized savings.
- **Risks**
  - Less risk reduction than the recommended mitigation bundle during the 2020 GRC period. This implies that the organization as well as the company has to tolerate a greater potential risk.
  - Delayed achievement of IGMM Level 3 program maturity across PG&E until 2032 or later.

This alternative mitigation bundle was not chosen primarily due to the significantly lower RSE of the mitigation bundle and the consequent risk reduction achieved during the 2020 GRC period. Despite the reduction in costs of the overall mitigation bundle, the risk reduction was low enough to make this mitigation bundle inefficient. Additionally, this mitigation bundle did not make much progress towards achieving a mature RIM program.

Table 20-7 below summarizes the mitigations; associated drivers, RSE, and associated estimated costs for each year covered by the 2020 GRC for alternative plan 2.

Table 20-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000s)	2021 Estimate ($000s)	2022 Estimate ($000s)
M22	Implement Records and Information Management Governance for Content in Unstructured Data Repositories - Alternative 2	0.0348	0.0209	2016	2022	All Drivers, F	665 - 735 (C) 1,865 - 2,062 (E)	665 - 735 (C) 2,240 - 2,476 (E)	570 - 630 (C) 3,610 - 3,990 (E)
M23	EDMS Migration- Alternative 2	0.0576	0.0331	2016	2020	All Drivers, F	– (C) 272 - 301 (E)	– (C) – (E)	– (C) – (E)
M24	Electronic Records Cleanup - Alternative 2	0.0933	0.0588	2016	2022	All Drivers, F	– (C) 1,951 - 2,157 (E)	– (C) 2,890 - 3,194 (E)	– (C) 2,900 - 3,205 (E)
M25	Implement Records and Information Management Governance for Content in Structured Data Repositories- Alternative 2	0.0267	0.0152	2018	2022	All Drivers, F	– (C) 16 - 18 (E)	– (C) 159 - 176 (E)	– (C) 824 - 911 (E)
M14B	Map Work Processes that Generate Records	0.8194	0.4007	2017	2022	D2	– (C) 516 - 570 (E)	– (C) 232 - 257 (E)	– (C) 212 - 234 (E)
M26	Enterprise Search - Alternative 2	0.0759	0.0363	2020	2022	D1, F	– (C) 18 - 19 (E)	63 - 70 (C) 95 - 105 (E)	63 - 70 (C) 95 - 105 (E)
ALTERNATIVE PLAN 2 TA RSE: 0.0901 TOTAL Expense and Capital by Year							**665 - 735 (C) 4,638 - 5,127 (E)**	**728 - 805 (C) 5,616 - 6,208 (E)**	**633 - 700 (C) 7,641- 8,445 (E)**

VII. Metrics

Proposed accountability metrics are in the process of being developed and include the following in list:

- **Implement Records and Information Management Governance for Content in Unstructured Data Repositories:** The metric proposed for this mitigation is the number of terabytes of data analyzed and cleansed. This includes disposition of records, migrating to the appropriate system and enabling records management as well as clean-up of redundant, obsolete, and trivial data. This may also include migrating content to a system such as SharePoint that will be set up with enterprise taxonomy and enabled for identifying and securing records. This metric was chosen because it will give an indication of the amount of progress being made on the project. The exposure of this risk is related to the amount of content in unstructured data repositories, consequently the risk reduction impact is best measured by the amount of content that has been analyzed and addressed.

- **EDMS Migration:** The metric proposed for this mitigation is the percentage of content stored in EDMS that has been successfully migrated. This metric was chosen because it will give an indication of the amount of progress being made on the project. Since the exposure of this risk is related to the amount of documents currently in EDMS, by focusing on the number of documents successfully migrated, this metric provides some indication of the risk reduction being made by lowering the exposure.

- **Electronic Records Cleanup:** The metric proposed for this mitigation is a combination of the growth in data in terabytes and the number of duplicate files. Kazeon will be used on an ongoing basis to govern the growth of file shares and SharePoint. It will also identify duplicate files and this information will be used by ERIM for governance to let LOBs know they need to do ongoing clean-up activities.

- **Preservation Strategy and Implementation:** The metric proposed for this mitigation is the number of systems that can be "locked down" for information retention. This metric was chosen because it will give an indication of the amount of progress being made on the project. Ultimately, the goal of this mitigation is to be able to automatically retain information in support of a legal discovery request. The greater the number of systems for which this can be implemented automatically, the lesser the exposure resulting in greater risk reduction.

- **Implement Records and Information Management Governance for Content in Structured Data Repositories:** The metric proposed for this mitigation is the number of systems that have retention controls. This metric was chosen because it will give an indication of the amount of progress being made on the project and consequently some indication of the risk reduction being made. Ultimately, the goal of this mitigation is to readily disposition information in structured data repositories and the number of such systems that have that capability serves as an indication of the reduction in exposure and consequently in risk.

- **Map Work Processes that Generate Records:** The metric proposed for this mitigation is the percentage of RIM regulatory requirements, controls and testing that have been verified. This metric was chosen because it is a metric that is already in use to track and report the progress in this mitigation which is already underway. The work processes that are the initial focus of this mitigation are those involving RIM legal and regulatory requirements. Consequently, the metric focuses on these.

- **Enterprise Search:** The metric proposed for this mitigation is the number of repositories that can be searched in one tool. This metric was chosen because it will give an indication of the amount of progress being made on the project and consequently some indication of the risk reduction. This project automates searching across multiple repositories by using one tool. The success of this project is very much dependent on the amount of systems that can be searched automatically, thereby reducing the amount of manual individual searches that need to be made.

Table 20-8 below provides the associated drivers, proposed metrics and metric targets per mitigation in the proposed plan. Proposed accountability metrics are in the process of being developed and include the following:

Table 20-8: Metrics

Mitigation	Associated Driver	Proposed Metric	Targets
Implement Records and Information Management Governance for Content in Unstructured Data Repositories	All Drivers	Terabytes of data that have been analyzed and cleansed.	Individual annual and monthly targets to be determined at the beginning of each year based on project estimate.
EDMS Migration	All Drivers	Percentage of content stored in EDMS that has successfully been migrated.	2017 Target: 95 percent
Electronic Records Cleanup	All Drivers	A combination of the growth in data in terabytes and the number of duplicate files.	Individual annual and monthly targets to be determined at the beginning of each year based on project estimate.
Preservation Strategy and Implementation	All Drivers	Number of systems that can be locked down.	Individual annual and monthly targets to be determined at the beginning of each year based on project estimate.
Implement Records and Information Management Governance for Content in Structured Data Repositories	All Drivers	Number of systems that have retention controls.	Individual annual and monthly targets to be determined at the beginning of each year based on project estimate.
Map Work Processes that Generate Records	D2	Percent of RIM Regulatory Requirements, Controls and Testing Verified.	2017 Target: 50 percent
Enterprise Search	D1	Number of repositories that can be searched in one tool.	Individual annual and monthly targets to be determined at the beginning of each year based on project estimate.

VIII. Next Steps

There is currently very little data to support the frequency of risk resulting from inadequate or inconsistent records and information management controls on the impact of operational decisions. The ERIM department will continue to improve PG&E's ability to identify records related issues and trending by leveraging data from CAP, NOV, and other existing measurement tools as well as working with the incident reporting teams to add RIM as an explicit risk driver in post incident assessment. The CAP Program was rolled out enterprise-wide in mid-2017, ensuring a broad and diverse pool of information going forward. The program specifically contains a records category, with five subcategories that will allow for ready identification of records related issues and additional insights into the RIM risk. Likewise, additional insights into the RIM risk are anticipated from monthly reviews by the ERIM department of NOVs and IAs with the intent to analyze the risk drivers for RIM-related issues. Both of these efforts were started in 2017.

Regardless of the modeling, the focus of the ERIM program is on continuing the maturity of PG&E’s records and information management. This will be achieved by completing initiatives and projects identified on ERIM program’s roadmap, as the roadmap is designed to increase the program’s maturity level as to IGMM Level 3 across the enterprise by 2022. This roadmap will also continue to be regularly reviewed and updated. It is anticipated that additional information will be obtained from the 2017-2018 field office assessments and Kazeon analysis findings regarding any additional risk or potential compliance gaps related to our legacy records. IGMM Level 3 assessments conducted by the SED for PG&E’s Gas Operations may identify additional opportunities requiring action and resource allocation. Lastly, developments and innovations in records management technology will impact the solutions considered and their implementation. The road map is dynamic and the resulting implementations will need to be as well to meet the demands imposed by the growth in information.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 21
SKILLED AND QUALIFIED WORKFORCE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 21
SKILLED AND QUALIFIED WORKFORCE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Skilled and Qualified Workforce
IN SCOPE	High consequence[1] work performed by employees and non-employee workers[2] in the following functions: • Gas transmission and distribution. • Electric transmission and distribution. • Non-Nuclear power generation
OUT OF SCOPE	Out of Scope activities include: • Nuclear Generation (Humboldt Bay and Diablo Canyon Nuclear Power Plants). • Errors not due to a worker's skills and qualifications. For example, an employee or non-employee worker with the necessary skills and qualifications, performs a task improperly, or errors due to impaired physical or mental health.
DATA QUANTIFICATION SOURCES	Assessment informed by Pacific Gas and Electric Company (PG&E) work procedure error and assessment data, frequency and consequence data from the asset based risk models included in the Risk Assessment and Mitigation Phase (RAMP) filing, and Subject Matter Expert (SME) input.

Maintaining a Skilled and Qualified Workforce (SQWF) has been part of PG&E's operations from its earliest days. Prior to 2013, when PG&E formalized Enterprise and Operational Risk Management, PG&E managed this issue through its employee training and qualifications programs. This included formal training developed by PG&E's centralized learning function (currently PG&E Academy), training developed in the lines of business, on the job training (OJT), joint employer-union apprenticeship programs approved by the state of California, and the gas operator qualifications program.

As the rate of change to technology, equipment, and procedures has increased, it is PG&E's belief that the risk of an adverse event occurring because an employee did not have the necessary skills and qualifications has also increased. Therefore, PG&E has adapted its operations to maintain an appropriate level of control around maintaining a

1 High consequence work in the electric area is defined as the work that requires a specific set of skills, which if not performed correctly is more likely to result in a safety incident. High consequence work in the gas area is defined as the tasks covered by the Operator Qualifications program. PG&E's Human Resources organization continues to work with the Power Generation organization to more clearly define high consequence work.

2 The SQWF risk definition includes both employees and non-employee workers, however to date PG&E has focused its SQWF evaluation and most mitigation efforts on employees. The Contractor Safety risk has been focusing on non-employee workers. In 2018 PG&E will determine the specific scope of SQWF as it relates to non-employee workers and develop a proposed mitigation plan.

SQWF. Fundamentally, PG&E's goal is to ensure that training and qualifications for high consequence work is current and applied to our workforce in a systematic and repeatable way. PG&E must ensure that processes are in place to quickly identify when new or additional training or qualifications are required by PG&E workers so that they can safely and efficiently perform their assigned work.

PG&E's Proposed Mitigation Plan seeks to improve and add to the control activities that reduce the SQWF risk. This also includes continued data collection to evaluate and measure the effectiveness of the controls and mitigations. Those efforts include increasing the availability of technical resources to field employees, systems that will enable supervisors and others to easily confirm qualifications status of employees, and bringing more processes under the scope of the control and mitigation activities. The data gathering and analysis efforts will enable PG&E to assess the risk more quantitatively, which will in turn help identify the most effective areas for future risk mitigations and risk reduction.

Historically, PG&E has had limited data available on the actual risk events where the lack of skills and qualifications were determined to be at least a contributing factor. PG&E expects to continue improving the RAMP modeling efforts in order to more quantitatively evaluate this risk. One specific enhancement will be the development of frequency and consequence data for high consequence work that impacts assets or operations not covered by the existing asset based RAMP risks. This additional data, when combined with the inputs from the asset based RAMP risks will provide a more complete picture of the SQWF risk. In addition, as more processes are evaluated and documented end to end, PG&E will also have an improved inventory of high consequence work. Collectively, these improvements will allow PG&E to more effectively target existing controls and proposed mitigations, identify where additional mitigations are needed, and evaluate the effectiveness of the controls and mitigations.

II. Risk Assessment

A. Background

The primary SQWF risk involves a worker performing tasks for which he/she does not have the skill or is not qualified and as a result causes an adverse event that leads to a serious injury or fatality.

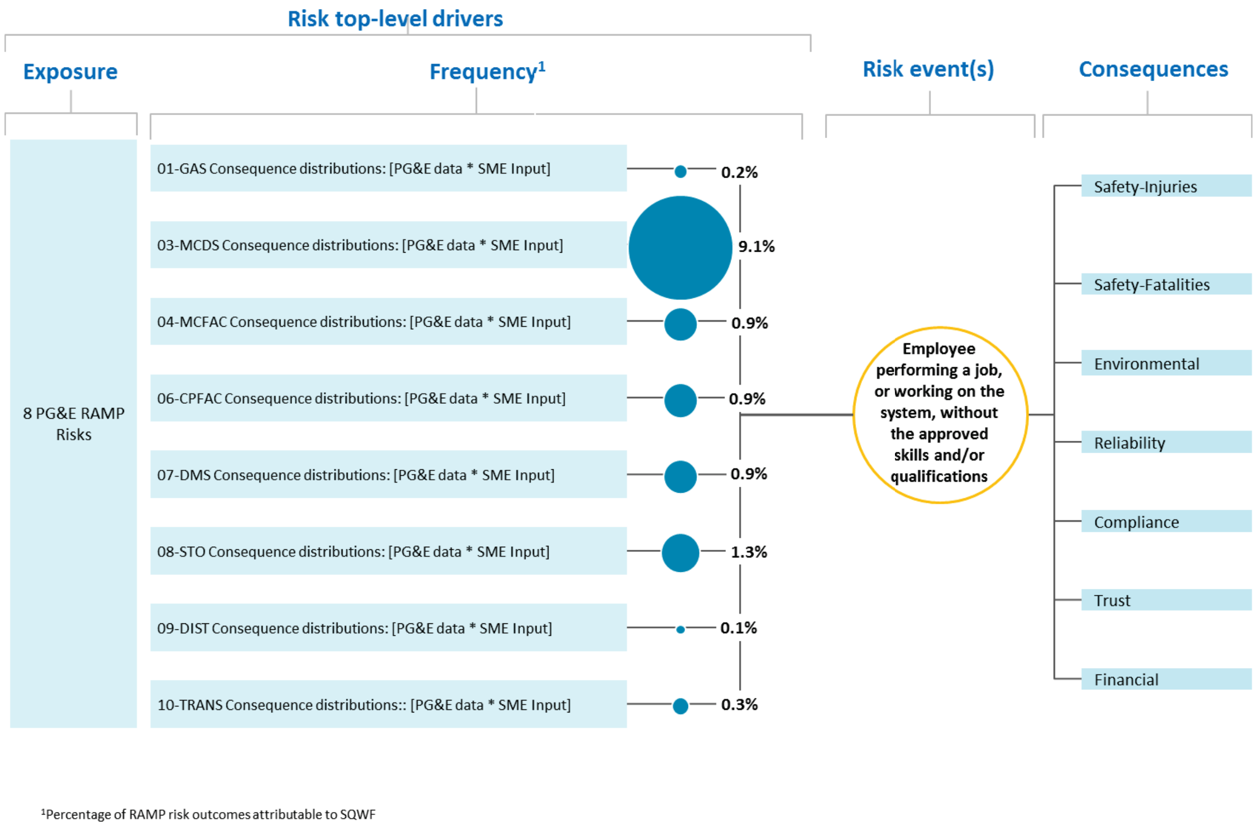
In the past, PG&E has evaluated the risk based on collaboration of SMEs from across the organization; including Human Resources, Gas Operations, Electric Operations, and Power Generation, to identify the drivers and consequences of possible scenarios. The SME judgement was augmented with available work procedure error data. Work procedure errors are incidents of events where it was determined after the fact that the worker did not follow the steps documented in a published procedure. The error may have been missing a step, performing steps out of sequence, and/or not following the specific directions within a step.

For purposes of the RAMP filing, PG&E assessed this risk based on its relationship with other RAMP risks. The RAMP risks with an underlying "Incorrect Operations" (or equivalent driver)[3] were identified and assessed. Next the proportion of the Incorrect Operations driver attributable to the SQWF risk was estimated using assessment pass rate data as a proxy combined with SME judgement. The adjusted distribution outcomes from the asset based RAMP risks were combined to produce a baseline assessment of the SQWF risk. Mitigations were then applied to each underlying asset based RAMP risk, using an effectiveness percentage.

Figure 21-1 below shows the bow tie for the SQWF risk. Included within the bow tie are the Incorrect Operations driver frequencies from each of the asset based risk models.

3 In some cases the asset based RAMP risk models did not identify the Incorrect Operations driver, and instead identified a different, but equivalent driver. For simplicity we will refer to this combination as the Incorrect Operations driver throughout the SQWF risk chapter.

Figure 21-1: SQWF Risk Bow Tie



B. Exposure

The exposure data used to quantify the SQWF risk identified in Figure 21-1 above are the portion of each asset based RAMP risk with Incorrect Operations as a driver. The percent of each associated RAMP risk caused by Incorrect Operations is displayed in Table 21-1. The SQWF risk model is a cross-cutting model and is based on the outputs from the asset based RAMP risks.

C. Drivers and Associated Frequency

Each of the asset based RAMP risk owners identified the proportion of the adverse events attributable to Incorrect Operation by employees or non-employee workers.[4] After review and discussion, PG&E SMEs determined that assessment pass rate data was the best available proxy for determining the

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4 For purposes of quantifying the SQWF risk, the model is currently limited to consequence and frequency inputs from the asset based risks included in PG&E's 2017 RAMP filing (see Table 21-1). As a result, the consequences and frequency of adverse events are understated. The impact of the proposed mitigations is also similarly limited to that associated with the asset based risks included in PG&E's 2017 RAMP filing. The understatement occurs because PG&E's 2017 RAMP filing does not capture all risks to the company that may have an Incorrect Operations component.

proportion of incorrect operation-caused asset based risk events attributable to SQWF.[5] The SME assumption is that if a worker performs a task incorrectly for an assessment, it is unlikely that they will perform it correctly on the job. This SME assumption potentially overstates the likelihood of a risk event occurring, because not every mistake a worker may make that causes them to fail an assessment will cause an adverse event when they perform the same task in the field. To account for uncertainty, these percentages are provided in a range of high and low used to create a distribution (see Table 21-2).

It is important to note that the size of the frequency bubbles in Figure 21-1 show the average percentage of the total asset based risk that the Incorrect Operations driver accounts for, and does not represent that driver as a proportion of the SQWF risk. The relative driver frequency for the SQWF risk is calculated by using the relative percentage of the total asset based risk that the Incorrect Operations driver accounts for against the asset based risk's expected value (EV) Multi-Attribute Risk Score (MARS). Table 21-2 below also shows the percentage of each asset based RAMP risk EV MARS for the SQWF baseline risk. As the data shows, while the Electric Transmission and Distribution risks have a very small percentage attributable to the SQWF risk (0.3 percent and 0.1 percent respectively), because of their overall larger MARS risk score they contribute 39 percent of the total MARS value to the SQWF risk.

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5 See workpaper PG&E Assessment Data (see the workpapers for Chapter 21, pages WP 21-32 to WP 21-34) for additional detail on how PG&E used the assessment data to determine the SQWF exposure.

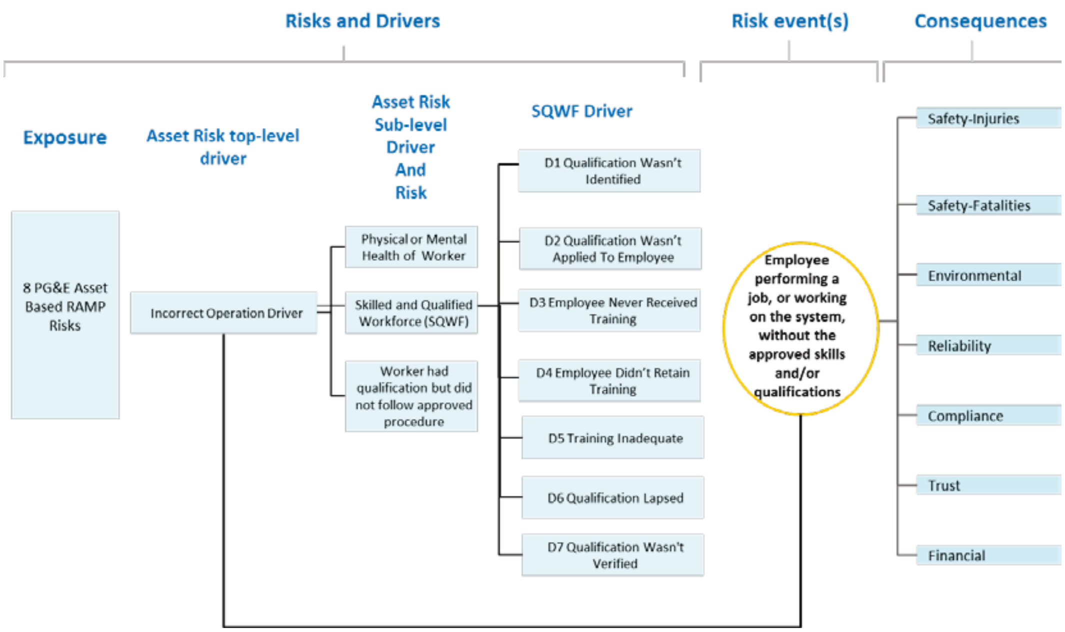
Table 21-1: Asset Based Risks Contributing to Skilled and Qualified Workforce Risk

Risk	Percent of Risk Caused by Incorrect Operations	Portion of Incorrect Operations Attributable to Lack of Skills or Qualifications		Average Driver Frequency Attributable to SQWF (Bow Tie Percentages)	Proportion of EV MARS From Each Asset Risk
		Low	High		
STO – Storage – Wells (Gas Operations)	7.8%	3.0%	30.0%	1.3%	4.9%
GSO – Maintaining System Capacity (Gas Operations)	0.0%	3.0%	30.0%	0.0%	0.0%
CPFAC – Compression & Processing Facility (Gas Operations)	5.7%	3.0%	30.0%	0.9%	5.0%
MCFAC – Measurement & Control Facility (Gas Operations)	5.7%	3.0%	30.0%	0.9%	3.0%
MCDS – Measurement & Control Downstream (Gas Operations)	55.2%	3.0%	30.0%	9.1%	25.8%
DMS – Distribution – Non-Cross Bore (Gas Operations)	5.6%	3.0%	30.0%	0.9%	18.4%
GAS – Transmission Pipeline (Gas Operations)	0.9%	3.0%	30.0%	0.2%	3.7%
DIST – Distribution Overhead Conductor Primary (Electric Operations)	0.4%	9.1%	26.3%	0.1%	26.4%
TRANS – Transmission Overhead Conductor (Electric Operations)	1.4%	9.1%	26.3%	0.3%	12.7%
HYD – Hydro Dam Failure (Power Generation)	0.0%	9.1%	26.3%	0.0%	0.0%

As described above, for the purpose of the SQWF modeling PG&E used the Incorrect Operations driver frequency identified for the asset based risk events. The SQWF risk is considered to be a sub-driver of the Incorrect Operations driver. PG&E's proposed mitigations in this chapter address these SQWF specific drivers. These SQWF specific drivers are not mutually exclusive, and in some cases, one driver might be one reason for another driver. For example, with the SQWF driver Employee Never Received Training, an employee may not have completed the training because they were never identified as needing the qualification or training which results in the SQWF driver Qualification Wasn't Applied to Employee.

Figure 21-2 below, shows the relationship between the eight asset based RAMP risks, the Incorrect Operation driver and the SQWF risk and its specific drivers.

Figure 21-2: Relationships Between Asset Risk Drivers and SQWF Risk Drivers and Consequences



As described above, PG&E used the Incorrect Operations driver frequency data as a proxy for the SQWF specific drivers because PG&E does not currently have data available to quantify the frequencies or outcomes associated with the specific SQWF drivers shown below. When evaluating controls and developing and evaluating mitigations, the more detailed SQWF drivers become useful to understand what behaviors and processes are being targeted. As these drivers are positively impacted, the number of risk events due to the Incorrect Operations driver would be expected to decrease. PG&E determined these SQWF specific drivers based on SME input.

D1 Qualification Wasn't Identified: The qualification was not identified during the job creation process, and was not assigned to the job. The employees holding the job classification are therefore not required to complete the training or assessment necessary to have the specific qualification.

D2 Qualification Wasn't Applied to Employee: An employee was not assigned either directly or indirectly, a qualification required for specific work. For example, the job classification for Journeyman Lineman can vary depending on where the employee is assigned to work. Skills and qualifications needed to work on the underground electrical equipment in San Francisco Division may not be needed for a Lineman working in the Yosemite Division.

D3 Employee Never Received Training: Employee was not required to complete or did not complete training that would have taught the necessary skills, but should have been.

D4 Employee Didn't Retain Training: Employee qualification is current, however the training was not effective or the employee did not retain the knowledge and skills taught during the training due to time or infrequently needing to use the skills.

D5 Training Inadequate: Training content may not have reflected current procedures and equipment, or the instructor may not have sufficient qualifications to teach the material

D6 Qualification Lapsed: The qualification expired or lapsed before the work was completed resulting in non-compliance and/or re-work.

D7 Qualification Wasn't Verified: No validation was performed for the employee's qualification, prior to scheduling the work.

D. Consequences

The consequences of an SQWF event, due to a worker performing a task without the necessary skills and qualifications, were modeled based on inputs from each of the asset based risks shown in Table 21-1 above. As described above, each asset based risk model identified the proportion of the risk attributable to the Incorrect Operation driver. The equivalent proportion of the consequence distribution[6] was then calculated and used as an input to the SQWF model, adjusted to reflect the percentage of the Incorrect Operation driver attributable to the SQWF risk. The sum of those adjusted distributions became the baseline consequences for the SQWF RAMP model.

Figure 21-3 below shows the tail average natural units and tail average MARS outcome for each of the risk attributes. The total SQWF baseline MARS is calculated to be 4.96.

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6 The consequence distribution is represented by the standardized risk attributes of safety, environmental, reliability, compliance, trust, and financial.

Figure 21-3: Baseline Consequence Attributes

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source	Aggregation of inputs from associated RAMP risks						
Outcome-TA-NU[1]	0.14	0.05	$ 1,649	356,646	$ 409,590	0.4%	$ 881,650
Outcome-TA-MARS[2]	0.04	1.41	0.00	0.89	0.04	2.05	0.53
						MARS Total	**4.96**

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

For a discussion of the specific data sources and assumptions, please see the respective chapters for the asset based risks. The aggregate annual baseline consequence for each attribute is shown in the table above.

III. 2016 Controls and Mitigations (2016 Recorded Costs)

PG&E controlled and continues to control for this risk through a combination of rigorous training programs for new and existing employees and ongoing assessments of specific skills and qualifications. These efforts were augmented with various procedures, and job aids available to employees. While these controls may have been sufficient in the past, as evidenced by the relatively low frequency of events, the current environment in which PG&E operates and the potential consequences, SQWF was elevated to be a top safety risk in 2013.

Collectively these controls reduced the likelihood that a worker would perform tasks for which they were not qualified. In some cases, specific controls are required by law, such as a federally regulated gas operator qualifications program. For purposes of this filing, PG&E has not attempted to quantify the specific cost or benefit from the existing and ongoing activities and programs that serve as controls as they are embedded in HR and the operating lines of business (LOB) recorded costs.

Each of the controls and mitigations described below targets one or more of the sub-drivers described in the Drivers and Associated Frequency section above.

C1 – Gas Operator Qualifications Program: This control addresses the management and administration of requirements for the Department of Transportation's 49 CFR 192[7] and California Public Utilities Commission's (CPUC or Commission) General Order (GO) 112.[8] These requirements identify the tasks for which there are required qualifications, require regular reassessment of workers performing these tasks, and provide controls to ensure a gas worker does not perform work without the required operator qualifications. This control addresses the Qualification Wasn't Identified and Qualification Wasn't Applied to Employee drivers.

C2 – Employee Knowledge and Skills Program: This control reassesses targeted electric field employees on specific knowledge and skills on a regular basis, which in turn helps offset any skill degradation. This control addresses the Employee Never Received Training, Employee Didn't Retain Training, and Training Inadequate drivers.

C3 – Job Profile, Job Description/Profiling Process: This control covers the documentation of the necessary qualifications for each job classification as part of the job creation and maintenance process. This identifies qualifications required of every employee who holds or will hold the specific job classification. Data is entered into PG&E's SAP human resources information system (HRIS) for tracking and assignment. This control addresses the Qualification Wasn't Identified driver.

C4 – Technical Training Profiling/Governance: This control is the identification or profiling of mandatory training in PG&E's SAP HRIS. Assignments are based on job classification, and the specific duties and qualifications required for individual positions. This control ensures workers are assigned to take the training associated with their job duties and required qualifications. This reduces the likelihood that a worker will not have the necessary skills and qualifications to perform assigned work. This control addresses the Qualification Wasn't Identified and Qualification Wasn't Applied to Employee drivers.

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7 49 CFR 192: Department of Transportation regulations regarding the Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, which includes requirements that qualified individuals perform specific tasks.

8 CPUC GO 112: State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems which has the following purpose: to establish, in addition to the Federal Pipeline Safety Regulations, minimum requirements for the design, construction, quality of materials, locations, testing, operations and maintenance of facilities used in the gathering, transmission and distribution of gas and in liquefied natural gas facilities to safeguard life or limb, health, property and public welfare and to provide that adequate service will be maintained by gas Operators under the jurisdiction of the Commission.

C5 – Standards and Procedures Review Process: This control is the regular review and update of guidance documents so that they reflect current safety procedures, equipment used in the field, and all appropriate regulatory and legal requirements. This control ensures that training/qualification programs are developed based on current standards and procedures. Keeping the documentation current identifies where training must also be updated. This control addresses the Training Inadequate driver.

C6 – Apprentice Training: A system of learning that combines OJT and related classroom instruction in accordance with state and federal laws, under which a person works with a journey-level craft person to gain the skills required to become a skilled and qualified craft person. This control provides training and learning opportunities (including assessments to demonstrate mastery of the material) to develop and increase the skills and knowledge required to safely and effectively complete assigned work. This control addresses the Employee Never Received Training driver.

C7 – Training Effectiveness Monitoring: This control is designed to help monitor the effectiveness through a range of metrics. Data is collected through objective online or physical tests, student assessments of class quality and field assessments of students performing the work. Low scores indicate a need for improved training in certain areas, thereby improving the training quality, and knowledge retention. This control addresses the Employee Didn't Retain Training and Training Inadequate drivers.

C8 – Display Training Status in Learning Management System (LMS): This control helps to provide real time visibility to employees of their training status (current, due in 90 days or past due). The easy access on PG&E's LMS's intranet site (called "My Learning") provides employees with an up-to-date status of their training, in order to keep their qualifications current. This control addresses the Qualification Lapsed driver.

Table 21-2 below shows each control, the drivers most closely associated with that control, and where the costs are recorded (funding source). Because managing the SQWF risk has been an ongoing part of PG&E's business, the costs for the identified controls are not separately tracked or recorded. These costs are embedded through the organization. PG&E has attempted to identify the specific proceeding or proceedings where most costs are recovered for the functions which implement the listed controls.

Table 21-2: Risk Controls and 2016 Recorded Costs

#	Control	Associated Driver and Consequence	Funding Source	2016 Recorded Expense ($000)	2016 Recorded Capital ($000)
C1	Gas Operator Qualifications Program	D1, D2	GRC and GTS	Not Available	Not Available
C2	Employee Knowledge & Skills Program	D3, D4, D5	GRC and TO	Not Available	Not Available
C3	Job Profile, Job Description/Profiling Process	D1	A&G Cost recovered in most proceedings as an allocation, including GRC, GTS, TO, and Energy Efficiency	Not Available	Not Available
C4	Technical Training Profiling/Governance	D1, D2	A&G Cost recovered in most proceedings as an allocation, including GRC, GTS, TO, and Energy Efficiency	Not Available	Not Available
C5	Standards and Procedures Review Process	D5	GRC, GTS, and TO	Not Available	Not Available
C6	Apprentice Training	D3	GRC, GTS, and TO	Not Available	Not Available
C7	Training Effectiveness Monitoring	D4, D5	A&G Cost recovered in most proceedings as an allocation, including GRC, GTS, TO, and Energy Efficiency	Not Available	Not Available
C8	Display Training Status in LMS	D6	A&G Technology Project – Cost recovered in most proceedings as an allocation, including GRC, GTS, TO, and Energy Efficiency	Not Available	Not Available
TOTAL Expense and Capital				Not Available	Not Available

IV. Current Mitigation Plan (2017-2019)

Most recently, in its 2017 General Rate Case (GRC) application, PG&E discussed the importance of a SQWF and outlined new and expanded activities planned for 2017-2019. Through the risk assessment and analysis process, PG&E identified the need for additional data to further refine and understand the risk and gaps where the existing controls did not adequately address the SQWF risk drivers. PG&E's 2017-2019 mitigation plan is intended to partially address these gaps.

In this period, PG&E is primarily focusing its efforts for skills and qualifications on activities that are foundational in nature. These activities are designed to align associated procedures, qualifications, and training required to perform high consequence work safely and efficiently. They are also designed to systematically determine which workers are expected to perform high consequence work through qualifications catalogs and training profiles so that the right workers are sent to the right training. In some cases PG&E will continue with programs started in earlier years, such as the Business Process Index (BPI) (M1A). In others will add new mitigations, such as the building of a new training substation in Livermore, California (M13 below), and address a driver (D7 Qualification Wasn't Verified) not currently covered by existing controls (M12).

PG&E's current and proposed mitigations fall into three major categories:

- **Foundational:** Work that will improve the data and information PG&E has in order to identify all high consequence work and tasks and further refine risk model inputs related to consequence and frequency. This work is not expected to directly reduce the risk, but PG&E believes that it is necessary for developing more effective mitigations in the future.
- **Technical Competence:** Improving access to technical procedures, standards, and job aids so that employees in the field can more easily look up material and have a refresher before completing a task. This is particularly important if the employee is faced with a task or equipment that they may not frequently work on and therefore may not recall all of the required steps and safeguards that should be implemented.
- **Qualification Verification:** Increase the visibility to and use of qualifications when scheduling and assigning work. This type of mitigation will reduce the likelihood that an employee is scheduled or assigned to complete work for which they do not have a current qualification. It will also serve as a reminder to employees who have not completed required refresher or update training as the associated qualification will have expired.

Below is a complete list of the mitigations PG&E has planned for 2017 through 2019:

M1A –BPI (Foundational): Establish and maintain a system that documents and aligns the work employees do with the procedures, training and associated qualifications. This relational database will require ongoing maintenance and updating as processes, procedures, and equipment change or as PG&E develops new or additional training. Developing and maintaining the BPIs will not directly reduce the SQWF risk, however the information included in the BPI is foundational to determining which procedures, training, and qualifications support the high consequence work. This work will enable the Qualification Cards and Work Scheduling Integration mitigations in our 2020-2022 plan. This mitigation will also enhance controls C3 and C4 through the information captured and supports the Training Inadequate driver.

M2 – Implementation of the Centralized Training Records Standard (Foundational): Centralize all training records that lead to a certification, a qualification or address a compliance requirement. Under this standard, all such records must be captured and stored in SAP for workers or made available within 48 hours for contractors. This centralization of records will allow PG&E to have a “single source of truth” when determining whether or not an worker has completed specific training, learned the expected skills and obtained the required qualifications. This mitigation supports the Qualification Wasn’t Applied to Employee and Employee Never Received Training drivers.

M3 – SAP Apprentice Training Automation (Foundational): Enhance SAP usability by developing a sustainable data collection and storage tool with mobile capability that meets all regulatory and record retention requirements, as well as the ability to generate reports to gauge program effectiveness and individual success. Apprentice programs are the formal training programs for many employees who will perform high-consequence work. Automating the tracking of these programs will reduce errors and provide a more consistent and auditable training documentation. This mitigation supports the Training Inadequate driver.

M4 – Perform an Assessment of Electric Transmission Operations (TO) and Distribution Operations (DO) Training and Improvements Needed (Foundational): For identified critical tasks needing improvement, ensure the development and delivery of the assessment programs. This is foundational work to prioritize the higher risk work/tasks performed in the field to apply the training cycle time evaluation. This mitigation supports the Training Inadequate driver.

M5 – Perform Cycle Time Evaluation for All Critical Task Assessments That Have Been Completed for Electric TO and DO (Foundational): Evaluate and determine the appropriate regular assessment cycle (i.e., how frequently employees should be retested on a specific skill or knowledge) based on skill or knowledge degradation for Electric Operations identified critical tasks. Understanding the skill degradation rate allows PG&E to reassess and retrain employees, if needed. Determining the appropriate cycle time reduces the cost of assessing too frequently, but also reduces the risk by assessing and retraining before employee’s skills become deficient. This mitigation supports the Employee Didn’t Retain Training driver.

M6 – Technical Training Profiling (Foundational): Expand profiling (i.e., identify all required technical and equipment training to a job classification, positon, organization or an individual) of training for the Gas and Electric organizations to help reduce training costs, improve scheduling and planning, and ensure the right person is in the right training at the right time. Profiling allows PG&E to identify the population of employees who are expected to perform work that requires specific training, and to plan the training resources necessary, as well as inform employees as to what training they are required to complete. This mitigation supports the Qualification Wasn’t Applied to Employee and Employee Never Received Training drivers.

M7 – Develop Job Qualification Profiles (Foundational): Map PG&E gas operator qualifications to the work performed by personnel in each PG&E gas job classification (and/or role) on a regular, consistent basis. This effort supports Gas Operator Qualifications program compliance requirements. This is foundational work that ensures correct qualification and task information is assigned to gas employees. This reduces the likelihood that an unqualified worker will performing work. This mitigation supports the Qualification Wasn't Identified driver.

M8 – Exam Materials Refresh (Foundational): Prioritize the identification, creation, and revision of tasks to ensure a comprehensive task list, and that exam materials test knowledge, skills and abilities, not just reading comprehension and memory. By improving the quality of exams, they will provide a better indicator that participants completing the specific course will have the expected knowledge and skills. This mitigation supports the Training Inadequate driver.

M9 – Metrics Development (HR) (Foundational): Identify data needed to quantify drivers, incidents and measure the effectiveness of controls. Determine what data is available and develop a centralized location to store that data, determine what additional data needed (such as frequency of drivers) to create a baseline measurement of the risk and to measure the effectiveness of controls and mitigations and develop and implement a plan to collect the needed data. This mitigation is not targeted to specific drivers.

M10 – Qualifications and Tasks loaded Into HR System of Record (Foundational): Catalog of qualifications and tasks required for each job classification. This foundational work will determine the qualifications for each job classification and load all available qualification data into PG&E's HR system of record. This work must be substantially completed before work scheduling can be successfully integrated with qualifications. This mitigation supports the Qualification Wasn't Applied to Employee driver.

M11 – IT Solution for Curriculum Management (Foundational): To support the training record keeping compliance requirements, develop and implement a sustainability storage solution for space and security. This is foundational work to ensure storage of training records which enables the tracking of training delivered and the content/quality of training. This mitigation supports the Qualification Wasn't Applied to Employee, Employee Never Received Training, Training Inadequate driver, and Qualification Wasn't Verified drivers.

M12 – Applicant Installer On-Boarding Process (Qualification Verification): This mitigation focuses on non-employee workers**.** Applicant Installers are third parties who are contracted by a home development builder to connect new homes to PG&E services. PG&E must contact Applicant Installer contractors at the beginning of their engagement and inform them about required qualifications to perform the contracted work, the process for the non-employee workers to obtain the required qualifications, and the process to validate those qualifications in real time at a job site and after the fact for audit purposes. This mitigation is designed to cover a specific set of non-employee workers performing work on PG&E assets. This mitigation addresses the Qualification Wasn’t Identified, and Qualification Wasn't Verified drivers.

M13 – Training Substation in Livermore (Technical Competence): Develop and construct a new training substation at the Livermore training facility. This will support improved training quality, and therefore the skills of employees who work on substations. This mitigation addresses the Training Inadequate driver.

Most of the planned activities described above are not tracked as formal projects, they are part of the function performed by the responsible departments and no specific incremental costs were requested or estimated. Table 21-3 lists all mitigations that are in progress or planned for 2017-2019, their start and end dates, the drivers (see section C above for the driver description), and for those mitigations that are specific projects or have separately tracked costs, the estimate costs.

Table 21-3: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver # and Consequence	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1A	BPI (Foundational)	2016	2019	D5	– (C) 800(E)	– (C) 800 (E)	– (C) 800 (E)
M2	Implementation of the Centralized Training Records Standard (Foundational)	2016	2017	D2, D3	Not Available		
M3	SAP Apprentice Training Automation (Foundational)	2016	2018	D5	Not Available		
M4	Perform an assessment of TO & DO training (Foundational)	2015	2018	D5	Not Available		
M5	Perform Cycle Time Evaluation for All Critical TO and DO Tasks That Have Completed Assessments (Foundational)	2016	2019	D4	Not Available		
M6	Technical Training Profiling (Foundational)	2016	2017	D2, D3	Not Available		
M7	Develop Job Qualification Profiles (Foundational)	2014	2018	D1	Not Available		
M8	Exam Materials Refresh (Foundational)	2015	2017	D5	Not Available		
M9	Metrics Development (HR) (Foundational)	2016	2017		Not Available		
M10	Qualifications and Tasks Loaded Into HR System of Record (Foundational)	2014	2018	D2	Not Available		
M11	IT Solution for Curriculum Management (Foundational)	2016	2018	D2, D3, D5, D7	Not Available		
M12	Applicant Installer On-Boarding Process (Qualification Verification)	2017	2017	D1, D7	Not Available		
M13	Training Substation in Livermore (Technical Competence)	2016	2019	D5	15,471 (C) 21 (E)	36,279 (C) 391 (E)	100 (C) – (E)
TOTAL Expense and Capital by Year					**Not Available**	**Not Available**	**Not Available**

V. Proposed Mitigation Plan (2020-2022)

The Risk Spend Efficiency (RSE) of PG&E's proposed mitigation plan is 0.387. PG&E's approach in 2020-2022 is to continue collect and analyze data regarding work procedures and errors so that both existing controls and new mitigations can be evaluated for effectiveness. At the same time, recognizing that change in technology, equipment and procedures will continue to impact employees working in the field, PG&E has developed a mix of additional mitigations that build upon the work it has completed to date and which, PG&E believes, will continue to reduce the likelihood[9] of an adverse event due to an employee not having the necessary skills and qualifications. As mentioned above, the proposed mitigations fall into the three defined categories: Foundational, Qualification Verification, and Technical Competence. This proposed plan optimizes the automation of the controls as well as minimizes the overstatement of benefits.

The proposed mix of mitigations balances the need to continue to develop foundational data to more completely understand and quantify the risk and the impact of existing and new mitigations, with providing resources to employees to give them real-time access to "how-to" information, and structural changes to integrate qualifications into work scheduling and related processes. PG&E's proposed mitigations also address D7 Qualification Wasn't Verified, which is currently not addressed with existing controls, and only addressed for non-employee workers in the 2017-2019 mitigation plan.[10] When possible the Human Resources organization is partnering with the operating LOBs to leverage other process changes they are planning, in order to minimize the cost of mitigating the SQWF risk. For example, the electric and gas LOBs have informed Human Resources that they intend to enhance their work scheduling process to make further use of information and tools. PG&E's proposed mitigation to integrate work scheduling with qualifications is proposed as part of that larger effort.

The RSE calculation in the SQWF model is currently limited to inputs from PG&E's asset based RAMP risks. These risks, particularly in the Electric line of business, cover a limited set of high consequence work processes that employees undertake and so are not able to quantify the full value of either the risk or the mitigations. This is one reason that the reported RSE would be understated.

In addition, PG&E does not have sufficient information to quantify the impact or overlapping mitigations. It is PG&E's belief that if we implement all of the mitigations proposed the cumulative impact will be less than the sum of the individual mitigations. For example, an employee would most likely not call the 24/7 Technical Support Desk and look up answers on their mobile device. We believe in most cases they would choose one or the other. As a result, the RSE would be overstated.

The specific mitigations PG&E is proposing to implement from 2020 through 2022 are described below:

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9 PG&E's proposed mitigations for the SQWF risk all focus on reducing the likelihood (frequency) of an incident or adverse event occurring. Should an event occur, the expected consequences of that event would be no different than before the mitigations were applied.

10 M11: IT Solution for Curriculum Management includes foundational work needed to mitigate driver D7: Qualification Wasn't Verified, however it will not actually mitigate the driver.

M1B – Expand BPI (Foundational): See the description for M1A – BPI, above.

Through this mitigation, PG&E will expand the BPI to additional work areas and functions. That expansion will allow PG&E to identify areas where additional training may be required, or assessments updated to reflect expected work conditions. It will also provide PG&E a means to further refine its focus on developing and targeting new and existing mitigations to areas most at risk for failure.

The total estimate cost for this mitigation is from $0.3 million to $0.9 million expense. Because this is foundational work, no risk reduction has been estimated. Additional details are shown in Table21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-9 to WP21-11).

M14A – On the Job Support – Mobile Technology for Foremen and Crew Leads (Technical Competence): This mitigation will make access to PG&E's technical documentation, including standards, procedures, and job aids available to PG&E's Foremen and Crew Leads through their hand held devices. This real-time, in the field, on-the-job access will allow field workers the ability to look up a specific procedure, as well as use a search function to find the information relevant to their situation. This mitigation addresses the Employee Didn't Retain Training and Training Inadequate drivers.

Today most crews have access to hard copy documents carried in their vehicles or to a more limited set of information stored on a computer or other mobile devices. These paper or off-line documents may not be up to date and can be very cumbersome to use when looking for information to address a specific situation found at the job site. A few field employees have access to existing online documentation through PG&E issued tablets. The ability to review a procedure or job aid in the field puts information in the hands of employees when and where they need it.

Reviewing procedures and job aids in the field can serve as a mini-refresher for employees who may be facing a situation or equipment with which they are unfamiliar.

Critical to the success of this mitigation is the second mitigation, M15: Enhance Technical Information Library (TIL) & Guidance Document Library (GDL). The online documentation must be easily readable and searchable from a mobile device for this mitigation to be successful.

PG&E has estimated that this mitigation will reduce the likelihood of an event, and therefore the risk by 7 percent for gas risks and 15 percent for the electric risks based on the change in assessment pass rate when employees have the opportunity to review procedures and other technical documentation. PG&E estimated this reduction using assessment pass rate data along with LOB SMEs as a proxy. Typically when an employee fails an assessment they are given an opportunity to review materials (often the same material as would be available via the mobile device) or receive coaching. They are allowed a second attempt to pass the assessment. The percentage of employees who are able to pass on the second attempt was used as the base for the risk reduction. This amount was then reduced based on SME judgement to account for situations where the employee does not realize they need to review the procedure or other materials because they believe they know the correct procedures. The risk reduction was then further reduced to minimize duplication with M15: Enhance TIL & GDL.

The total estimate cost for this mitigation is from $1.3 million to $1.5 million expense and the Tail Average RSE was calculated to be 0.641. Additional details are shown in Table 21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-12 to WP21-16).

M15 – Enhance TIL and GDL (Technical Competence): The TIL and GDL are online repositories for PG&E's policies, standards, procedures and guidance documents. PG&E's employees, both in the office and in the field, are expected to refer to these documents whenever they are completing a new or unfamiliar task or procedure. They also serve as reference guides when an employee is uncertain what steps to take when completing assigned work. This mitigation addresses the Employee Didn't Retain Training and Training Inadequate drivers.

This mitigation will improve the ease of use and ability to search for documents from a mobile device. Most of PG&E's existing documents were developed in a format to be read from a laptop or desktop computer or printed and consumed in a paper format. With the increased availability and capability of mobile devices, updating the libraries and their contents is essential if they are to be used and accessed in the field.

This mitigation includes the following updates to the TIL and GDL: Improve ease of use through developing a standard, mobile friendly, format for new documents and reformatting of existing documents. Enhance search engine/function with key words and task names. Create the data and capability to link a specific task from the work scheduling system to the appropriate procedure or job aid.

This mitigation by itself provides little direct risk reduction, however it is essential to achieve the risk reduction estimate under mitigation M14: On the Job Support – Mobile Technology described above. When implemented with the above mitigation, PG&E estimates that this mitigation will reduce the likelihood of an event, and therefore the risk, by 2 percent. The estimate risk reduction is based on PG&E's SME judgement.

The total estimate cost for this mitigation is from $1.0 million to $1.1 million expense and the Tail Average RSE was calculated to be 0.195. Additional details are shown in

Table 21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-17 to WP21-18).

M17 – Work Scheduling Integration with Qualifications (Qualification Verification): This mitigation will automate the verification of qualifications by integrating PG&E's SAP HR system where qualifications are tracked with the work scheduling system. With this integration, as part of the work scheduling process, workers' qualifications will be checked and workers will only be assigned to complete work where they hold the necessary qualifications. Because the scheduling is often done centrally, the scheduler may not aware of each employee's specific qualifications. They know the minimum and typical qualifications for the job classification, but not each individual employee's status. It is the responsibility of the employee, crew foreman and supervisor to know and assign work to a specific individual accordingly. This mitigation addresses the Employee Didn't Retain Training, Qualification Lapsed, and Qualification Wasn't Verified drivers.

In order for this mitigation to be fully implemented, in addition to the integration between the systems, enhancements will be needed in the work scheduling process and work scheduling system, to schedule work at a more granular level. This increased granularity will allow for matching the work to the specific employee qualifications. The mitigation described below, M19: Electric and Power Generation Review and Update Expected Job Functions, will be required for the full implementation of this mitigation. Further defining and updating the electric and power generation job functions will allow PG&E to update and refine the qualifications required for each employee which will allow improved matching with work assignments.

PG&E based this estimated reduction on SMEs opinion that, for the electric risks, the estimate would be twice as effective as the implementation of Qualification Cards (see the description of M18: Qualification Cards for Electric and Power Generation for additional information below). Because of the existing Gas Operator Qualification program and the use of qualification cards, PG&E's SMEs estimated that the benefits of the additional systematic check of qualifications at the point of work scheduling to the Gas asset risks would be slightly less than those for the Electric asset risks.

The total estimate cost for this mitigation is from $2.9 million to $3.2 million expense and $0.2 million to $0.3 million capital. The Tail Average RSE was calculated to be 0.454. Additional details are shown in Table 21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-22 to WP21-24).

M18 – Qualification Cards for Electric and Power Generation (Qualification Verification): This mitigation will expand the use of Qualification Cards to Electric Operations and Power Generation. Qualification Cards contain information about the qualification status for the employee. PG&E's Gas Operations organization currently uses Qualification Cards.

The scanning of qualification cards at the yard/headquarters or job site, before work begins, reduces the risk that an employee will be requested or assigned to perform a task for which they are not currently qualified. Employees who are not currently qualified, for any reason (e.g., their training or certification may have expired, or they may never have completed the required training, or if new or different equipment is being used they may not be certified for the specific equipment) should not be assigned to complete work where those qualifications are required.

The implementation of M17: Work Scheduling Integration with Qualifications mitigation will not entirely replace the use of Qualification Cards as not all work is scheduled in PG&E's work scheduling systems. For instance, during storms and other emergency situations, crews and individual employees may be assigned work by supervisors or foremen instead of waiting for the job scheduling system to be updated. In these situations, the Qualification Cards would allow a supervisor or crew lead in the field to check an employee's qualification status before that employee is allowed to begin work. This mitigation addresses the Qualification Lapsed and Qualification Wasn't Verified drivers.

PG&E estimated the benefit of this mitigation on reducing the likelihood of an event occurring by comparing the minimum proportion of Incorrect Operations for the gas asset based risks (where qualification cards are in use) with those for the electric asset based risks (where PG&E proposes to deploy qualification cards). See Table 21-1, the low range percent passing for the gas assessments vs. the electric assessments. The difference in the two is 6 percent, which PG&E used as the estimate for the effectiveness of this mitigation. While the Power Generation Hydro Dam Failure risk does not have the Incorrect Operation driver, PG&E believes that the enterprise wide use of Qualification Cards for field employees would reinforce the message of safety and the importance of understanding what work you are qualified to do. It also holds supervisors or crew leads accountable to check and confirm that employees hold the necessary qualifications and skills before work is performed.

The total estimate cost for this mitigation is from $1.0 million to $1.1 million expense and the Tail Average RSE was calculated to be 0.008. Additional details are shown in Table 21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-25 to WP21-27).

M19 – Electric and Power Generation Review and Update Expected Job Functions (Foundational): PG&E's electric and power generation functions currently have less detail in terms of the specific qualifications and skills required to perform all of the different tasks expected of these employees. In the gas organization, the Operator Qualification program has driven a qualification focused culture which PG&E believes results in a reduced risk around employees performing work for which they are not qualified. The nuclear organization has a similar qualifications based focus for assigning and performing work. PG&E's SMEs further believe that, by bringing this same qualification focus to the electric and non-nuclear generation organizations the SQWF risk will be reduced, benefiting employees and the public.

Fundamental to a qualifications-based focus is the understanding and documenting detailed, specific tasks each employee is expected to perform and the knowledge and skills necessary to perform each task. This foundational work will continue to analyze the work performed in the electric and power generation organizations and develop the documentation necessary to create qualifications specific to the work. This mitigation addresses the Employee Didn't Retain Training and Training Inadequate drivers.

The work described in this mitigation is an ongoing activity and part of a regular business process managed by Human Resources in partnership with the LOBs. Therefore, costs are not tracked and have not specifically been estimated for this function. Because this is foundational work, no risk reduction has been estimate. Additional details are shown in Table 21-4 below and workpapers (see the workpapers for Chapter 21, pages WP21-28 to WP21-29).

M20 – Improve, Collect, and Analyze Data Related to Skill Degradation (Foundational): Understanding how quickly employees lose proficiency after training is important to determining at what point PG&E must apply some sort of mitigation in order to maintain a workforce that always has the skills and qualifications necessary to safely and effectively perform work. We know that over time we lose proficiency at tasks, sometimes it is because we do something infrequently, others it is because we become complacent in how we approach a task, and yet others may be simply due to the passage of time.

Studying the rate of skill degradation and understanding what factors influence it will allow PG&E to more efficiently determine retraining or refresher training cycles. If refresher training is required too soon there is a cost in terms of the actual training and lost productivity. In addition over time employees may become less engaged in training if they believe that they are learning things they already know. Yet if the refresh period is set too long, employees may not have the level of skill needed to safely perform work.

The total estimate cost for this mitigation is from $2.2 million to $2.5 million expense. Because this is foundational work, no risk reduction has been estimated.

Additional details are shown in Table 21-4 below and the workpapers (see the workpapers for Chapter 21, pages WP21-30 to WP21-31).

Table 21-4: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Expand BPI (Foundational)	N/A	N/A	2019	2022	D1, D2, D5	– (C) 100 - 300 (E)	– (C) 100 - 300 (E)	– (C) 100 - 300 (E)
M14A	On the Job Support – Mobile Technology – Foreman and Crew Leads	0.843	0.354	2021	2022	D4, D5	– (C) – (E)	– (C) 380 - 420 (E)	– (C) 380 - 420 (E)
M15	Enhance TIL and GDL	0.195	0.082	2021	2022	D4, D5	– (C) – (E)	– (C) 760 - 840 (E)	– (C) 247 - 273 (E)
M17	Work Scheduling Integration with Qualifications	0.454	0.192	2020	2022	D4, D6, D7	– (C) 855 - 945 (E)	– (C) 1,140 - 1,260 (E)	238 - 263 (C) 855 - 945 (E)
M18	Qualification Cards for Electric and Power Generation	0.008	0.003	2020	2021	D6, D7	– (C) 760 - 840 (E)	– (C) 190 - 210 (E)	– (C) – (E)
M19	Electric and Power Generation Review and Update Expected Job Functions (Foundational)	N/A	N/A	2020	2022	D4, D5	Not Available – not tracked separately, part of the ongoing course of business		
M21	Improve, Collect, and Analyze Data Related to Skill Degradation (Foundational)	N/A	N/A	2020	2022	D4	– (C) 46 - 50 (E)	– (C) 1,093 - 1,208 (E)	– (C) 1,093 - 1,208 (E)
PROPOSED PLAN TA RSE: 0.387[11] **TOTAL Expense and Capital by Year**							**– (C) 1,761 - 2,135 (E)**	**– (C) 3,663 - 4,238 (E)**	**238 – 263 (C) 2,674 - 3,145 (E)**

VI. Alternatives Analysis

PG&E has developed two alternative plans to the proposed mitigation plan described above. Each of these plans continues to focus on the three areas described above (Technical Competence, Qualification Verification, and Foundational) with different approaches or scope of deployment.

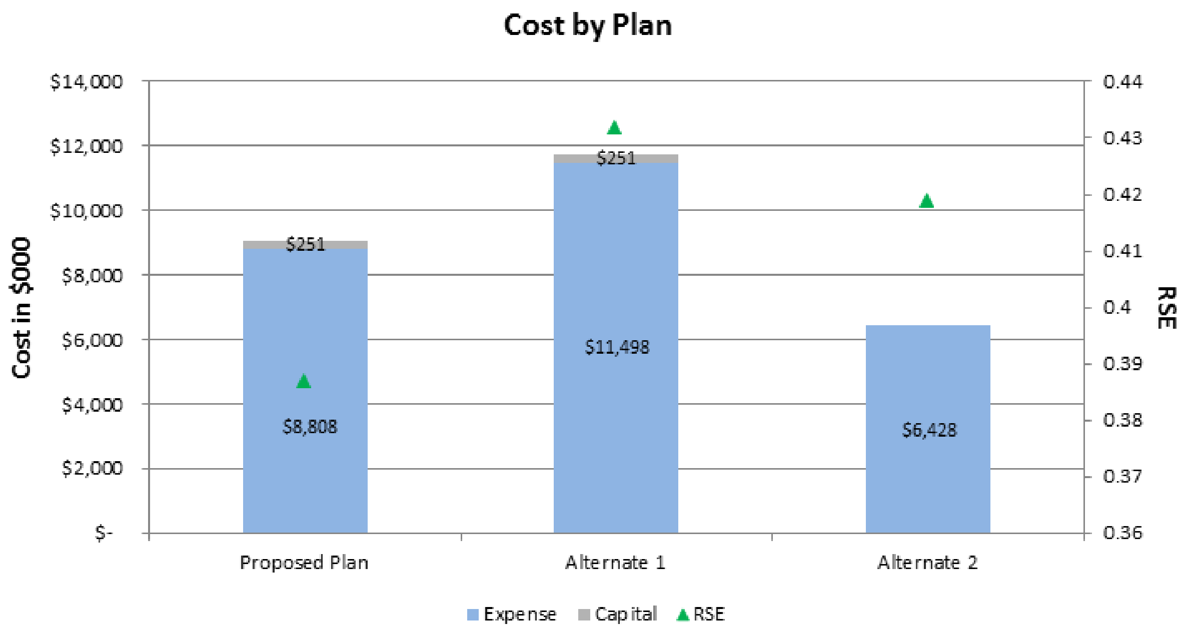
11 The cost of foundational items, while shown in the table, was not included in the Risk Spend Efficiency calculation.

Alternative Plan 1 would be a more robust approach, implementing the full list of mitigations PG&E evaluated in preparation for the RAMP filing. While the RSE would indicate this is the preferred proposal, due to limitations in technology deployment and overstatement of benefits it is not the proposed. Alternative Plan 2 although it would be a less complex solution, it was not chosen because it relies more on human based mitigations and leaves out the critical new system control in M17: Work Scheduling and Integration with Qualifications mitigation. Additional detail regarding the two alternatives is provided below. Table 21-5: Mitigation List provides a matrix comparing PG&E's proposed and alternative plans and Figure 21-4: Alternatives by Cost and RSE Score provides a summary of the three plans.

Table 21-5: Mitigation List

#	Mitigation	TA RSE (Units/$M)	EV RSE (Units/$M)	Proposed Plan	Alternative Plan 1	Alternative Plan 2	WP #
M1B	Expand BPI (Foundational)	N/A	N/A	X	X	X	WP21-9
M14A	On the Job Support – Mobile Technology – Foreman and Crew Leads	0.843	0.354	X			WP21-12
M14B	On the Job Support – Mobile Technology – All Field Employees	0.641	0.269		X	X	WP21-12
M15	Enhance TIL and GDL	0.195	0.082	X	X	X	WP21-17
M16	Implement a 24/7 Technical Support Desk	0.579	0.245		X	X	WP21-19
M17	Work Scheduling Integration with Qualifications	0.454	0.192	X	X		WP21-22
M18	Qualification Cards for Electric and Power Generation	0.008	0.003	X	X	X	WP21-25
M19	Electric and Power Generation Review and Update Expected Job Functions (Foundational)	N/A	N/A	X	X	X	WP21-28 to WP21-29
M20	Improve, Collect, and Analyze Data Related to Skill Degradation (Foundational)	N/A	N/A	X	X	X	WP21-30

Figure 21-4: Alternatives by Cost by RSE Score



A. Alternative Plan 1

The RSE for alternative plan 1 is calculated to be 0.432. It was developed to include all of the mitigations that PG&E actively evaluated as part of developing its RAMP filing to maximize risk reduction. This plan would have the following changes relative to the proposed plan:

- Replace **M14A** with **M14B – On the Job Support – Mobile Technology for All Field Employees.** This is an expansion of M14A – On the Job Support – Mobile Technology for Foremen and Crew Leads, by deploying the mobile technology to all field employees instead of just foremen and crew leads. This mitigation requires the same development as M14A – On the Job Support – Mobile Technology for Foremen and Crew Leads, described above with increased change management costs due to the larger population.
- Add **M16: Implement a 24/7 Technical Support Desk**, which would be staffed by highly skilled and experienced employees. For additional details on this mitigation please see the workpapers for Chapter 21, pages WP21-19 to WP21-21.

This alternative mitigation plan was not chosen primarily for the following reasons:

- When PG&E began evaluating mitigation alternatives it was expected that by the end of 2022 all, or most field employees would have mobile devices in the field. After further review and discussion with the Information Technology organization, the deployment of mobile devices to all field employees by the end of 2022 is uncertain. As additional employees are assigned mobile devices they will be able to take advantage of the on the job support, however for purposes of calculating the benefit from this mitigation PG&E's proposed plan only assumes that supervisors and crew foremen will have mobile devices.

- The benefits of a 24/7 help desk were difficult to estimate and PG&E believes that the benefits of this bundle of mitigations is overstated as the benefits from the 24/7 help desk would likely be at least partially duplicative of those seen when mobile technology with real-time access to procedures and other support materials was made available to all field employees.

  As data and quantification/modeling matures over the coming years, PG&E will again evaluate whether adding in a 24/7 technical help desk would be a beneficial mitigation to propose.

Table 21-6: Alternative Plan 1 and Associated Costs, provides a summary view of the mitigations evaluated as Alternative Plan 1.

Table 21-6: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Expand BPI (Foundational)	N/A	N/A	2019	2022	D1, D2, D5	– (C) 100 - 300 (E)	– (C) 100 - 300 (E)	– (C) 100 - 300 (E)
M14B	On the Job Support – Mobile Technology - All Field Employees	0.641	0.269	2021	2022	D4, D5	– (C) – (E)	– (C) 675 - 746 (E)	– (C) 675 - 746 (E)
M15	Enhance TIL and GDL	0.195	0.082	2021	2022	D4, D5	– (C) – (E)	– (C) 760 - 840 (E)	– (C) 247 - 273 (E)
M16	Implement a 24/7 Technical Support Desk	0.579	0.245	2020	2022	D4, D5	– (C) 124 - 137 (E)	– (C) 608 – 672 (E)	– (C) 1,235 - 1,365 (E)
M17	Work Scheduling Integration with Qualifications	0.454	0.192	2020	2022	D3, D6, D7	– (C) 855 - 945 (E)	– (C) 1,140 - 1,260 (E)	238 - 263 (C) 855 - 945 (E)
M18	Qualification Cards for Electric and Power Generation	0.008	0.003	2020	2021	D6, D7	– (C) 760 - 840 (E)	– (C) 190 - 210 (E)	– (C) – (E)
M19	Electric and Power Generation Review and Update Expected Job Functions (Foundational)	N/A	N/A	2020	2022	D4, D5	Not Available – not tracked separately, part of the ongoing course of business		
M20	Improve, Collect, and Analyze Data Related to Skill Degradation (Foundational)	N/A	N/A	2020	2022	D4	– (C) 46 - 50 (E)	– (C) 1,093 - 1,208 (E)	– (C) 1,093 - 1,208 (E)
ALTERNATIVE PLAN 1 TA RSE: 0.432[12] **TOTAL Expense and Capital by Year**							**-0 (C) 1,884 - 2,272 (E)**	**– (C) 4,565 - 5,235 (E)**	**238 - 263 (C) 4,204 - 4,836 (E)**

B. Alternative Plan 2

In Alternative Plan 2 PG&E evaluated the lowest cost bundle of mitigations. The RSE for alternative plan 2 is calculated to be 0.419, which is slightly higher than the 0.387 for PG&E's proposed mitigation plan. While, this alternative plan again addresses all three areas described above (Technical Competence, Qualification Verification, and Foundational), it eliminates the single systematic mitigation considered, M17: Work Scheduling Integration with Qualifications, included with PG&E's proposed mitigation plan. This continued reliance on a group of manual processes, would continue to leave open an increased opportunity for a failure due to human error.

The specific changes in Alternative Plan 2 as compared with PG&E's proposed plan are:

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12 *Ibid.*

- Replace **M14A** with **M14B - On the Job Support - Mobile Technology for All Field Employees**. This is an expansion of M14A – On the Job Support - Mobile Technology for Foremen and Crew Leads, by deploying the mobile technology to *all* field employees instead of just foremen and crew leads. This mitigation requires the same development as M14A – On the Job Support – Mobile Technology for Foremen and Crew Leads, described above.
- Add **M16: Implement a 24/7 Technical Support Desk**, which would be staffed by highly skilled and experienced employees. For additional details on this mitigation please see workpapers for Chapter 21, pages WP21-19 to WP21-21.
- Eliminate M17: Work Scheduling Integration with Qualifications.

Table 21-7 below provides a summary view of the mitigations evaluated as alternative plan 2.

Table 21-7: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE (Units/ $M)	EV RSE (Units/ $M)	Start Date	End Date	Associated Driver and Consequence	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Expand BPI (Foundational)	N/A	N/A	2019	2022	D1, D2, D5	– (C) 100 - 300 (E)	$$$ (C) 100 - 300 (E)	$$$ (C) 100 - 300 (E)
M14B	On the Job Support – Mobile Technology - All Field Employees	0.641	0.269	2021	2022	D4, D5	– (C) – (E)	– (C) 675 - 746 (E)	– (C) 675 - 746 (E)
M15	Enhance TIL and GDL	0.195	0.082	2021	2022	D4, D5	– (C) – (E)	– (C) 760 - 840 (E)	– (C) 247 - 273 (E)
M16	Implement a 24/7 Technical Support Desk	0.579	0.245	2020	2022	D4, D5	– (C) 124 - 137 (E)	– (C) 608 - 672 (E)	– (C) 1,235 - 1,365 (E)
M18	Qualification Cards for Electric and Power Generation	0.008	0.003	2020	2021	D6, D7	– (C) 760 - 840 (E)	– (C) 190 - 210 (E)	– (C) – (E)
M19	Electric and Power Generation Review and Update Expected Job Functions (Foundational)	N/A	N/A	2020	2022	D4, D5	Not Available – not tracked separately, part of the ongoing course of business		
M20	Improve, Collect, and Analyze Data Related to Skill Degradation (Foundational)	N/A	N/A	2020	2022	D4	– (C) 46 - 50 (E)	$0 (C) $1,093 - $1,208 (E)	$0 (C) $1,093 - $1,208 (E)
ALTERNATIVE PLAN 2 TA RSE: 0.419[13] **TOTAL Expense and Capital by Year**							**– (C)** **906 - 1,190 (E)**	**– (C)** **2,817 - 3,303 (E)**	**– (C)** **2,114 - 2,526 (E)**

13 *Ibid.*

VII. Metrics

PG&E uses a variety of metrics that are both lagging (actual incidents) as well as what it believes are leading (assessment pass rates, documentation assessments) to monitor the SQWF risk and to assess the impact of existing controls and mitigations. The following are the primary metrics used to track the overall SQWF risk:

- Number of incidents where an employee performs high consequence work without the proper skills and qualifications where an adverse event occurred;
- Percent of high consequence processes with completed BPI;
- BPI percent complete alignment of controls (e.g., standards, procedures, training, assessments, etc.); and
- Pass/fail rate for assessment programs for high consequence work.

Table 21-8 lists the metrics that PG&E proposes to use to evaluate the success of the proposed mitigations. PG&E has not yet established specific targets for the proposed metrics, the ongoing data collection and evaluation work will be used to determine baseline values, after which targets will be established.

Table 21-8: Proposed Mitigation Plan Metrics

Mitigation	Associated Driver #	Proposed Metric
All	All	Number of incidents where an employee performs high consequence work without the proper skills and qualifications where an adverse event occurred
M1B: Expand BPI	D1, D2, D5	• Percent of identified high consequence processes with a completed BPI • BPI percent complete alignment of controls (e.g., standards, procedures, training, assessments, etc.) • Pass/fail rate for assessment programs for high consequence work
M14A: On the Job Support – Mobile Technology – Foremen and Crew Leads	D4, D5	• Usage statistics: Number of times workers use the technology and the documents or information that is accessed • Improvement in skill degradation rate • Employee satisfaction rating of the usefulness, quality and effectiveness of the technology and available materials • Reduction in number of risk incidents (worker performing work w/out proper skills and qualifications causing an adverse impact) after implementation of the mitigation
M15: Enhance TIL and GDL	D4, D5	• Percentage of identified high priority documents that are updated to be mobile friendly. • Usage statistics will be captured under M14: On the Job Support – Mobile Technology
M17: Work Scheduling Integration With Qualifications	D6, D7, D3	Reduction in the number of risk incidents - worker performing work without proper skills and qualifications, causing an adverse event.
M18: Qualification Cards for Electric and Power Generation	D7, D6	• Percent of electric transmission and distribution field employees and non-nuclear power generation employees assigned qualification cards. • Percent of qualification card scans where a worker is found to not be qualified for assigned work. • Reduction in number of risk incidents (worker performing work w/out proper skills and qualifications)
M19: Electric and Power Generation Review and Update Expected Job Functions	D4, D5	Percent of targeted job classifications that have the more detailed (from a qualification and job function basis) requirements identified.
M20: Improve, Collect, and Analyze Data Related to Skill Degradation	D4	There is no specific metric tied to this mitigation, beyond the completion of the study.

VIII. Next Steps

In addition to continuing to support existing controls and deploy the mitigations planned or proposed for 2018 through 2022, PG&E will focus on collecting and evaluating data and process information from the proposed foundational mitigations and existing controls in order to more fully understand the nature of the risk, frequency of events, and the impact of existing controls and mitigations on the risk. This data will become an input as PG&E refines and improves the RAMP model for evaluating the SQWF risk.

PG&E's focus in 2018 and 2019 will be to develop processes to integrate incident, assessment, and business performance data in order to gain a more complete view of the work processes and the interrelationships between the processes and SQWF incidents. With these insights PG&E will be in a better position to evaluate this risk further and see where the proposed plan can be enhanced further. PG&E also expects to complete an initial review of the skilled and qualified risk as it relates to non-employee workers and in coordination with the Safety Department, develop a plan to address identified gaps.

In addition, PG&E will continue to refine its risk modeling capabilities. These refinements may include:

- Develop data sources for incidents that are not directly related to other asset based RAMP risks. This expansion of data inputs will provide a more complete picture of the frequency of events and the likely consequences when those events occur.
- Develop a framework to estimate the impact of multiple mitigations on risk reduction. This will allow PG&E to minimize the duplication of benefits and the associated overstatement or risk reduction and RSE.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 22
CLIMATE RESILIENCE

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 22
CLIMATE RESILIENCE

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

I. Executive Summary

RISK NAME	Climate Resilience
IN SCOPE	The impacts attributable to climate change on Pacific Gas and Electric Company's (PG&E or the Company) infrastructure, operations, employees, and customers associated with 11 identified Risk Assessment and Mitigation Phase (RAMP) risks.
OUT OF SCOPE	Other climate change risks posed to the Company. (The Climate Resilience model only includes inputs from 11 RAMP risks and does not consider climate change impacts on non-RAMP risks.)
DATA QUANTIFICATION SOURCES	Assessment informed by public climate change modelling, PG&E data, industry data, and subject matter expertise.

PG&E has a long history of taking action to combat climate change and is committed to building greater climate resilience. Doing so is integral to the Company's ongoing efforts to provide safe, reliable, affordable and clean energy throughout northern and central California.

From extreme weather to rising tides, the threat climate change poses to crucial sectors of the U.S. economy is becoming all too apparent. For energy providers such as PG&E, it requires taking action now to manage the potential risk to the Company's assets, infrastructure, operations, employees, and customers. PG&E is committed to partnering with stakeholders to ensure that the Company is sufficiently resilient to withstand and recover from climate-driven events and long-term trends.

PG&E is working to better understand the current and future impacts of climate change. The Climate Resilience RAMP model explores six drivers to this risk that the scientific community projects will likely increase with rising greenhouse gas (GHG) emissions: (1) rising sea levels; (2) major storm events; (3) increasing temperatures and heatwaves; (4) wildfires; (5) drought; and (6) subsidence (see associated workpaper for a discussion of these drivers, including citations). For PG&E, climate resilience is defined as the actions to be taken related to PG&E's assets, infrastructure, operations, employees and customers to mitigate against potential consequences and adapt to a changing climate and associated weather patterns.

Other natural hazards also pose risks to Company assets and infrastructure, as well as to PG&E's employees and customers, including weather-related events such as extreme winds and ice storms, as well as geohazards such as earthquakes and tsunamis. At the time of this report, due to the complex nature of extreme winds and ice storms, there is limited agreement across climate models and overall low confidence in the scientific community regarding how climate change may alter the frequency or severity of these events in PG&E's service area. Additionally, the scientific community has not found a direct relationship between climate change and earthquakes and tsunamis. PG&E will continue to review developments in the science for climate-related hazards pertaining to PG&E's service area.

As outlined in PG&E's November 2016 Climate Change Vulnerability Assessment and Resilience Strategies report,[1] building climate resilience is linked to PG&E's long-term success, business strategy, and operational objectives and actions. PG&E is increasing its climate resilience through numerous measures already underway, including an enhanced governance structure and efforts to integrate resilience into Company planning processes.

The Climate Resilience RAMP model indicates potential additional PG&E safety consequences due to climate change, even in the near term.[2] Per the model, in 2022, PG&E could experience safety consequences for PG&E's workforce and the public of an additional 25-129 injuries and 1-3 fatalities per year due to climate change impacts, and in 2050, an additional 66-173 injuries and 2-5 fatalities due to climate change impacts.

PG&E is proposing "foundational work" rather than mitigations that will help PG&E anticipate and plan for a changing "new normal" in terms of weather and climate-change related events. It is increasingly challenging to rely on historical data to determine what to expect and plan for in terms of a "100-year storm event" or "number of heatwaves per summer." Additionally, with increasing global GHG emissions, this "new normal" will evolve over time. PG&E is working in a structured manner to conduct foundational work in order to propose mitigations to reduce climate risk in PG&E's next RAMP filing. This foundational work will guide PG&E's efforts to design a Companywide climate change risk integration strategy. This strategy will inform resource planning and investment and operational decisions, and result in the potential for additional programs to identify and pursue mitigations that will incorporate the resilience and safety of PG&E's assets, infrastructure, operations, employees, and customers.

In future RAMP filings, the Company plans to explore how best to assess mitigations and RSEs with respect to increasing climate resilience. As discussed in Chapter A, PG&E's risk mitigation process will continue to evolve, incorporating new data and analysis. For example, learnings from the recent catastrophic North County firestorms may help inform PG&E's climate resilience mitigation plans.

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1 http://www.pgecurrents.com/wp-content/uploads/2016/02/PGE_climate_resilience.pdf.

2 Supporting analysis and figures for these findings are provided in a workpaper appended to this chapter.

II. Risk Assessment

A. Background

Climate resilience is defined as the actions to be taken related to PG&E's assets, infrastructure, operations, employees and customers to mitigate against the potential consequences of and adapt to a changing climate and associated weather patterns. The Climate Resilience RAMP risk is a cross cutting risk similar to the Skilled and Qualified workforce risk and the Enterprise Records and Information Management risk. However, the Climate Resilience RAMP risk is unique. It is the only risk for which PG&E examines two timeframes (2022 and 2050), and two GHG emissions scenarios (Scenarios A and B). PG&E examined two timeframes to assess climate change-related risk within the next General Rate Case period (ending in 2022) as well as within a reasonable planning horizon (ending in 2050). PG&E examined two GHG emissions scenarios to capture a range of possible climate change impacts associated with different levels of GHGs in the atmosphere. Scenario A denotes relatively low GHG emission projections; and Scenario B denotes relatively high GHG emission projections.

Climate resilience is also unique in applying climate change multipliers to assess potential increased safety consequences due to climate change impacts. The goal of the risk assessment was to quantify the potential increase in baseline consequences due to the escalating effects of climate change using probabilistic modelling and the risk quantification methodology implemented across the PG&E RAMP risks.

B. Exposure

PG&E is working to prepare for both near- and longer-term impacts from climate change and examining both low and high projections of GHG emissions. The state of California recommends that state agencies use higher GHG emission scenarios (such as Scenario B) for climate change resilience planning before 2050.[3] Therefore, PG&E is considering Scenario B projections as a "new normal" on which to base preparations for mean and extreme risks posed by climate change in the near- and longer-term.

For RAMP stand-alone risks, such as Transmission Pipeline Rupture with Ignition, the exposure is defined as the asset class and footprint covered by the risk such as miles of gas transmission pipeline. For cross cutting risks, like Climate Resilience, the exposure is one level higher, focusing on the stand-alone risks

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3 "Planning and Investing for a Resilient California: A Guidebook for State Agencies" (2017).

themselves rather than the specific asset class or footprint to which the stand-alone risk applies. There are currently 11 stand-alone risks included in RAMP that are affected by climate change and therefore contribute to the climate change risk exposure. The owners of PG&E's stand-alone risks (Risk Owners) and Subject Matter Experts (SMEs) assessed the exposure of PG&E's footprint to climate change drivers. The 11 stand-alone risks PG&E used in its Climate Resilience model are identified below.

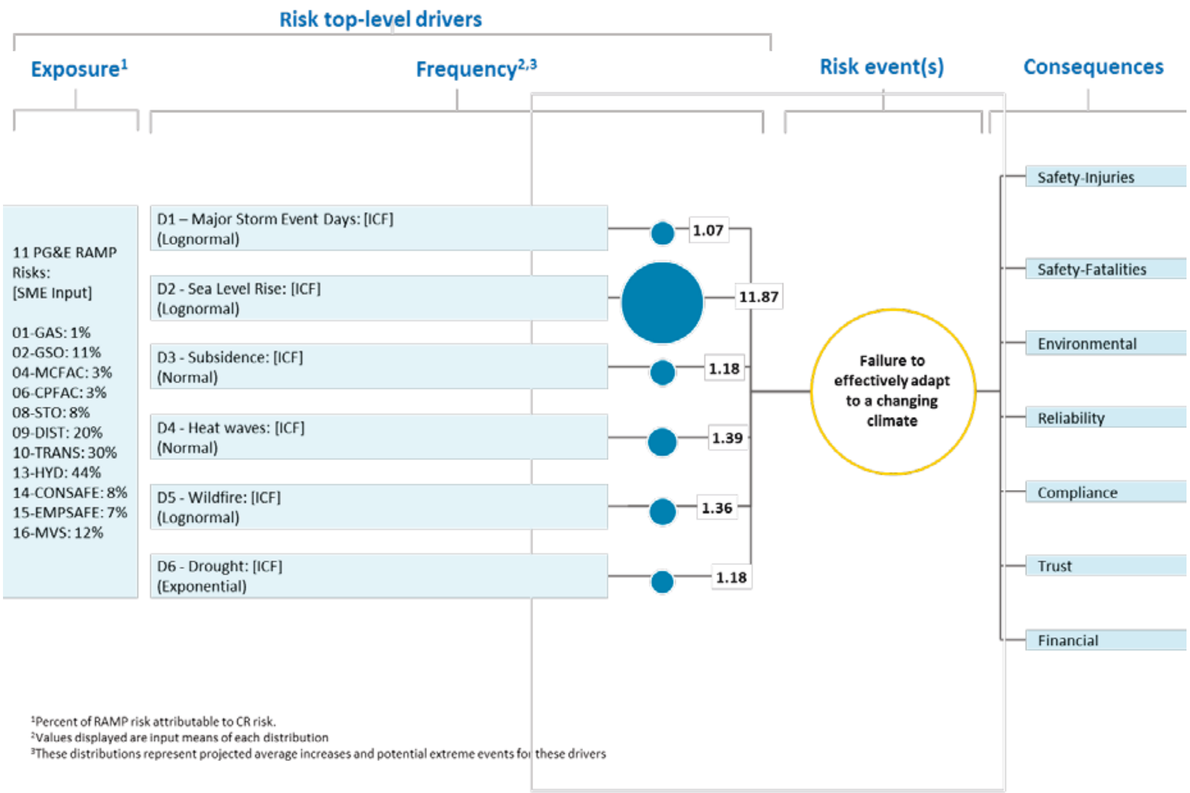
Table 22-1: Stand-Alone Risks That Provide Inputs Into Climate Resilience RAMP Model

Code	Risk Name
DOCP	Distribution Overhead Conductor Primary
TRANS	Transmission Overhead Conductor
STO	Natural Gas Storage Well Failure – Loss of Containment with Ignition at Storage Facility
GSO	Failure to Meet Capacity for System Demands
CPFAC	Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility
MCFAC	Measurement and Control (M&C) Failure – Release of Gas with Ignition at M&C Facility
GAS	Transmission Pipeline Rupture with Ignition
HYD	Hydro System Safety - Dams
MVS	Motor Vehicle Safety
EMPSAFE	Employee Safety
CONSAFE	Contractor Safety

Because RAMP is a safety-related proceeding, only top safety risks, as identified through the RAMP process, were analyzed in this version of the Climate Resilience model. Other PG&E risks were excluded. For example, PG&E considers the catastrophic failure of a substation to be primarily a reliability risk, and thus did not analyze this risk in the current iteration of the Climate Resilience model. Nevertheless, PGE&E believes that its related assets and physical locations, such as substations, could be impacted by climate change. For these reasons, PG&E believes that the exposure and impact of climate change on potential baseline consequences may be greater than is discussed in this chapter.

PG&E used the bow tie methodology to develop a quantitative operational risk model specific to Climate Resilience risk. The risk bow tie in Figure 22-1, below, is an illustrative representation of the analysis performed, depicting the exposure and drivers and how they contribute to the likelihood and consequence of the risk event. The risks listed in the exposure section of the bow tie figure are those that have been identified as impacted by Climate Change. The percentages listed are representative of the percentage of risk driver events SMEs attribute to impacts from Climate Change. See Figure 22-2 for more detail on how the risk driver events and Subject Matter Expertise is incorporated into the Climate Resilience model.

Figure 22-1: Risk Bow Tie



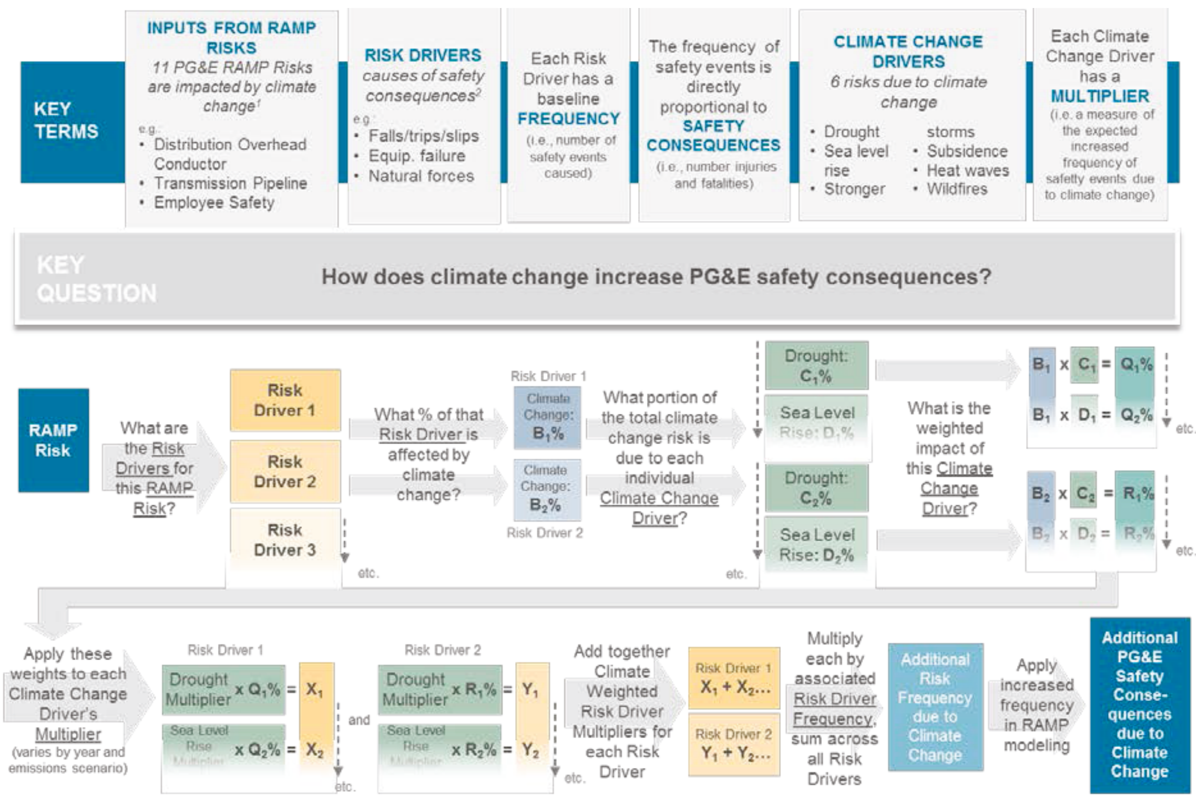
C. Drivers and Associated Frequency

PG&E has prioritized building resilience to the following six risk drivers: Major Storm Event Days, Sea Level Rise, Subsidence, Heat Waves, Wildfire, and Drought. To quantify risk for these drivers, PG&E relied on a combination of historical and projected information for key climate and weather variables. PG&E describes the model, data, methods used to characterize the historic and projected information, and key assumptions related to deriving multipliers for each of the risk drivers in an associated workpaper. In all cases, PG&E has endeavored to use the best available scientific information to inform its approach and analysis. Climate change is an active area of scientific investigation, and while PG&E aims to use the most up-to-date information, PG&E acknowledges that new information may become available during this proceeding that could affect the results shown here.

In the Climate Resilience model (and as described in Figure 22-2), PG&E applied climate change multipliers associated with the six drivers to the individual stand-alone risk drivers for each stand-alone risk based on guidance from SMEs and

Risk Owners. Multipliers can be interpreted as: how much a risk driver increases in frequency due to the changing climate. For example, a drought multiplier of 1.40 in 2050 implies that the number of months of drought in 2050 may increase by a factor of 40 percent from the baseline. Applying multipliers increases the potential frequency of risk events and proportionally increases the risk consequence outcomes for each of the 11 stand-alone risks affected by climate change. The figure below illustrates the process by which multipliers are used in the Climate Resilience modeling.

Figure 22-2: Climate Resilience Risk Modeling: Multiplier Methodology



1. Affected RAMP risks are: Distribution OH Conductor, Transmission OH Conductor, Storage – Wells, Maintaining System Capacity, Compression & Processing Facility, Measurement & Control Facility, Transmission Pipeline, Hydro Dam Failure, Motor Vehicle Safety, Employee Safety, and Contractor Safety
2. See Table A for full list of risk drivers by RAMP Risk

PG&E developed climate change multipliers to capture the expected increased frequency of risk events due to climate change. There is one multiplier per climate change driver. A multiplier of 1 is equivalent to no change compared to the historical event frequencies, which are assumed to be consistent with the baseline year of 2017. We assumed the six climate change multipliers to be independent of each other (non-correlated) in the model.

Table 22-2 provides multipliers for climate drivers during the two climate timeframes we are preparing for: 2022 and 2050. We have generated ranges for each of these multipliers based on historic data and future models to capture not only mean expected future conditions but also extreme events (tail average) and the uncertainty associated with projected climate information.

For context, multiplier averages presented in Table 22-2 can be interpreted as the average percent increased frequency of risk events due to climate change. Taking drought as an example, the estimate is an average increase of 9-18 percent in the number of months PG&E's service territory that will experience moderate drought by 2022. Similarly, the estimate is an average increase of 20-40 percent in the number of months of moderate drought by 2050. However, these averages do not present the whole picture. Through utilizing a multiplier distribution rather than just an average as inputs into the Climate Resilience model, we are capturing not only projected average increases but also potential extreme events associated with these drivers.

Table 22-2: Climate Resilience Multiplier Means and Distributions

Climate Drivers	2022 Potential Multipliers	2050 Potential Multipliers
Major Storm Event Days (number of major event days per year)	Scenario A: 1.00 ± SD: 1.39 Scenario B: 1.07 ± SD: 1.39 *Log-normal Distribution* *Truncated Range: 0.0 – 52.90**	Scenario A: 1.00 ± SD: 1.39 Scenario B: 1.15 ± SD: 1.39 *Log-normal Distribution* *Truncated Range: 0.0 – 52.90**
Sea Level Rise (inches of sea level rise by 2022, 2050)	Scenario A: 1.53 ± SD: 2.84 Scenario B: 11.87 ± SD: 2.84 *Log-normal Distribution*	Scenario A: 6.50 ± SD: 5.22 Scenario B: 34.37 ± SD: 5.22 *Log-normal Distribution*
Subsidence (inches of subsidence per month)	Scenario A: 1.09 ± SD: 0.40 Scenario B: 1.18 ± SD: 0.40 *Normal Distribution*	Scenario A: 1.20 ± SD: 0.40 Scenario B: 1.40 ± SD: 0.40 *Normal Distribution*
Heat Waves (number of 5-day heat waves per year)	Scenario A: 1.00 ± SD: 0.86 Scenario B: 1.39 ± SD: 0.97 *Normal Distribution* *Truncated Range: 0.0 – 52.14**	Scenario A: 1.99 ± SD: 1.12 Scenario B: 2.45 ± SD: 1.15 *Normal Distribution* *Truncated Range: 0.0 – 52.14**
Wildfire (percent of PG&E service area burned per year)	Scenario A: 1.23 ± SD: 1.08 Scenario B: 1.36 ± SD: 1.08 *Log-normal Distribution* *Truncated Range: 0.0 – 381.68**	Scenario A: 1.60 ± SD: 1.08 Scenario B: 1.98 ± SD: 1.08 *Log-normal Distribution* *Truncated Range: 0.0 – 381.68**
Drought (number of months of moderate drought per year)	Scenario A: 1.09 (Mean) Scenario B: 1.18 (Mean) *Exponential Distribution* *Truncated Range: 0.0 - 3.64**	Scenario A: 1.20 (Mean) Scenario B: 1.40 (Mean) *Exponential Distribution* *Truncated Range: 0.0 - 3.64**

*Constrains the range to maximum possible in one year

D. Consequences

The consequences of climate change are considered in the context of how much worse climate change could make PG&E's other risks. The multi attribute risk score (MARS) is calculated for the average impact and the tail average impact for each of the two scenarios contemplated in this analysis (Scenario A and Scenario B.) The MARS presented in Table 22-3 show the respective Climate Resilience risk scores, which can be interpreted as a quantification of PG&E's incremental risk from climate change, in addition to the 11 stand-alone risks affected by climate change.

Given that the Climate Resilience RAMP risk is a cross-cutting model, the consequence attributes for the Climate Resilience model are a direct result of the 11 stand-alone risks which contributed to the model. As such, there exists consequence data for each of the 11 stand-alone risks as well as for the years and scenarios analyzed. All of the outputs are presented in a workpaper appended to this chapter.

Table 22-3: Overall Preliminary Climate Resilience Average MARS

Scenario	MARS Overall Average Risk Score (Mean)	MARS Overall Average Risk Score (Tail Average)
2022A	19.08	592.43
2022B	80.41	665.33
2050A	76.06	658.80
2050B	226.57	845.01
Source: 22 - CR - Climate Resilience Risk - DRAFT - v3.21.xlsm\.		

Figure 22-3: Consequence Attribute

	Safety-Injuries	Safety-Fatalities	Environmental	Reliability	Compliance	Trust	Financial
Source							
	Aggregation of inputs from associated RAMP risks						
Outcome-TA-NU[1]	128.11	3.13	$ 46,682,612	105,499,888	$ 33,663,334	8.64%	$ 384,260,608
Outcome-TA-MARS[2]	34.97	85.22	4.27	263.75	3.37	43.19	230.56
						MARS Total	665.33

[1]Ave of Year 1-6 Tail Ave outcomes in Natural units
[2]Ave of Year 1-6 Tail Ave outcomes in MARS units

III. 2016 Controls and Mitigations (2016 Recorded Costs)

Building climate resilience is linked to PG&E's long-term success, business strategy, and operational objectives and actions. PG&E has participated in numerous third-party-led studies to assess impacts and costs of different climate scenarios, including research conducted by the University of California Berkeley, the California Department of Water Resources, the Bay Area Council, and the Electric Power Research Institute.

Planning for climate change is a long term process; however, the impacts from climate change may be experienced by PG&E in the near term. As such, PG&E prioritized emergency preparedness and response as well as information gathering to support long-term planning for climate resilience. In 2016, PG&E inventoried actions across the Company already aimed at improving climate resilience; however, more active internal coordination is planned to ensure the Company continues to make long-term investment decisions using new information on climate change impacts as it becomes available.

PG&E is also focused on building climate resilience in the communities it serves. PG&E is working to further embed management of climate hazards into key functional areas within the business—from risk management to emergency preparedness and response. PG&E recognizes that collaborating with, and listening to, external stakeholders is crucial to this process. PG&E is actively engaging in resilience-related dialogues with national, state and local stakeholders to help guide the Company's climate resilience strategy.

PG&E designated climate resilience an enterprise risk in 2017. As a result, PG&E did not capture costs associated with climate resilience in a systematic way in 2016; PG&E began systematically capturing these costs in 2017.

IV. Current Mitigation Plan (2017-2019)

This section describes a series of foundational work activities PG&E is undertaking to better understand the risks posed to the Company by climate change and to increase the Company's climate resilience. This foundational work will allow PG&E to identify gaps within planned mitigations.

M1A – Develop and Pilot Climate Resilience Screening Tool: Ensuring Companywide access to pertinent and useable information about projected climate change impacts is essential to increasing PG&E's resilience. PG&E is in the process of developing a Climate Resilience Screening Tool, which will help incorporate climate risk mitigation into PG&E's decision-making through existing processes such as new major infrastructure investments. PG&E expects to develop an initial version of this tool by the end of 2018.

M1B – Implement Climate Resilience Screening Tool: PG&E will implement the Climate Resilience Screening Tool within the entire Company and build it out to cover all climate impacts of concern. The tool will make climate impact information readily available and help guide decisions in the face of a changing climate.

M2 – Establish Standardized Process to Respond to Community Requests for Climate Impact Information: Building climate resilience will require collaboration with other organizations, including state and local government agencies. As such, PG&E is committed to collaborating on risk mitigation activities through partnerships and data sharing whenever possible. California Senate Bill 379 requires cities and counties to include climate adaptation and resilience strategies in the safety elements of their general plans upon the next revision on or after January 1, 2017. To be responsive to requests from communities within PG&E's service area, PG&E is developing a standardized process to provide information on the resilience of the gas and electric services it provides. PG&E also is exploring working with the state and other utilities to better serve community data requests through standardized processes and repositories.

M3 – Establish Governance for Integrating Climate Resilience Into Line of Business (LOB) Procedures: In 2017, PG&E established an executive-level Climate Resilience Coordination Committee and a supporting Climate Resilience Working Group, which meet regularly to govern and guide the work of incorporating climate resilience across the Company.

M4 – Administer the Better Together Resilient Communities Grant Program (BTRC Grant Program): Beginning in 2017, the PG&E Corporation Foundation is administering the Better Together Resilient Communities grant program, a five-year, $2 million shareholder-funded grant program to support climate resilience in the communities PG&E serves. Each year for the next five years, the PG&E Corporation Foundation will award four $100,000 grants, adding up to $2 million. The grant program focuses on increasing the resilience of communities in PG&E's service area, prioritizing projects in disadvantaged communities that are replicable and have a measurable impact. This program will not only build community engagement around climate resilience, but it will provide replicable case studies which can be used more broadly across PG&E's service area and beyond. PG&E will make the findings and lessons learned from the projects publicly available.

M5A – Develop Climate Resilience Metrics: PG&E will begin work on developing internal metrics to track and measure progress addressing the risks associated with climate change, the impacts of climate change on PG&E, as well as Company actions to address these impacts.

M6 – Train PG&E Staff on Climate Resilience: PG&E recognizes that climate resilience should underpin decisions across all lines of business. To equip PG&E staff to utilize climate resilience tools and metrics, PG&E will develop trainings with an initial focus on employees involved in planning decisions. This training will be closely linked with other work streams within this RAMP filing. PG&E will train employees about the risk climate change poses to the Company's assets, infrastructure, operations, employees and customers; and how to use the Climate Resilience Screening Tool.

M7A – Conduct Risk Driver-Specific Deep Dives: PG&E intends to do one "deep dive" into a different climate change driver each year. Part of this work will include conducting pilot projects to increase PG&E's understanding of the potential risks climate change poses to PG&E's assets, infrastructure, operations, employees, and customers. Each deep dive will access and utilize publicly-available information and prioritize information specific to PG&E's decision-making processes. For each deep dive, an example of the types of activities that may be conducted is provided below.

- M7A1 – Sea Level Rise Deep Dive:
  - Determine data needs of PG&E's LOBs for future modeling and risk analysis;
  - Pilot sea level rise and flooding scenario with Company infrastructure to assess localized operational impacts; and
  - Integrate results of research and studies into near- and longer-term infrastructure planning to incorporate resilience into vulnerable systems and system reliability.
- M7A2 – Wildfire Deep Dive:
  - Continue PG&E's ongoing efforts to assess wildfire risk through weather estimate models, support public education campaigns to raise awareness about wildfire prevention and response, and engage in wildfire prevention methods;
  - Pilot additional ways to incorporate wildfire risk into Company systems and processes; and
  - Pilot analysis of potential interactive effects between climate change drivers, such as drought, increasing temperatures, and wildfire.
- M7A3 – Increasing Temperatures and Heatwaves Deep Dive:
  - Continue PG&E's ongoing efforts to use PG&E's heat storm model to provide advance estimates of heat wave duration and outage estimates and pilot ways to mitigate peak demand during heat events;
  - Pilot ways to incorporate rising temperatures and heatwave risk from scenario planning into Company systems and processes, such as integrated resource planning; and
  - Pilot analysis of potential interactive effects of climate change drivers.

M8 – Research and Study Climate Impacts: PG&E intends to support ongoing climate change research to evolve PG&E's understanding of potential climate change impacts within its service area and the risks posed to PG&E's assets, infrastructure, operations, employees, and customers. This work will include incorporating new climate change data analysis, visualization, and modeling and will be foundational to building PG&E's climate resilience.

M9 – Develop LOB Plans for Asset Prioritization: PG&E will develop LOB-specific plans to prioritize assets at risk from the impacts of climate change and develop a framework to assess the need to replace, upgrade, harden or relocate infrastructure. This foundational work will enable PG&E to prioritize investments over time to increase PG&E's climate resilience.

Table 22-4: 2017-2019 Mitigation Work and Associated Costs

#	Mitigation Name	Start Date	End Date	Associated Driver #	2017 Estimate ($000)	2018 Estimate ($000)	2019 Estimate ($000)
M1A	Develop and Pilot Climate Resilience Screening Tool	2017	2018	All	86	130	–
M1B	Implement Climate Resilience Screening Tool	2018	2019	All	–	34	77
M2	Establish Standardized Process to Respond to Community Requests for Climate Impact Information	2017	2017	All	19	–	–
M3	Establish Governance for Integrating Climate Resilience into LOB Procedures	2017	2019	All	55	–	–
M4	Administer the BTRC Grant Program	2017	2019	All	34	40	41
M5A	Develop Climate Resilience Metrics	2018	2019	All	–	137	157
M6	Train PG&E Staff on Climate Resilience	2018	2019	All	–	136	156
M7A1	Sea Level Rise Deep Dive	2017	2017	Sea Level Rise	90	–	–
M7A2	Wildfire Deep Dive	2018	2018	Wildfire	–	104	–
M7A3	Increasing Temperatures/Heatwaves Deep Dive	2019	2019	Heatwaves	–	–	128
M8	Research and Study Climate Impacts	2017	2019	All	155	103	138
M9	Develop LOB plans for asset prioritization	2017	2019	All	45	99	102
TOTAL Expense by Year					**518**	**783**	**798**

V. Proposed Mitigation Plan (2020-2022)

This section describes the proposed climate resilience foundational work plan for 2020-2022, which will build upon the Company's previous work. This Climate Resilience RAMP filing is unique and foundational when compared to other RAMP risks and their associated models in that it does not directly propose risk mitigations, but is intended to create knowledge, tools, and a platform through which to mitigate risk when applied by PG&E's lines of business in the future. PG&E did not consider mitigations in the Climate

Resilience model and therefore did not calculate RSEs. Consequently, there is no expected quantified risk reduction.

PG&E cannot control the societal impacts of climate change. However, PG&E can build an understanding of short- and long-term climate impacts and Company vulnerabilities in to manage the potential risk to the Company's assets, infrastructure, operations, employees, and customers. The foundational work proposed here will not impact the climate change drivers per se, but will work to reduce the impact posed by these drivers over time.

PG&E prioritizes providing safe, reliable, affordable and clean energy to its customers. Currently, PG&E's climate resilience activities and RAMP filing are focused on increasing understanding of the risks posed by climate change. Based on this increased understanding of risks that PG&E faces, the Company will propose climate resilience-related mitigations across lines of business to reduce PG&E's vulnerability to the impacts of a changing climate.

M5B – Develop and Report on Climate Resilience Metrics: PG&E will develop and report on climate resilience metrics to track the Company's progress in reducing risk from climate change. These metrics will reflect actions to reduce risk to its assets, infrastructure, operations, employees, and customers. The details of what will be tracked, how it will be tracked, and how it will be reported will be determined in consultation with relevant stakeholders.

M7B – Conduct Risk Driver-Specific Deep Dives: PG&E intends to do one "deep dive" into a different climate change driver each year. Part of this work will include conducting pilot projects to increase understanding of the potential risks climate change poses to the Company's assets, infrastructure, operations, employees, and customers. Each deep dive will access and utilize publicly-available information and prioritize information specific to PG&E's decision-making processes. PG&E will integrate information into the Screening Tool as a way to inform PG&E's decision-making. For each deep dive, an example of the types of activities that may be conducted is provided below. The ordering of the Deep Dives may change based on opportunities or available data.

- M7B1 – Major Storm Event Days Deep Dive:
    - Build on PG&E's ongoing efforts to use storm models to predict sustained power outages across its service area, identify high-risk areas susceptible to rainfall-induced landslides, and identify resources needed to build resilience to increasing storm severity and frequency;
    - Pilot ways to incorporate changing storm dynamics into Company systems and processes and to protect vulnerable infrastructure; and

- Pilot analysis of interactive effects of climate change drivers, such as the impacts of stronger storms as well as periods of drought on hydropower infrastructure and generation.

- M7B2 – Drought Deep Dive:
  - Build on PG&E’s ongoing efforts to collaborate on research to better measure and monitor snowpack, climate soil moisture and other factors to improve monitoring and predictive tools for hydroelectric operations and pilot water conservation techniques;
  - Pilot ways to incorporate changing drought frequency and severity into Company systems and processes and to protect vulnerable infrastructure; and
  - Pilot analysis of interactive effects of climate change drivers, such as drought effects on land subsidence.
- M7B3 – Subsidence Deep Dive:
  - Build on PG&E’s ongoing efforts to assess and monitor assets in subsidence zones, and pilot strategies to reduce risk to vulnerable infrastructure;
  - Pilot ways to incorporate increasing subsidence risk into Company systems and processes; and
  - Pilot analysis of interactive effects of climate change drivers, such as subsidence and flooding from sea level rise and stronger storms.

Table 22-5: Proposed Mitigation Plan and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Implement Climate Resilience Screening Tool	N/A	N/A	2020	2022	All	74	77	79
M4	Administer the BTRC Grant Program	N/A	N/A	2020	2022	All	42	43	45
M5B	Develop & Report on Climate Resilience Metrics	N/A	N/A	2020	2022	All	159	161	164
M6	Train PG&E Staff on Climate Resilience	N/A	N/A	2020	2022	All	158	160	163
M7B1	Major Storm Event Days Deep Dive	N/A	N/A	2020	2020	Major Storm Event Days	135	–	–
M7B2	Drought Deep Dive	N/A	N/A	2021	2021	Drought	–	137	–
M7B3	Subsidence Deep Dive	N/A	N/A	2022	2022	Subsidence	–	–	139
M8	Research and Study Climate Impacts	N/A	N/A	2020	2022	All	139	140	142
M9	Develop LOB Plans for Asset Prioritization	N/A	N/A	2020	2022	All	105	109	112
TOTAL Expense by Year							**812**	**828**	**844**

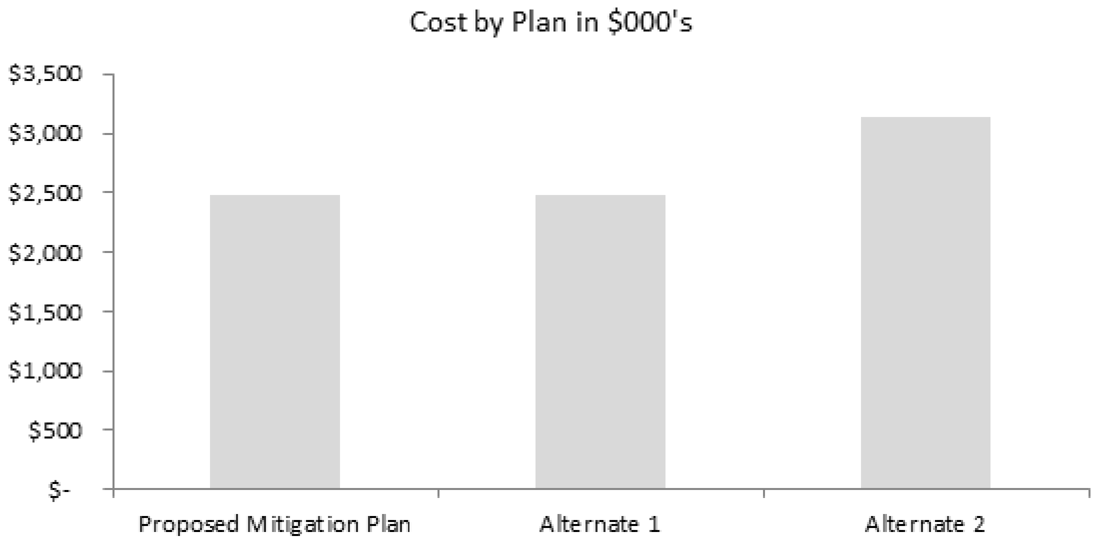
VI. Alternatives Analysis

After assessing all of the mitigations, PG&E has two Alternative plans to the proposed mitigation plan. Plan 1 was created based on the assumption that an accelerated undertaking of the deep dives would accelerate the Company’s ability to incorporate more detailed climate change information into PG&E’s decision making. Plan 2 was created based on the assumption that more funding for training and deep dives, would enable those activities to be undertaken in a more comprehensive manner. Table 22-6 shows the mitigations considered in the proposed and alternatives plans and Figure 22-4 shows each plan’s cost. The components of the two alternative plans and their cost are shown below in Tables 22-7and 22-8, respectively.

Table 22-6: Mitigation List

#	Mitigation	Expected Value Risk Spend Efficiency Score (Units/ 1$M)	Tail Average Risk Spend Efficiency Score (Units/ 1$M)	Proposed Plan	Alternative 1	Alternative 2	WP #
M1B	Implement Climate Resilience Screening Tool	N/A	N/A	X	X	X	WP 22-32
M4	Administer the BTRC Grant Program	N/A	N/A	X	X	X	WP 22-28
M5B	Develop & Report on Climate Resilience Metrics	N/A	N/A	X	X	X	WP 22-36
M6	Train PG&E Staff on Climate Resilience	N/A	N/A	X	X		WP 22-40
M6	Train PG&E Staff on Climate Resilience (50 percent increase in resources)	N/A	N/A			X	WP 22-40.
M7B1	Major Storm Event Days Deep Dive	N/A	N/A	X			WP 22-44
M7B1	Major Storm Event Days Deep Dive (accelerated pace)	N/A	N/A		X		WP 22-44
M7B1	Major Storm Event Days Deep Dive (doubled resources)	N/A	N/A			X	WP 22-44
M7B2	Drought Deep Dive	N/A	N/A	X			WP 22-47
M7B2	Drought Deep Dive (accelerated pace)	N/A	N/A		X		WP 22-47
M7B2	Drought Deep Dive (doubled resources)	N/A	N/A			X	WP 22-47
M7B3	Subsidence Deep Dive			X			WP 22-50
M7B3	Subsidence Deep Dive (accelerated pace)	N/A	N/A		X		WP 22-50
M7B3	Subsidence Deep Dive (doubled resources)	N/A	N/A			X	WP 22-50
M8	Research and Study Climate Impacts	N/A	N/A	X	X	X	WP 22-20
M9	Develop LOB Plans for Asset Prioritization	N/A	N/A	X	X	X	WP 22-24

Figure 22-4: Alternatives by Cost



A. Alternative Plan 1

The Alternative 1 foundational work would conduct all three of the deep dive projects (major storm event days, drought, and subsidence deep dives) in 2020 instead of conducting them one per year (2020-2022). All other foundational work would remain the same. The deep dives are essential to help PG&E better understand how climate change impacts PG&E's assets, infrastructure, operations, employees and customers, as well as the steps we can take to reduce the risks posed by a changing climate. The earlier this work is conducted, the more quickly PG&E can incorporate lessons learned into PG&E's planning and processes and the development of measurement approaches. However, given the significant level of activity involved in the climate resilience foundational work, PG&E determined that conducting one deep dive per year is a more realistic level of effort. Because this alternative is foundational work rather than a mitigation, there will be no effect on RSE.

Table 22-7: Alternative Plan 1 and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Implement Climate Resilience Screening Tool	N/A	N/A	2020	2022	All	74	77	79
M4	Administer the BTRC Grant Program	N/A	N/A	2020	2022	All	42	43	45
M5B	Develop & Report on Climate Resilience Metrics	N/A	N/A	2020	2022	All	159	161	164
M6	Train PG&E Staff on Climate Resilience	N/A	N/A	2020	2022	All	158	160	163
M7B1	Major Storm Event Days Deep Dive	N/A	N/A	2020	2020	Major Storm Event Days	135	–	–
M7B2	Drought Deep Dive	N/A	N/A	2020	2020	Drought	135	–	–
M7B3	Subsidence Deep Dive	N/A	N/A	2020	2020	Subsidence	135	–	–
M8	Research and Study Climate Impacts	N/A	N/A	2020	2022	All	139	140	142
M9	Develop LOB Plans for Asset Prioritization	N/A	N/A	2020	2022	All	105	109	112
TOTAL Expense by Year							**1,082**	**691**	**705**

B. Alternative Plan 2

The Alternative 2 foundational work differs from the proposed plan in two ways: (1) increase funding for training PG&E staff on climate resilience by 50 percent; and (2) double funding for each of the deep dives. All other foundational work would remain the same. Increasing funding for training would enable PG&E to deploy climate resilience training to selected groups in PG&E's field offices, as well as the development of online course trainings to reach all PG&E staff.

Increasing funding for the deep dives would allow PG&E to investigate each climate change impact in two locations instead of one. PG&E's service area covers approximately two-thirds of the state of California, and, as such, is very diverse. Having the opportunity to do deep dives in geographically diverse parts of the service area would help capture some of this variability and increase PG&E's understanding of how climate change impacts its assets, infrastructure, operations, employees and customers, as well as the steps we can take to reduce the risks posed by a changing climate.

Alternative 2 would provide the opportunity to increase the pace of PG&E's climate resilience initiative in important ways; however, it would increase costs by 26 percent, and it was not selected it in an effort to prioritize customer affordability. Because this alternative is foundational work rather than a mitigation, there will be no measurable risk reduction and therefore no calculated RSE.

Table22-8: Alternative Plan 2 and Associated Costs

#	Mitigation Name	TA RSE	EV RSE	Start Date	End Date	Associated Driver #	2020 Estimate ($000)	2021 Estimate ($000)	2022 Estimate ($000)
M1B	Implement Climate Resilience Screening Tool	N/A	N/A	2020	2022	All	74	77	79
M4	Administer the BTRC Grant Program	N/A	N/A	2020	2022	All	42	43	45
M5B	Develop & Report on Climate Resilience Metrics	N/A	N/A	2020	2022	All	159	161	164
M6	Train PG&E Staff on Climate Resilience	N/A	N/A	2020	2022	All	237	241	244
M7B1	Major Storm Event Days Deep Dive	N/A	N/A	2020	2020	Major Storm Event days	269	–	–
M7B2	Drought Deep Dive	N/A	N/A	2021	2021	Drought	–	274	–
M7B3	Subsidence Deep Dive	N/A	N/A	2022	2022	Subsidence	–	–	278
M8	Research and Study Climate Impacts	N/A	N/A	2020	2022	All	139	140	142
M9	Develop LOB Plans for Asset Prioritization	N/A	N/A	2020	2022	All	105	109	112
TOTAL Expense by Year							**1,026**	**1,045**	**1,064**

VII. Metrics

As discussed above, PG&E will be performing an evaluation of effective metrics related to climate resilience as part of its foundational activities. PG&E will propose metrics for measuring successful risk reduction based on the findings of that work.

VIII. Next Steps

California has experienced a series of extreme weather events, which raises the potential for a "new normal" that will continue to evolve over time. Consistent with this evolution, PG&E's climate resilience efforts will be cyclical, where we take steps in the near-term while simultaneously updating our knowledge with the most recent climate change science, which in turn will transform how we put information into action in the future.

PG&E recognizes the significance of climate change impacts and has begun incorporating climate resilience into its decision-making. PG&E's 2016 Climate Change Vulnerability Assessment and Resilience Strategies report highlighted areas of PG&E's potential climate change risk exposure. The quantitative Climate Resilience RAMP modeling exercise, described in this chapter, confirms that PG&E faces additional financial, safety, reliability, compliance, environmental and trust risks from various climate drivers. Importantly, the potential consequences indicated by the Climate Resilience model consider inputs only from the 11 operational risk models included in this filing and do not predict consequences for PG&E's other risks as discussed in the exposure section above.

Areas for continued model development and risk quantification include building out a more inclusive Climate Resilience model. PG&E plans to explore incorporating data from the high GHG emissions scenario directly into stand-alone risk models so that the Climate Resilience model is integrated into the other Company models. Incorporating future projections of climate and weather data will streamline the Company's approach to understanding and mitigating future risks from climate change across different lines of business.

Additionally, PG&E's enhanced management of climate resilience metrics could improve the accuracy of the inputs to future RAMP models. Therefore, the foundational work proposed in this chapter is critical for ensuring the Company is prepared to protect its assets, infrastructure, operations, employees and communities. The results and understandings from the foundational work will inform future proposed mitigations.

PG&E intends to continue to prioritize climate resilience action post-2022, including building on many of the RAMP activities described in this chapter. This initial Climate Resilience RAMP filing provides important information that will enable PG&E to make enhanced decisions to mitigate climate change risk. The foundational work proposed in this chapter will allow PG&E to intensity its efforts to reduce climate change risk to the Company, its employees, and its customers.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
APPENDIX 1
RISK ASSESSMENT FOR SUBSTATIONS

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
APPENDIX 1
RISK ASSESSMENT FOR SUBSTATIONS

TABLE OF CONTENTS

LIST OF FIGURES

I. Introduction

Pacific Gas and Electric Company (PG&E) does not consider risks associated with substations to be top safety-related risks. As such, they were not treated similarly to other Risk Assessment and Mitigation Phase (RAMP) risks. Regardless, PG&E will discuss the current risk methodology and mitigation approach to substation risks in this appendix chapter. Historically, safety incidents resulting in a serious injury or fatality within a substation were rare. The most recent fatality was over twenty years ago when a failed regulator spilled hot oil onto an employee. As a result, similar existing equipment was retrofitted, procedures revised, and additional training and precautions provided to employees. New units have incorporated designs to prevent a similar type of incident.

Using lessons learned from past safety incidents, PG&E has implemented multiple layers of controls to prevent unauthorized public access, provided extensive training for personnel, and incorporated design standards and specifications which help achieve operational excellence. Consequently, risks associated with substations are weighted more heavily on reliability than safety. The recent Larkin substation outage in San Francisco is consistent with this: the outage affected approximately 88,000 customers for 6-8 hours but did not involve any safety incidents.

II. Substation Risk Methodology

Existing PG&E company standards provide procedures for risk methodology in analyzing substation risks. To provide further context, we will describe three examples to illustrate the current risk profile of substations. PG&E addresses the risk of substation assets through the following:

(a) PG&E's risk prioritization and methodology;

(b) A description of the controls currently in place;

(c) PG&E's prioritization of risk mitigation alternatives; and

(d) PG&E's risk mitigation plan taking into account: financial constraints; execution feasibility; affordability impacts; any other constraints.

A. Risk Prioritization and Methodology

PG&E's enterprise approach to risk prioritization is described in the 2017 General Rate Case (GRC) testimony Exhibit (PG&E-2), Chapter 3, Risk Assessment and Mitigation, otherwise known as the Risk Program. Electric Operation's (EO) specific risk prioritization and methodology is described in Exhibit (PG&E-4), Chapter 2, Electric Distribution Risk Management. The enterprise testimony describes a long-term vision for managing risks to achieve data-driven and risk-based decision making to support safe, reliable and efficient electric and gas service.

Risks associated with electric substations are part of the EO risk register and are reviewed annually through PG&E's risk management process. Substation risks can be quantified into three categories: event-based, process-based, and asset based:

- Event-based risks are quantified according to external threats for events such as earthquakes, sabotage and nearby gas lines. Failure of Substation (Catastrophic) is an event-based risk. While this risk was previously identified as an Enterprise Risk, the risk score was reduced in 2017, which removed it from the Enterprise Risk category. This risk score reduction was due to new information on the reduced probability of a gas pipe failure at a key substation. The impact of the risk did not change, but the likelihood or frequency of a gas line failure affecting a large key substation was reduced.
- Process-based risks relate to inadequate spares, restoration plans, workforce planning, etc. The risk register has two process-based substation risks: Critical Equipment Procurement and Seismic Resiliency.
- Asset-based risks are associated with equipment types such as busses, power transformers, circuit breakers, switches, etc. The risk register has eight substation asset-based risks: Substation Transformers and Voltage Regulators, Substation Protective Relays, Instrument Transformers and Station Batteries, Substation Voltage and Flow Control Equipment, Substation Circuit Breakers and Switchgear, Substation Grounding Systems, Substation Switches, Unit Substations, and Substation Bus Structure. The most significant concern for asset-based risks is aging infrastructure. A large portion of the existing inventory of substation equipment is at or past the expected service life. Overall, results from PG&E's substation risk assessments show a low historical frequency of safety incidents, but high impacts to reliability from customer outages. Substations are indirectly covered in other risk register items but in less detail and with less interdependence.

B. Controls Currently in Place

Controls currently in place for managing substation risks include design standards, specifications, procedures, maintenance (preventive and corrective), inspections, procurement strategies, operational contingencies, training, and planned and unplanned replacements. Controls are categorized as administrative, detective, preventive and are assessed at different strengths and coverage (high, medium, or low). Effectiveness of the controls is evaluated as adequate, minor gaps, or further risk reduction needed.

C. Risk Mitigation Alternatives

PG&E's prioritization of risk mitigation alternatives is ongoing. Substation mitigation alternatives are described in PGE&'s 2017 GRC testimony Exhibit (PG&E-4) Chapter 12, Substation Asset Management (SAM). Examples of mitigation alternatives are described in project business cases such as repair or replacement, or replacement with several options of varying benefits. Current risk assessments take into account expected equipment service life and estimating of system failures. See the second example on aging infrastructure, below.

D. Financial constraints; execution feasibility; affordability impacts

PG&E's risk mitigation plan and integrated planning process take into account financial constraints or budgets, execution feasibility, and affordability impacts. Substation risks are quantified primarily by reliability measures or customer outages. Safety is not a primary driver as historical safety incidents are very low, and PG&E has adequate controls to mitigate safety issues. Financial constraints and affordability impacts are evaluated through the integrated planning process leveraging the Risk Informed Budget Allocation. Execution feasibility is handled through existing PG&E work management and project management process that includes material availability, long lead times, resource allocation, permitting, constructability, and other factors.

III. Three examples of risk quantification:

In this section, PG&E describes risk events related to a substation failure and their impacts:

I. Asset-based risk from single asset failure causing a large outage such as the recent Larkin event.

II. Asset-based risk of aging infrastructure in the large fleet of equipment.

III. Event-based failure such as the 1989 Loma Prieto earthquake.

<u>Example I: Single Asset Failure Causing a Large Outage</u>

The recent Larkin outage, that impacted approximately 88,000 San Francisco customers, was in part due to asset failure in the 12kV circuit breaker and associated bus cables.

Two questions PG&E considered:

1. How many substations are of similar size that if rendered inoperable may affect a large population?
2. Was this equipment failure a systemic risk or an isolated incident?

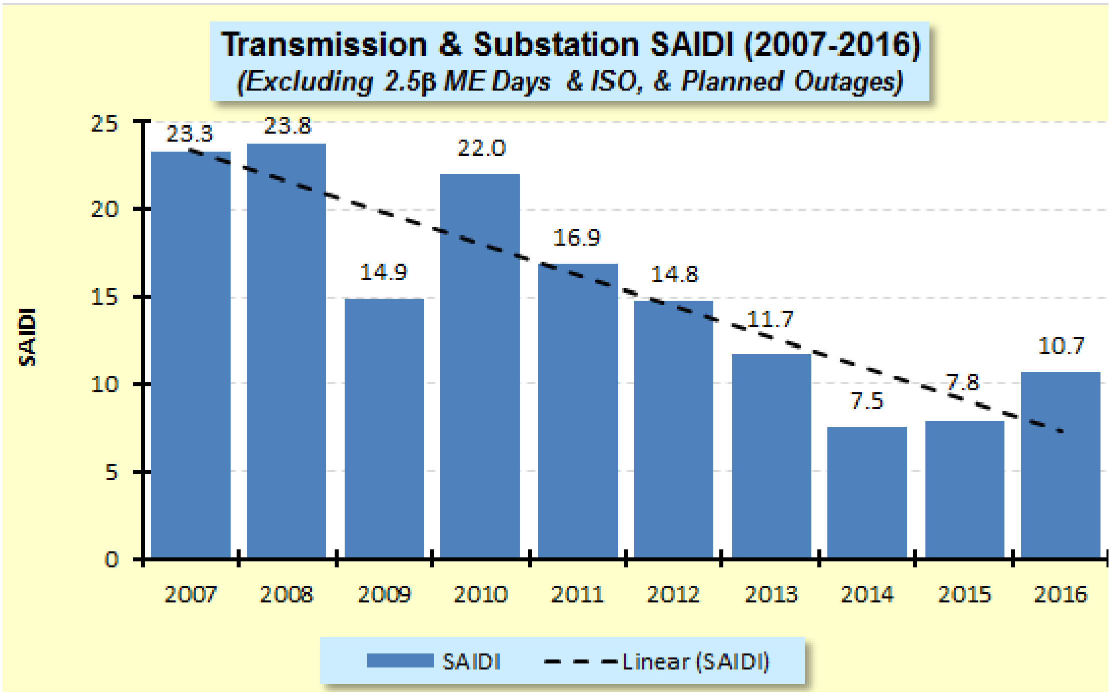
Larkin substation is one of PG&E's largest substations, measured by number of customers served. PG&E has approximately 960 total substations and only four substations have a customer count of over 50,000. The Larkin substation upgrade project was under construction during the recent outage. Planned upgrades, when completed, will significantly reduce the risk likelihood of a similar failure and its potential impact to customers. The other three large substations have received significant upgrades and have a lower risk of a similar outage.

Based on analysis of historical failure data, circuit breaker failures are not a systemic risk, and outages caused by these failures are a very small percentage of the system. In the past eight years (2009-2016), PG&E has recorded an average of 8.5 failures per year in a population of approximately 5,200 distribution class circuit breakers. This results in a failure rate of 0.16 percent per year. In terms of customer impact, a commonly used reliability metric in the utility industry is the System Average Interruption Duration Index (SAIDI). Distribution circuit breakers contribute an average of 0.44 SAIDI minutes. In the same time period, the combined average transmission line and substation SAIDI were 13.3 minutes. This translated to distribution circuit breakers contributing to 3.3 percent of all outages from transmission lines and substations.

The recent Larkin outage impacted a significant amount of customers but PG&E has only a handful of substations of this size, and large outages from these types of failures have a low likelihood of occurrence. While single asset failures may lead to large outages, PG&E believes that statistically these events are infrequent and do not contribute significantly to customer outages.

At the transmission system level, PG&E has seen reliability improvements from its investments over the past 10 years. The chart below shows PG&E's SAIDI results for its combined transmission and substation system over the last 10 years. PG&E has reduced the average duration of equipment-caused outages from 23.3 minutes to 10.7 minutes, a reduction of 54 percent. The improvements in reliability, or the reduction in customer outages, are strongly correlated to PG&E's investments to upgrade or replace substation assets.

Figure App1-1: Transmission and substation SAIDI



Example II: Aging Infrastructure

The second example is of the risk of aging infrastructure, for example, the distribution substation power transformer asset classes. PG&E has approximately 2,200 units of distribution transformers with an average age of 44 years old. The more immediate concern is the inventory of single phase units with an average age of 59 years. The industry range for the expected service life of a these units is between 40 to 70 years depending on make, model, condition, loading, location, and other factors. PG&E has approximately 680 units older than 60 years and potentially near the end of their service life. PG&E leverages a risk-informed approach to proactive replacements informed by more than the single factor of age. Even though PG&E has units older than the expected service life, EO takes into account other indicators such as oil sampling, loading, and environmental exposures to provide an enhanced assessment of whether a transformer is actually at or near the end of its service life.

Transformer failures have increased over the past five years. Although these failures have not resulted in safety incidents, outages impacting customers have occurred. PG&E is taking proactive measures, such as probabilistic modeling, to track and trend failures and make risk-informed investment decisions. Current models estimate a continued increase of transformer failures per year. EO is evaluating the need to increase proactive replacement rates to offset this trend and will adjust our investment plan accordingly.

Example III: Event Based Failure

The third example is an event-based failure such as the 1989 Loma Prieta earthquake. This earthquake event caused loss of service to three large substations and blackouts to two metropolitan areas: San Francisco and Monterey. This event caused PG&E to initiate an improvement plan that is still ongoing today. Part of this improvement plan included the quantification of earthquake damage to substation infrastructure.

PG&E worked with electric utilities in the western regions at higher risk of earthquakes. These companies included Southern California Edison, San Diego Gas and Electric, Los Angeles Department of Water and Power, Bonneville Power Administration, Pacific Corp, British Columbia Hydro, and others. The utilities collaborated together to improve seismic standards and share best practices.

PG&E also leverages internal seismologists and external experts in developing models that predict damage probabilities. These models, also known as damage modeling, leverage the United States Geological Survey earthquake database, California Geological Survey non-public soil data for landslides and liquefaction, and reconnaissance reports of electric infrastructure damage from around the world in countries such as Japan, New Zealand, and Chile.

As a result, PG&E has detailed models of equipment failure probabilities for over 50 California earthquake scenarios. In response, PG&E invested well over $100 million to replace vulnerable equipment, retrofit key control buildings, and improve emergency response capabilities. In a similar effort, PG&E has undertaken significant investments to lower the risk of underground cable failures between key substations in high earthquake zones. One such project is the Embarcadero to Potrero submarine cable installation.

IV. Conclusion

PG&E's substation investment plans are data-driven and risk-informed. This chapter provides some examples of data-driven and risk-informed approaches to how PG&E manages substation assets. PG&E's risk register provides a central location for the summary of these risk assessments and data modeling. As incidents occur, investigations are documented, lessons learned shared, and work procedures updated with additional training to applicable personnel.

PACIFIC GAS AND ELECTRIC COMPANY
2017 RISK ASSESSMENT AND MITIGATION PHASE
APPENDIX 2
STEADY STATE OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
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STEADY STATE OPERATIONS

TABLE OF CONTENTS

TABLE OF CONTENTS
(CONTINUED)

TABLE OF CONTENTS
(CONTINUED)

I. Introduction

A. 2017 General Rate Case Decision 17-05-013: Steady State Requirement

The 2017 General Rate Case (GRC) Settlement Agreement,[1] which was approved by the Commission in Decision (D.) 17-05-013, includes the following provision (Settlement Agreement, Section 3.2.8.1; CPUC Decision 17-05-013, Section 4.2.8.1):

> (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 Risk Assessment Mitigation Phase (RAMP) filing next rate case showing 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 this chapter, Pacific Gas and Electric Company (PG&E) discusses its risk-informed approach to pro-active asset replacement for each of its operating lines of business: Gas Operations (GO), Electric Operations (EO), and Generation.

B. "Steady State Replacement"

PG&E construes "steady state replacement," as described in the Settlement Agreement, to include ongoing replacements and 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.

II. Gas Operations

A. Gas Operations Asset Management Overview[2]

The Asset Management (AM) structure within GO consists of eight asset families, listed below, as part of PG&E's AM framework for GO under the Publicly

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1 The Settlement Agreement was filed by PG&E and Settling Parties on August 3, 2016 with the California Public Utilities Commission (CPUC or Commission) in Docket No. A.15-09-001.

2 PG&E's Gas Safety Plan (GSP), information regarding PG&E's AM approach and asset families. The GSP is available on PG&E's website, https://www.pge.com/en_US/safety/gas-safety/safety-initiatives/pipeline-safety/pipeline-safety.page.

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 and includes a plan detailing risk mitigations, strategic objectives and asset maintenance for the life cycle of the assets. The asset family structure allows PG&E to drive risk management strategies consistently within and among the GO asset families.

1. Transmission Pipe
2. Natural Gas Storage
3. Distribution Mains
4. Distribution Services
5. Customer Connected Equipment
6. Measurement and Control
7. Compression and Processing
8. Liquefied Natural Gas/Compressed Natural Gas

B. **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 Transmission System
  - Transmission Pipeline
  - Compressor Units
- Gas Distribution System
  - Distribution Mains
  - Curb Valves
  - Distribution Regulator Stations
  - High Pressure Regulator Stations
- Gas Storage
  - Well Refurbishments

PG&E also replaces other gas assets such as valves, distribution services, Supervisory Control and Data Acquisition (SCADA) equipment, and station components, as identified through maintenance programs. For assets in GO, age is one of the factors considered in asset replacement decisions. Other factors include risk assessment, asset condition, reliability, and cost effectiveness. GO takes a risk informed approach to AM and as such the AM/risk framework includes understanding of the data associated with the asset.

Asset replacement is the most effective mitigation for certain risk drivers.[3] For example, the Vintage Pipe Replacement Program for transmission pipe (replaces pipe with vintage construction/construction defects interacting with land movement) is a key mitigation for threats leading to Loss of Containment and LoS 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 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. Further details on the programs discussed here can be found in the RAMP risk chapters as these programs are identified as controls and/or mitigations in the RAMP filing.

1. Transmission Pipe

For the Transmission Pipe asset family, the key steady state replacement program is the Transmission Pipe Replacement Program.[4] This program addresses pipe replacements specific to: (1) the Vintage Pipe Replacement Program; and (2) pipe replacement for other pipeline safety and reliability purposes.

a) Vintage Pipe Replacement Program

The Vintage Pipe Replacement Program is a mitigation for the “Transmission Pipeline Rupture with Ignition” risk and addresses various drivers including manufacturing defects, 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 replace, by the end of 2027, all of 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

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3 Refer to the RAMP risk chapters for the definition of risk drivers for each risk.

4 Refer to PG&E’s 2019 Gas Transmission and Storage (GT&S) rate case application for further details on these programs.

population (approximately 50 miles of pipeline). PG&E proposes to continue to monitor for land movement risk changes for the remaining vintage pipe population (approximately 596 miles of pipeline).

b) 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. These pipeline replacement programs are controls that are in place to manage the "Transmission Pipeline Rupture with Ignition" risk.

2. Compression and Processing

Compressor Units are the key assets within this asset family. Currently, approximately 50 percent of compressor station assets are older than 60 years while the expected useful life of our compressor units is 60 years. Station health assessment is based on facility age, obsolesce and operational needs.

a) Compressor Units Control Replacements

This program is a key mitigation for the "Compression and Processing (C&P) Failure – Release of Gas with Ignition at Manned Processing Facility" risk. In particular, the mitigation reduces the likelihood of the risk event occurring due to any equipment related issues.

The long-term compression investment plan outlines replacement scope until 2025 to average ~1-2 units per 3- to 4-year cycle. The plan provides a tool to evaluate possible changes in investment associated with reduction of compression utilization or changes in markets. Analysis has been performed to understand the drivers and priority of "next in queue" compression replacement to ensure that investments are not placed in assets which do not align with long term projections.

3. Distribution Mains and Services

For the Distribution Mains and Services (DMS) asset families, the key steady state replacement programs include the Distribution Main Replacement and Curb Valve Replacement programs discussed below.

a) Distribution Main Replacement Program

The Pipeline Replacement Program is a key control for the risk drivers associated with "Release of Gas with Ignition on Distribution Facilities – Non Cross Bore" risk event. Aging infrastructure could lead to the risk event caused by the material/weld risk driver. Pipeline Replacement addresses drivers including corrosion, and material/welds and thereby reduces the likelihood of the risk event occurring due to these risk drivers.

The long term plan for DMS AM is to limit asset age to less than 100 years by:

- Replacing all Gas Pipeline Replacement Program priority pipe, pre-1940 bare steel and non-cathodically protected steel pipe by 2020 (approximately 180 miles);
- Increasing replacement of Aldyl-A year over year (approximately 5,450 miles); and
- Completing all identified reliability main replacement.

PG&E's 2017 GRC prepared testimony[5] outlines main replacement increase from 126 miles in 2016 to 169 miles in 2019. This is a significant increase in pipeline replacement from 27 miles installed in 2010. Risk factors for relative risk prioritization include age, material type, leak history, cathodic protection, seismic impact, proximity to the public, public works coordination, and other operational factors.

b) Curb Valve Replacement

This program is focused on the inspection and replacement of Kerotest Valves located in PG&E's San Francisco Division. These valves have shown a history of repeated leaks and PG&E is proactively replacing these valves to prevent future leaks as part of the Distribution Integrity Management Program Emergent Work mitigation. This program is a key mitigation for the "Distribution Pipeline Rupture with Ignition" risk and addresses

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5 See PG&E Exhibit (PG&E-3), Chapter 4.

the equipment failure risk driver thereby reducing the likelihood of the risk event occurring due to equipment failures.

4. **Measurement and Control**

The assets in the Measurement and Control (M&C) asset family include regulation stations. Station health assessments and district regulator station health assessments are based on a series of ten metrics including age, obsolescence, physical condition, functional performance, and maintenance metrics.

a) **Distribution Regulator Station Replacement**

The Distribution Regulator Station Replacement program is a key mitigation for the "Measurement and Control (M&C) Failure – Release of Gas with Ignition Downstream" risk. The asset replacement decision is based on age as well as maintenance feedback. As equipment ages and reaches the end of its service life, the probability that it will either fail in service or become obsolete increases, which increases the risk of loss of service, reliability and over-pressure events. Capital expenditures for distribution stations include full station rebuilds (historically averaged about 10-15 per year) and replacement of failed or aging components.

b) **High-Pressure Regulator Program**

Similar to the Distribution Regulation Station Replacement program, this initiative is performed to mitigate the risk of over-pressurization of downstream piping and reduce gas leaks. Accelerated gas transmission leak surveys identified a significant number of leaks associated with High-Pressure Regulator (HPR) sets. This initiative includes: (1) eliminating of the use of HPR Customer Sets wherever possible; and (2) redesigning the remaining sets.

5. **Storage**

For the storage asset family, AM is focused on rework and refurbishments of wells within the storage fields.

a) **Storage Well Refurbishments**

The Storage Well Inspection Program is a key mitigation for the "Natural Gas Storage Well Failure – Loss of Containment with Ignition at a Storage Facility" risk and addresses several drivers including any 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, 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, 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 as follows:

- Near-term: Plugging and abandoning two wells at Los Medanos as PG&E considers the impact of new regulations moving forward.
- Long-term: Proposed regulations and Natural Gas Storage Strategy includes continued operations of McDonald Island and 11 news wells and decommission Los Medanos or Pleasant Creek storage fields. Twenty-seven wells are located at Los Medanos and Pleasant Creek.

C. How Gas Operations Identifies Equipment and Prioritizes Replacements, Incorporating Risk

PG&E 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 in-line inspection.
- 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 assesses the condition of assets using information from SAP, preventive and corrective maintenance records, Corrective Action Program, process hazards analysis, etc. For assets in

GO, age is one of the factors considered in asset replacement decisions. Other factors include risk assessment, asset condition, reliability and economics and often may have higher weighting on replacement decisions. 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. Each project/program is classified as Mandatory, Compliance, Commitment, Customer Generated (Work Requested by Others (WRO)), Support, Interdependent, and None. And then projects/programs are 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. For further information on this process, please refer to PG&E's 2019 GT&S rate case, Chapter 4.

III. Electric Operations

A. Asset Management Strategy Overview

Electric Asset Management (EAM) has structured programs in place to manage and maintain its distribution assets.[6] These programs provide a systemwide look into the condition of the distribution system equipment, and propose replacement projects, changes to operations and maintenance practices to reduce risk and improve the safety and reliability of the distribution system. Asset replacement projects are identified from the asset strategy of that particular asset, based on expected asset life and input from field personnel, typically from patrol and inspect or other monitoring activities. EAM considers multiple factors such as age, risk, asset condition, reliability performance, and economics in replacement decisions for equipment in PG&E's distribution system. AM practices will continue to evolve as PG&E strengthens its understanding of the various asset types and incorporates new knowledge and technology in its programs.

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6 Programs for transmission assets are discussion in PG&E's Transmission Owner filings.

In the Distribution Line Equipment section, PG&E will also discuss how its Reliability Program is incorporated into its AM strategies and prioritization methodologies.[7]

B. **Asset Management Programs**

PG&E has proactive replacement programs for the following key distribution asset classes:

- Distribution Substation Equipment
  - Transformers
  - Circuit Breakers
- Distribution Line Equipment
  - Distribution Wood Poles
  - Distribution Overhead Conductor
  - Distribution Underground Cable

PG&E also replaces substation equipment such as batteries, insulators and ground grids, and repairs or replaces additional distribution line equipment, such as capacitors, sectionalizers and reclosers as identified through maintenance programs. Equipment replacements are performed when an asset health assessment determines that the equipment poses a risk of failure, is no longer able to perform the required functions, or is nearing the end of its useful life and it is too expensive to continue to maintain. Reliability, economics and other factors such as interrelationships with other projects also influence replacement decisions.

C. **How Electric Operations Identifies and Prioritizes Equipment Replacements, Incorporating Risk**

PG&E takes a risk informed approach to AM for EO. PG&E quantifies risks using the Enterprise Risk Management process, which includes enterprise risks such as wildfire, and risks related to distribution and transmission equipment. Following that process, PG&E performs a RIBA analysis to characterize risks based on a number of factors. The RIBA process is used to evaluate projects and programs from a safety, environmental, and reliability perspectives to assess the degree of relative risk exposure and impact being addressed. The purpose of a RIBA score is to capture on a relative basis the safety, environment and reliability risks that each project or program in EO aims to prevent, based on the worst direct

7 This is consistent with PG&E's 2017 GRC Settlement Agreement, which includes a requirement related to Reliability Program investments in the Electric line of business.

reasonable impact or event that the work activity mitigates. In addition to safety, environmental and reliability risks, other factors including, but not limited to, compliance requirements and project inter-dependencies are incorporated into the evaluation to inform capital 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 capital investment plan that meets the most critical demands of the electric distribution system, consistent with available resources and operational performance requirements.

PG&E is also developing the System Tool for Asset Risk, which will provide asset health and risk scores that will be used to identify and prioritize asset replacement investments. The following sections describe considerations and strategies for key asset replacement programs.

1. Distribution Substations

PG&E's has 770 electric distribution substations in its electric distribution system. Substation equipment includes transformers, circuit breakers and related switchgear, with the primary purpose of stepping down transmission level voltages and conveying electricity to the distribution system through transformers and feeders. PG&E has established standards and maintenance procedures for substation equipment, and has proactive replacement programs for key equipment as part of its substation AM program.

Substation equipment may be replaced for a variety of reasons, including: the equipment: failing, reaching the end of its useful life, experiencing operational performance issues, not meeting current operational or cybersecurity standards, replacement parts becoming unavailable, or cost of maintainenance becoming too high. The majority of substation equipment replacement projects involve more than just the in-kind replacement of a single piece of equipment with a 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. In addition, when PG&E is replacing equipment, it may make engineering and economic sense to upgrade or add other equipment to improve performance, enhance public safety, or to comply with current standards. Another example is that when replacing a substation circuit breaker or transformer, PG&E may upgrade the associated connectors, switches, and communication equipment if appropriate, which would not have been done but for the replacement of the circuit breaker or transformer. This approach of work bundling results in efficient execution of work, lowering the net present value of replacement cost of the associated assets.

a) Transformers

Distribution substation transformers step down transmission-level voltage to distribution-level voltage, connecting the high-voltage electricity from PG&E's electric transmission system to lower-voltage for delivery to PG&E's customers. PG&E maintains an inventory of approximately 2,200 distribution substation transformers throughout its service territory.

PG&E's practice is to identify, prioritize and replace 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. The analysis uses results from dissolved gas analysis oil tests, which detect breakdown of insulating material, and also considers overstress, impact of failure, and load density. In addition to the proactive planned replacement based on asset health indices, PG&E replaces transformers to provide increased capacity, and performs emergency replacements based on actual failures or condition codes such as gassing.

Beginning in 2018, PG&E will begin a program to extend the life of certain transformers aside from the traditional repair or replace options during an unplanned condition. This new program provides an additional option that allows capitalized component replacement on a planned basis at a fraction of the cost of the full transformer replacement. Transformers that receive the life extension work are expected to gain at least 15-20 additional years of service.

b) Circuit Breakers

Substation circuit breakers and associated switchgear are designed to 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 units.

The circuit breaker replacement program is a combination of proactive planned replacement based on asset health indices, capacity additions or replacements typically from bus upgrades, and emergency replacements based on actual failures such as "failed to close" or condition codes such as unrepairable leaks. 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.

In addition to proactive replacement in the Breaker Replacement program, circuit breakers may be replaced as part of larger substation switchgear projects, or may be replaced on an emergency basis for in-service or imminent failures.

2. Distribution Line Equipment

Overhead and underground distribution lines and their associated equipment are designed to safely and reliably deliver electricity from the substations to customer neighborhoods and businesses. EO has established standards and work procedures to implement the requirements of CPUC General Orders (CPUC GO 95, Rules for Overhead Electric Line Construction; CPUC GO 128, Rules for Underground Electric Construction; and CPUC GO 165, Inspection Requirements for Electric Distribution and Transmission Facilities) for distribution line equipment. In addition to compliance activities, EO seeks to proactively identify and replace equipment prior to failure, and has proactive AM programs for the following types of equipment:

Proactive overhead conductor and underground cable asset replacements are part of PG&E's Reliability Program. PG&E's Targeted Circuits program, which addressed the Company's worst performing circuits, also replaces equipment as part of targeted work to improve reliability. PG&E constantly manages a broad portfolio of reliability improvement projects necessary to meet the broad needs of a diverse customer base and expectations for dependable service. As part of PG&E's approach to system reliability solutions, this work includes evaluating various improvement proposals and calculating cost vs. benefit ratios. In addition, PG&E regularly considers benefit to cost ratios, and other factors, e.g., the RIBA process, to support the associated prioritization in spending.

a) Distribution Wood Poles

There are 2.3 million wood poles on PG&E's distribution system that support all distribution voltages from 4 kilovolt (kV) to 21 kV. PG&E has a program to test, treat, and track the condition of poles, and a condition-based pole replacement program.

PG&E's distribution wood pole population is decreasing a small amount each year as overhead lines are converted to underground, and expansions to serve new neighborhoods are required to be underground lines.

Distribution wood poles are inspected in accordance with CPUC GO 165 and replaced based on CPUC GO 95 safety factor requirements. PG&E does annual patrols in urban areas, and bi-annual patrols in rural areas looking for damaged poles among other things. PG&E performs a detailed inspection every five years looking for external damage or deterioration, and performs an intrusive inspection on poles not treated with wood preservative Pentachlorophenol (Penta) every 10 years to identify any internal or below ground decay that may be present in the pole. Penta poles under 50 years of age are intrusively inspected every 20 years, and represent about 30 percent of the pole population. As part of the intrusive inspection, where appropriate, an external preservative is applied to poles, extending their life.

Poles that do not pass inspection criteria are tagged for replacement under the Pole Replacement program. Poles that are in good condition except for deterioration around the ground line are reinforced by installing a steel truss and banding it to the pole, restoring the original strength of the pole. PG&E's proactive pole replacements can vary from year to year, as poles are replaced based on inspection assessments. PG&E recognizes that its aging asset base may require increased replacements in future years.

Other programs, such as Capacity, Reliability, Emergency, Maintenance, and WRO, also address replacement or relocation of distribution wood poles.

PG&E is performing accelerated retirement of higher risk poles in the wildfire areas in 2018 and 2019, per the 2017 GRC settlement agreement.

b) Distribution Overhead Conductor

PG&E has approximately 82,000 circuit miles of overhead conductor on its distribution system that operate between 4 kV to 34 kV, which includes a large percentage of small conductor.[8]

As required by the 2017 GRC Decision, PG&E is working with an external party to conduct a primary distribution overhead conductor study, expected to be completed by year-end 2017. The study will determine the expected service life, asset vintages, primary factors affecting service life and need for replacement, and estimate for near and long term replacement rates of PG&E's distribution overhead conductor. PG&E will include the results of the study in its 2020 GRC.

PG&E's Reliability Program proactively replaces overhead conductor identified through failure history, splice inventory, type of conductor, geographic area, or customer impacts. All of these attributes are used to identify the worst areas of the system for replacement. Engineers scope the size of replacement projects by also incorporating other factors, such as natural breaks in circuit design, geographic construction constraints, ability to easily execute, and work bundling. PG&E's strategy for replacement in the Reliability Program is based on failure rates obtained through wire down data analysis and splice data through the infrared program. The primary focus is on small copper conductor with multiple splices, and small aluminum conductor steel-reinforced cable conductor with multiple splices in a coastal environment.

Overhead conductor is also replaced or installed as part of other business programs, such as Capacity, Emergency, Maintenance, New Business, and WRO. Capacity replacements are based on expected overload.

As discussed in the "Distribution Overhead Conductor Primary" risk chapter of this report, PG&E is proposing to replace additional overhead conductor in high risk wildfire areas. After reviewing the results of the ongoing overhead conductor study, PG&E may adjust its planned replacement rate.

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8 Small overhead conductors are defined as either #6 copper wire or #4 aluminum conductors with steel reinforcement.

c) **Distribution Underground Cable**

PG&E has approximately 26,000 circuit miles of primary distribution (excluding network) cables. Cables are categorized by the following insulation types, along with their typical deployment periods:

- Paper Insulated Lead Cable (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 – Deployed from the early 1960s through the 1980s.
- Cross-Linked Polyethylene – 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.

PG&E proactively replaces underground cable in its Underground Asset Management (UAM) Program. Capital investment in this program includes cable replacement by re-pulling new cable within the existing infrastructure, and trenching or boring to install new underground facilities where replacement in place is not feasible or cost effective. Cable replacement projects can also include upgrading switches, transformers, enclosures, and other associated equipment. The UAM Program generally involves replacing primary distribution cables and components due to reliability performance, asset age and condition, compliance, and potential safety risks to the public and employees.

Replacement strategy includes reliability performance based replacements in areas experiencing two or more sustained outages within the last five years. Projects are prioritized mainly based on number of sustained outages, customer outage minutes, and circuit configuration. This strategy also includes evaluating non-PILC cables for targeted replacement using cable testing[9] or cable injection[10] instead of wholesale replacement. In addition, PG&E's strategy 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 Reliability Program. Underground cable is also replaced as part of Capacity program if there is an overload, or current exceeding cable's normal current rating on the conductor, and in PG&E's Emergency and Maintenance programs. Lastly, PG&E's strategy includes condition based replacement of distribution cables identified during 3-year cycle detailed inspections and infrared scanning of the underground system as part of maintenance. In addition to cable replacements, approximately 200 miles of underground cable is added to the system each year in programs such as Rule 20, WRO and New Business.

Maintenance is a very important aspect of preventing cables from premature failing and can help extend their life spans. Any defects on cables, accessories or other connected equipment can lead to failures, which would impose fault related stress on the cables. Over time, fault stress can cause deterioration of cables. In some cases, a catastrophic failure could damage adjacent equipment and cables immediately. Utilizing visual inspections and infrared, many of these equipment can be identified and replaced before they fail, prolonging the life of cables and other connected equipment.

As the cable population continues to age, the number of failures is expected to increase. Cable replacement amounts will also need to increase to maintain the current level of performance.

Generation

D. **Asset Management Strategy Overview**

Power Generation's AM Program provides a systemwide look into the condition of the hydro system equipment and proposes projects and/or changes to

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9 Cable testing involves an electrical process for applying voltage signals to cable to evaluate operating condition.

10 Cable rejuvenation is a technology that involves the injection of silicon fluid into specific types and conditions of cable with the goal of extending operating life.

operations and/or maintenance practices to ensure that Power Generation's long term investment plan reduces risk and improves the safety and reliability of the hydro portfolio.

E. Asset Management Programs

1. Hydroelectric

PG&E has 106 hydroelectric generating units at 66 powerhouses with a generating capacity of 3,892 megawatts (MW). PG&E has a hydroelectric AM program, which among other equipment includes the following crucial operating equipment as part of its hydroelectric AM program:

a) Storage and Conveyance

- Dams
- Penstocks
- Water Conveyance

b) Power Train

- Turbines
- Generator Rotors and Stators
- GSU Transformers

2. Fossil and Solar

PG&E has three fossil-fuel generating stations that are between seven and eight 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 component of the power train.

PG&E also has ten solar photovoltaic generating facilities. The majority of these sites are less than six years old. PG&E has a program in place to repair or replace the inverters.

Major components necessary to provide safe and reliable service are proactively replaced, repaired or refurbished.

3. 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 an NRC required robust maintenance rule (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.[11]

F. How Power Generation Identifies Equipment and Prioritizes Replacements, Incorporating Risk

1. Asset Management Practices

The AM team 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

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11 DCPP Retirement Joint Proposal (A.16-08-006).

the assessment standard/procedure. Assessment results are analyzed and interpreted, and corresponding condition indicators are logged in the Generation Risk Information Tool (GRIT) that is linked directly to each equipment record.[12]

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 is able to quantify the risk its hydro assets pose. Risk scores are logged in GRIT.

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 highly deteriorated (due to cavitation or corrosion) turbine runner, or it might re-line a degraded section of canal.

f) Risk Informed Budget Allocation

All of PG&E's hydro expense and capital projects are evaluated using the RIBA risk scoring methodology. Each project is scored to assess the risks to safety, the environment, and reliability that would be mitigated by the project. These scores are then used by management (along with other key data) to prioritize proposed work.

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[12] GRIT is used for the penstock program and powertrain programs. The dams and water conveyance program assessment results are tracked separately

2. 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 with regard to 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 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.[13]

(1) Dams

Dams are routinely maintained with mitigations to address any issues that develop, and not typically replaced. PG&E's dams are associated with the Enterprise Risk, "Hydro System Safety – Dams." The dam safety program is governed by the California State Division of Safety of Dams (DSOD) and the Federal Energy Regulatory Commission (FERC). The following includes the AM approach to dams:

- Routine observations by trained Hydro O&M personnel;

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13 The 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.

- Regular inspections by qualified engineers in PG&E's Facility Safety Program;
- Regular regulatory inspections by the FERC and DSOD;
- Five-year Independent Consultant Safety Inspections in accordance with Chapter 18 of the Code of Federal Regulations 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 high cost (~$20-$100 million) projects.

(2) Penstocks

Penstocks are typically repaired or refurbished, not replaced, based on condition and consequence of leakage. 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.

(3) 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 a number of 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.

(1) 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.

PG&E is targeting the replacement of several turbines over the next five years.

(2) 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
- Life extension through stator rewinds and rotor cleaning or refurbishment based on asset condition.

PG&E has plans to rewind several rotors and the associated generator stators will be cleaned or refurbished over the next five years.

(3) 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. 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 five years.