BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation into Southern California Gas Company's Risk Assessment and Mitigation Phase November 2019 Submission.	Investigation 19-11-010 (Opened November 7, 2019)
Order Instituting Investigation into San Diego Gas & Electric Company's Risk Assessment and Mitigation Phase November 2019 Submission.	Investigation 19-11-011 (Opened November 7, 2019)

JOINT 2019 RISK ASSESSMENT AND MITIGATION PHASE REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M)

ELLIOTT S. HENRY
555 West Fifth Street, Suite 1400
Los Angeles, CA 90013
Telephone: (213) 244-8234
Email: ehenry@socalgas.com

LAURA M. EARL
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1541
Email: learl@sdge.com

Counsel for Respondents: Southern California Gas Company and San Diego Gas & Electric Company

November 27, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation into Southern California Gas Company's Risk Assessment and Mitigation Phase November 2019 Submission.	Investigation 19-11-010 (Opened November 7, 2019)
Order Instituting Investigation into San Diego Gas & Electric Company's Risk Assessment and Mitigation Phase November 2019 Submission.	Investigation 19-11-011 (Opened November 7, 2019)

JOINT 2019 RISK ASSESSMENT AND MITIGATION PHASE REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904-G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M)

I. INTRODUCTION

In compliance with California Public Utilities Commission (Commission or CPUC) Decisions (D.) 14-12-025, D.16-08-018, D.18-12-014, and I.19-11-010/-011 (cons.) and the Commission's Rules of Practice and Procedure, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) hereby jointly submit their Risk Assessment Mitigation Phase (RAMP) Reports (Reports). The purpose of the RAMP Reports is to present an assessment of the key safety risks of SoCalGas and SDG&E and the proposed activities for mitigating those risks. These Reports present the SoCalGas and SDG&E safety risks as required by the December 12, 2018, Safety Model Assessment Proceeding (S-MAP) Decision and the Settlement Agreement included therein (SA Decision).[1] SoCalGas and SDG&E met with stakeholders on several occasions to discuss their approach to the RAMP Reports, throughout their development.[2] The basis for these Reports and an overview of their contents is described

[1] D.18-12-014 adopted the Settlement Agreement with modifications and reflects minimum required elements to be used by the utilities for risk and mitigation analysis in their RAMP and General Rate Case (GRC) proceedings. Additionally, D.18-12-014 continued and modified requirements previously established in D.16-08-018 and the risk-based decision-making frameworks adopted in D.14-12-025.

[2] These stakeholders included, among others: The Commission's Safety & Enforcement Division (SED), Office of the Safety Advocate (OSA), and The Utility Reform Network (TURN).

below. SoCalGas and SDG&E request that the Commission find these Reports to satisfy the requirements of D.14-12-025, D.16-08-018, and D.18-12-014.[3]

II. BACKGROUND AND PROCEDURAL HISTORY

In D.14-12-025, the Commission adopted a risk-based decision-making framework into the Rate Case Plan for the energy utilities' General Rate Cases (GRCs). This risk-based decision-making framework was developed as a result of Senate Bill (SB) 705. SB 705 ultimately led to Public Utilities (P.U.) Code Section 963, which states that "[i]t 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."[4] In 2014, the California Legislature amended the P.U. Code by adding Section 750, which directed the Commission to "develop formal procedures to consider safety in a rate case application by an electrical corporation or gas corporation."

As a result of these directives, the Commission, in D.14-12-025, established two new proceedings to address risk assessment procedures, a Safety Model Assessment Proceeding and the Risk Assessment Mitigation Phase. These proceedings inform and provide additional information for the GRC applications in which utilities request funding for safety-related activities.

D.16-08-018 (the interim S-MAP decision) adjudicated the consolidated S-MAP applications and determined the format of future RAMP submissions. In addition, D.16-08-018 adopted guidelines for what the RAMP submissions should include, as well as an evaluation method to be used with RAMP submissions.

After several months of negotiations, on April 23, 2018, Pacific Gas & Electric Company, Southern California Edison Company, SoCalGas, SDG&E, TURN, Energy Producers and Users Coalition, Indicated Shippers and the Public Advocates Office (then Office of Ratepayer Advocates), submitted to the Commission a Settlement Agreement in the S-MAP proceeding. The Settlement Agreement included the minimum required elements to be used by the utilities for risk and mitigation analysis for safety risks in their respective RAMP and GRC

---

3 *See* D.18-04-016 at 1, 4, and Conclusion of Law 2.

4 P.U. Code § 963(b)(3)

proceedings.[5] Later that year, D.18-12-014 adopted the S-MAP Settlement Agreement with modifications. The topics covered in the Settlement Agreement include:

- Building a Multi-Attribute Value Function (MAVF);
- Identifying Risks for Investor-Owned Utilities' Enterprise Risk Register;
- Risk Assessment and Risk Ranking in Preparation for RAMP;
- Selecting Enterprise Risks for RAMP; and
- Mitigation Analysis for Risks in RAMP.[6]

On August 30, 2019, SoCalGas and SDG&E submitted a letter requesting an Order Initiating Investigation (OII) to open a proceeding for the RAMP Reports. The Commission filed an OII for SoCalGas (I.19-11-010) and SDG&E (I.19-11-011) on November 7, 2019, initiating the OIIs in connection with SoCalGas' and SDG&E's upcoming Test Year (TY) 2022 GRC applications.[7] The Commission consolidated the OIIs.[8]

III. PROPOSED SCHEDULE

A prehearing conference is scheduled for January 7, 2020.[9] On or before January 15, 2020, SDG&E, SoCalGas, and SED will hold a public workshop on SDG&E's and SoCalGas' RAMP submissions.[10] By March 30, 2020, SED will file and serve a staff report on SDG&E's and SoCalGas' RAMP submissions.[11] Later events are identified in the OII as follows:

---

[5] D.18-12-014 at 19.

[6] *Id.* at 2.

[7] There has not been a final decision in the Rate Case Plan proceeding (Rulemaking (R.) 13-11-006) on whether SoCalGas and SDG&E will have their current GRC cycle extended to four years. At the time of the filing of these Reports, it remains an open issue whether SoCalGas and SDG&E will have a TY 2022 GRC.

[8] I.19-11-010/-011 (cons.), Administrative Law Judge's Ruling Consolidating Proceedings and Setting Prehearing Conference Schedule (November 21, 2019) at 1 and Ordering Paragraph 1.

[9] I.19-11-010, Order Instituting Investigation into the Risk Assessment and Mitigation Phase Submission of Southern California Gas Company (dated November 7, 2019) at 7 and I.19-11-011, Order Instituting Investigation into the Risk Assessment and Mitigation Phase Submission of San Diego Gas & Electric Company (dated November 7, 2019) at 7.

[10] *Id.*

[11] *Id.*

- By April 20, 2020, SED will hold a public workshop on SED's staff report;
- By May 20, 2020 other parties may file and serve comments on SDG&E and SoCalGas' RAMP submissions, and on SED's staff report;
- Between April and May of 2020, additional workshops may be held on RAMP-related items, if needed;
- Between June and August 2020, SDG&E and SoCalGas will incorporate RAMP results into their TY 2022 GRC filing;
- By September 2, 2020, SDG&E and SoCalGas will file TY 2022 GRC applications and serve prepared testimony including changes resulting from the RAMP process.[12]

IV. ROADMAP OF REPORTS

The RAMP Reports of SoCalGas and SDG&E are attached hereto. An overview of the RAMP Reports and discussion of additional RAMP requirements noted in D.14-12-025, D.16-08-018, and D.18-12-014 can be found in the following chapters, copies of which are included in each company's individual Report:

Chapter	Subject
RAMP-A	Overview and Approach
RAMP-B	Risk Presentation
RAMP-C	Risk Quantification Framework
RAMP-D	Risk Spend Efficiency – Methodology
RAMP-E	A Discussion of the Use of Risk Spend Efficiency
RAMP-F	Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety[13]
RAMP-G	Lessons Learned

Each risk chapter is presented in the below order.

---

12 *Id.* As noted above, these dates are subject to potential changes from a decision in the Rate Case Plan. *See also* R.13-11-006 (There has not been a final decision in the Rate Case Plan proceeding on whether SoCalGas and SDG&E will have their current GRC cycle extended to four years, as of the time of filing these Reports.).

13 SDG&E and SoCalGas each have Safety Culture chapters that are specific to their respective companies.

For SoCalGas:

Chapter	Subject
SCG-1	Medium Pressure Gas Pipeline Incident (Excluding Dig-ins)
SCG-2	Employee Safety
SCG-3	Contractor Safety
SCG-4	Customer and Public Safety
SCG-5	High Pressure Gas Pipeline Incident (Excluding Dig-ins)
SCG-6	Third Party Dig-in on a Medium Pressure Pipeline
SCG-7	Third Party Dig-in on a High Pressure Pipeline
SCG-8	Storage Well Integrity Event
SCG-9	Cybersecurity

For SDG&E:

SDG&E-1	Wildfires Involving SDG&E Equipment
SDG&E-2	Contractor Safety
SDG&E-3	Employee Safety
SDG&E-4	Electric Infrastructure Integrity
SDG&E-5	Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-ins)
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-ins)
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline
SDG&E-10	Cybersecurity

V. CONCLUSION

SoCalGas and SDG&E hereby jointly submit their RAMP Reports and request that the Commission find these Reports to be compliant with the requirements set forth in D.14-12-025, D.16-08-018, and D.18-12-014. SoCalGas and SDG&E also request that the proceeding schedule be adhered to, to the extent possible, so that their TY 2022 GRC proceeding may be timely filed in September 2020.

Respectfully submitted,

Laura M. Earl[14]

LAURA M. EARL
8330 Century Park Court, CP32D
San Diego, CA 92123
Telephone: (858) 654-1541
Email: learl@sdge.com

Counsel for Respondent:
San Diego Gas & Electric Company

November 27, 2019

[14] Signed on behalf of Southern California Gas Company in accordance with Rule 1.8(d).

Risk Assessment Mitigation Phase

(RAMP-A)

Overview & Approach

November 27, 2019

SoCalGas
A Sempra Energy utility®

TABLE OF CONTENTS

I. RAMP OVERVIEW

A. Introduction

Southern California Gas Company (SoCalGas or Company) presents its 2019 Risk Assessment Mitigation Phase (RAMP) Report to the California Public Utilities Commission (Commission or CPUC) in the RAMP Order Instituting Investigation (OII) proceedings, I.19-11-010 (approved on November 7, 2019). This 2019 RAMP Report marks a significant milestone in the Company's risk-informed decision-making framework process and in the journey of the California investor-owned utilities' (IOUs) efforts over the past several years to incorporate in this Report the "quantitative approach to risk assessment and risk prioritization"[1] approved by the Commission in Decision (D.) 18-12-014, the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement Decision (SA Decision). This Chapter provides an overview of the Company's 2019 RAMP Report and outlines the approach and guiding principles applied to this RAMP Report.

The RAMP is considered the first phase of the Company's next General Rate Case (GRC), Test Year (TY) 2022. The purpose of the RAMP is 'to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks."[2] Consistent with this purpose, the 2019 RAMP Report focuses on the Company's key safety risks and the current and proposed activities to help mitigate those risks. Specifically, the RAMP Reports of Southern California Gas Company (SoCalGas) and SDG&E present 18 risk specific chapters; eight for SoCalGas, nine for SDG&E, and one joint SoCalGas/SDG&E chapter. These chapters are categorized into risks related to 1) gas assets, 2) electric assets, and 3) human systems (or cross-cutting) risks. Each identified RAMP risk is discussed in detail in the individual risk chapters associated to a particular Risk Event[3] and complies with the directives in the SA Decision.

---

1 D.18-12-014 at 28.

2 D.14-12-025 at 31 (citation omitted).

3 Attachment A-1 provides a glossary of the terms used in this 2019 RAMP Report.

Although this is not the Company's first RAMP Report, it is the first RAMP Report that implements the methodology and processes adopted in the SA Decision;[4] including developing a new Multi-Attribute Value Function (MAVF).[5] This RAMP Report also reflects lessons learned from the Company's 2016 RAMP Report as well as from the RAMP filings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE).

B. Requirements for RAMP

This 2019 RAMP Report was developed in accordance with Commission guidance and the directives adopted in D.14-12-025, D.16-08-018, and the SA Decision. The SA Decision adopted the following minimum required elements:[6]

- Building a MAVF (Step 1A);
- Identifying Risks for Investor-Owned Utilities' Enterprise Risk Register (Step 1B);
- Risk Assessment and Risk Ranking in Preparation for RAMP (Step 2A);
- Selecting Enterprise Risks for RAMP (Step 2B); and
- Mitigation Analysis for Risks in RAMP (Step 3).

In addition to the above, the SA Decision also adopted modifications or enhancements of D.16-08-018 as follows:

- In the MAVF, establish a minimum 40% safety weight unless utilities can justify a lower weight based on their respective analyses;
- Enhance the current RAMP 10-major components;
- Update the risk lexicon; and
- Identify future matters for an Order Instituting Rulemaking that will explore lessons learned from the first S-MAP, adopt a Long-Term Road

---

[4] *See* D.18-12-014, which adopted the S-MAP Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[5] The MAVF is discussed further in Chapter RAMP-C.

[6] D.18-12-014 at Attachment A, A-4.

Map, and develop a scope and timeline for successive S-MAP applications.

A roadmap demonstrating compliance with the RAMP requirements, in particular the 10 components of RAMP filings, is provided further below.

In addition to the RAMP requirements set forth in various risk-related proceeding directives, the Company's TY 2019 GRC decision (D.19-09-051) included items to be addressed in this RAMP Report. One such directive requires inclusion of a re-testing implementation plan related to pipelines under Pipeline Safety Enhancement Plan (PSEP) Phase 2B as part of this 2019 RAMP filing, and provides specific items to be included in this plan.[7] The Company intends to present information, as required in D.19-09-051, in RAMP and GRC filings when the anticipated PSEP Phase 2B projects are within the applicable GRC period. At this time, the Company forecasts that its PSEP Phase 2B projects will begin after 2025, which is approximately two GRC cycles from now; clearly not in scope of the Company's 2019 RAMP Report or the TY 2022 GRC. Consistent with the foregoing, a letter to Executive Director, Alice Stebbins, was sent on October 31, 2019, requesting an extension of time to comply with this directive related to the PSEP Phase 2B implementation plan in D.19-09-051.[8] The extension was granted on November 18, 2019, and therefore the PSEP Phase 2B implementation plan ordered in D.19-09-051 is not included in this RAMP Report.

In addition, D.19-09-051 suggested that many of the recommendations put forth by the Office of the Safety Advocate (OSA) regarding enhancements to the Company's safety culture and safety management systems, in particular American Pipeline Institute (API) Recommended Practice (RP) 1173, are "better addressed in SoCalGas' next RAMP filing."[9] The Company includes supplemental information on safety culture and its safety management systems in

---

7 D.19-09-051 at Ordering Paragraph 15.

8 SDG&E did not include PSEP forecasts in the TY 2019 GRC. While D.19-09-051 only ordered SoCalGas to complete the re-testing implementation plan, SDG&E also anticipates classifying pipeline segments as Phase 2B for inclusion in future GRC requests. Accordingly, both SoCalGas and SDG&E requested an extension to comply with what was ordered in D.19-09-051.

9 D.19-09-051 at 97.

Chapter RAMP-F of this RAMP Report and looks forward to continuing to work with stakeholders on these matters.

II. RAMP APPROACH

A. General Approach

The Company's intent is to present a transparent and collaborative RAMP Report that advances utility risk-informed decision-making within the Commission's regulatory process. To accomplish this, the Company developed this RAMP Report in accordance with the SA Decision, with due consideration of feedback received from various stakeholder groups,[10] and incorporated lessons learned. Each are further discussed in this Section.

1. Roadmap of Compliance with RAMP Requirements

The approach adopted by the Company herein satisfies the following "Ten Major Components of RAMP Filings" as enhanced by the SA Decision.[11] Further, this approach, together with the enterprise risk management framework presented in Chapter RAMP-B, satisfies the Cycla ten-step evaluation process.

1. **Identify its top risks.** The Company identified its respective top risks as part of the 2018 Enterprise Risk Registry (ERR). The 2018 ERR was used as the starting point for RAMP. Consistent with the SA Decision, the risks presented within this 2019 RAMP Report include, at minimum, those risks that were the top 40% of risks identified in the Company's 2018 ERR with a safety score greater than zero.
2. **Describe the controls or mitigations currently in place.** Section V of each individual risk chapter describes the Company's current baseline controls and proposed mitigations as part of the Company's Proposed Risk Mitigation Plan. A Control, as defined by the Lexicon adopted in D.18-12-014, is a "[c]urrently

[10] On January 9, 2019, the Company had a meeting with the Safety Enforcement Division (SED) regarding RAMP. On February 5, 2019, the Company provided SED with a preview of its showing for the March 5, 2019 workshop. On March 27, 2019, the Company had a follow-up discussion with The Utility Reform Network (TURN), SED, and OSA. SED and OSA met with the Company again on July 10, 2019.

[11] D.18-12-014 at 33-35.

established measure that is modifying risk."[12] Therefore, the Company generally considered Controls to be activities in place as of the end of 2018 and baseline costs represent costs incurred for said Controls in 2018. The Controls currently in place are identified in each risk chapter in Section I.B and are further described in Section V of each risk chapter. Baseline and forecasted costs are identified within Section VII of each risk chapter.

3. **Present its plan for improving the mitigation of each risk.** The Company's proposed Risk Mitigation Plans, presented within each of the individual risk chapters, are plans that the Company believes are feasible to be executed and which it plans to put forth in the next GRC application, currently anticipated to be filed in September 2020. The proposed Risk Mitigation Plans are contingent on resource availability, permitting, operational compliance, and other factors, and therefore the Company's identified activities may be subject to constraints and/or delays.

4. **Present two alternative mitigation plans that it considered.** Section VIII within each of the individual risk chapters present at least two considered alternative mitigations with associated costs and Risk Spend Efficiencies (RSEs). The Company's alternative mitigation plans presented herein are defined as specific individual activities that were considered in the process of determining the Company's risk management efforts but are not currently proposed at this time. Although an increase/decrease in scope of activities may be a feasible approach to alternatives, the individual risk chapters (with the exception of the Cybersecurity risk chapter) do not take this approach, based on feedback from the Commission's Safety and Enforcement Division (SED).

5. **Present an early stage "risk mitigated to cost ratio" or related optimization.** For each Control or Mitigation activity where an RSE analysis is performed, the Company includes a post-mitigation analysis, which includes a Likelihood of

[12] *Id.* at 16. A Mitigation is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event." *Id*. at 17.

Risk Event (LoRE) and Consequence of Risk Event (CoRE), within Section VI of each individual risk chapter. In addition, Appendix D-1 provides a ranking of the Company's Controls and Mitigations by RSE, where an RSE analysis is performed, consistent with the SA Decision.[13] Controls and mitigations with RSEs are listed in descending order.

6. **Identify lessons learned in the current round to apply in future rounds.** As the first utilities to prepare a RAMP Report under the current S-MAP framework, "lessons learned" are discussed in Chapter RAMP-G.

7. **Move toward probabilistic calculations, to the maximum extent possible.** This 2019 RAMP Report applies the probabilistic analysis required by the SA Decision. The Company will continue working toward a more probabilistic analysis in future RAMP reports, as further discussed in Chapter RAMP-C.

8. **For those business areas with less data, improve the collection of data and provide a timeframe for improvement**. The Company will position itself to continually improve data collection efforts and therefore improve the risk assessment process. Further discussion on data collection can be found in Chapter RAMP-G.

9. **Describe the company's safety culture, executive engagement, and compensation policies.** Chapter RAMP-F is dedicated to describing the Company's safety culture, executive engagement, and compensation policies.

10. **Respond to immediate or short-term crises outside of the RAMP and GRC process.** Although this 2019 RAMP Report identifies the Company's key safety risks, the Company responds to immediate or short-term needs outside of this RAMP effort and continually manages risk.

B. RAMP Workshop Requirement

The SA Decision requires the Company to host a publicly noticed workshop in preparation for the RAMP filing (Pre-RAMP Workshop). The Company's Pre-RAMP

---

[13] *Id.* at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

Workshop was properly noticed and held on March 5, 2019.[14] The intent of the Pre-RAMP Workshop was to gather input from stakeholders to inform the determination of the final list of risks to be included in the 2019 RAMP Report. Accordingly, the Company provided the following information to the interested parties on February 19, 2019, in advance of the workshop:

- their preliminary list of RAMP risks;
- the Safety Risk Score for each risk in the ERR; and
- the Multi-Attribute Risk Score for the top ERR risks.

Representatives from the SED and Energy Division, The Utility Reform Network (TURN), OSA, and Indicated Shippers attended the Company's Pre-RAMP Workshop. The Company appreciates the input received during the Pre-RAMP Workshop,[15] had subsequent discussions with the above-noted stakeholders and has incorporated or otherwise addressed such feedback, as described below, in this 2019 RAMP Report.

1. Use of National Data for Determining the Risk Quantification Score

During the Pre-RAMP Workshop, TURN raised concerns that the use of national data could potentially overestimate the safety implications of a given risk and may undermine strides and investments that have been made in California to improve safety. The Company appreciates TURN's feedback on the use of national level data. As noted above, the methods implemented in this RAMP Report, which were adopted in the SA Decision, are more quantitative than before, making the use of data, as well as subject matter expertise, necessary. That said, many of the risks included in the Company's ERRs are low frequency, high consequence events (e.g., high pressure pipeline incidents) for which there is minimal available data related to the Company's systems. Because relying solely on the Company's own data would limit the available data set, national data was appropriately applied to inform the risk assessments in this RAMP Report.

---

[14] The presentation provided for the Pre-RAMP workshop may be accessed on the California Public Utilities Commission, Utility Risk Assessment and Safety Advisory website (Major Proceedings), *available at* https://www.cpuc.ca.gov/riskassessment/.

[15] The Company made its determination of the final list of risks to be addressed in the RAMP Report based on the input received from SED and other interested parties. *See* D.18-12-014 at Attachment A, A-10.

When national or external data was used, the Company supplemented its analysis with subject matter expertise, consistent with the SA Decision,[16] to confirm certain portions of the risk assessment, including the applicability of the data to the Company. Additionally, the Company primarily used national data to estimate an incident rate in the pre-mitigation risk score. The incident rate was then scaled to the characteristics of the Company's system or service territory.

Moreover, the use of external data is not new. External data is often used to determine potential outcomes of a risk event and the magnitude of the impacts. References to industry incidents has been informative in helping the Company determine the potential severity of the risks. Chapter RAMP-C further discusses the Risk Quantification Framework and expands on the use of national data. Further discussion on the Company's data collection efforts are included in Chapter RAMP-G.

2. Consideration of Mitigation Effectiveness

During the Pre-RAMP Workshop, SED asked how the Company planned to address mitigation effectiveness in the 2019 RAMP Report. The Company replied by explaining that estimated risk reduction benefits would be addressed in the individual risk chapters. Subject Matter Experts (SME) for each respective risk developed risk reduction benefit percentages for each Control and Mitigation where an RSE analysis was performed. Estimated risk reduction benefits are an input to each RSE. The overall methodology for determining risk reduction benefits is addressed in Chapter RAMP-D and within Section VI of each risk chapter.

As for reporting of mitigation effectiveness, *the Phase Two Decision Adopting Risk Spending Accountability Report Requirements and Safety Performance Metrics for Investor-Owned Utilities and Adopting a Safety Model Approach for Small and Multi-Jurisdictional Utilities*[17] defers approval of specific reporting requirements for the Risk Mitigation Accountability Report, contemplated in D.14-12-025, and the identification and benchmarking of industry risk-based decision-making practices to a subsequent S-MAP. The Company looks

---

16 *Id.* at Attachment A, A-8 – A-9 (Identification of Potential Consequences of Risk Event, Identification of the Frequency of the Risk Event).

17 D.19-04-020.

forward to collaborating with the Commission and other stakeholders on developing operative methodologies for further determining mitigation effectiveness.

3. Scoping of Risks

During the Pre-RAMP Workshop, the scope of risks and the potential overlap between risks were addressed. Based on this feedback, the Company reviewed its risks to clarify the scope of each in this RAMP Report and refined it as necessary to align with the data that was used to determine the pre-mitigation risk score. For details regarding the calculation of pre-mitigation risk scores, please refer to Chapter RAMP-C. Additional information is also included in Chapter RAMP-G.

4. Changes Compared to the Pre-RAMP Workshop

The pre-mitigation risk scores presented at the Pre-RAMP Workshop were the result of a preliminarily MAVF.[18] The Company notes that the SA Decision permits adjustments to a MAVF over time. The Company communicated the preliminary state of its Risk Quantification Framework at the Pre-RAMP Workshop and stated that its Risk Quantification Framework may evolve prior to filing the RAMP Report.

Following the Pre-RAMP Workshop, the Company revised certain aspects of its Risk Quantification Framework. The attributes themselves (Safety, Reliability, and Financial) have not changed. The scaled units for the Safety attribute have been refined and are in accordance with MAVF Principle 5 of the SA Decision. These revisions to the Risk Quantification Framework result in modifications to the pre-mitigation risk scores as compared to the information served in preparation for the Pre-RAMP Workshop. In addition, after the Pre-RAMP Workshop, the Company added a 100,000 multiplier to the Risk Quantification Framework risk score for purposes of readability. While the multiplier changed the Risk Quantification Framework numbers, the presence of the multiplier did not in itself change the underlying math. Rather, it simply changed the position of the decimal (*e.g.*, 17.2 instead of 0.000172). Appendix A-2 provides a summary of changes to the materials presented for the Pre-RAMP Workshop using this revised Risk Quantification Framework. The rationale for the Company's Risk Quantification Framework is discussed in Chapter RAMP-C.

---

[18] The Company refers to its MAVF herein as the Risk Quantification Framework.

5. Incorporation of Lessons Learned

As mentioned above, this RAMP Report is the first instance in which the new S-MAP methodology will be applied to and presented in RAMP and GRC filings. While the Company has experienced one full RAMP/GRC process (*i.e.*, filing the first-ever RAMP Report in November 2016, incorporating the RAMP results into its TY 2019 GRC, and getting a final decision in the TY 2019 GRC that reflected RAMP), this RAMP Report differs from the Company's prior RAMP Report by implementing both the requirements set forth in the SA Decision and also by implementing lessons learned. Not only does the Company have its own experience to draw from, it has also learned from PG&E's 2017 RAMP filing, SCE's 2018 RAMP filing, and the resulting feedback from SED and other parties.

For instance, a "lessons learned" from its prior RAMP filing is that the Company attempts to show activities and corresponding cost forecasts in this 2019 RAMP Report either within a single risk chapter and/or allocated between risks. In the 2016 RAMP filing, the Company did not attempt to split or apportion the costs of mitigation to each risk. Rather, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters. Additionally, in this 2019 RAMP Report, the Third Party Dig-in risk has been addressed in two separate risk chapters, Third Party Dig-in on a High Pressure Pipeline and Third Party Dig-in on a Medium Pressure, for additional granularity and alignment of Controls and Mitigations (compared with one chapter addressing all Third Party Dig-ins in the Company's 2016 RAMP Report).

Further, there were risk chapters that were included in the 2016 RAMP Report that are now identified as Drivers/Triggers instead of Risk Events that warrant distinct risk chapters. These items (*e.g.*, climate change) are discussed within the individual risk chapters and assessed as Drivers/Triggers that may contribute to an identified Risk Event (*e.g.,* asset failure). Additional lessons learned are discussed in Chapter RAMP-G.

C. Guiding Principles

The Company strives to provide transparency and uniformity of its risk presentation. This is demonstrated by also providing detailed workpapers submitted concurrently with this RAMP Report. In addition, there are several assumptions and decisions that the Company applied broadly in developing the 2019 RAMP Report. This section outlines these main assumptions and guiding principles that were globally applied throughout the 2019 RAMP Report.[19] Many of these global assumptions resulted from lessons learned and are therefore also discussed in Chapter RAMP-G.

1. The 2018 Enterprise Risk Registry Served as a Starting Point

The Company used its 2018 ERR as a starting point for selecting the risks to be addressed in the 2019 RAMP Report consistent with the requirements called forth in the SA Decision.[20] Although the 2018 ERR was based on the Company's 7x7 matrix, all the risks in the 2018 ERR were re-assessed within the new quantitative assessment for RAMP and the assessments in this Report reflect the implementation of the new methodology.[21] These risks were then evaluated using the process and methods approved in the SA Decision. SoCalGas' and SDG&E's 2018 ERR each identified 24 risks. Of those risks, 11 risks for SoCalGas and 12 risks for SDG&E had a safety score greater than zero. Therefore, using the processes adopted in the SA Decision, there were five risks in the top 40% for the Company that required further analysis. The result, after consulting with stakeholders, is that SoCalGas selected eight risks, SDG&E selected nine risks, and there is one risk shared between SoCalGas and SDG&E that are included in this 2019 RAMP Report.[22] Further discussion regarding the ERR-related processes are provided in Chapter RAMP-B.

The 2018 ERR was the basis for the selection of RAMP risks, based on the data used for purposes of performing the quantitative analysis, including the pre-mitigation risk score. However, the risk definitions and scope for a given risk may slightly differ from the 2018 ERR.

---

19 Unless otherwise noted throughout the 2019 RAMP Report, these global assumptions and parameters apply to all risk areas.

20 D.18-12-014 at Attachment A, A-7 (Risk Identification and Definition).

21 The SA Decision was issued in December 2018 after the Company's 2018 ERRs were finalized.

22 D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP) (Based on input received from SED, other interested CPUC staff, and interested parties, the utility will make its determination of the final list of risks to be addressed in its RAMP.).

2. The Risk Quantification Framework Generally Excluded Secondary Impacts from the Assessment

As discussed in Chapter RAMP-C, secondary impacts were generally excluded from the risk quantification assessments; only direct impacts of a risk event were evaluated for purposes of determining the pre-mitigation risk score. Accounting for secondary impacts is particularly challenging as the impacts would span across multiple risk areas and an improved methodology and data collection is needed to determine how to best account for risk reduction benefits that may indirectly mitigate other risks.

The Company recognizes that not capturing indirect impacts may underestimate the magnitude of certain risks. Although secondary impacts are managed daily, and these impacts certainly present additional risks, there are a number of hypothetical events, considerable assumptions, and limited data that may be relied upon for quantifying such impacts with a reasonable degree of confidence. An example of an event with a secondary impact is a prolonged power outage which leads to inoperable traffic lights that could result in an automobile accident, the consequences of which may include a serious injury and/or fatality. The Company will continue collaborating with the other California IOUs and stakeholders to continue to refine the process and develop improved methodologies for capturing data to support quantifying secondary impacts.

3. Cost Information Presented in RAMP

The purpose of RAMP is not to request funding. Any funding requests will be made in the Company's TY 2022 GRC application, currently anticipated to be filed in September 2020. The range of costs presented in this 2019 RAMP Report are those costs which the company anticipates requesting recovery for in the TY 2022 GRC. For this 2019 RAMP Report, the baseline costs of Controls and Mitigations are the costs incurred in 2018. This is because at the time of this RAMP Report, the last available recorded annual financial data is 2018. The cost forecasts presented herein include forecasts for anticipated capital expenditures over the forecast years of the next GRC cycle (2020-2022) and estimated operations and maintenance (O&M) cost forecasts for TY 2022. The 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas O&M costs are presented for TY 2022. All dollars are presented in direct, constant 2018 thousands of dollars. This approach is anticipated to be consistent with the Company's GRC presentation. Section VII of each risk Chapter presents a summary of the baseline and forecasted costs for each Control and Mitigation by tranche.

a. RAMP Cost Forecasts are Presented in Ranges

The Company has developed cost estimates for the 2020-2022 GRC period for each Control and Mitigation, unless otherwise noted. The Company presents these cost forecasts, for both O&M and capital, in 2018 direct dollars. Using reasonable efforts, the Company has developed estimated forecast costs in ranges. It is important to note that these costs are estimates at this point in time. The Company's TY 2022 GRC will further refine the cost estimates shown in this RAMP Report with supporting testimony.

b. Cost Forecast Methodologies

The Company generally applied a forecast methodology (*e.g.*, base year, historical average, zero-based) to identify forecast cost estimates, consistent with how costs are presented in the GRC. The Company's accounting systems are not configured to capture all costs by the level or type of risk-management activities as anticipated by the RAMP process – costs are tracked by cost center (O&M) and budget code (capital). Therefore, estimates, assumptions, and available accounting data were provided by SMEs where feasible. For Controls and Mitigations funded through capital expenditures, the Company generally does not include associated O&M expense, which typically amounts to less than 2-3% of the capital spend. As the exclusion does not materially change the risk analysis, the Company will address such expenses in its TY 2022 GRC.

c. TY 2019 Authorized Funding

The Company's test year for its prior GRC application was 2019, for which the CPUC recently issued a final decision on September 26, 2019.[23] The Company is thus expeditiously moving forward with many of the programs authorized in that decision. Because this RAMP has a base year of or identifies baseline costs for 2018, if no historical spend was recorded in 2018 or prior, an activity was denoted as a Mitigation, rather than a Control. Many of the activities

23 *See* D.19-09-051.

authorized in the TY 2019 GRC are underway and have recorded costs in 2019. This will be shown in the TY 2022 GRC. Therefore, if funding was authorized in the TY 2019 GRC, it may still be labeled as a Mitigation, even though the Company is actively performing such activities in 2019.

d. Exclusions

For the 2019 RAMP Report, internal labor for certain baseline controls (*e.g.*, internal labor to attend training, adhering to internal protocols or standards, internal time spent at meetings, etc.) is generally excluded from the O&M baseline and forecasted cost estimates. Forecasting internal labor requires the use of cost assumptions (*e.g.*, x number of employees, x length of training, x average hourly wage). As the Company moves towards a more probabilistic approach, it was determined that cost estimates for internal labor that are not specifically accounted for in that manner should not be explicitly identified in RAMP. Further, internal labor costs are not currently tracked in such a manner which would impede accountability reporting requirements. In the spirit of the SA Decision, the Company aims to demonstrate progress toward "probabilistic calculations" for RSEs and thus attempted to eliminate assumptions, such as internal labor cost estimates, as an input to those calculations where possible. The Company points out that the exclusion of internal labor costs in this RAMP Report resulted in decreased O&M cost forecasts in some instances, particularly those related to employee, contractor, and customer and public safety.

Further, the Company expects to include the costs presented herein in its TY 2022 GRC applications. While non-GRC costs are not included herein, the Company provides in this RAMP Report a complete narrative description of the activities being proposed in the respective risk chapters' Risk Mitigation Plans, even though costs for such activities may not be specifically identified or included. This approach is necessary because, in computing RSEs, the Company found that in one instance the risk reduction was estimated for the program in its entirety, not limited to those presented in GRCs. Therefore, on a piloted basis, in the Electric Infrastructure Integrity risk chapter (Chapter SDG&E-4), SDG&E included the costs applicable to the program (GRC and non-GRC costs) to match the estimated total program benefits.

The determination of treatment of costs in this 2019 RAMP Report was highly influenced through lessons learned from the Company's 2016 RAMP Report, the TY 2019 GRC, new spending accountability reporting requirements, and overall configuration of internal accounting and tracking systems. The Company will continue to implement lessons learned and refine the process.

4. Treatment of Risk Mitigating Activities Presented in Risk Chapters

In a few cases within this RAMP Report, a Control or Mitigation may help mitigate multiple risks. For example, a safe driving training program helps mitigate employee safety risk but also helps mitigate customer and public safety. A Control or Mitigation may address multiple risks, but the full cost for those Controls and/or Mitigations that address multiple risks are presented in a single risk chapter, unless otherwise noted. While the costs may reside within the risk chapter of primary benefit, other risk chapters may qualitatively discuss how the mitigation affects the risk in the chapter receiving the benefit. As an additional "lessons learned" from its prior RAMP filing, the Company attempts to show cost forecasts either within a single risk Chapter and/or allocated between risks. In the 2016 RAMP filing, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters. As the Company continues to move towards probabilistic RSE calculations, the Company aims to present costs in a single instance, even though these activities may provide risk mitigation benefits to multiple risks. Chapter RAMP-D contains further discussion on this topic.

Given that risks are dynamic and cross-cutting in nature, there are activities in this 2019 RAMP Report that contribute to mitigating other risks. This is outlined in Appendix A-3. The Company notes that for purposes of funding, these activities will only be requested once in the GRC.

This RAMP Report provides analysis of activities in scope of the risk description (as required by the SA Decision) and provides a qualitative discussion of certain risk mitigation activities that are otherwise out-of-scope due to the risk definition, to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of the Company's mitigation activities. For example, emissions reduction activities in compliance with Senate Bill (SB) 1371 that could result in collateral safety benefits are discussed in the Medium Pressure Pipeline Incident risk chapter. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions. These distinctions are discussed in the applicable narratives within the individual risk chapters, in Section VI. Similarly, a narrative discussion of certain activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis.

5. RSE Analysis

The SA Decision directs the Company to provide a Step 3 analysis of mitigations.[24] As further discussed in Chapter RAMP-D, RSE Methodology, where costs are not identified or not available for a given Control/Mitigation, such as with non-GRC jurisdictional or certain internal labor costs, no RSE calculation is provided. Additionally, the Company did not perform RSE calculations on certain mandated activities. Mandated activities are defined in this RAMP Report as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order.[25] Activities with no RSE score are identified within Section VI of the individual risk chapters. Lastly, the RSEs are generally expressed in ranges.[26]

III. RAMP REPORT OVERVIEW

A. Selection of RAMP Risks

As discussed above, SoCalGas and SDG&E held a Pre-RAMP Workshop on March 5, 2019. Per the SA Decision,[27] the Company will make its determination of the final list of risks to be addressed in the RAMP based on the input received from SED and other interested parties. After considering feedback from the Pre-RAMP Workshop and subsequent discussions with interested parties, 18 separate risk chapters are being presented in this RAMP Report: eight for SoCalGas, nine for SDG&E, and one joint SoCalGas/SDG&E chapter.

---

[24] D.18-12-014 at Attachment A, A-11 – A-13.

[25] For purposes of this report, the Company uses the term "mandated" in place of compliance. However, the term mandated is defined consistently with how compliance is described in Row 28 of the SA Decision. *Id.* at Attachment A, A-14 – A-17 (Step 3 Supplemental Analysis in the GRC).

[26] Risk mitigation activities with no direct safety impact will not have a range in scoring since only the safety attribute weighting contributes to the ranges.

[27] D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP).

The Company actively manages several other risks that are not part of the 2019 RAMP Report but are integral to daily operations and are reflected in the ERR. For example, the Company continuously monitors risks related to reliability and resiliency of the system as well as risks related to technology applications and business resumption. Consistent with the SA Decision, a supplemental analysis will be conducted in the GRC for programs not included in this RAMP Report that meet certain criteria, including those associated with ERR risks that were not included in RAMP.

B. Report Overview

This 2019 RAMP Report focuses on the Company's key safety risks and the current and proposed activities to help mitigate those risks. Each risk is discussed in detail in the individual chapters associated with a particular Risk Event. The Company also presents the following chapters, which set the foundation for this filing:[28]

- RAMP-A: Overview & Approach
- RAMP-B: Enterprise Risk Management (ERM) Framework
- RAMP-C: Risk Quantification Framework
- RAMP-D: Risk Spend Efficiency (RSE) Methodology
- RAMP-E: A Discussion on the Use of Risk Spend Efficiencies
- SCG RAMP-F: Safety Culture, Executive Engagement, and Compensation Policies
- RAMP-G: Lessons Learned

SoCalGas' 2019 RAMP Report comprises the following risk chapters:

Chapter	Risk
SCG-1	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
SCG-2	Employee Safety
SCG-3	Contractor Safety
SCG-4	Customer and Public Safety
SCG-5	High Pressure Gas Pipeline Incident (Excluding Dig-in)
SCG-6	Third Party Dig-in on a Medium Pressure Pipeline
SCG-7	Third Party Dig-in on a High Pressure Pipeline

[28] Chapters RAMP-A through RAMP-E and RAMP-G contain largely the same content for both SoCalGas and SDG&E; however, Chapter RAMP-F is Company-specific as denoted by SCG RAMP-F and SDG&E RAMP-F.

Chapter	Risk
SCG-8	Storage Well Integrity Event
SCG-9/ SDG&E-10	Cybersecurity

SDG&E's 2019 RAMP Report comprises the following risk chapters:

Chapter	Risk
SDG&E-1	Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)
SDG&E-2	Contractor Safety
SDG&E-3	Employee Safety
SDG&E-4	Electric Infrastructure Integrity
SDG&E-5	Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline
SCG-9/ SDG&E-10	Cybersecurity

The chapter number associated with the RAMP risk chapters identified above (*e.g.,* SDG&E-1) were assigned based on each Company's ERR risks sorted in descending order by the Safety risk score as presented at the Pre-RAMP Workshop.[29]

C. Risk Chapter Overview

In each individual risk chapter, the Company presents each risk's baseline Controls, identifies new and/or incremental proposed Mitigations to address these risks, and presents at least two alternative mitigation plans for each risk.[30] The process for selecting the risks presented in the 2019 RAMP Report is further detailed in Chapter RAMP-B.

The Company presents the following sections in each chapter:

1. Introduction
2. Risk Overview – This section provides context to the given risk including background and why this is a risk in the Company's ERR.

---

29 *See* D.18-12-014 at Attachment A, A-8 (Risk Assessment).

30 Compliance requirements are further addressed in Section II herein.

3. Risk Assessment – In accordance with the SA Decision,[31] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of each identified risk.
4. Risk Quantification – This section provides an overview of the scope and methodologies applied for the purpose of risk quantification.
5. Risk Mitigation Plan – This section includes Controls that are expected to continue and proposed Mitigations for the period of the Company's TY 2022 GRC cycle.
6. Post-Mitigation Analysis of Risk Mitigation Plan – This section describes the Step 3 analysis performed for the identified Controls and Mitigations presented as part of the Risk Mitigation Plan pursuant to the terms of the SA Decision.
7. Summary of Risk Mitigation Plan Results – This section provides a summary table of the Risk Mitigation Plan, including Controls and proposed Mitigation activities, associated costs, and RSEs, by tranche.
8. Alternative Mitigation Plan Analysis – This section presents at least two alternative mitigation plans considered as part of the risk assessment process included forecasted costs and post-mitigation analysis.

In sum, this RAMP Report represents a significant step forward in how the Company thinks about, plans for, and mitigates its key safety risks. This RAMP Report will inform the safety-related funding requests that the Company will include in its TY 2022 GRC application, currently anticipated to be filed in September 2020.

[31] D.18-12-014 at 33 and Attachment A, A-11 (Bow Tie).

APPENDIX A-1

APPENDIX A-1

Glossary of Risk Terms

The following are terms used by the Company for purposes of the 2019 RAMP Report:

Term	Definition
Baseline Costs	Costs incurred for Controls in 2018.
Base Year	The last available year of recorded financial data. In the 2019 RAMP Report the Base Year is 2018.
High Alternative	Risk Quantification Framework that provides a narrower range of the Safety attribute compared to the Single Point method (*see* Chapter RAMP-C)
Low Alternative	Risk Quantification Framework that provides a wider range of the Safety attribute compared to the Single Point method (see Chapter RAMP-C).
Mandated	Activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. For purposes of the 2019 RAMP Report, SoCalGas and SDG&E use the term "mandated" synonymously with compliance. "Mandated" in this RAMP Report is defined consistently with "compliance" as described in Row 28 of the SA Decision.
Measurement Unit	The measured attribute, also analogous to "Natural Unit" per the SA Decision Lexicon.
Monte Carlo analysis (simulation or modeling)	A technique used to understand the impact of uncertainty related to a particular risk.
Non-GRC costs	Costs with forecasts and recovery sought in a separate CPUC proceeding (outside of the GRC) and/or outside the CPUC's jurisdiction.
Pre-Mitigation Risk Score	Risk score measuring the current state of the risks with the current controls in place.
Post-Mitigation Risk Score	Risk score after implementing the mitigation activity.
Risk Quantification Framework	The Company's Multi Attribute Value Function (MAVF) presented in this 2019 RAMP Report.
SA Decision	Commission Decision (D.) 18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement With Modifications
Secondary Impacts	Impacts that are "downstream" of the initial risk event; this includes indirect impacts from a risk event.
Serious Injury	Defined as an event that requires overnight hospitalization.
Single Point	Risk Quantification Framework presented in the RAMP as mandated by the Settlement Agreement that includes one range for each Attribute.

Term	Definition
Sub-Attribute	An observable and measurable attribute that, in an attribute hierarchy, relates to a higher-level attribute. Also referred to as a lower-level attribute.
Subject Matter Expert(s)	Individual(s) with special skills or knowledge on a topic.
Tail Risks	Risk events that have a small probability of occurring, typically measured by three standard deviations from the mean of a normal distribution. Sometimes referred to as low frequency, high consequence risk events.
Test Year	First year of a General Rate Case (GRC) cycle. The 2019 RAMP Report is prepared in anticipation of the Company's subsequent GRC – the Test Year (TY) 2022 GRC.

The risk lexicon adopted by the SA Decision was used in the 2019 RAMP Report and is included below for reference:[1]

Term	Definition
Alternative Analysis	Evaluation of different alternatives available to mitigate risk.
Attribute	An observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability. Changes in the levels of attributes are used to determine the consequences of a Risk Event. The attributes in an MAVF should cover the reasons that a utility would undertake risk mitigation activities.
Bow Tie	A tool that consists of the Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of Consequences on the right side that show the potential outcomes if the Risk Event occurs.
Consequence (or Impact)	The effect of the occurrence of a Risk Event. Consequences affect Attributes of a Multi Attribute Value Function (MAVF).
Control	Currently established measure that is modifying risk.
CoRE	Consequences of a Risk Event.
CPUC	California Public Utilities Commission
Driver	A factor that could influence the likelihood of occurrence of a Risk Event. A driver may include external events or characteristics inherent to the asset or system.
Enterprise Risk Register (also referred to as "risk registry" or "ERR")	An inventory of enterprise risks at a snapshot in time that summarizes (for a utility's management and/or stakeholders such as the CPUC) risks that a utility may face. The ERR must be refreshed on a regular basis and can reflect the changing nature of a risk; for example, risks that were consolidated together may be separated, new risks may be added, and the level of risks may change over time.

[1] D.18-12-014 at 16.

Term	Definition
Exposure	The measure that indicates the scope of the risk, e.g., miles of transmission pipeline, number or employees, miles of overhead distribution lines, etc. Exposure defines the context of the risk, i.e., specifies whether the risk is associated with the entire system, or focused on a part of it.
Frequency	The number of events generally defined per unit of time. (Frequency is not synonymous with probability or likelihood.)
General Rate Case (GRC)	A CPUC proceeding that is denominated a general rate case, as well as PG&E's Gas Transmission and Storage (GT&S) rate proceeding.
Inherent Risk	The level of risk that exists without risk controls or mitigations.
Likelihood or Probability	The relative possibility that an event will occur, quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certain we are that the event will occur.
LoRE	Likelihood of a Risk Event.
Mitigation	Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.
Multi-Attribute Value Function (MAVF)	A tool for combining all potential consequences of the occurrence of a risk event, and creates a single measurement of value.
Natural Unit of an Attribute	The way the level of an attribute is measured or expressed. For example, the natural unit of a financial attribute may be dollars. Natural units are chosen for convenience and ease of communication and are distinct from scaled units.
Outcome	The final resolution or end result.
Planned or Forecasted Residual Risk	Risk remaining after implementation of proposed mitigations.
Range of the Natural Unit	Part of the specification of an Attribute. For an Attribute with a numerical natural unit, such as dollars, the smallest observable value of the Attribute is the low end of the range and the largest observable value is the high end of the range. Therefore, any Attribute level that results as a consequence of an event, or a risk mitigation action, or of doing nothing should be found within the range. For weighting purposes, the range of the natural units of an Attribute should be able to describe any mitigation action. For an Attribute with a categorical natural unit, such as corporate image, the range of the Attribute is from the least desirable level to the most desirable level.
Residual Risk	Risk remaining after current controls.
Risk	The potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various outcomes of an adverse event and their associated

Term	Definition
	probabilities. Different stakeholders may have varied perspectives on risk.
Risk Driver	Same as definition for Driver.
Risk Event	An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address. In particular, the occurrence of a Risk Event changes the levels of some or all of the Attributes of a risky situation.
Risk Score	Numerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time.
Risk Tolerance	Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.
Scaled Unit of an Attribute: a value that varies from 0 to 100	The scaled unit is set to 0 for the most desirable level of natural unit in the range of natural units. The scaled unit is set to 100 for the least desirable level of natural unit in the range of natural units. For any level of attribute between the most desirable and the least desirable levels, the scale unit is between 0 and 100. The benefit achieved by changing the level of an Attribute in natural units is measured by the corresponding difference in scaled units. In the special case of moving from the least desirable level to the most desirable level, the benefit is equal to 100 scaled units.
Tranche	A logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment.
Settlement Agreement	The entirety of the agreement between Pacific Gas & Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company, The Utility Reform Network, Energy Producers and Users Coalition, Indicated Shippers, and the Public Advocate's Office of the Public Utilities Commission.

APPENDIX A-2

APPENDIX A-2
SoCalGas' 2019 RAMP Report Risk Quantification Framework
Compared to the Pre-RAMP Workshop Presentation

Risk	Risk Scores Presented at the Pre-RAMP Workshop[1]				Risk Scores Presented in the 2019 RAMP Report					
	Safety	Reliability	Financial	MAVF	Safety	Reliability	Financial	Single Point Risk Score	Low Alternative	High Alternative
SCG-1 Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	0.71	0.005	3.9	0.073	0.70	0.005	3.8	1581	315	3692
SCG-2 Employee Safety	0.55	0	0.3	0.055	0.55	0	0.3	1112	117	2771
SCG-3 Contractor Safety	0.52	0	0.3	0.052	0.52	0	0.3	1037	109	2582
SCG-4 Customer and Public Safety	0.37	0	1.2	0.037	0.37	0	1.2	765	98	1875
SCG-5 High Pressure Gas Pipeline Incident (Excluding Dig-in)	0.15	0.00001	1.1	0.015	0.15	0.00001	1.1	321	51	772
SCG-6 Third Party Dig-in on a Medium Pressure Pipeline	0.148	Not Presented During the Pre-RAMP Workshop			0.13	0.02	15.1	936	698	1333
SCG-7 Third Party Dig-in on a High Pressure Pipeline	0.04				0.04	0.00001	0.1	78	9	194
SCG-8 Storage Well Integrity Event	0.005				0.005	0	16.9	348	339	363
SCG-9/SDG&E-10 Cyber Security	0				0.013	0.04	3.7	920	897	958

[1] This is consistent with what the Company presented during the Pre-RAMP Workshop on March 5, 2019 and reflects changes as discussed in Chapter RAMP-C.

APPENDIX A-2
SDG&E's 2019 RAMP Report Risk Quantification Framework
Compared to the Pre-RAMP Workshop Presentation

Risk	Risk Scores Presented at the Pre-RAMP Workshop[1]				Risk Scores Presented in the 2019 RAMP Report					
	Safety	Reliability	Financial	MAVF	Safety	Reliability	Financial	Single Point Risk Score	Low Alternative	High Alternative
SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)	0.98	0.04	280	0.162	0.96	0.04	225	7215	5493	10085
SDG&E-2 Contractor Safety	0.65	0	5	0.66	0.65	0	5	1408	231	3371
SDG&E-3 Employee Safety	0.53	0	1	0.054	0.53	0	1	1086	127	2684
SDG&E-4 Electric Infrastructure Integrity	0.3	0.15	6	0.061	0.3	0.15	6	3720	3180	4620
SDG&E-5 Customer and Public Safety	0.16	0	0.2	0.016	0.16	0	0.4	323	39	796
SDG&E-6 Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	0.11	Not Presented During the Pre-RAMP Workshop			0.11	0.001	0.7	252	47	594
SDG&E-6 Third Party Dig-in on a Medium Pressure Pipeline	0.03				0.03	0.004	1.7	172	125	250
SDG&E-7 High Pressure Gas Pipeline Incident (Excluding Dig-in)	0.01				0.02	0.000001	0.04	31	4	77
SDG&E-8 Third Party Dig-in on a High Pressure Pipeline	0.002				0.002	0.0000004	0.01	4	1	11
SCG-9/SDG&E-10 Cyber Security	0				0.013	0.04	3.7	920	897	958

[1] This is consistent with what the Company presented during the Pre-RAMP Workshop on March 5, 2019 and reflects changes as discussed in Chapter RAMP-C.

APPENDIX A-3

Risks are dynamic and cross-cutting in nature and the controls and mitigations presented in the 2019 RAMP Report may contribute to mitigating other risk areas as shown below.[1]

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C1	Operating Conditions	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C2	Recloser Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C3	Other Special Work Procedures	SDG&E-3 Employee Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C4	Distribution System Inspections – Corrective Maintenance Program	SDG&E-4 Electric Infrastructure Integrity
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C5	Distribution System Inspections – Quality Assurance/Quality Control	SDG&E-4 Electric Infrastructure Integrity
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C6	Substation System Inspections	
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C7	Transmission System Inspections	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C9	Cleveland National Forest Fire-Hardening	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C10 / M5	Fire Risk Mitigation	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C11 / M6	Pole Risk Mitigation and Engineering	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C12 / M9	Wire Safety Enhancement	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C13 / M11	Fire Threat Zone Advanced Protection	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C14 / M14	Replacement and Reinforcement	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C15	Tree Trimming	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C16	Pole Brushing	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C17	Fire Science & Climate Adaptation Department	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C18 / M21	Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C19 / M22	Camera Networks and Advanced Weather Station Integration	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C20 / M23	High-Performance Computing Infrastructure	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C21/M25	Asset Management	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C23 / M30	Communication Practices	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C25 / M31	Emergency Management Operations	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C26	Disaster and Emergency Preparedness Plan	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C27	Customer Support in Emergencies	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C28 / M32	Wildfire Infrastructure Protection Teams (Contract Fire Resources)	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C29 / M33	Aviation Firefighting Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C30	Industrial Fire Brigade	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C31 / M34	Wireless Fault Indicators	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M1	Distribution System Inspections – Infrared/Corona	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M2	Distribution System Inspections – Drone Inspections	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M3	Distribution System Inspections – Circuit Ownership	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M4	Strategic Undergrounding	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M7	Expulsion Fuse Replacement	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M8	Hotline Clamps	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M10	Covered Conductor	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M12	LTE Communication Network	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M15	Backup Power for Resilience – Generator Grant, Critical Infrastructure, and HPWREN	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M16	Backup Power for Resilience – Microgrids	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M17	Lightning Arrester Removal/Replacement Program	SDG&E-5 Customer and Public Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M18	SCADA Capacitors	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M19	Enhanced Vegetation Management	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M20	Fuel Management Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M24	Ignition Management Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M26	Monitoring and Correcting Deficiencies	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M27	Wildfire Mitigation Personnel	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M28	NMS Situational Awareness Upgrades	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M29	Situational Awareness Dashboard	SDG&E-5 Customer and Public Safety
SDG&E-2	Contractor Safety	SDG&E-2-C1	Contractor Safety Oversight Program	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C2	Contractual Requirements	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C3	Third-Party Administration and Tools	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C4	Stop the Job	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Pipeline Gas Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C5	Near Miss/Close Call Reporting Program	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M1	Expanded Contractor Oversight Program (Additional FTEs, enhance reporting software)	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M2	Updated Class 1 Contractor Safety Manual, Development of Class 2 Contractor Safety Manual	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M3	Near Miss/Close Call reporting portal/app All contractor safety data from ISN and predictive solutions rolled up into real-time dashboard	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C1	Mandatory employee health and safety training programs and standardized policies	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C10	Personal protection equipment	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C11	Near Miss, Stop the Job and jobsite safety programs	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C2	Drug and alcohol testing program	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C3	Safety culture	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-3	Employee Safety	SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Pipeline Gas Incident
SDG&E-3	Employee Safety	SDG&E-3-C5	A comprehensive Environmental & Safety Compliance Management Program (ESCMP)	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C6	Employee safety training and awareness programs	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C7	Employee wellness programs	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	SDG&E-2 Contractor Safety
SDG&E-3	Employee Safety	SDG&E-3-C9	Safe driving programs	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M2	Safety in Action Program Enhancement	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M4	Implementing findings from VPP program assessments	SDG&E-2 Contractor Safety
SDG&E-3	Employee Safety	SDG&E-3-M5	Energized Skills Training and Testing Yard	SDG&E-2 Contractor Safety SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M6	Employee Wildfire Smoke Protections – Cal/OSHA emergency regulation	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C1	GO165: Distribution Inspect and Repair program – Overhead	SDG&E-1 Wildfires SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C2	4 kV Modernization and System Hardening – Distribution	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C3	Distribution Overhead Switch Replacement Program	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C5	Restoration of Service	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C6	Underground Cable Replacement Program - Reactive	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C7	Tee Modernization Program - Underground	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C9	DOE Switch Replacement – Underground	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C10	Vegetation Management (Non-HFTD)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C14	Field SCADA RTU Replacement	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C15	Distribution Circuit Reliability	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C16	Emergency Substation Equipment	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C19	Underground Cable Replacement Program – Proactive	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C20	Enterprise Asset Management – Substation	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M1	Overhead Public Safety (OPS) Program	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M3	Proactive Substation Reliability for Distribution Components	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M4	Substation Breaker Replacements – FLISR (Fault Locations, Isolation, and Restoration)	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M5	Enterprise Asset Management – Distribution	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-5	Customer and Public Safety	SDG&E-5-C1	Public Safety Communications	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-5	Customer and Public Safety	SDG&E-5-C2	Field & Public Safety	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-5	Customer and Public Safety	SDG&E-5-C3	First Responder Outreach & Training	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-5	Customer and Public Safety	SDG&E-5-M1	Expansion of Utility Incident Command	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-5	Customer and Public Safety	SDG&E-5-M2	Expanded Public Safety Communications	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C1	Cathodic Protection	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C2	Assessment of Buried Piping in Vaults	SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C3	Regulator & Valve Inspections and Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C4	Plastic Pipe Replacement	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C5	Leak Repair	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C7	Utility Conflict Review (Right of Way)	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C8	Meter Inspection and Maintenance	SDG&E-5 Customer and Public Safety SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1	Early Vintage Program (Pipeline)	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2	Early Vintage Program (Fittings)	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C1	Locate and Mark Training	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C2	Locate and Mark Activities	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C3	Locate and Mark Annual Refresher Training and Competency Program	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C4	Locate and Mark Operator Qualification	SDG&E-3 Employee Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C5	Locate & Mark Quality Assurance Program	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C6	Damage Prevention Analyst Program	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C7	Prevention and Improvements-Refreshed Laptops	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8	Public Awareness Compliance	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C9	Increase Reporting of Unsafe Excavation	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C14	Locating Equipment	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C15	Remain Active Members of the 811 California One-Call Centers	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M2	Establish a program to address the area of continual excavation	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M4	Utilize electronic positive response	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M5	Enhance process to utilize and leverage emerging excavation technology to help with difficult locates	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M7	Leverage data gathered by locating equipment	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M8	Install warning mesh above buried company facilities	SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C1	Cathodic Protection	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C2	Valve Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C3	Pipeline Safety Enhancement Plan – Pipeline Replacement	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C5	Pipeline Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C6	Pipeline Safety Enhancement Plan – Pressure Testing	SDG&E-5 Customer and Public Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C1	Locate & Mark Training	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C2	Locate & Mark Activities	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C3	Locate & Mark Annual Refresher Training & Competency Program	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C4	Locate & Mark Operator Qualification	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C5	Locate & Mark Quality Assurance Program	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C6	Damage Prevention Analyst Program	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C7	Prevention & Improvements-Refreshed Laptops	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8	Public Awareness Compliance	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C9	Increase Reporting of Unsafe Excavation	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C11	Public Awareness - Meet with the Cities with the Highest Damage Rates	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C14	Locating Equipment	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C16	Install warning mesh above buried company facilities	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M2	Establish A Program To Address The Area Of Continual Excavation	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M3	Recording Photographs For Each Locate & Mark Ticket Visited By Locator	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M4	Utilize Electronic Positive Response	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M5	Enhance Process To Utilize And Leverage Emerging Excavation Technology To Help With Difficult Locates	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M6	Promote Process And System Improvements In USA Ticket Routing And M onitoring	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M7	Leverage Data Gathered By Locating Equipment	SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C1	Perimeter Defenses	SDG&E-4 Electric Infrastructure Integrity SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C2	Internal Defenses	SDG&E-4 Electric Infrastructure Integrity SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C3	Sensitive Data Protection	
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C4	Operational Technology (OT) Cybersecurity	SDG&E-3 Employee Safety SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement	

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation

1 This table does not present an exhaustive list of risks that may be addressed by the controls and mitigations presented in this 2019 RAMP Report

Risk Assessment Mitigation Phase

(RAMP-B)

Enterprise Risk Management Framework

November 27, 2019

A Sempra Energy utility

TABLE OF CONTENTS

I. INTRODUCTION

This chapter discusses the risk management framework for Southern California Gas Company (SoCalGas or Company). For purpose of RAMP, the Company has integrated the directives established in Decision (D.) 18-12-014 and the Settlement Agreement adopted therein (SA Decision) into the Company's existing enterprise risk management (ERM) framework. This chapter describes in detail the current ERM framework utilized by the Company.

II. ENTERPRISE RISK MANAGEMENT FRAMEWORK

As described in the direct testimony of Risk Management and Policy witness Diana Day in the Test Year 2019 General Rate Case,[1] the Company's risk framework:

> is modeled after ISO [International Organization for Standardization] 31000, an internationally recognized risk management standard. This framework consists of an enterprise risk management governance structure, which addresses the roles of employees at various levels ranging up to the Companies' Board of Directors, as well as risk processes and tools. One such process is the six-step enterprise risk management process.

Figure 1 below describes the Company's enterprise risk management process, by which the Company identifies, manages, and mitigates enterprise risks, and aims to provide consistent, transparent, and repeatable results.

1 A.17-10-007/-008 (cons.), Exhibit (Ex.) 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-8.

Figure 1: Enterprise Risk Management Process

The process illustrated in Figure 1 aligns with Cycla Corporation's 10-step evaluation method, which was adopted by the Commission in 2016 "as a common yardstick for evaluating maturity, robustness, and thoroughness of utility Risk Assessment and Mitigation Models and risk management frameworks."[2] While the lexicon used by Cycla differs slightly from that of the Company, the content is largely aligned. Table 1 below provides a side-by-side comparison of the steps in the Company's ERM process to the Cycla method sections.

Table 1: ERM Process Alignment with the Cycla Method

Steps in Cycla[3]	**Corresponding Risk Step in Enterprise Risk Management Process**
Step 1: Identify Threats	1. Risk Identification

---

2 D.16-08-018 at Ordering Paragraph (OP) 4.

3 *Id.* at 17, referencing Evaluation of PG&E's 2014 Gas Distribution General Rate Case (GRC) Filing, by Cycla Corporation, Attachment 3, page 2, Figure 3-1.

<u>Step 2</u>: Characterize Sources of Risk; <u>Step 3</u>: Identify Candidate Risk Control Measures (RCMs)	2. Risk Analysis
<u>Step 4</u>: Evaluate the Anticipated Risk Reduction for Identified RCM	3. Risk Evaluation & Prioritization
<u>Step 5</u>: Determine Resource Requirements for Identified RCMs; <u>Step 6</u>: Select RCMs Considering Resource Requirements and Anticipated Risk Reduction	4. Risk Mitigation Plan Development & Documentation
<u>Step 7</u>: Determine Total Resource Requirement for Selected RCMs; <u>Step 8</u>: Adjust the Set of RCMs to be Presented in Rate Case Considering Resource Constraints; <u>Step 9</u>: Adjust RCMs for Implementation following CPUC Decision on Allowed Resources	5. Risk Informed Investment Decisions and Risk Mitigation Implementation
<u>Step 10</u>: Monitor the Effectiveness of RCMs	6. Monitoring and Review

The Company performs its ERM process annually, resulting in an enterprise risk registry (ERR). The ERR contains each of the Company's identified enterprise-level risks. Each risk is assigned to one or more risk owner(s), a member of the senior management team who is ultimately responsible and accountable for the risk, and one or more risk manager(s) responsible for ongoing risk assessments and overseeing the implementation of risk plans. The ERM organization facilitates sessions amongst the Company's risk owners to identify, evaluate, and prioritize risks, and to review mitigation plans and consider how investments align with risk priorities.

As Ms. Day explained: "The enterprise risk management process is both a 'bottom-up' and 'top-down' approach, by taking input from the risk managers and the risk owners to ultimately finalize the risk registry. As with any useful risk assessment, the enterprise risk registry is not intended to be static; it must be refreshed on an annual basis. Risks are dynamic; risks that were consolidated together may be separated out, new risks may appear, and the level of the risk may change over time."[4]

Each of the steps in the ERM process are discussed further below.

A. Risk Identification

Risk identification is the process of finding, recognizing, and describing risks. As the first step in the risk management process, the ERM organization works with various business units to update existing risk information and identify enterprise-level risks that have emerged or accelerated since the prior assessment. This part of the process also includes the identification of risk events, their causes, and potential consequences. Figure 2 below provides a depiction of the Risk Bow Tie, which is a commonly-used tool for risk analysis. The risk Bow Tie is a way to systematically and consistently evaluate the Drivers/Triggers, possible outcomes, and Potential Consequences of a Risk Event. The left side of the Risk Bow Tie illustrates potential Drivers and/or Triggers that may lead to a Risk Event (center of the Risk Bow Tie) and the right side shows the Potential Consequences of a Risk Event.[5]

---

[4] Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-9.

[5] This 2019 RAMP Report uses the SA Decision lexicon. Please refer to Appendix A-1 in Chapter RAMP-A for a glossary of terms.

Figure 2: Example of Risk Bow Tie

The Company breaks down risks into two groupings – operational risks and cross-cutting risks. Operational risks are those events that have operational implications and may result in damage to or loss of company or public assets, serious injury and/or fatality, and/or interruption of service to customers. An example of an operational risk is Third Party Dig-in on a Medium or High Pressure Pipeline Incident. Cross-cutting risks, while not specific to one asset or group of assets, may also have similar potential consequences to those of operational risks. An example of a cross-cutting risk is Employee Safety, since it focuses on human systems and cuts across all asset types.

The categorization of the 2019 RAMP Report's risks is outlined in Table 2 below. As discussed in RAMP-A, there are 18 separate risk chapters presented: eight for Southern California Gas Company (SoCalGas), nine for SDG&E, and one joint SoCalGas/SDG&E chapter.

Table 2: Categorization of Risks

<table>
<tr><th>Category</th><th>SoCalGas</th><th>SDG&E</th></tr>
<tr><td rowspan="5">Gas</td><td colspan="2">Medium Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td colspan="2">High Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td colspan="2">Third Party Dig-in on a Medium Pressure Pipeline</td></tr>
<tr><td colspan="2">Third Party Dig-in on a High Pressure Pipeline</td></tr>
<tr><td>Storage Well Integrity Event</td><td>N/A</td></tr>
<tr><td rowspan="2">Electric</td><td>N/A</td><td>Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)</td></tr>
<tr><td>N/A</td><td>Electric Infrastructure Integrity</td></tr>
<tr><td rowspan="4">Cross-Cutting</td><td colspan="2">Employee Safety</td></tr>
<tr><td colspan="2">Contractor Safety</td></tr>
<tr><td colspan="2">Customer and Public Safety</td></tr>
<tr><td colspan="2">Cybersecurity</td></tr>
</table>

B. Risk Analysis

Risk analysis is the process of understanding the risk and the degree of risk. Risk analysis provides a basis for risk evaluation and decisions about risk mitigation. Risk analysis is undertaken using varying methodologies, depending on the risk and the availability of data and resources. The Company utilizes a combination of qualitative (*e.g.*, calibrated subject matter expertise) and quantitative analyses (including external data) to analyze its risks.

C. Risk Evaluation and Prioritization

Using the information from the prior steps, an evaluation and prioritization is performed. The result of this step is pre-mitigation risk scores for each risk in the ERR and a relative ranking reflecting consensus around risk priorities. This step involves a discussion of each ERR risk, including changes in the risk frequency or impact, challenges, and elements of the previous assessment's implementation of mitigants. Arriving at a risk prioritization can be an iterative process; risks that may be very different are compared to one another to determine a relative ranking (for example, evaluating an IT risk in comparison with a customer service risk).

In 2018, the Company completed its ERR before year-end and in advance of the issuance of the SA Decision. The evaluation and prioritization process for the 2018 ERRs used the Company's 7x7 matrix, a risk tool that aids in developing the pre-mitigation risk score for ERR risks. Subsequently, the SA Decision was adopted in December 2018 and provided, among other things, a new methodology to be used as the basis of this RAMP Report, rather than the 7x7 matrix.

In particular, the SA Decision established a multi-attribute value function (MAVF).[6] For purposes of this RAMP Report, the Company developed a new MAVF consistent with the SA Decision. Using this MAVF, the Company conducted a secondary analysis on each risk that was identified in its 2018 ERR, which resulted in new pre-mitigation risk scores. This process, methodology, and calculations for the pre-mitigation risk scores are further discussed in Chapter RAMP-C.

D. Risk Mitigation Plan Development & Documentation

Based on the analysis and evaluation of risks in the prior steps, risk owners and managers develop, and document risk mitigation plans to capture the state of the risk given current control activities and any additional mitigations. On an annual basis, the ERM organization facilitates the risk mitigation planning session where risk owners present their key risk mitigation plans and alternatives considered to the senior management team and discuss the feasibility and prudence of those plans. This risk mitigation planning session helps shape the Company's priorities going into the annual investment planning process and helps identify gaps and/or areas of overlap in risk mitigation plans.

E. Risk-Informed Investment Decisions and Risk Mitigation Implementation

The capital planning process is the Company's current annual process for prioritizing funding based on risk informed priorities and input from operations. The capital allocation

---

6 D.18-12-014 at Attachment A, A-8 (Risk Assessment).

planning sessions begin with input from functional capital committees that comprise subject matter experts who perform high level assessments of the capital requirements based on achieving the highest risk mitigation at the lowest attainable costs. These requirements are presented to a cross-functional team representing each functional area with capital requests. This committee reviews the resource requirement submissions from all functional areas, and projects are evaluated against priority by assessing a variety of metrics including safety, cost effectiveness, reliability, security, environmental, strategic, and customer experience. Recommendations for capital spending are then presented to an executive committee for approval. Once the capital allocations are approved, each individual operating organization is chartered to manage their respective capital needs within the capital allotted by the plan. This includes re-prioritizations as necessary to address imminent safety concerns as they arise. Similar to the Company's risk evaluation processes, the capital planning process is continuing to evolve as the Company endeavors to achieve the goal of determining more quantitatively the risk reduction per dollar invested.

F. Monitoring and Review

Monitoring and reviewing the aspects of risk management supports the Company's efforts to continuously improve their risk management practices. Periodic reviews of the ERR are performed to keep the register current and facilitate discussions on any emerging new risks that the Company could face. In addition to using risk scores to monitor changes in risks, the Company leverages risk metrics similar to those identified in the S-MAP to hold parties accountable and improve risk oversight.

III. CONTINUOUS IMPROVEMENT OF RISK MANAGEMENT PRACTICES

The Company's risk management practices continue to mature. This is evidenced through the implementation of the processes and methodologies in the SA Decision, as well as other steps the Company is taking for advancement. The TY 2019 GRC presented a vision related to integrating risk, asset, and investment management to be accomplished over future

GRC cycles.[7] The Company is moving on that trajectory, further integrating risk, asset, and investment management into the Company's culture.

While the Company's risk practices to date have largely focused on expressing risks in terms of risk events, there is a growing interest in aligning risks with asset management practices. Accordingly, there are considerable efforts underway to provide additional granularity of risks and asset health.

One effort demonstrating additional granularity is the development of operating unit risk registries. As explained by Ms. Day, "[t]he operating unit risk registries are intended to provide each operating unit with a tool to capture its specific risks and enable a more structured management of lower consequence risks that occur more frequently and are dealt with at the operating unit levels. As the operating unit risk registries evolve and mature, they will inform the assessment of risks at the enterprise level and provide improved risk quantification and granularity across the Company."[8] The Company continues to work on developing operating unit risk registries in different operating areas of the Company and refining the process. The Company is leveraging the operating unit risk registries to inform internal asset management strategies to continue the integration of risk and asset management.

Additionally, the Company is committed to developing a Safety Management System (SMS),[9] which, according to the Office of Safety Advocate (OSA), is "a key tool for achieving safety goals, managing risks and opportunities, and meeting requirements and expectations."[10] A prudent SMS will further integrate risk, safety, and asset management under one framework. SMS is further discussed in Chapter RAMP-F.[11]

---

7 Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at Figure DD-4.

8 *Id.* at DD-23.

9 A.17-10-007/008 (cons.), Ex. 90 (SCG/SDG&E Buczkowski/Geier Rebuttal) at DLB/DLG-5.

10 A.17-10-007/008 (cons.), Ex. 442 (OSA Contreras Prepared Testimony) at 2-20.

11 Chapter RAMP-F is Company-specific as denoted by SCG RAMP-F and SDG&E RAMP-F.

SoCalGas
A Sempra Energy utility®

The Company continually seeks to implement metrics into its risk-based decision-making processes. Risk metrics span risk, asset, and investment management, in that they help evaluate and monitor asset health and potentially inform and demonstrate progress related to investments. D.19-04-020 approved safety performance metrics, which are reportable on an annual basis beginning in March 2020. The Company's data collection efforts and the metrics themselves will continue to support risk-based decision-making. Further, metrics are tied to investments in that the Company will provide an explanation in its annual Risk Spending Accountability Reports of how the reported safety metric data reflects progress against the safety goals in the Company's RAMP and GRC. In addition to CPUC-reportable metrics, the Company is in the process of identifying ways in which to quantify and track effectiveness related to its mitigations from this 2019 RAMP Report.

IV. EVOLUTION OF RISKS IN THE ERR COMPARED TO 2016 RAMP AND TY 2019 GRC

The SA Decision requires that the RAMP Report highlight changes to the ERR from previous RAMP or GRC filings.[12] Pursuant to this requirement, Appendix B-1 puts forth a comparison of the risks in this 2019 RAMP Report compared to those that were presented in the Company's 2016 RAMP Report, which was integrated into the TY 2019 GRC, and the 2018 ERR.

The primary driver for changes in the risks selected for the 2019 RAMP Report is related to the assessment methodology as established by the SA Decision. Essentially, in using the more quantitative method for risk assessment from the SA Decision[13] compared to the Company's prior risk analysis tools (*i.e.*, the 7x7 matrix), certain risks' scores in the Safety attribute changed (*e.g.*, Workplace Violence). The Company notes that the risks are dynamic; accordingly, risks in the ERR may change annually based on the ERM process identified above. Some risks that the Company manages, while important, did not rise to the enterprise-level to be included in the 2018 ERR. In addition, as discussed in Chapter RAMP-A, the Company generally excluded

---

[12] D.18-12-014 at Attachment A, A-7 (Risk Identification and Definition).

[13] *See id.* at Attachment A, A-8 – A-9 (Step 2A).

secondary impacts from its quantitative analysis when identifying risks for this 2019 RAMP Report. Additionally, as explained in Chapter RAMP-A, for this 2019 RAMP Report, some risks from the Company's 2016 RAMP Report are no longer presented as distinct risk chapters, but rather are identified as Drivers/Triggers to other risks. Examples of these include records management and climate change. Because the Company's ERRs are risk-event based, meaning generally risks in the ERR are identified as risk events, capturing risks such as records management and climate change as Drivers/Triggers to other risks is aligned with the Company's enterprise risk management framework. Records management and climate change adaptation are further discussed below.

A. Records Management

Records management-related risks were captured in the Company's 2018 ERRs as mitigations related to risks supporting the Company's efforts to construct, operate, and maintain the system safely and prudently as well as satisfy regulatory compliance requirements and data retention policies. A number of risks presented in the 2019 RAMP Report have records management related Drivers/Triggers associated with them. For example, the Medium Pressure Pipeline Incident risks (SCG-1 and SDG&E-6) have an "Incorrect/inadequate asset records" Driver/Trigger incorporated into their respective Bow Ties. Although there are some Controls and Mitigations that directly mitigate this risk, there may be additional efforts by the Company to target this risk that are not presented in the 2019 RAMP Report. Maintaining asset records, having adequate systems and processes in place for capturing changes in asset information, and executing projects that improve data automation and validation are critical to the Company's operations.

B. Climate Change Adaptation

Climate Change Adaptation was included in the Company's 2018 ERRs. The risk of Climate Change Adaptation remains a significant issue globally and here in California. The Company has several programs in place and takes the risk of climate change very seriously. The Company views climate change as a driver and/or trigger to some of the top-identified safety risks included herein. To address the risk of climate change, the Company's RAMP Report focuses on the drivers of climate change and the potential resulting impacts, which in turn yielded the adaptation assessment and mitigation efforts presented in the risk chapters of this 2019 RAMP Report. Therefore, Climate Change Adaptation is not included as an individual risk chapter within this 2019 RAMP Report, but is addressed within the risk chapters, including Wildfire (Chapter SDG&E-1), Electric Infrastructure Integrity (SDG&E-4), Medium Pressure Pipeline Incident (SCG-1 and SDG&E-6) and High Pressure Pipeline Incident (SCG-5 and SDG&E-8),[14] as a driver/trigger.

[14] In certain risk chapters, such as the High Pressure Pipeline Incident, the Driver/Trigger "Natural forces (natural disasters, fires, earthquakes)," includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, wildfires and high winds.

APPENDIX B-1

Appendix B-1 – Comparison of 2016 RAMP Risks to 2018 ERR and 2019 RAMP Risks

<table>
<tr><th colspan="3">SoCalGas</th></tr>
<tr><th>2016 RAMP Risks Integrated into TY 2019 GRC</th><th>2018 ERR</th><th>2019 RAMP Risk[1]</th></tr>
<tr><td>Catastrophic Damage involving Medium-Pressure Pipeline Failure</td><td>Medium Pressure Gas Pipeline Incident (Excluding Dig-in) that Leads to Catastrophic Damage</td><td>Medium Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td rowspan="3">Employee, Contractor, Customer and Public Safety</td><td>Employee Safety</td><td>Employee Safety</td></tr>
<tr><td>Contractor Safety</td><td>Contractor Safety</td></tr>
<tr><td>Customer and Public Safety</td><td>Customer and Public Safety</td></tr>
<tr><td>Catastrophic Damage involving High-Pressure Pipeline Failure</td><td>High Pressure Gas Pipeline Incident (Excluding Dig-in) that Leads to Catastrophic Damage</td><td>High Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td rowspan="2">Catastrophic Damage Involving Third Party Dig-Ins</td><td>Third Party Dig-in on a Medium Pressure Pipeline that Leads to Catastrophic Damage</td><td>Third Party Dig-in on a Medium Pressure Pipeline</td></tr>
<tr><td>Third Party Dig-in on a High Pressure Pipeline that Leads to Catastrophic Damage</td><td>Third Party Dig-in on a High Pressure Pipeline</td></tr>
<tr><td>Catastrophic Event related to Storage Well Integrity</td><td>Storage Well Integrity Event that Leads to Catastrophic Damage</td><td>Storage Well Integrity Event</td></tr>
<tr><td>Cyber Security</td><td>Cyber Security</td><td>Cybersecurity</td></tr>
<tr><td>Workplace Violence</td><td>Workplace Violence</td><td>n/a</td></tr>
<tr><td>Physical Security of Critical Gas Infrastructure</td><td>Physical Security of Critical Gas Infrastructure</td><td>n/a</td></tr>
<tr><td>Workforce Planning</td><td>Workforce Planning</td><td>n/a</td></tr>
<tr><td rowspan="2">Records Management</td><td>Inadequate Asset Records for High Pressure Gas that Lead to Catastrophic Damage</td><td>n/a</td></tr>
<tr><td>Inadequate Asset Records for Medium Pressure Gas that Lead to Catastrophic Damage</td><td>n/a</td></tr>
<tr><td>Climate Change Adaptation</td><td>Climate Change Adaptation</td><td>n/a</td></tr>
<tr><th colspan="3">Other Risks in the SoCalGas 2018 ERR[2]</th></tr>
<tr><td colspan="3">System Reliability Impacts Due to Loss of a Storage Field</td></tr>
<tr><td colspan="3">Insufficient Supply to the Natural Gas Transmission System</td></tr>
<tr><td colspan="3">Southern System Reliability</td></tr>
<tr><td colspan="3">Inability to Recover Technology and Applications</td></tr>
<tr><td colspan="3">Gas Pipeline Safety Regulatory Compliance</td></tr>
</table>

1 Each risk presented in the 2019 RAMP Report was part of the 2018 ERR; however, risk names as presented in the 2019 RAMP Report may be modified slightly in comparison to the 2018 ERR to align with the risk definition applied for purposes of the 2019 RAMP Report. Per the SA Decision, "[t]he [ERR] is the starting point for identifying the risks that will be included in the RAMP." (D.18-12-014, Attachment A, at Item No. 8.)

2 These risks were part of the 2018 ERR but were not included in the 2016 RAMP Report or the 2019 RAMP Report.

Ability to Continue to Procure Insurance
Environmental Compliance
Failure of Disaster Recovery / Business Resumption
Capacity Restrictions or Disruptions to the Natural Gas Transmission System

SDG&E		
2016 RAMP Risks Integrated into TY 2019 GRC	**2018 ERR**	**2019 RAMP Risk**[1]
Wildfires Caused by SDG&E Equipment	Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)	Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)
Employee, Contractor and Public Safety	Contractor Safety	Contractor Safety
	Employee Safety	Employee Safety
	Customer and Public Safety	Customer and Public Safety
Electric Infrastructure Integrity	Electric Infrastructure Integrity	Electric Infrastructure Integrity
Catastrophic Damage Involving Medium-Pressure Pipeline Failure	Medium Pressure Gas Pipeline Incident (Excluding Dig-ins) that Leads to Catastrophic Damage	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
Catastrophic Damage involving Third Party Dig-Ins	Third Party Dig-in on a Medium Pressure Pipeline that Leads to Catastrophic Damage	Third Party Dig-in on a Medium Pressure Pipeline
	Third Party Dig-in on a High Pressure Pipeline that Leads to Catastrophic Damage	Third Party Dig-in on a High Pressure Pipeline
Catastrophic Damage involving High-Pressure Gas Pipeline Failure	High Pressure Gas Pipeline Incident (Excluding Dig-ins) that Leads to Catastrophic Damage	High Pressure Gas Pipeline Incident (Excluding Dig-in)
Cyber Security	Cyber Security	Cybersecurity
Major Disturbance to Electrical Service (Blackout)	Electric Grid Failure and Restoration (Blackout/ Failure to Black Start)	n/a
Fail to Black Start		
Aviation Incident	Aviation Incident	n/a
Unmanned Aircraft System (UAS) Incident		
Workplace Violence	Workplace Violence	n/a
Records Management	Inadequate Asset Records for High Pressure Gas that Lead to Catastrophic Damage	n/a

[1] Each risk presented in the 2019 RAMP Report was part of the 2018 ERR; however, risk names as presented in the 2019 RAMP Report may be modified slightly in comparison to the 2018 ERR to align with the risk definition applied for purposes of the 2019 RAMP Report. Per the SA Decision, "[t]he [ERR] is the starting point for identifying the risks that will be included in the RAMP." (D.18-12-014, Attachment A, at Item No. 8.)

	Inadequate Asset Records for Electric	n/a
Climate Change Adaptation	Climate Change Adaptation	n/a
Distributed Energy Resources (DER)	n/a	n/a
Public Safety Event – Electric[2]	n/a	n/a
Workforce Planning	n/a	n/a
Other Risks in the SDG&E 2018 ERR[3]		
Capacity Restrictions or Disruptions to the Natural Gas Transmission System		
Ability to Continue to Procure Insurance		
Negative Customer Impacts Caused by Outdated Customer Information Systems		
Insufficient Supply to the Natural Gas Transmission System		
Inability to Recover Technology and Applications		
Physical Security of Critical Electric Infrastructure		
Environmental Compliance		
Massive Smart Meter Outage		

2 Elements of this risk (*e.g.*, controls) are now included in other risks in the 2018 ERR.
3 These risks were part of the 2018 ERR but were not included in the 2016 RAMP Report or the 2019 RAMP Report.

Risk Assessment Mitigation Phase
(RAMP-C)
Risk Quantification Framework

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This chapter provides a detailed overview of the multi-attribute value function (MAVF) applied to quantitatively assess risks throughout this report (referred to herein as the Risk Quantification Framework), including illustrating hypothetical examples of risk scores (using the ranges displayed in the examples). The Risk Quantification Framework is used to analyze risk by estimating current risk scores (the Pre-Mitigation Risk Scores) and forecasting future risk scores if new activities are started or current ones are ceased (the Post-Mitigation Risk Scores).

- Section II provides an overview of the quantitative analysis used to analyze each risk, according to the S-MAP settlement agreement (the SA Decision).[1]
- Section III describes the requirements of the MAVF per the SA Decision, and how the Company's Risk Quantification Framework was accordingly constructed.
- Section IV describes the steps to apply the Risk Quantification Framework in accordance with the SA Decision.
- Section V shows a hypothetical example of a risk score calculation using the Risk Quantification Framework.
- Section VI describes the decisions made in constructing the Risk Quantification Framework, including the scaling and weighing of attributes, demonstrating compliance with the SA Decision.
- Finally, Section VII demonstrates the Company's efforts towards development of probabilistic calculations and analysis, and discusses quantitative methodologies including statistical information and the use of computer software in development of this RAMP Report.

As the first to apply the quantitative analysis required by the SA Decision, the Company possesses a number of observations about the process that may aid the California Public Utilities Commission (Commission or CPUC) and other investor-owned utilities (IOU) in future applications of the framework. The Company offers these "lessons learned" in Chapter RAMP-G.

---

1 The SA Decision is Decision (D.) 18-12-014, including the settlement agreement adopted therein.

II. OVERVIEW AND APPROACH

The quantitative analysis applied in this RAMP Report is derived from the SA Decision, and can be outlined as follows:

- Develop a MAVF, which the Company refers to as the Risk Quantification Framework;[2]
- Consider risks as defined and scoped in the Company's Enterprise Risk Register (ERR);[3]
- Compute a Safety Risk Score using the Safety Attribute of the MAVF for each risk included in the ERR;[4]
- For each identified risk that meets the SA Decision thresholds:[5]
  - Estimate the frequency of a risk event occurring in a given year and use that value for the Likelihood of Risk Event (LoRE);
  - Estimate the average (mean) consequences if the Risk Event were to occur;
  - Apply the average consequences to the Risk Quantification Framework to create a value known as the Consequence of Risk Event (CoRE); and
  - Multiply the values of LoRE and CoRE to determine a Risk Score for that risk. The result of this calculation constitutes a Pre-Mitigation Risk Score.

As required by the SA Decision, a resulting Pre-Mitigation Risk Score will be used: (1) to demonstrate a risk score for each risk along with a ranking, and (2) as an input into the calculations to determine the change in risk scores when a risk-reducing activity is started or ceased.

---

2 *Id.* at Attachment A, A-5 – A-6 (Step 1A).

3 *Id.* at Attachment A, A-7 (Step 1B).

4 *Id.* at Attachment A, A-8 – A-9 (Step 2A).

5 *Id.* at Attachment A, A-11 – A-13 (Step 3).

III. RISK QUANTIFICATION FRAMEWORK (OVERVIEW)

A. Introduction

The Risk Quantification Framework (or MAVF) is a tool for combining all potential consequences of the occurrence of a risk event to create a measurement of value. This section presents the Risk Quantification Framework that will be used throughout this RAMP Report. Section IV of this chapter provides a thorough walkthrough of how this Risk Quantification Framework is applied, and Section V provides an example of its application. Section VI of this chapter describes the rationales for how the Company set the assumptions used in this Risk Quantification Framework.

This RAMP Report is the first filing that implements the SA Decision, and therefore there is still much to be learned and improved in the future.[6] The quantitative aspects shown in this chapter are not meant to reflect precision or a comprehensive view of risk, but rather serve as a starting point on which to build. Further, as explained below, the Risk Quantification Framework is the result of many discretionary assumptions. Should those assumptions change, different results would be expected.

B. Risk Quantification Framework

According to the SA Decision, the Risk Quantification Framework requires a company to select certain "attributes," defined as "an observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability."[7] The attributes "should cover the reasons that a utility would undertake risk mitigation activities" and must be reflected in "the way the level of an attribute is measured or expressed."[8] The determination of attributes is left to each utility's discretion. These attributes are a subset of the many criteria used to assess and manage risk. The selection of attributes for RAMP Report purposes is predicated on, among

---

6 The Company offers "lessons learned" to aid the Commission and other IOUs in future applications of the framework in Chapter RAMP-G.

7 D.18-12-014 at Attachment A, A-2.

8 *Id.* at Attachment A, A-2 – A-3.

other factors, the level of data available, the strength of the data available, and the commonality of the attribute across risks.

The SA Decision also requires construction of a scale "that converts the range of natural units … to scaled units to specify the relative value of changes within the range, including capturing aversion to extreme outcomes or indifference over a range of outcomes."[9] Attributes also must be assigned weights reflecting each attribute's relative importance to other identified attributes:

> Weights are assigned based on the relative value of moving each Attribute from its least desirable to its most desirable level, considering the entire range of the Attribute.… Weights are assigned based on actual Attribute measurement ranges, not a fixed weight arbitrarily assigned to an Attribute. For example, the Attribute weights will reflect the relative importance of moving the safety outcomes from the least to the most desirable levels as compared with moving financial outcomes from the least to the most desirable levels in a risky situation.[10]

The following three tables show a Risk Quantification Framework utilized in this RAMP Report. Each table shows chosen attributes and assigned weights and scales. A narrative summary of the choices examined and made in assigning values to the variables shown below (*e.g.*, attributes, scales, weights) is described in Section VI below.

The Risk Quantification Framework is a prescribed methodology that is performed in accordance with the SA Decision, which may provide a data point to help inform risk-based decision making (amongst many other available data points). There are numerous ways to select attributes, scaling and weights. However, the SA Decision contains a prescribed methodology for selecting attributes, scaling and weights, which limits a utility's choices in certain ways. The choices elected in accordance with the SA Decision's prescribed methodology should not be viewed as a precise reflection of real-world circumstances and are made for RAMP purposes only.

---

9 *Id.* at Attachment A, A-5.

10 *Id.* at Attachment A, A-6.

The SA Decision requires the Company to follow six principles to construct its MAVF.[11] The Company applied these six principles to arrive at the Risk Quantification Framework summarized in Table 1 below. The top-level attributes of Safety, Reliability, and Financial are consistent with the minimum attributes required by the SA Decision.[12] Given that "[a]ttributes are combined in a hierarchy,"[13] the top-level attributes are further broken down into sub-attributes.[14] Measurement of each sub-attribute is also required and is assigned based on the unique characteristics.[15] These sub-attributes are then rolled up to the top-level attribute. The combined measurement of each top-level attribute is represented in Table 1 below as the Measurement Unit. The scales contained in Table 1 also reflect the SA Decision's MAVF principles and were constructed to represent the relative value of changes in a range of the measured units.[16] Similarly, the Company completed a weighting process in accordance with the SA Decision[17] to develop the weights in Table 1 below (as further described in Section VI.C, *infra*).

---

[11] *Id.* at Attachment A, A-5 ("MAVF").

[12] *Id.* at Attachment A, A-8 ("Risk Assessment").

[13] *Id.* at Attachment A, A-5 ("MAVF Principle 1 – Attribute Hierarchy").

[14] *Id.* at Attachment A, A-5, ("MAVF Principle 1 – Attribute Hierarchy") and ("MAVF Principle 2 – Measured Observations") refer to lower-level attributes in the context of building a MAVF. The term "lower-level attribute" is referred to herein as "sub-attribute."

[15] *Id.* at Attachment A, A-5 ("MAVF Principle 2 – Measured Observations") and ("MAVF Principle 3 – Comparison").

[16] *Id.* at Attachment A, A-5 ("MAVF Principle 5 – Scaled Units").

[17] *Id.* at Ordering Paragraph 2 and at Attachment A, A-6 ("MAVF Principle 6 – Relative Importance").

Table 1: Risk Quantification Framework Top-Level Attributes

Top-Level Attribute	Measurement Unit[18]	Scale	Weight
Safety	Safety Index	0 – 30	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 2 below shows the sub-attributes contained in the Safety top-level attribute from Table 1 above. The measured unit for each of Safety's sub-attributes, when used together, create a single Safety Index value that is used in Table 1 above.[19] The components of the Safety Index are provided in Table 2 below.

Table 2: Risk Quantification Framework Safety Index

Safety Sub-Attributes	Value
Fatality	1
Serious Injury	0.25

Similar to Table 2 above, the following Table 3 shows the sub-attributes that are included in the Reliability top-level attribute from Table 1. Each sub-attribute is measured by its own unit. The Company's determination of Attributes, Scales and Weights are explained in Section VI, *infra*. When all of the four sub-attributes for reliability are summed together, it creates a single Reliability Index value that is used in Table 1 above.[20] These are shown in Table 3 below.

18 "Measurement Unit" used herein is the measured attribute, also analogous to "Natural Unit" per the SA Decision Lexicon included in D.18-12-014 at Attachment A, A-3.

19 MAVF Principle 1 - Attributes are combined in a hierarchy. *See* D.18-12-014 at Attachment A, A-5.

20 *Id.*

Table 3: Risk Quantification Framework Reliability Index

Reliability Sub-Attribute	Measurement Unit	Scale	Weight
Gas Core Meters	Number of Gas Core Meters Experiencing Outage	0 – 75,000 meters	25%
Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day	0 – 500 MMcf	25%
Electric SAIDI	System Average Interruption Duration Index (SAIDI) minutes	0 – 100 minutes	25%
Electric SAIFI	System Average Interruption Frequency Index (SAIFI) outages	0 – 1 outages	25%

Despite some of the prescriptive elements in the SA Decision, there remain a wide range of possible choices available to each utility in assigning attributes, weights, scales, and other variables. Because of this, the Company has chosen to provide a range of scoring, based upon two additional alternative Risk Quantification Framework methods. These alternative methods, and the rationales behind their presence, are described in greater detail in Section VI of this chapter. The two alternatives demonstrate a range of risk scores for each risk and consequently demonstrate a range of RSEs for each activity. The Risk Quantification Framework provides a direction on how to improve risk, but it is not a precise tool and should not be construed as such.

The structure of the alternatives is exactly the same as described above, with the only change being in the scale factor for the Safety Attribute. The "High Alternative" has a safety scale of 0 – 12, rather than 0 – 30; and the "Low Alternative" has a safety scale of 0 – 300, rather than 0 – 30. The SA Decision requires the Company to produce a single risk score and RSE using the adopted methodology. The Company refers herein to the result from its chosen Risk Quantification Framework methodology as the "Single Point" result. The Single Point represents a single score out of a range of possibilities, resulting from applying the SA Decision, using the Company's chosen set of assumptions. However, because of the uncertainty and subjective nature of the methodology with respect to the relative importance of each attribute, as further described in Section VI, *infra*, the Company is presenting a range of potential scales (and the resulting RSEs) in this RAMP Report. A Safety Index Scale that has a tighter range will tend to emphasize safety more than a Safety Index Scale that has a wider range. For example, a Safety Score of 2 will be 1/6 of the score when the Scales range from 0 – 12, but that score will only be 1/150 of the score when the Scales range from 0 – 300.

Summary tables for both alternatives are shown below in Tables 4 and 5.

Table 4: High Alternative

Top-Level Attribute	Measurement Unit	Scale	Weighting
Safety	Safety Index	0 – 12	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 5: Low Alternative

Top-Level Attribute	Measurement Unit	Scale	Weighting
Safety	Safety Index	0 – 300	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

As a hypothetical example, suppose there was a risk that had a likelihood of exactly one event per year, and that the consequence of the event occurring lead to exactly one fatality every time. The LoRE for this risk would be 1, and the CoRE would be calculated using the Risk Quantification Framework.

The Single Point method would yield a CoRE of:

$$(1/30) * 60\% + (0/1) * 20\% + (0/\$1B) * 20\% = \mathbf{0.02}$$

The High Alternative shown above would yield a CoRE of:

(1/12) * 60% + (0/1) * 20% + (0/$1B) * 20% = **0.05**

The Low Alternative shown above would yield a CoRE of:

(1/300) * 60% + (0/1) * 20% + (0/$1B) * 20% = **0.002**

The three different methods, each based on a LoRE of 1, can be summarized in the following table:

Table 6: Example of Illustrative Risk Showing Single Point and Alternative Scorings

	LoRE	CoRE	Risk Score
Single Point	1	0.024	2,400
High Alternative	1	0.05	5,000
Low Alternative	1	0.002	200

IV. APPLICATION OF RISK QUANTIFICATION FRAMEWORK

Per the SA Decision, the Risk Quantification Framework must use specific methods of applying statistical information. The following statistical concepts are key to understanding the Risk Quantification Framework: (a) risks are evaluated at the "risk-level" as defined by the Company's ERR, (b) each risk is evaluated for annual frequency using the risk quantification method (as required by the SA Decision), (c) each risk is evaluated by considering all possible consequences attributed to a risk event (rather than specific scenarios), and (d) averages, or expected values, are used for LoRE and CoRE.

In more detail, the Risk Quantification Framework methodology uses the following steps:

Step 1: Estimate LoRE. Estimate the frequency of a risk event occurring in a given year and set the LoRE to this value. If the frequency is estimated to be less than one per year, the frequency is put into decimal form. For example, if the estimate was a frequency of a risk event occurring 5 times a year, the LoRE would be set to 5. If the frequency of a risk events was estimated to be one event in 10 years, the LoRE would be set to 0.1. Depending on the risk, the frequency of Risk Events in the RAMP Report range from approximately 0.06 to 2000.

Step 2: Estimate consequences of event for each attribute. As discussed above, the Risk Quantification Framework has three attributes with several sub-attributes. This step uses the average consequence for each attribute and sub-attribute based on the wide variety of possible consequences. For example, suppose a Risk Event had a 10% chance of having a $2 million consequence and a 90% chance of having a $100,000 consequence. The value used for the financial consequence would be the weighted average of those chances, or (10% x $2 million) + (90% x $100,000) = $290,000. A similar exercise is done for all of the attributes in the Risk Quantification Framework.

Step 3: Estimate CoRE. Once the averages of consequences for each attribute are determined, use the Risk Quantification Framework to obtain a single consequence value known as the Consequence of Risk Event (CoRE). CoRE is a value that incorporates all attributes.

Step 4: Calculate Risk Score. Lastly, multiply the LoRE and the CoRE to calculate the Risk Score. To ease readability, the Risk Score is multiplied by 100,000, then rounded to the nearest whole number, or decimal if less than 1.

These steps are also undertaken for the two alternative methods mentioned above in Section III of this chapter. The alternatives differ in Step 3 (because of a slight variation in how CoRE is calculated). Then Step 4 for each alternative uses the alternative CoRE values to multiple with LoRE.

The application of these process results in the Company's Single Point method and the two alternatives – low alternative, and high alternative.

V. HYPOTHETICAL EXAMPLE OF RISK SCORE CALCULATION USING THE RISK QUANTIFICATION FRAMEWORK WITH ALTERNATIVES

The following example will follow steps 1 - 4 shown above. All values in this example are illustrative and not representative of a specific risk.

A. Example: Risk XYZ Single Point Method

Step 1: Estimate LoRE. Internal and external data suggest that Risk XYZ will have an average of 12 Risk Events per year.

Step 2: Estimate consequences of attributes. Internal and external data suggest that if a Risk Event were to occur for Risk XYZ, the consequences would average as follows:

a. Fatalities: 0.02 (*i.e.* 1 fatality for every 50 risk events)
b. Serious Injuries: 0.1 (*i.e.* 1 serious injury for every 10 risk events)
c. Electric SAIDI: 0 minutes of SAIDI
d. Electric SAIFI: 0 outages of SAIFI
e. Gas Core Meters: 0 meters
f. Gas Curtailment: 0 curtailment
g. Financial: $1.5 million from damage to property

Step 3: Estimate CoRE. Using the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% = 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{30}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\% = \frac{0.045}{30}\ x\ 60\% + \frac{0}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x = 0.0012$

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.0012. Risk Score = 12 x 0.0012 x 100,000 = 1,440. The Risk Score of Risk XYZ is 1,440.

As mentioned in Section III of this Chapter, the Company is providing ranges for each risk score. The risk scores will be calculated using the High Alternative and Low Alternative methods. The values for High Alternative and Low Alternative only differ in how CoRE is calculated.

B. Example XYZ using Low Alternative

Step 1: Same as above.

Step 2: Same as above.

Step 3: Estimate CoRE. Using the Low Alternative version of the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% = 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{300}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\% = \frac{0.045}{300}\ x\ 60\% + \frac{0.0125}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x = 0.0039$

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.00039. Risk Score = 12 x 0.00039 x 100,000 = 468. The Low Alternative Risk Score of Risk XYZ is 468.

C. Example XYZ using High Alternative

Step 1: Same as above

Step 2: Same as above

Step 3: Estimate CoRE. Using the High Alternative version of the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% =\ 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{12}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\%\ =\ \frac{0.045}{12}\ x\ 60\% + \frac{0}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x\ =$ 0.00255

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.00255. Risk Score = 12 x 0.00255 x 100,000 = 3,060. The High Alternative Risk Score of Risk XYZ is 3,060.

Table 7: Summary of Risk XYZ Risk Scores

	Low Alternative	Single Point	High Alternative
Risk XYZ	468	1,440	3,060

VI. MAVF CONSTRUCTION

Per the SA Decision, each utility is required to create a multi-attribute value function that will be used in the RAMP Report for risk scoring.[21] As stated above, the MAVF is a tool for combining all potential consequences of the occurrence of a risk event to create a measurement of value. The Company's MAVF construction followed the steps outlined in the SA Decision.[22] The process of creating the MAVF is complex and should be considered a non-perfect method to

[21] *Id.* at Attachment A, A-5 – A-6 (Step 1A).

[22] *Id.*

interpret the utility risk. Because the Company is in the process of determining effective quantitative risk methods, the value functions presented in this RAMP Report are the beginning steps into a complex and multi-layered methodology.

It is important to note that the construction of the MAVF discussed herein was a single effort undertaken for both SoCalGas and SDG&E. The attributes, scales, and weighting of attributes in the MAVF were determined collectively for both Companies given the Companies' shared assets (*e.g.*, natural gas distribution system, IT infrastructure), and shared risk management framework.

There were several considerations when developing the Companies' first Risk Quantification Framework, as described below.

A. Determination of Attributes

An attribute, as defined by the SA Decision, is "an observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability. Changes in the levels of attributes are used to determine the consequences of a Risk Event."[23] Following MAVF Principle 1, the Company considered a large number of attributes for the Risk Quantification Framework. The method of attribute inclusion was: (a) create a list of potential attributes - where the list was generated by combining efforts with the CPUC workshops, consulting internal subject matter experts (SMEs), and researching external entities, and (b) determine the ability to include such attributes by considering availability of data, consistency of data, commonality of the attribute across risks, and complications arising from their inclusion, among others. The attributes included in this RAMP Report are not meant to represent all dimensions of risk management that occur at the Company but are useful for the purposes of this filing, namely to create estimated risk quantification that can assist in decision-making.

An example of a potential attribute that was not selected due to the unavailability of consistent data is company trust. It is possible to measure company trust through public surveys or polling, but the purpose of the attribute for the RAMP Report is to determine pre- and post-activity measurements and it will require consistency of individuals for each survey or polling,

23 *Id.* at Attachment A, A-2.

and a measurement after each activity, which can be in the hundreds. The Company has, for now, concluded that measuring company trust for each change in risk-reducing activities would be an exercise that requires large amounts of guesswork and subjectivity. Perhaps in the future, the concept of company trust will be more easily measurable, or some appropriate proxy will be devised so that this attribute could be included.

Environmental attributes were also not selected. While the Company is very focused on environmental impacts and thoughtfully consider how to reduce those impacts, for the purposes of quantification, the Company was unable to determine how to express an environmental attribute that would meet the standards of the SA Decision. There are several dimensions of impacts related to the environment, including impacts to water, soil, air, species, and cultural. Within those dimensions there are numerous sub-dimensions. For example, pollution of air can take many forms that include greenhouse gas (GHG) emissions, but also near-ground pollution such as exhaust from vehicles and generators that have more of a local impact to air quality.

In addition to the various challenges described earlier as to the scope and impacts of the environmental attributes, it was also difficult to define relative weights between each of these environmental impacts. One option was to focus on a narrower view of environmental impacts, such as only considering GHG for use in the attribute. But it was understood that this narrow approach would lead to undesirable outcomes by overestimating certain projects and giving an incorrect impression that the Company was not interested in reducing the other non-represented impacts.

Future versions of the Risk Quantification Framework may be designed with the goal of expanding and refining the number of attributes and sub-attributes in line with other key parameters used in day-to-day decision making.

B. Scales of Attributes

The SA Decision directs the utility to construct a scale that converts the range of natural units to scaled units.[24] While the notion of applying scales for attributes appears to be straightforward, there are many aspects to consider, especially when applying the next step of

---

24 *Id.* at Attachment A, A-5 – A-6 (Step 1A).

assigning weights to each scale. The SA Decision states that the top of the scale approximates the maximum expected results for a risk. However, the SA Decision method also requires expected values to be used and expected values have very different "maximum expected results" depending on each scenario used. For example, a plane crash might lead to a few hundred deaths, but the annual expected value of fatalities for a particular airline in a given year is something far less. The Company exercised its discretion[25] to make a reasoned decision in choosing the top end of the scales for the attributes because not all risk scenarios involving a particular risk yield the same maximum expected results. As discussed in the Weights of Attributes section below, scales and weights are strongly connected.

C. Weights of Attributes

1. Quantitative Notes on Weights

The weight applied to each attribute is an important step in determining risk scores. Different weights applied to several risks can lead to different rankings of those risks. Below is a simplified, illustrative example of sample risks that show how weights can alter results:

Table 8: Illustrative Example of Weighting

	Safety Score	Financial Score	Risk Score Method 1: Safety: 90% Weight Financial: 10% Weight	Risk Score Method 2: Safety: 50% Weight Financial: 50% Weight
Risk A	0.5	0.2	4700	3500
Risk B	0.2	0.6	2400	4000

In Table 8, above, Risk A has a Risk Score near twice as large as Risk B (4700 vs 2400) using Method 1 (90% Safety and 10% Financial) but has a lower risk score using Method 2. This is because Risk A has more Safety risk relative to Risk B, and a weighting that favors Safety would therefore favor Risk A. This example illustrates that choosing weights can have significant impact on the scoring that follows. The Company is aware that its choice of weights is not perfect for all situations, and therefore scores should be thought of as estimates, rather than precise values.

25 The discretion built into the MAVF may be a good topic of consideration for future S-MAP proceedings.

There is a very strong relationship between scales and weights. The two characteristics work hand-in-hand to create the value framework. The following example highlights this point.

Suppose there are two Multi-attribute Value Functions that only have attributes for Safety and Financial. Their illustrative characteristics are shown below:

Table 9: Illustrative Example of Scale & Weight

	MAVF #1	**MAVF #2**
Safety Scale	0 – 100 (measured in fatalities)	0 - 10 (measured in fatalities)
Safety Weight	80%	50%
Financial Scale	0 - $1 billion (measured in $)	0 - $1 billion (measured in $)
Financial Weight	20%	50%

Now suppose there is a risk that has been assessed as having an expected value of impacts as $100M financial loss for property damage, and 2 fatalities. The Consequence of Risk Event for each MAVF would be:

MAVF #1: CoRE = (2 / 100) * 80% + ($100 million / $1000 million) * 20% = 0.036

MAVF #2: CoRE = (2 / 10) * 50% + ($100 million / $1000 million) * 50% = 0.15

Note that the portion of the CoRE that comes from the Safety is:

MAVF #1: CoRE = (2 / 100) * 80% = 0.016

MAVF #2: CoRE = (2 / 10) * 50% = 0.1

Although MAVF #1 has a higher weighting for Safety (80% versus 50%), it gives a lower score for safety, due to the scale being different. Therefore, it is not enough to solely focus on the weight of each attribute to determine the importance of the attribute in the risk score.

2. Methodology for Determining Weights

The SA Decision requires that the Safety Attribute of the MAVF have a minimum weight of 40%.[26] Other than that safety minimum weight requirement, the SA Decision provides discretion for the Company to select the applicable weights through its own internal processes.

The main method to determine weights for the Company's Risk Quantification Framework was to consider alignment with the Company's ERM ERR process. During the creation of the ERR, a qualitative scoring method that contained several risk dimensions was used.

Using the ERR as a starting point, initial weights were identified and considered for use in the RAMP Report. Although the ERR is more of a qualitative than quantitative view of risk, it can lend itself to numerical comparisons. For example, in the ERR, an attribute of Health, Safety, and Environmental (HSE) are weighted 40%, and Reliability is weighted as 20%. Therefore, an HSE score of 4 would give twice the value to the Risk Score as a Reliability score of 4. Below is sample from the qualitative scoring method that is currently part of the Company's ERR:

Table 10: Qualitative Scoring

	Impact Score 4	**Impact Score 3**	**Weight**
Health, Safety and Environmental	Permanent/Serious Injuries or Illnesses: Few serious injuries or illnesses to the public or employees. Significant and short-term impacts to environment	Minor Injuries or Illnesses: Minor injuries or illnesses to many public members or employees. Moderate and short-term impacts to environment	40%
Operations and Reliability	> 10,000 customers affected; impacts single critical location or customer; disruption of service greater than 1 day	> 1,000 customers affected; impacts single critical location or customer; disruption of service for 1 day	20%

[26] D.18-12-014 at Ordering Paragraph 2.

By observing the relationship between the types of impacts that would create an HSE score of 4 versus a Reliability score of 4, for example, it is possible to adjust the Risk Quantification Framework to find similar relationships.

Additional information considered in the creation of Risk Quantification Framework weights was to utilize an industry-leading reliability study that comments on financial equivalences with reliability.[27] The study considers the amount of financial loss to customers due to loss of electric power. As mentioned in more detail below, because every electric outage is unique, the study is used as a guide rather than as a source of precise equivalences. While there is not an equivalent reliability study available specific to financial loss to customers due to loss of natural gas, the findings in the study can be extrapolated to generally apply to all utility customers.

The use of the ERR and the reliability study led to a rough approximation of how weights might look across all three attributes. Draft versions of the scales and weights were created and run through a series of real-world events to check the results for reasonableness. Adjustments were made after the reasonableness test runs and results were internally discussed.

During the internal testing and discussions, it became clear that no set of scales and weights would lead to expected results for all situations for all individuals. Different subject matter experts had their own experience of how to value different scenarios. More refinements were made, and a set of scales and weights that may reflect a compromise on how different subject matter experts and external sources view this relationship is being utilized in this RAMP Report.

To summarize how weights used in the Risk Quantification Framework were attained, the solution was a reconciliation of different values and data points and considers the following items: a) current ERR framework, b) electric reliability study, c) historical comparison of gas and electric reliability impacts to society, d) scenario testing, e) input from ERM staff and leadership, f) research into other utilities and industries, g) input from personnel of varying levels

[27] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States* (June 2009), *available at* https://emp.lbl.gov/sites/default/files/lbnl-2132e.pdf.

at the Company through the senior vice president level, and h) using rounded numbers for readability.

3. Observations when Determining Weights

This section discusses several issues the Company encountered when determining the final scales and weights to utilize for the Risk Quantification Framework.

The Risk Quantification Framework utilizes three attributes – safety, reliability and financial. In an ideal world, the relationship between each of the three pairwise combinations (*i.e.,* reliability vs. safety, safety vs. financial, and financial vs. reliability) would be consistent. In mathematics, the transitive property is commonly stated as "If a=b and b=c, then a=c." But for multi-attribute value functions the transitive property is less clear. As noted above, for electric reliability, the Lawrence Berkeley study was used as a starting point to compare reliability to financial. Using that data, a blackout occurring across SDG&E's service territory for eight hours would have a financial impact to SDG&E's customers of over $1 billion. As stated previously, while there is not a gas customer-specific equivalent study, the results generally can be extrapolated to SoCalGas customers. This hypothetical created one pairwise combination of the attributes (reliability vs. financial). Separately, a hypothetical question was posed to determine another pairwise combination (reliability vs. safety): "Which risk event would you least like to happen, a systemwide blackout for eight hours that harms no one or a safety incident at a substation that results in an employee fatality?" The Company prioritized the elimination of the safety incident. With the two pair-wise comparisons developed, the transitive property was applied to derive the third pair-wise comparison. When doing so, the third pair-wise comparison (safety vs. financial) did not follow the first two pair-wise comparisons and thus led to unhelpful values for the third pair-wise comparison.

Another issue is that the Company is not accustomed to quantifying the value (financially or otherwise) of preventing safety incidents. Safety is not simply a priority at the Company; it is our culture and is the Company's core value.

Another concept observed during the creation of the Risk Quantification Framework relates to comparing the value of preventing an incident versus the value of remediating the impact if the incident were to happen. For example, if an employee becomes injured on the job, it might take some amount of financial effort and Human Resource involvement to make sure the employee is taken care of and that the employee's group has a trained person to temporarily fill the role. The value of trying to prevent the event is not equal to the value of the expected remediation costs

To address uncertainty and discretion, the Company constructed a Risk Quantification Framework that demonstrates the variability in outcomes based upon the reasoned inputs used by the Company. The Company uses in this RAMP Report three versions of the Risk Quantification Framework, which together will create a "Single Point" number as well as a range around that number. The information at the beginning of this chapter discussed the Single Point version, which satisfies the SA Decision. The additional range of outputs will be reflected in the Risk Score of each risk and in the RSE values that are created for each risk-reducing activity. The range created by presenting options of the Safety Scale provides different views on how interested parties might view a risk based on differing views of safety. The ranges are illustrated in Tables 11, 12, and 13 below:

Table 11: Single Point

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 30	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 12: High Alternative

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 12	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 13: Low Alternative

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 300	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

D. Implementation of Attributes

The SA Decision contemplates expression of attributes in "natural units."[28] The natural unit of an attribute is defined as follows:

> [T]he way the level of an attribute is measured or expressed. For example, the natural unit of a financial attribute may be dollars. Natural units are chosen for convenience and ease of communication and are distinct from scaled units.[29]

The top-level attributes of Safety and Reliability comprise sub-attributes that are used to create Safety and Reliability indices, respectively. The Safety Index has two sub-attributes, while the Reliability Index has four sub-attributes. The measurement units chosen to represent the natural units for the sub-attributes are shown in Table 14 below. The sub-attributes within safety and reliability are used to create an index for the top-level attribute.

Table 14: Attributes

Attribute	**Sub-Attribute**	**Measurement Unit**
Safety	Fatality	Number of Fatalities
Safety	Serious Injury	Number of Serious Injuries
Reliability	Gas Core Meters	Number of Gas Core Meters Experiencing Outage
Reliability	Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day

[28] D.18-12-014 at Attachment A, A-3.

[29] *Id.*

Reliability	Electric SAIDI	System Average Interruption Duration Index (SAIDI)
Reliability	Electric SAIFI	System Average Interruption Frequency Index (SAIFI)

E. Safety Attribute

The Safety Attribute consists of a Safety Index, which is calculated by assessing its two sub-attributes. The sub-attributes are included because the data is readily available. The relative value between Fatalities and Serious Injuries is derived from information provided through the Occupational Health & Safety Administration (OSHA) and the Federal Aviation Administration (FAA).[30] Fatalities each receive a score of 1, and Serious Injuries receive a score of 0.25 each. A Serious Injury is usually defined as an event that requires overnight hospitalization or a permanent disfigurement of an individual.[31] The sum of these two sub-attributes create the Safety Index, which is then used as a top-level attribute in the Risk Quantification Framework.

Table 15: Safety Attributes

Safety Sub-Attribute	Value
Fatality	1
Serious Injury	0.25

In the RAMP Report, safety impacts are agnostic to (a) cause or reason for the event that results in safety impact, (b) characteristics of those affected, (c) level of fault for the utilities or others, (d) mitigating or aggravating circumstances related to the person's situation, and (e) other such concerns.

---

[30] *See* United States Department of Labor, *Severe Injury Reports*, *available at* https://www.osha.gov/severeinjury/; *see also* United States Department of Labor, *Reports of Fatalities and Catastrophes – Archive*, *available at* https://www.osha.gov/fatalities/reports/archive; *see also* Federal Aviation Administration, *Data & Research*, *available at* https://www.faa.gov/data_research.

[31] 8 CCR § 330(h).

F. Reliability Attribute

The Reliability Attribute comprises a Reliability Index that consists of four equally weighted sub-attributes. The sub-attributes with their Natural Units (Measurement Units) are shown in Table 16 below. The Reliability Index shown below is structured similarly to the overall Risk Quantification Framework and also contains attributes, scales, and weights.

Table 16: Reliability Attributes

Reliability Sub-Attribute	**Measurement Unit**	**Scale**	**Weight**
Gas Core Meters	Number of Gas Core Meters Experiencing Outage	0 – 75,000 meters	25%
Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day	0 – 500 MMcf	25%
Electric SAIDI	System Average Interruption Duration Index (SAIDI) minutes	0 – 100 minutes	25%
Electric SAIFI	System Average Interruption Frequency Index (SAIFI) outages	0 – 1 outages	25%

The SA Decision requires a utility to identify relative weights between sub-attributes like gas and electric reliability, but relating the gas to electric reliability is difficult, with little industry consensus on how to do so. The rationale for the scales/weights used for the Reliability attributes was therefore based on a combination of external information and internal subject matter expert judgment. "Worst case" scenarios that have occurred involving gas and electric outages were used to consider the impact from gas and electric reliability. In 1994, the Northridge earthquake affected tens of thousands of core gas customers, and the Pacific Southwest blackout of 2011 affected all of SDG&E's customers for several hours. It was reasoned that the respective impacts of these events could be used as a baseline to create the sub-attribute scales with the Northridge gas event approximately equaling 200 minutes of a system wide SDG&E blackout.

In addition, with respect to gas Reliability sub-attributes, residential and select commercial gas customers are designated as "core" customers and have top priority to receive gas service during outages.[32] The prioritization means that core customers will not normally get curtailed during gas supply shortages. Core customers can also be affected by local pipeline events such as dig-ins or equipment issues. The gas reliability sub-attribute Gas Core Meters is used to value the importance of maintaining natural gas service to core customers.

The gas Reliability sub-attribute of Gas Curtailment is a new measurement, one that the Company believes can be useful in describing the impact to customers and society. For various reasons – such as when there is a disturbance with a major gas transmission pipeline and a coincident high demand for natural gas – there are situations when natural gas service needs to be curtailed to non-core customers. The order in which curtailments are undertaken is systematic, with a goal to prevent severe disruptions to the community. However, when large curtailments are necessary, the impact to the greater community can eventually be felt. The Company strives to prevent all curtailments, especially those that require curtailing over 250MMcfd. Curtailments at that higher level can impact critical infrastructure such as electric generation, major industries, and hospitals. The use of this sub-attribute helps to value the importance of keeping curtailments limited in size and duration.

Valuing electric reliability is a complex endeavor but requires a simplified view for the purposes of the RAMP Report. To the customer, electric reliability is a composite of at least the following items: a) having electricity when the customer wants it, b) having a high quality of electricity without flicker or dimming, c) having power restored quickly if an outage occurs, and d) having access to information about when power will be restored.

The Institute of Electrical and Electronics Engineers (IEEE) has been viewed as a leader on topics related to Electric Reliability. IEEE publishes a document, known as IEEE 366-2012, that is considered the industry "best practice" for how to measure electric reliability. The IEEE 1366-2012 has 12 distinct measurements that utilities can use to express reliability, and some of those measurements have sub-measurements providing essentially infinite combinations of

32 *See* SoCalGas Rule 1 at Sheet 3 ("Core Service: Service to end-use Priority 1 or Priority 2A as set forth in Rule No. 23").

measurements. For example, one measurement indicates the number of customers who experience a certain number of outages in a year. That measurement can be used to evaluate customers who experience one outage, or three outages, or seven outages, and so on. The large number of possibilities of measurements is indicative of how complex the subject can be.

SDG&E has used eight different measurements in the past few years to internally measure its reliability (SAIDI, SAIFI, Worst Circuit SAIDI, Worst Circuit SAIFI, MAIFI, CAIDI, SAIDET, and ERT). For the Risk Quantification Framework, SAIDI and SAIFI were the sole indices used due to their widespread industry usage and their relative ease to use from a forecasting perspective. Future versions of the Risk Quantification Framework may include additional methods of valuing electric and gas reliability.

The electric reliability sub-attribute of Electric SAIDI measures the average duration of service loss for each utility's electric meters over the span of a year. SAIDI is a widely used index in the electric utility industry and is frequently used to compare utilities' performance. This index does not distinguish between the type of customer or the time of day of an electric outage.

The electric reliability sub-attribute of Electric SAIFI measures the average number of outages that each utility's electric meters experiences over the span of a year. This index does not distinguish between the type of customer or the time of day of an electric outage. A SAIFI value of 0.8, for example, means that on average 80% of customers served by the utility experienced an outage during a calendar year. But because SAIFI measures averages, using SAIFI alone is not enough to ascertain how many different customers experienced outages. If a utility had 100,000 meters, a SAIFI value of 0.8 could mean that 80,000 meters experienced one outage during one calendar year or it could mean that 40,000 meters experienced two outages during one calendar year.

There is significant complexity when trying to determine appropriate scales and weights to SAIDI and SAIFI in the Risk Quantification Framework. Different outages have different impacts depending on who is affected and when the outage occurred. For example, given a choice between three short outages or one long outage, a small retail store may prefer the shorter outages. Shorter outages may only temporarily affect their sales and not significantly affect their infrastructure. A large factory however may prefer one long outage, because some machinery may be negatively affected by outages and subjecting the equipment to multiple outages can be detrimental to the business' operations. Similarly, a three-hour electric outage at a residence will be dramatically different while cooking a Thanksgiving feast versus one while everyone at the residence is at school or work.

Although gas and electric sub-attributes give information to help understand levels of reliability risk, in the end, they are merely numbers that tell a story. Particularly with reliability, limited data exists to determine the equivalency of gas reliability relative to other attributes resulting in the need to leverage electric reliability data at this time. Accordingly, there is no single combination of reliability attributes that will give the perfect answer on how to measure risk. The values shown throughout the RAMP Report should be thought of as an approximation of risk rather than a precise value.

G. Financial Attribute

The Financial attribute has no sub-attributes or index and is measured in dollars. Like the other attributes, the Financial attribute is used to estimate aspects of the impact from risk events. However, different types of costs are measured in the attribute. The types of costs measured include: societal damage (including physical damages, lost wages, relocation costs, etc.) and utility repair costs (labor, materials). As required by D.16-08-018, the Financial attribute does not include any direct impacts related to shareholder financial interests, such as fines to shareholders, stock price changes, changes in credit ratings, or unrecoverable legal fees.

The quantitative approach used by the Company considered historical events as a guide for possible future impacts. But precision for the financial attribute is difficult to achieve. Risk events are rarely reported with a single summation of all financial impacts. Depending on the risk event, differing approaches were used to estimate the financial impacts. For pipeline risks, Pipeline and Hazardous Materials Safety Administration (PHMSA) data was used in combination with internal data, but the financial values provided by PHMSA do not necessarily include all financial impacts to society. For electrical outages, estimates were made for the amount of labor and cost of repair.

Financial estimates are gathered from various sources including internal estimates based on claims data or work orders, third party sources, news reporting, among others. Because these data sources rarely include all financial impacts from a risk event, estimates are used.

VII. PROBABILISTIC INFORMATION

This section will discuss quantitative methodologies, including statistical information as well as how computer software was used for this RAMP Report.

The SA Decision requires utilization of specific quantification methods for the RAMP Report. Among those methods are the creation of LoRE and CoRE values for each current risk. These two values are then multiplied together to obtain a risk score. Additionally, LoRE and CoRE are used to calculate Risk Spend Efficiencies (RSEs) by estimating new LoRE and CoRE when risk-reducing activities are introduced or ceased.

A. Expected Values

As mentioned above, LoRE and CoRE utilize expected values. The term "Expected Value" is a statistical term meaning the weighted average. For example, suppose there was a casino game that paid $10 to the player 25% of the time and paid $1 to the player the other 75% of the time. The expected value of this game would $3.25 because $10 * 25% + $1 * 75% = $3.25. The term "Expected Value" is not meant to imply that the Company expects a certain outcome. Note that in the example above, the expected value of $3.25 can never occur, because only the values of $10 and $1 can be paid out.

B. Likelihood of Risk Event (LoRE)

In the context of the SA Decision, the "Likelihood" is not a true likelihood in the usual statistical or probabilistic sense. In standard mathematics, a likelihood is the probability of an event occurring given a set of conditions (*e.g.*, the chance that a red jellybean is drawn from a jar of jellybeans). These standard probabilities can take a value between 0 and 1, where 0 indicates the event will never occur and 1 indicates the event will always occur. In traditional terms, the probability of flipping a coin and obtaining "tails" is 0.5. For purposes of the RAMP Report, however, likelihood is used in the sense of frequency, and that frequency is always in the context of the annual frequency of an event.

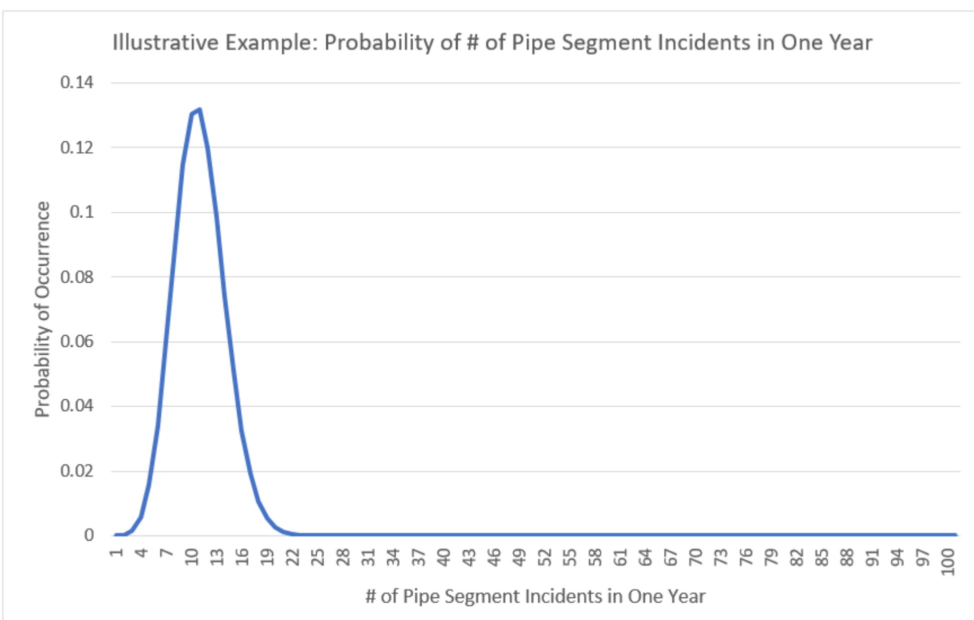
The following is an illustrative example to highlight how likelihoods are used in the RAMP Report:

i. Example: Illustrative Gas Risk

The RAMP Report views risks at the "risk-level" over the span of a year. Suppose that the Company has an item in its ERR known as Illustrative Gas Risk. For the RAMP Report, it is necessary to determine the likelihood of that risk occurring each year. In this illustrative example, assume the following:

- The utility uses data to estimate the incident rate.
- The illustrative gas system is composed of 100 pipe segments.
- Each pipe segment has a likelihood of an event of 1/10 over a given year.
- If the pipe segment had an event, the event would cause some amount of safety, reliability, and financial impact to society and to the utility.

From a purely probabilistic point of view, the likelihood that at least one pipe segment will have an incident in a given year is quite high (>0.999 or over 99.9%). The graph below shows the probability of the number of incidents, given the assumptions above:



For the RAMP Report, the important concept is not the *likelihood that a pipe segment will have an incident*, but rather, the number of pipe segments that are estimated to have an incident in a year. The likelihood value that is provided is the "Expected Value" of the frequency. In the example above, the expected value of pipe segments that will have an incident in a given year is determined by multiplying the number of pipe segments in the system by the likelihood of a single pipe segment incident occurring: 100 x 1/10 = 10.

In this example, the LoRE for this system would be 10, which behaves like an estimated frequency of the number of incidents predicted in a year.

Depending on the risk, LoREs were compiled using a combination of internal data, external data, and/or SME input. In the individual risk chapters throughout the RAMP Report, the methods used to estimate LoRE are indicated in Sections IV and VI.

C. Consequence of Risk Event (CoRE)

The CoRE is determined by estimating each of the data points required by the Risk Quantification Framework as discussed below. Like LoRE, the data points that inform CoRE are also expected values. For example, the number of serious injuries used in the calculations are the expected values of serious injuries if the risk event were to occur. Applying this to one of the RAMP risks, an illustrative example can be found in the SoCalGas Customer and Public Safety Risk Chapter (Chapter SCG-4) where actual safety consequences range from one serious injury to several fatalities. The calculations used in the Risk Quantification Framework for that risk use the expected value of that range. In the case of Customer and Public Safety, the expected value of the safety impact when a risk event occurs is 0.37.

The expected values of each of the seven attributes and sub-attributes are used as inputs into the Risk Quantification Framework to produce a CoRE for each risk. This process was undertaken many times for each risk; once to establish the current Risk Score, and once for each activity where the estimations of CoRE are performed as if the risk-reducing activity has been put in place in order to calculate RSEs.

Depending on the risk, the data used to compute CoREs was a combination of internal data, external data, and/or SME input. In the individual risk chapters throughout the RAMP Report, the methods used to estimate CoRE are indicated in Sections IV and VI.

D. Modeling

Computer software was used for many quantitative aspects of the RAMP Report. The primary software applications used by the Company was Microsoft Excel, Visual Basic, and @Risk. Additional work was also done with Microsoft Access, R, and Python. Various business units at the Company have unique ways of storing and accessing data that involve other software.

Monte Carlo simulations were performed on each risk. Monte Carlo analysis is a technique used to understand the impact of uncertainty related to a particular risk. Although the Settlement Agreement does not specify that Monte Carlo simulations are necessary, the modeling assisted in several ways that bolstered the analysis and occasionally informed critical elements. Throughout the individual risk chapters, analytical methods are discussed including the extent of modeling.

One of the benefits of modeling is that it can be used to demonstrate a range of outcomes that might be observed, given a set of inputs. When trying to identify ranges of outcomes, or the certainty thereof, performing Monte Carlo modeling can be easier to implement than precise statistical equations.

Devising ranges is an important part of risk analysis. Consider two risks, both with an expected value of a $10 million loss, but with very different ranges. Suppose Risk A rarely occurs, but when it does, it can require $1 billion of reparations; but, assuming it is a 1/100-year event, its expected value is $10 million ($1 billion x 1/100). Risk B has risk events that occur several times a year and the annual financial impact varies only slightly from $8 million to $12 million, with an expected value of $10 million. Certain stakeholders may be interested in knowing that the risks are not similar in their range of outcomes. Creating ranges of outcomes, whether through Monte Carlo modeling or via pure statistical approaches, can illuminate differences in risks.

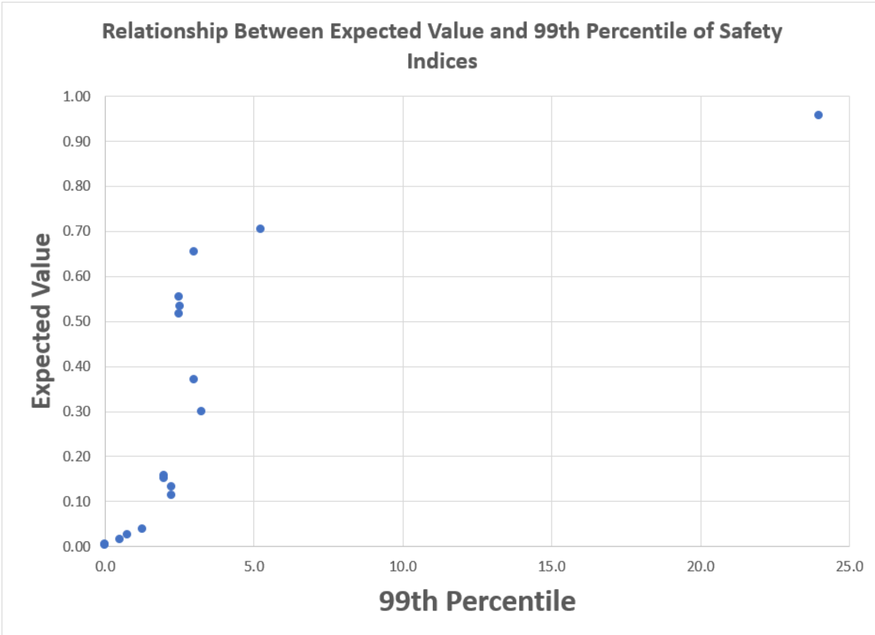
The Company found that using a Monte Carlo analysis to show where differences arise between these various types of risks (*i.e.*, one with a more consistent loss compared to a rarer but more significant loss) can be informative. To obtain a 99th Percentile, each risk was modeled 10,000 times, then ranked in order of consequence from lowest to highest. The 99th Percentile is the 100th worst consequence out of the 10,000 runs. This analysis was conducted by ERM to determine how large of an impact risks might have, even though less frequent. The result of this analysis is shown in Table 17 below.

Table 17: Risks Sorted by Expected Value of Safety Index

Utility	Risk Name	Expected Value Safety Index	99th Percentile of Safety Index
SDG&E	Wildfire	0.96	24.0
SDG&E	Contractor Safety	0.65	3.0
SDG&E	Electric Infrastructure Integrity	0.53	2.5
SDG&E	Employee Safety	0.30	3.3
SDG&E	Customer and Public Safety	0.16	2.0
SDG&E	Medium Pressure Gas Pipeline Incident	0.11	2.3
SDG&E	Third Party Dig-in on a Medium Pressure Pipeline	0.03	0.8
SDG&E	High Pressure Gas Pipeline Incident	0.02	0.5
SDG&E	Third Party Dig-in on a High Pressure Pipeline	0.00	0.0

Utility	Risk Name	Expected Value Safety Index	99th Percentile of Safety Index
SCG	Medium Pressure Gas Pipeline Incident	0.70	5.3
SCG	Employee Safety	0.55	2.5
SCG	Contractor Safety	0.52	2.5
SCG	Customer and Public Safety	0.37	3.0
SCG	High Pressure Gas Pipeline Incident	0.15	2.0
SCG	Third Party Dig-in on a Medium Pressure Pipeline	0.13	2.3
SCG	Third Party Dig-in on a High Pressure Pipeline	0.04	1.3
SCG	Storage Well Integrity	0.01	0.0

In some cases, in the RAMP analysis, the 99th percentile gives a different risk ranking than the Expected Value. The following is a graph showing the relationship between the Expected Value and the 99th Percentile for each risk's Safety Index. Note that the relationship between the two variables is not very strong, which supports the case that Expected Values are sufficient in themselves to understand the consequences from infrequent risks.



Because this alternative analysis provides useful information on rarer but more significant risk events, the individual risk chapters in this RAMP Report include this alternative analysis in addition to the standard modeling.

E. Key Considerations

1. Secondary Impacts

The Company uses the term "Secondary Impacts" to distinguish between the impacts that are directly caused by a Risk Event, and those impacts that are "downstream" of the initial Risk Event. Because each risk has its own definition of a Risk Event, it is difficult to generalize the difference between the direct impacts and secondary impacts. Table 18 below provides examples, using the Companies' different RAMP risks:

Table 18: Illustrative Examples of Secondary Impacts

	Direct Impact	**Secondary Impact**
Electric Infrastructure Integrity	Person hurt due to touching fallen electrical wire	Driver of vehicle not stopping at traffic light that is not operating properly during electrical outage
Medium Pressure Gas Incident	Person hurt due to gas explosion	Customer experiencing gas outage decides to cook using a charcoal barbecue, and is accidentally injured

Cyber Security	Intruder uses remote attack to overload transformer which subsequently explodes and harms individuals	Intruder uses remote attack to steal financial information from utility customer, which leads to financial harm to customer

Secondary Impacts are generally not used in risk scoring in this RAMP Report because they are difficult to estimate and track and are not always controllable by the Company. Data sources used for risk assessments do not consistently track secondary impacts, if tracked at all. Secondary impacts will rarely be a large driver of risk scores, even if the data was well collected. One illustrative example mentioned earlier-- large electrical outages that span entire cities--could have secondary impacts, but the history of such events fail to provide sufficient data to measure that risk. SDG&E experienced a systemwide blackout in 2011 due to electrical problems outside of its service territory. The blackout caused outages in all of San Diego and Imperial counties, as well as parts of Orange County and western Arizona. The outage in SDG&E's service territory lasted nearly 12 hours, with the average customer without power for over eight hours. During that time, safety-related incidents were reported. It is clear that undesirable outcomes can occur in large electric or gas outages, but the available data is not conducive to determining expected values of impact. Perhaps in future years, there will be more opportunities to refine how to use secondary impact information as part of risk assessments.

VIII. CONCLUSION

The purpose of this chapter was to describe the quantitative approaches used throughout this RAMP Report and to provide a detailed overview of the Company's Risk Quantification Framework. The framework is intended to be "customizable."[33] The SA Decision recognizes that there are both advantages and disadvantages to the currently adopted approach.[34] The Company offers further discussion on this topic in Chapter RAMP-E. The Company also offers "lessons learned" to aid the Commission and other IOUs in future application of the framework in Chapter RAMP-G, from the perspective of one of the first utilities to apply the new Risk Quantification Framework adopted by the SA Decision.

---

33 D.18-12-014 at 27.

34 *See* D.18-12-014 at 28-30.

Risk Assessment Mitigation Phase

(RAMP-D)

Risk Spend Efficiency – Methodology

November 27, 2019

SoCalGas
A Sempra Energy utility®

TABLE OF CONTENTS

I. INTRODUCTION

This chapter addresses how Risk Spend Efficiencies (RSEs) are calculated in this 2019 Risk Assessment Mitigtion Phase (RAMP) Report. RSEs are numerical values that attempt to portray changes in risk scores per dollar spent. The change in a risk score is one data point that can help to inform decision-making and can be due to: (a) the amount of risk reduction when a new activity is completed, or (b) the amount of risk increase if a currently on-going activity is ceased.[1] The overall guiding principle of an RSE is that it presents the difference between the risk score over a certain span of time if the activity is undertaken versus if the activity is not undertaken. However, as discussed further in Chapters RAMP-C and RAMP-E, these data points should be viewed critically. This chapter: (1) illustrates how RSEs are created, with examples of RSEs for both Controls and Mitigations, (2) explains how benefits over time are treated, and (3) explains how the Company determined which activities to perform an RSE on in this RAMP Report (and which activities would not have RSEs).

II. DETERMINING RISK SPEND EFFICIENCIES

As discussed in Chapter RAMP-C, each risk has a Risk Score, calculated using the Risk Quantification Framework. The Risk Score that is developed is meant to represent the current risk situation. The current situation for each risk attempts to consider existing activities (known as Controls), current work standards, and all other current characteristics, such as asset conditions, environmental conditions, etc. As described in Decision (D.) 18-12-014, a Control is a "[c]urrently established activity that is modifying risk."[2] A Mitigation is an "activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[3]

---

1 It should be noted that in reality risk reductions could be the result of other activities that have a positive effect, the improvement of industry wide data, or other factors not necessarily tied to the mitigation itself. *See* Chapter RAMP-E for additional discussion of this point.

2 D.18-12-014 at 16.

3 *Id.* at 17.

Risk Scores are calculated by multiplying the Likelihood of Risk Event (LoRE) and the Consequence of Risk Event (CoRE), where LoRE is the annual frequency of the Risk Event and CoRE is the output of the Risk Quantification Framework assuming a Risk Event occurred. Please see Chapter RAMP-C for more information on how LoRE and CoRE are created and used.

The risk score that results from using the Risk Quantification Framework is the baseline used when calculating RSEs. Next, a second estimate for LoRE and CoRE that considers a change in a risk-reducing activity is estimated. For Mitigations, the second LoRE and CoRE are estimated assuming the new activity is in place. For Controls, the second LoRE and CoRE reflect the estimated risk if the activity is ceased.

For purposes of this RAMP Report, the terms "pre-mitigation[4] LoRE" and "pre-mitigation CoRE" refer to the estimated risk values given current situations. The terms "post-mitigation LoRE" and "post-mitigation CoRE" refer to the estimated risk values if an activity is ceased or a new activity is undertaken. The same terminology applies to the Risk Scores, which are the product of LoRE multiplied by CoRE. In short:

$$pre - mitigation\ Risk\ Score = (pre - mitigation\ LoRE)\ x\ (pre - mitigation\ CoRE)$$

and

$$post - mitigation\ Risk\ Score = (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)$$

The RSE is the ratio between the pre-mitigation and post-mitigation Risk Scores divided by the cost. In its most simplistic form, the equation is:

$$simplified\ RSE = \frac{(pre - mitigation\ Risk\ Score) - (post - mitigation\ Risk\ Score)}{\$\ cost\ of\ activity}$$

4 The terms "pre-mitigation" and "post-mitigation" used herein (and referenced in the SA Decision) are not intended to suggest that all activities are Mitigations (*i.e.,* this terminology also applies to Controls).

Later in this chapter, there is an in-depth discussion on the more detailed points of the RSE calculation, including concepts such as the duration of benefits and the present value of benefits pursuant to the SA Decision.[5]

A. Illustrative Example (One Year Mitigation)

The following is a more thorough example of a one-year mitigation that builds upon the brief example above. Suppose there is a risk in the Company's Enterprise Risk Register (ERR), known as Risk X, which has been assessed using the Risk Quantification Framework. Suppose the assessment generated an assumption that a Risk Event related to Risk X would occur four times a year. Further, the assessment considered the Potential Consequences when the Risk Events occur. Suppose, for this example, that when a Risk Event occurs, the assessment, consistent with methods described in Chapter RAMP-C, estimates a 1/10 chance that there will be four serious injuries, no reliability consequence, and an average financial consequence of $15 million to repair damage to equipment.

Step 1: The first step is to formulate the pre-mitigation LoRE and CoRE. In this example, LoRE is simply four, because the LoRE is the average annual frequency. To determine CoRE, the Risk Quantification Framework is applied. Key parameters from the Risk Quantification Framework discussed in Chapter RAMP-C are in the following table:

Table 1: Single Point [6]

Attribute	Scale	Weight
Safety	0-30	60%
Reliability	0-1	20%
Financial	0-$1B	20%

---

5 D.18-12-014 at Attachment A, A-13 (Risk Spend Efficiency (RSE) Calculation).

6 As discussed in Chapter RAMP-C, because of the wide range of possible choices available to each utility in assigning attributes, weights, scales, and other variables chosen through implementing the SA Decision, the Company has also chosen to provide a range of scoring, based upon two additional alternative Risk Quantification Framework methods. To simplfy this example, the Company is presenting only the Single Point methodology.

Step 2: Applying the formula explained in Chapter RAMP-C, CoRE would be calculated as:

$$CoRE = \left[\frac{0.1}{30}\right] x\ 60\% + \left[\frac{0}{1}\right] x\ 20\% + \left[\frac{\$5}{\$1000}\right] x\ 20\% = .003$$

Step 3: The final step is to multiply by 100,000, as discussed in Chapter RAMP-C, for readability purposes. Therefore, the pre-mitigation Risk Score is:

$$Risk\ Score = LoRE\ x\ CoRE\ x\ 100{,}000 = 4\ x\ .003\ x\ 100{,}000 = 1{,}200$$

Suppose now that there is a proposed activity that will help reduce risk associated to Risk X. Perhaps the activity is replacing older equipment with newer equipment. Assume that, based upon data, it is estimated that undertaking the proposed activity will reduce the likelihood of Risk X occurring by 25%. In this example, the LoRE would therefore change from four to three. This activity, however, is not believed to affect the consequence if the Risk Event were to occur, so the CoRE stays the same.

Therefore, the post-mitigation Risk Score would be:

$$\begin{aligned} post - mitigation\ Risk\ Score \\ &= (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)\ x\ 100{,}000 \\ &= 3\ x\ .003\ x\ 100{,}000 = 900 \end{aligned}$$

Suppose the useful life of this activity is for one year, and that it costs \$10 million to perform. The RSE calculation would therefore be:

$$\begin{aligned} RSE = \frac{(post - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{\$10M} = \frac{1200 - 900}{\$10M} \\ = \frac{300}{\$10M} = 3 \end{aligned}$$

B. Illustrative Example (One Year Control)

A similar process is used when Control activities are considered. One important distinction for such situations is that in the RAMP Report, when considering the change in Risk

Score if a control were no longer in place, the difference between the pre-mitigation Risk Score and the post-mitigation Risk Score will still be shown as a positive number because the cost of the activity in the denominator would be savings. For consistency, in the RAMP Report both the numerator and the denominator will be shown as positive numbers.

Suppose there is a risk in the Company's ERR known as Risk ABC and this risk has been assessed using the Risk Quantification Framework. Suppose the assessment led to the estimate that a Risk Event related to Risk ABC would occur once every five years. Further, the assessment estimated the consequences to be two fatalities, no reliability consequence, and an average financial consequence of $50 million to repair and replace equipment damaged by the event.

The first step is to formulate the pre-mitigation LoRE and CoRE. In this example, LoRE is 1/5 or 0.2. To determine CoRE, the Risk Quantification Framework is applied as follows:

$$CoRE = \left[\frac{2}{30}\right] x\ 60\% + \left[\frac{0}{1}\right] x\ 20\% + \left[\frac{\$50}{\$1000}\right] x\ 20\% = .05$$

For readability purposes, the utilities multiply these small decimal numbers by 100,000. Therefore, the pre-mitigation Risk Score is:

$$Risk\ Score = LoRE\ x\ CoRE\ x\ 100{,}000 = 0.2\ x\ .05\ x\ 100{,}000 = 1000$$

Suppose there is a current activity that contributes to the Risk Score as it stands currently. Further, suppose there is a proposal to alter the activity in some way, such as changing the frequency of inspection. An example might be to stop a Quality Assurance program. Lastly, assume that based upon available data and subject matter expertise, it is believed that the likelihood of the risk event will be increased by 10% and save $25 million. In this example, the LoRE would therefore change from 0.2 to 0.22 (i.e. 10% more than 0.2 is 0.22). Ceasing this activity is not believed to affect the consequence if the Risk Event were to occur, so the CoRE stays the same.

Therefore, the post-mitigation Risk Score would be:

$$post - mitigation\ Risk\ Score = (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)$$
$$= 0.22\ x\ .05\ x\ 100{,}000 = 1{,}100$$

Suppose the useful life of this activity is for one year. The RSE calculation would therefore be:

$$RSE = \frac{(pre - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{-\$25M} = \frac{1000 - 1100}{-\$25M}$$
$$= \frac{100}{\$25M} = 0.4$$

The Control therefore has an RSE of 0.4.

III. DURATION OF BENEFITS

One of the more nuanced aspects of RSEs is how to address risk-reducing activities that have long-term benefits. The RSE is a comparison between performing an activity versus not performing that activity. In some cases, the implications of an activity have long term affects: pipelines last many years, computer software can be used for several years, etc. To utilize RSEs properly, some consideration needs to be given for the length of time, or duration, of predicted benefits.

A working assumption is that activities involving assets receive benefits for the life of the asset. Other activities, such as training or inspection programs, might have shorter durations of benefits. An illustrative example is a tree trimming program, which will only have a duration of benefits that match the time it takes for a tree to grow back to its former size.

Any activity that has a duration of benefits exceeding one year requires additional data points for the RSE calculation. In “Example (One Year Control)” above, the assumption was that the activity has a one year duration of benefits. However, if the assumption was raised to three years of benefits, the activity can be considered to affect three years of risk results. The two tables below illustrate the differnces in assuming the duration of benefits last for one versus three years.

Table 2: "Example (One Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	1078	1078	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	0	0	0	0

Table 3: "Example (Three Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	980	980	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	98	98	0	0

As shown in these tables above, the three-year benefit stream provides more value than the one-year benefit stream. The RSE calculation needs to address these differences.

C. Discounting of Benefits

The SA Decision allows accounting of long term benefits of activities but requires an extra step before inclusion into the RSE.[7] The SA Decision mandates that future benefits have less value than present benefits. The Company meets this requirement by applying a "discount" rate to the difference in the Risk Score. In this RAMP filing, the Company uses a 3% discount rate for purposes of determining the present value of the risk reduction benefits or numerator of the RSE calcualtion. As shown in the example below, this discount rate lowers the benefits of years after the first by 3%, compounded each year. The Company applied a 3% discount rate based on federal recommendations.[8]

---

7 D.18-12-014 at Attachment A, A-13 (Risk Spend Efficiency (RSE) Calculation).

8 *See* Centers for Disease Control and Prevention, Dataset Number SD-1002-2017-0, *Economic Burden of Occupational Fatal Injuries in the United States Based on the Census of Fatal Occupational*

Table 4: "Example (Three Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	980	980	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	98	98	0	0
Discounted Difference	98 / (1) = 98	98 / (1.03) = 95.1	98 / $(1.03)^2$ = 92.4	0	0

As shown in the table above, the benefit decreases from 98 in the first year to 92.4 in the third year. The term "Present Value" can be used when discussing the future benefits of a long-term activity. For the example above, the present value of the benefit in 2022 is 92.4.

For activities that have multiple years of benefits, the simplified RSE calculation changes from:

$$RSE = \frac{(pre - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{\$\ of\ activity}$$

to:

$$RSE = \frac{\sum_i^L Present\ Value\ ((pre - mitigation\ Risk\ Score_i) - (post - mitigation\ Risk\ Score_i))}{\$\ of\ activity}$$

where i is the year of the project, and L is the duration of benefits measured in years.

Unjuries, 2003-2010 (August 2017) (citing 1996 recommendation from U.S. Department of Health and Human Services Panel on Cost-Effectiveness in Health and Medicine).

D. Discounting of Costs

Similar to the discounting of benefits mentioned in the section above, the SA Decision requires that the cost of activities also be discounted if they span more than one year. However, in a General Rate Case (GRC), the Company presents its forecasts in base year,[9] direct constant dollars. The base year for the Company's Test Year 2022 GRC is 2019.[10] While the Company will be seeking approval for Test Year 2022 forecasts for operations and maintenance (O&M) and 2020-2022 for capital expenditures, all these forecasts will be presented in 2019 constant dollars. Please note that these direct dollar forecasts will be converted into an overall revenue requirement through the Results of Operations (RO) model. In this RAMP Report, the Company is presenting costs in direct constant 2018 dollars. Therefore, for the purposes of the RSE calculation the costs are effectively already discounted prior to being used in the RSE calculation. Meaning, the cost for activities with multi-year expenditures does not take into account inflation prior to their usage for RSEs. For example, suppose there was a capital project that sought $10 million a year for all three years of the next GRC forecast period (2020 through 2022). In the RAMP and in GRC, the Company would present these costs as $10 million for each year, 2020, 2021, and 2022. No inflation is shown for those years; therefore, there is no need to further discount costs shown for years 2021 and 2022.

IV. APPLICATION OF RISK SPEND EFFICIENCIES

The RAMP Report includes 151 activities for SoCalGas and 224 activities for SDG&E. Of these, 100 and 146 activities for SoCalGas and SDG&E, respectively, had RSEs calculated.[11] RSEs were calculated for a wide variety of activities, including all in-scope non-mandated

---

9 The term "base year" refers to the last recorded year available prior to a GRC filing.

10 The Company notes that as of the filing date of this RAMP Report, a Proposed Decision is pending before the Commission which could possibly change the anticipated filing date of the Company's next GRC application. *See* R.13-11-006, Proposed Decision Modifying the Commission's Rate Case Plan for Energy Utilities (October 4, 2019).

11 The references here account for activities at the tranche level and also include the activities presented as alternatives.

activities, certain mandated Controls, and all Mitigations whether they were mandated or not. RSEs were calculated for all non-mandated activities and all new activities. This was a substantial undertaking for the Company, especially when taking into account that this is the first implementation of these more quantitative analyses pursuant to the SA Decision.

Despite the Company's best efforts, in the development of particular RSEs for the many Mitigations and Controls in this RAMP Report, it was discovered that in certain situations RSEs could not be reasonably calculated in certain circumstances or were of minimal value. These situations include:

1) Where there is mandated work that is difficult to separate from other work. For example, when a particular regulation, and therefore Control, has been in place for decades, it is difficult to separate how it impacts likelihoods and consequences of Risk Events. It is difficult to unravel the value of that Control to determine quantitatively the benefits it currently gives, especially in any meaningful way.
2) Where non-risk-reducing activities enable risk-reducing activities. For example, line inspections do not, by themselves, reduce risk directly but they do provide information to operators and field personnel which is then used to find appropriate remediations where necessary. In the case of inspections, they are bundled together with their remediations when calculating RSEs.
3) Where activities fall outside of the scope of the risk, but nevertheless are related to the risk and were included in the Risk chapter. From an analytic perspective, it is not appropriate to calculate an RSE for an activity that is not included in the scope of how the risk scores were calculated. An example of this is the Company's Customer and Public Safety risk. The scope of that risk is confined to events that are under the Company's control (see RAMP SCG-4 and SDG&E-5 for more details on risk scope). In other words, the risk scope for Customer and Public Safety risk does not include issues that are outside the control of the utility, and therefore the Risk Score does not assess those types of Risk Events. However, the Company performs activities that aim to mitigate public safety risk.

Those activities that assist customers in being safe are presented in the Company's Customer and Public Safety risk chapter, but an RSE has not been performed since those activities are outside of the scope of risk. For example, Company employees respond to all emergency calls from customers regarding gas leaks, and therefore the Company should be funded for that activity - but because essentially all emergency calls from customers are related to events that are outside the control of the Company, they are not considered within the scope of the risk score. Therefore, since responding to emergency calls is outside of the Customer and Public Safety risk scope, there is no change in the risk score due to the activity, which would result in an RSE score of 0.

V. CONCLUSION

The calculation of RSEs in this RAMP Report represents the Company's best efforts and is in compliance with the SA Decision. The methodologies and processes herein have advanced the RSEs. As further discussed in Chapter RAMP-E, RSEs should be considered as a single data point, rather that the sole source for risk-based decision-making.

APPENDIX D-1

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1] Low Alternative	RSE[1] Single Point	RSE[1] High Alternative
1	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C6	GIPP - Tranche 1 Medium Pressure	63.58	**319.61**	746.34
2	Contractor Safety	SCG-3-C5	Contractor Engagement	25.47	**242.07**	603.08
3	Contractor Safety	SCG-3-C4	Third-Party Administration Tools	21.78	**207.00**	515.70
4	Cybersecurity	SCG-9-C1	Perimeter Defense	127.50	**130.75**	136.17
5	Cybersecurity	SCG-9-C5	Obsolete IT Infrastructure Modernization	66.06	**67.74**	70.55
6	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C2	Cathodic Protection	10.51	**65.91**	158.25
7	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C6	Damage Prevention Analyst Program	44.59	**59.78**	85.10
8	Cybersecurity	SCG-9-C3	Sensitive Data Protection	58.13	**59.61**	62.08
9	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M2	Establish a program to address the area of continual excavation	40.94	**54.89**	78.14
10	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C1	GIPP - Tranche 2 High Pressure	8.69	**54.46**	130.74
11	Cybersecurity	SCG-9-C4	Operational Technology (OT) Cybersecurity	51.60	**52.92**	55.11
12	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C6	Damage Prevention Analysts Program	4.69	**39.50**	97.50
13	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C3-T3	PSEP - Pipeline Replacement - Tranche 3 Phase 2A	8.00	**31.17**	69.77
14	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C16	Install warning mesh above buried company facilities	3.11	**26.14**	64.53
15	Cybersecurity	SCG-9-C2	Internal Defense	24.49	**25.12**	26.16
16	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M8	Install warning mesh above buried company facilities (open trench new facilities only)	16.99	**22.78**	32.42
17	Contractor Safety	SCG-3-M1	Expanded Contractor Safety Oversight	2.26	**21.52**	53.63
18	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C6	Transmission Integrity Management Program (TIMP)	3.29	**20.64**	49.56
19	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T4	Public Awareness Compliance - Excavators	12.66	**16.97**	24.16
20	Employee Safety	SCG-2-M5	Expanded Safety Congress and expanded Executive Safety Council	1.74	**16.64**	41.46
21	Customer and Public Safety	SCG-4-C6	Quality Assurance and Controls Program	2.74	**15.06**	35.60
22	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C7-T1	DREAMS Vintage Integrity Plastic Plan (VIPP)	2.68	**13.45**	31.40
23	Employee Safety	SCG-2-C7	Near Miss, Stop the Job and jobsite safety programs	1.31	**12.48**	31.10
24	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C5	Locate and Mark Quality Assurance Program	9.14	**12.26**	17.45
25	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T4	Public Awareness Compliance - Excavators	1.41	**11.88**	29.32
26	Employee Safety	SCG-2-M4	Safety video library	1.22	**11.65**	29.03
27	Employee Safety	SCG-2-M6	Expanded Safety Culture Assessments	1.22	**11.65**	29.03
28	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C9	Increase Reporting of Unsafe Excavation	8.41	**11.27**	16.05
29	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	7.85	**10.53**	14.99
30	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C4-T3	PSEP - Pressure Testing - Tranche 3 Phase 2A	2.62	**10.22**	22.87
31	Contractor Safety	SCG-3-C1	Contractor Safety Oversight	1.06	**10.12**	25.22
32	Employee Safety	SCG-2-M3	Establish proactive monitoring for indoor air quality (IAQ) and chemicals of concern	1.02	**9.71**	24.19
33	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C5	Locate and Mark Quality Assurance Program	1.00	**8.43**	20.80
34	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C9	Increase Reporting of Unsafe Excavation	0.83	**6.99**	17.25
35	Employee Safety	SCG-2-C8	Safety Culture	0.70	**6.69**	16.66
36	Employee Safety	SCG-2-M1	OSHA 30-hour construction certification training	0.68	**6.47**	16.13
37	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C9	Distribution Riser Inspection Project	1.23	**6.21**	14.49
38	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T1	Public Awareness Compliance - The Affected Public	4.24	**5.69**	8.10
39	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C1	Cathodic Protection (CP)	1.01	**5.06**	11.81
40	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C8	Sewer Lateral Inspection Project (SLIP)	0.89	**4.46**	10.43
41	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M6	Promote process and system improvements in USA ticket routing and monitoring.	3.04	**4.07**	5.79
42	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T1	Public Awareness Compliance - The Affected Public	0.48	**4.01**	9.89
43	Employee Safety	SCG-2-C5	Safe Driving Programs	0.41	**3.90**	9.72
44	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T3	Public Awareness Compliance - Local Public Officials	2.81	**3.77**	5.37
45	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C7-T2	DREAMS Bare Steel Replacement Program (BSRP)	0.64	**3.20**	7.48
46	Employee Safety	SCG-2-C9	Utilizing Occupational Safety and Health Administration (OSHA) and industry best practices and industry benchmarking	0.33	**3.15**	7.85
47	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	2.14	**2.87**	4.08
48	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M6	Promote process and system improvements in USA ticket routing and monitoring	0.34	**2.85**	7.03
49	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T3	Public Awareness Compliance - Local Public Officials	0.32	**2.69**	6.65
50	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C3	Meter and Regulator (M&R) Maintenance	0.47	**2.35**	5.50
51	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.23	**1.92**	4.75

SoCalGas
A Sempra Energy utility

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
52	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.22	**1.85**	4.56
53	Employee Safety	SCG-2-M2	Industrial hygiene program refresh	0.19	**1.80**	4.48
54	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T2	Public Awareness Compliance - Emergency Officials	1.32	**1.77**	2.51
55	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.15	**1.29**	3.18
56	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T2	Public Awareness Compliance - Emergency Officials	0.14	**1.15**	2.84
57	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C3-T2	PSEP - Pipeline Replacement - Tranche 2 Phase 1B	0.29	**1.14**	2.54
58	Employee Safety	SCG-2-C3	Wellness Programs	0.12	**1.10**	2.75
59	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M2	Establish a program to address the area of continual excavation	0.13	**1.10**	2.72
60	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C5	PSEP - Valve Automation	0.49	**1.04**	1.96
61	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.67	**0.90**	1.28
62	Storage Well Integrity Event	SCG-8-C6	Integrity Demonstration, Verification, and Monitoring Practices	0.62	**0.64**	0.66
63	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M4	Utilize electronic positive response	0.46	**0.62**	0.89
64	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C7	Prevention and Improvements - Refreshed Laptops	0.41	**0.54**	0.77
65	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M4	Utilize electronic positive response	0.05	**0.44**	1.07
66	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C7	Prevention and Improvements - Refreshed Laptops	0.05	**0.38**	0.94
67	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M3	Recording photographs for each locating mark ticket that is visited by the locator	0.26	**0.35**	0.50
68	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C17	Prevention and Improvements - Fiber Optics	0.04	**0.34**	0.85
69	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M3	Recording photographs for each locate and mark ticket visited by locator	0.03	**0.24**	0.60
70	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M1	Automate Third Party Excavation Reporting	0.02	**0.03**	0.04
71	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.02**	0.05
72	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M7	Leverage data gathered by locating equipment	0.01	**0.02**	0.02
73	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M7	Leverage data gathered by locating equipment	0.00	**0.01**	0.03

[1]The RSE ranges are further discussed in Chapter RAMP-C.

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
1	Contractor Safety	SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings	58.51	**356.94**	854.34
2	Electric Infrastructure Integrity	SDG&E-4-M3-T1	Proactive Substation Reliability for Distribution Components Streamview Bank 30 Re-build	225.33	**225.33**	225.33
3	Wildfires	SDG&E-1-C15	Tree Trimming	151.32	**198.75**	277.80
4	Contractor Safety	SDG&E-2-C3	Third-Party Administration and Tools	32.24	**196.72**	470.84
5	Wildfires	SDG&E-1-M8	Hotline Clamps	137.89	**181.11**	253.15
6	Wildfires	SDG&E-1-Group3	PSPS Group	100.08	**131.45**	183.73
7	Cybersecurity	SDG&E-10-C1	Perimeter Defense	127.50	**130.75**	136.17
8	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C6	Damage Prevention Analysts Program	92.03	**126.35**	183.55
9	Wildfires	SDG&E-1-M7	Expulsion Fuse Replacement	92.16	**121.05**	169.19
10	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M2	Establish a program to address the area of continual excavation	71.84	**98.63**	143.27
11	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C1	Cathodic Protection	11.40	**91.00**	223.66
12	Electric Infrastructure Integrity	SDG&E-4-M3-T2	Proactive Substation Reliability for Distribution Components Pacific Beach 12kV Replacement Re-build	82.20	**82.20**	82.20
13	Employee Safety	SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	8.52	**73.12**	180.77
14	Cybersecurity	SDG&E-10-C5	Obsolete IT Infrastructure Modernization	66.06	**67.74**	70.55
15	Wildfires	SDG&E-1-M19	Enhanced Inspections, Patrols, and Trimming	51.39	**67.50**	94.35
16	Electric Infrastructure Integrity	SDG&E-4-C10	Vegetation Management (Non-HFTD)	39.34	**65.50**	109.10
17	Cybersecurity	SDG&E-10-C3	Sensitive Data Protection	58.13	**59.61**	62.08
18	Contractor Safety	SDG&E-2-C1	Contractor Safety Oversight Program	9.20	**56.13**	134.34
19	Cybersecurity	SDG&E-10-C4	Operational Technology (OT) Cybersecurity	51.60	**52.92**	55.11
20	Wildfires	SDG&E-1-M18	SCADA Capacitors	39.02	**51.26**	71.64
21	Electric Infrastructure Integrity	SDG&E-4-M1	Overhead Public Safety (OPS) Program	9.09	**47.54**	111.63
22	Wildfires	SDG&E-1-C28 / M32	Wildfire Infrastructure Protection Teams	34.46	**45.27**	63.27
23	Contractor Safety	SDG&E-2-M3	Near Miss/Close Call Reporting Portal/App	7.25	**44.26**	105.94
24	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M8	Install warning mesh above buried company facilities (above open trench new facilities only)	30.42	**41.77**	60.67
25	Electric Infrastructure Integrity	SDG&E-4-C15	Distribution Circuit Reliability	40.25	**40.25**	40.25
26	Employee Safety	SDG&E-3-C3	Safety Culture	4.58	**39.24**	97.03
27	Employee Safety	SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA)	4.42	**37.91**	93.73
28	Wildfires	SDG&E-1-C29 / M33	Aviation Firefighting Program	27.33	**35.89**	50.17
29	Employee Safety	SDG&E-3-M4	Implementing findings from VPP program assessments	3.98	**34.12**	84.36
30	Wildfires	SDG&E-1-FiRM	FiRM Group	25.69	**33.74**	47.16
31	Employee Safety	SDG&E-3-M2	Safety In Action Enhancement Program	3.77	**32.33**	79.92
32	Wildfires	SDG&E-1-M10	Covered Conductor	24.30	**31.91**	44.61
33	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C16	Install warning mesh above buried company facilities	4.01	**31.85**	78.24
34	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C6-T1	PSEP - Pressure Testing - Tranche 1 Phase 1B	5.27	**30.84**	73.45
35	Customer and Public Safety	SDG&E-5-C2	Field & Public Safety (CSF/AMO Quality Assurance Program)	4.83	**28.24**	67.24
36	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T2	Early Vintage Program (Pipeline) - Tranche 2 Early Vintage Steel Replacement	5.09	**27.53**	64.92
37	Electric Infrastructure Integrity	SDG&E-4-C14	Field SCADA RTU Replacement	26.65	**26.65**	26.65
38	Wildfires	SDG&E-1-Group2	FTZAP & LTE Communications Network	20.15	**26.47**	37.00
39	Wildfires	SDG&E-1-M17	Lightning Arrester Removal / Replacement Program	19.31	**25.36**	35.44
40	Electric Infrastructure Integrity	SDG&E-4-C19-T2	Underground Cable Replacement Program – Proactive - Tranche 2 Unjacketed Cable - Branch	25.32	**25.32**	25.32
41	Cybersecurity	SDG&E-10-C2	Internal Defense	24.49	**25.12**	26.16
42	Wildfires	SDG&E-1-C30	Industrial Fire Brigade	18.35	**24.11**	33.70
43	Wildfires	SDG&E-1-M4	Strategic Undergrounding Underground Circuit Line Segments	17.52	**23.01**	32.16
44	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	2.81	**22.47**	55.22
45	Electric Infrastructure Integrity	SDG&E-4-M3-T4	Proactive Substation Reliability for Distribution Components New Substation	21.36	**21.36**	21.36
46	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C6	Damage Prevention Analysts Program	2.68	**21.27**	52.26
47	Employee Safety	SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	2.47	**21.18**	52.36
48	Wildfires	SDG&E-1-Group1	Non-Mandated Inspections Group	15.60	**20.49**	28.64
49	Electric Infrastructure Integrity	SDG&E-4-C3-T3	Distribution Switch Replacement Program - Tranche 3 Switches in Contamination District One with large customer count that could benefit from SCADA	20.46	**20.46**	20.46
50	Contractor Safety	SDG&E-2-M1	Expanded Contractor Oversight Program	3.02	**18.44**	44.12
51	Wildfires	SDG&E-1-M20	Fuel Management Program	13.93	**18.29**	25.57
52	Wildfires	SDG&E-1-PRiME	PRiME Group	13.70	**18.00**	25.15
53	Employee Safety	SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)	2.00	**17.14**	42.38
54	Employee Safety	SDG&E-3-C9	Safe Driving Programs	1.98	**16.95**	41.90
55	Electric Infrastructure Integrity	SDG&E-4-C3-T1	Distribution Switch Replacement Program - Tranche 1 Hook Stick Switches and Solid Blades in Contamination District One	16.80	**16.80**	16.80
56	Electric Infrastructure Integrity	SDG&E-4-M4-T2	Substation Breaker Replacements – Tranche 2 Murray Breaker Replacement	16.53	**16.53**	16.53
57	Electric Infrastructure Integrity	SDG&E-4-C7	Tee Modernization Program - Underground	16.06	**16.06**	16.06
58	Wildfires	SDG&E-1-C9	Cleveland National Forest Fire Hardening	11.14	**14.63**	20.44
59	Employee Safety	SDG&E-3-M5	Energized Skills Training and Testing Yard	1.49	**12.79**	31.63
60	Electric Infrastructure Integrity	SDG&E-4-C2	Overhead 4kV Modernization and System Hardening - Distribution	4.11	**12.56**	26.65
61	Electric Infrastructure Integrity	SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive	4.15	**12.29**	25.85
62	Electric Infrastructure Integrity	SDG&E-4-M3-T3	Proactive Substation Reliability for Distribution Components Ash 12kV Cap Replacement Re-build	12.20	**12.20**	12.20
63	Electric Infrastructure Integrity	SDG&E-4-C3-T2	Distribution Switch Replacement Program - Tranche 2 Tie Switches (Gang or Hook Stick) in Contamination District One	11.81	**11.81**	11.81
64	Employee Safety	SDG&E-3-C7	Employee Wellness Programs	1.31	**11.22**	27.73
65	Electric Infrastructure Integrity	SDG&E-4-C19-T1	Underground Cable Replacement Program – Proactive - Tranche 1 Unjacketed Cable - Feeder	10.39	**10.39**	10.39
66	Electric Infrastructure Integrity	SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive	2.63	**8.44**	18.13

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
67	Employee Safety	SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	0.88	**7.53**	18.61
68	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C5	Locate and Mark Quality Assurance Program	5.22	**7.16**	10.41
69	Electric Infrastructure Integrity	SDG&E-4-C9	DOE Switch Replacement - Underground	7.00	**7.00**	7.00
70	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T1	Early Vintage Program (Pipeline) - Tranche 1 Early Vintage Threaded Main Replacement	1.20	**6.51**	15.35
71	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T4	Public Awareness Compliance - Excavators	3.96	**5.43**	7.89
72	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T3	Early Vintage Program (Pipeline) - Tranche 3 Oil Drip Removal	0.98	**5.28**	12.46
73	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C1	Cathodic Protection	0.77	**4.16**	9.81
74	Electric Infrastructure Integrity	SDG&E-4-M4-T1	Substation Breaker Replacements – Tranche 1 San Ysidro Breaker Replacement	3.55	**3.55**	3.55
75	Employee Safety	SDG&E-3-C11	Near Miss, Stop the Job and jobsite safety programs	0.39	**3.30**	8.17
76	Wildfires	SDG&E-1-C12 / M9	Wire Safety Enhancement	1.96	**2.57**	3.59
77	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2-T2	Early Vintage Program (Fittings) - Tranche 2 High/Medium Valve Separation Removal	0.45	**2.45**	5.77
78	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C9	Increase Reporting of Unsafe Excavation	1.68	**2.31**	3.35
79	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T1	Public Awareness Compliance - The Affected Public	1.32	**1.81**	2.63
80	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C5	Locate and Mark Quality Assurance Program	0.20	**1.58**	3.87
81	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	1.03	**1.41**	2.05
82	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C4	Plastic Pipe Replacement	0.24	**1.28**	3.03
83	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C3-T2	Pipe Replacement - Tranche 2 Phase 1B (PSEP)	0.20	**1.19**	2.83
84	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T4	Public Awareness Compliance - Excavators	0.15	**1.18**	2.91
85	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M2	Establish a program to address the area of continual excavation	0.14	**1.09**	2.69
86	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T3	Public Awareness Compliance - Local Public Officials	0.76	**1.05**	1.52
87	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.71	**0.98**	1.42
88	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C2	Assessment Buried Piping in Vaults	0.15	**0.81**	1.91
89	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T2	Public Awareness Compliance - Emergency Officials	0.39	**0.53**	0.77
90	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.38	**0.53**	0.77
91	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.36	**0.49**	0.71
92	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C9	Increase Reporting of Unsafe Excavation	0.06	**0.49**	1.20
93	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C7	Prevention and Improvements - Refreshed Laptops	0.31	**0.43**	0.63
94	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T1	Public Awareness Compliance - The Affected Public	0.05	**0.39**	0.96
95	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.04	**0.36**	0.87
96	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M6	Promote process and system improvements in USA ticket routing and monitoring	0.04	**0.30**	0.75
97	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2-T1	Early Vintage Program (Fittings) - Tranche 1 Dresser Mechanical Coupling Removal	0.05	**0.28**	0.65
98	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T3	Public Awareness Compliance - Local Public Officials	0.03	**0.22**	0.54
99	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.03	**0.22**	0.54
100	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	0.14	**0.19**	0.28
101	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T2	Public Awareness Compliance - Emergency Officials	0.01	**0.12**	0.29
102	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.01	**0.11**	0.26
103	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M4	Utilize electronic positive response	0.07	**0.10**	0.14
104	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C7	Prevention and Improvements - Refreshed Laptops	0.01	**0.09**	0.22
105	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M3	Recording photographs for each locate & mark ticket visited by locator	0.01	**0.04**	0.10
106	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M4	Utilize electronic positive response	0.00	**0.02**	0.05

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
107	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.00**	0.01
108	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M7	Leverage data gathered by locating equipment	0.00	**0.00**	0.00
109	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.00**	0.00
110	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M7	Leverage data gathered by locating equipment	0.00	**0.00**	0.00
111	Wildfires	SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	0.00	**0.00**	0.00
112	Wildfires	SDG&E-1-M16	Backup Power for Resilience - Microgrid	0.00	**0.00**	0.00
113	Wildfires	SDG&E-1-C31 / M34	Wireless Fault Indicators	0.00	**0.00**	0.00
114	Wildfires	SDG&E-1-M28	NMS Situational Awareness Upgrades	0.00	**0.00**	0.00

[1]The RSE ranges are further discussed in Chapter RAMP-C.

Risk Assessment Mitigation Phase

(RAMP-E)

A Discussion of the Use of Risk Spend Efficiency

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

Over the last five years the California Public Utilities Commission (the CPUC or Commission), its Safety and Enforcement Division (SED), the Investor Owned Utilities (IOUs), and intervenors have been collaborating on developing and implementing into the regulatory process a reliable and more quantitative process to better understand how utilities mitigate risks. One of the concepts adopted to provide more information is the Risk Spend Efficiency (RSE).

In theory, RSEs are a mechanism that can help IOUs and the Commission understand risks and mitigations better and compare mitigations in addressing risks. Conceptually, RSEs could be a useful tool to assist in decision-making, but even when they were first suggested to the Commission, RSEs had critical shortcomings – shortcomings that continue with their most recent iteration. Because of these continuing deficiencies (and newer ones that have been discovered as RSEs have evolved and expanded), RSEs remain a data point for utilities to consider, but not the deciding factor for mitigation selection – a fact that is recognized by SED, the IOUs, and even the Commission in Decision (D.) 18-12-014, the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement Decision (SA Decision).

Southern California Gas Company (SoCalGas or Company) supports tools to prioritize and optimize their activities that mitigate risks. As such, the Company agrees with the concept of an RSE. In implementing RSEs, however, the Company has found that they are not as effective at prioritizing work as some have expected. As demonstrated in this Chapter, there are challenges with RSEs, including considerable subjectivity, that limit their extensive use at this stage.

The purpose of this 2019 RAMP Report Chapter is to:

- Discuss the background of RSEs and their evolution since 2015;
- Explain why RSEs, as currently constructed, should not be used to prioritize or select investments; and
- Suggest actions that could be taken to strengthen the RSE concept.

This Chapter is structured as follows:

- RSE History

- Shortcomings of RSEs
- Conclusion and Potential Next Steps

II. RSE HISTORY

A. First Presentation of RSEs

The concept of RSE was first publicly discussed in a Commission proceeding in an August 3, 2015 workshop. The basic formula proposed for determining an RSE was:

$$\textit{Risk Spend Efficiency for a Mitigation} = \frac{\textit{Risk Score Pre-Mitigation} - \textit{Risk Score Post Mitigation}}{\textit{Cost to Implement the Mitigation}}$$

Southern California Edison Company (SCE) proposed the use of RSEs with purportedly two long-term goals:

- Develop a multi-year spending plan based on the most effective mitigation.[1]
- Use RSEs to measure the effectiveness of mitigations.[2]

But, even in this initial foray into the development of RSEs, SCE recognized a number of shortcomings and challenges, including:

- Data on incidents and assets is not always available, or not compiled in a manner that facilitates analysis;
- Industry data and informed judgment will be needed as utility data is developed;
- Further analysis is needed to isolate risk drivers;
- Models for forecasting asset condition and asset failures are necessary;
- Risk evaluation, mitigation evaluation, and prioritization methodologies need to evolve; and

---

1 Southern California Edison Company, *SMAP Workshop* (August 3, 2015) at 2, *available at* https://www.cpuc.ca.gov/General.aspx?id=9099.

2 *Id.*

- RSEs were an input into the decision-making process, but any prioritization approach had to consider non-risk related inputs (including funding, compliance requirements, ongoing projects, resources, and operational constraints).[3]

As discussed below, these challenges and others persist.

B. Treatment of RSEs Since Creation

The Commission has required each utility to include RSEs in their RAMP filings since 2016.[4] All four IOUs have completed their first RAMP filings incorporating RSEs. In each of these filings, and in the feedback of SED and others, the persistent challenges with RSEs have been noted.

SoCalGas and SDG&E

In their 2016 RAMP filing, SoCalGas and San Diego Gas & Electric (SDG&E) developed estimates and ranges for RSEs.[5] In that first presentation of RSEs, they were calculated by dividing Annual Risk Reduction (as the number developed through SoCalGas' and SDG&E's risk scoring processes) by Total Mitigation Cost (the forecasted 3-year capital expenditure plus the annual Operating and Maintenance (O&M) expenses), multiplied by the number of years for which benefits from the risk reduction are expected.[6]

SED reviewed SoCalGas' and SDG&E's filing and concluded that "[t]he concept of [RSE] has not been completely developed in the S-MAP proceeding, and the Sempra Utilities' RAMP represents the first attempt to quantify and RSE for identified risks as a way of measuring the impacts of mitigations. Because of the novelty of the approach, staff feels it is something

---

3 *Id*. at 5.

4 California Public Utilities Commission, *Safety and Enforcement Division Evaluation Report on the Risk Evaluation Models and Risk-based Decision Frameworks in A.15-05-002, et al.* (March 21, 2016) at 78-79.

5 Investigation (I.) 16-10-015/-016 (cons.), Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company (November 30, 2016) at A-9.

6 *Id.*

that needs to be further reviewed and refined. Or, given the attempts in S-MAP to provide a more quantifiable methodology, perhaps it will be supplanted by some other process."[7] SED also recognized that, "This is admittedly an evolving area."[8]

<u>Pacific Gas & Electric Company (PG&E)</u>

In its 2017 RAMP filing, for RSE calculations, PG&E used a different formula to calculate RSEs for mitigations. PG&E essentially calculated RSEs for broader mitigation *plans*, incorporating a number of mitigations under one umbrella RSE. PG&E noted in their filing that the concept of RSEs was one of many factors that should be taken into consideration in determining where to make investments.[9]

In their review of PG&E's RSE methodology, SED agreed that RSEs were not the only factor for consideration in selecting mitigations.[10] For example, SED acknowledged that "resource constraints, compliance constraints, or operational constraints" could lead to selection of mitigations with lower RSEs.[11] In addition, SED referenced PG&E's self-assessment regarding the use of RSEs: "[I]mprovements 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."[12] SED pointed out how mitigation isolation could be a "pitfall" and "suboptimal from an aggregate risk portfolio standpoint."[13]

---

7 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016* (March 8, 2017) at 6.

8 *Id*.

9 I.17-11-003, 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (November 30, 2017) at A-14.

10 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003* (March 30, 2018) at 35.

11 *Id*. at 17.

12 *Id.* at 25.

13 *Id*. at 18.

SCE

In its 2018 RAMP filing, SCE used an approach similar to PG&E, but instead calculated the difference between the Multi-Attribute Risk Scores (MARS) before and after a mitigation.[14] SED included in their review several comments regarding SCE's filing. An important comment was that SCE's "[R]isk reduction analysis including RSEs would be most appropriate for decision-makers to be able to assess programs based on SCE's internal standards based on safety risks and costs."[15] SED continued to recognize that RSEs remain one element of the risk/mitigation analysis – not the entire analysis.

S-MAP

In the SA Decision, the Commission reconfirmed that the utilities will provide RSE calculations in the RAMP for all mitigations and alternatives.[16] The Settlement Agreement adopted in the SA Decision increases the quantitative aspects of RSEs and standardizes to some extent the process for developing RSEs between the utilities. However, many shortcomings of RSEs are not alleviated by the Settlement Agreement, and the process included therein has created new challenges with RSEs. Thus, while the process underlying the creation of RSEs became more quantitative, the value of RSEs still should not be overstated.

II. SHORTCOMINGS OF RSEs

In their current iteration, RSEs have a significant number of limitations keeping them from being entirely reliable or valuable as a decision-making tool. Below (in no particular order) several of these shortcomings are described.

Lack of data: The foundation of the RSE process is the availability of broad, accurate data for every risk and mitigation. Without such data, RSEs become drastically devalued by uncertainty. To properly calculate an RSE, as required by the Settlement Agreement, there must

---

14 I.18-11-006, Southern California Edison Company's 2018 Risk Assessment and Mitigation Phase Report (November 15, 2018) at 2-13.

15 California Public Utilities Commission, *A Regulatory Review of the Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case Investigation 18-11-006* (May 15, 2019) at 48.

16 D.18-12-014 at 22-23.

be an accurate measure of the frequency and consequences of a risk, the effects of a mitigation on both the frequency and consequence of a risk, and the cost required to implement the mitigation.

The problem is that for the majority of risks and mitigations, such data is scant or incomplete. For example, the Commission requires the Company to inspect the system annually, but there has been little data as to how many incidents were avoided through such annual inspections. Nevertheless, if an anomaly is observed during an inspection the Company would respond as needed. While the Company may capture additional information during an inspection, the data may not always be useful for risk reduction analysis. Therefore, the risk reduction benefit associated with annual inspections cannot be accurately determined at this time. All of the IOUs and SED have acknowledged the challenge with this dearth of data.[17] As SED noted, as recently as last year, "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."[18] Without current and accurate data the value of RSEs is limited.[19]

Another challenge commonly experienced with data is determining which data is most appropriate. Although utility specific data is best, it is not always available. The Company explains within specific RAMP chapters when data came from other sources. But when data is pulled from other sources, it can invite a host of questions. Most notably, how comparable a situation was to the one that the data was pulled from. For example, for an asset-based risk, the nationally-relied upon data could be based on a utility which had not invested as much in the safety of its infrastructure. But, at the same time, the utility's infrastructure may be less likely to experience risk events for other reasons, such as population densities, environment, or other

[17] *See* I.16-10-015/-016 (cons.), I.17-11-003 and I.18-11-006.

[18] California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003* (March 30, 2018) at 25.

[19] Another issue, not addressed here, is the associated cost of collecting data, which presents its own difficulties and constraints.

factors. It is difficult to balance all of these factors properly. For example, in evaluating the risk reduction benefits of certain mitigations, such as mitigating service damages within a sewer lateral, the Company relied on national PHMSA data to determine the incident rate since there was limited Company data available for such incidents. A mitigation focused on relocating services from within sewer laterals to remove the likelihood of damage addresses identified threats of low frequency, but potentially high consequence events. Although there is limited internal data to support that incidents related to this threat have occurred, the Company relied on nationally available data to determine the potential consequence of this threat.

<u>Frequency of Incidents</u>: Related to the previous point, the lack of the availability of data is difficult to overcome in some instances because of the infrequency of incidents for many risks. This is particularly the case with "tail" risks. Tail risks are those risks which occur very infrequently, finding themselves on the very extreme end of a probability curve (*i.e.*, the "tail"). Understanding the reduction in risk associated with infrequent catastrophic incidents is difficult to determine because of the frequency of events. For example, Florida Power & Light (FP&L) invested billions of dollars in "hardening" their electric system against hurricane risk starting in 2004. A significant hurricane did not impact their system until 2016. Accurately determining the benefit of FP&L's investments (*i.e.*, the risk reduction) took over 12 years.

<u>Reliance on Subject Matter Experts (SMEs)</u>: The lack of available data and frequency of tail risks leads to a reliance on SMEs to assess how much a risk will be reduced by the implementation of a mitigation and requires SMEs to calibrate that the available data is appropriate and applicable to our operations. As SED has acknowledged, the RSE is a product of SME input.[20] As a result, it is subject to the potential issues that can occur with uncalibrated SME input.

<u>Changes Occur</u>: Conditions change over time. Consequences and frequencies of events, priorities for the Commission and utilities, and other important factors in decision-making can

---

[20] California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016* (March 8, 2017) at 16.

change, even within a rate case cycle. As a result, predictive RSEs can be of limited value and fairly speculative. One of the clearest examples of this is when calculating RSEs for vegetation management mitigations. In such calculations, one cannot reasonably take into account changes in growth rates, costs or even fluctuations in weather. Vegetation can change in an area; unpredicted weather patterns can change the biological and geographical landscape. RSEs can therefore vary widely from forecast to reality. The Commission appears to recognize this, as evidenced by its acknowledgement that utilities require flexibly to adapt to changing conditions and in addressing risk.

Changing Methodologies and Tools: Comparing past and future RSEs, even from one cycle to the next, is generally of limited value. Changes will occur in methodologies and tools over time. This is recognized in D.18-12-014, which notes that utilities' multi-attribute value functions (MAVFs) will evolve over time.[21,22] This evolution can take many forms. It can result from simply refining data, but also wholesale changes to the structure of the Company's Risk Quantification Framework. The Company is already aware that intervenors encourage the IOUs to incorporate additional attributes into the MAVF, such as an environmental attribute and a customer satisfaction attribute. Although such attributes may be, to some extent, built into the current three attributes, adding new attributes will undoubtedly affect RSEs for many if not all mitigations. RSEs are thus of limited value in that they cannot effectively be compared between cycles.

Non-RSE Factors: Perhaps one of the most critical shortcomings of RSEs is that there is much they do not capture. The methodologies for determining RSEs do not take into consideration all the factors that go into the decision to select a mitigation. For example, if a utility intends to replace a bare wire conductor with insulated conductor, the RSE calculation will consider the risk reduction achieved by installing the new conductor and the cost of the new conductor. While factors such as resource availability, permitting requirements, and changing climate conditions are not considered within the RSE calculation, these factors are certainly

[21] D.18-12-014 at 54.

[22] The Company at times refers to its MAVF herein as the Risk Quantification Framework.

taken into consideration for decision-making purposes. Similarly, certain human factor benefits, such as those related to training and communicating with the public, are not easily captured as part of the RSE calculation. For example, the human benefits related to improved training and tools to allow the use of a newer laptop technology to enhance data collection was not captured in the RSE, which contributed to a low score resulting for this mitigation. This deficiency in RSEs has been recognized in essentially every RAMP filing and the SED report discussion therein.[23]

RSEs Cannot Be Compared Across Utilities: RSEs cannot be compared in any meaningful way across utilities. Although the Commission and Intervenors have in the past expressed a desire to be able to compare RSEs across utilities for similar risks/mitigations, that is not possible at this time.[24] Each of the utilities will use different formulas and methodologies in calculating RSEs. Each utility might use different attributes, different weights and scaling, and even different frequency and consequence valuations. SED acknowledged this in reference to PG&E's RAMP where it noted that the calculations and methodologies in calculating RSEs are complex and require significant effort to interpret.[25] Although the Settlement Agreement standardized certain processes and aspects of the creation of RSEs, the differences still confound any meaningful comparison.

Lack of Common View of Risk Tolerance: As noted by PG&E in their 2017 RAMP filing, a deeper understanding of the implications of differing risk tolerances is required before comparability can truly be achieved.[26] For example, SED, an intervenor, and a utility might have different views regarding the number of fire incidents that should be able to occur on a particular system. Some might say they want zero incidents while others may say there should be no

---

23 *See* I.16-10-015/-016 (cons.), I.17-11-003 and I.18-11-006.

24 D.16-08-018 at 164.

25 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric* Company *Investigation 17-11-003* (March 30, 2018) at 23 and 139-140.

26 I.17-11-003, 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (November 30, 2017) at A-6.

incidents that burn beyond three-square feet. These varying tolerances lead to different mitigations and RSEs. In addition, certain outcomes can be a higher priority because of their cause, even if the RSE cannot reflect that type of preference. The Company attempted to capture some of this in the alternative methodology discussed in Chapter RAMP-D, which can emphasize a need to reduce more significant events compared to more frequent risk events.

Mitigation Synergy not Recognized: As the MAVF for creation of RSEs currently stands, it is incapable of correctly showing the value of RSEs when mitigations are combined or broken up. Some mitigations work best when combined with one or more mitigations. Because RSEs have to be presented as standalone scores, the value of combining RSEs cannot be captured. Similarly, some mitigations apply across multiple risks. The RSE calculation methodology as it currently stands does not allow for a recognition of such benefits. Although combining the benefits across all risks impacted improves accuracy, this would significantly add to the complexity of the analysis and presentation of the mitigation benefits. For example, the replacement of live front equipment mitigation impacts both the Electric Infrastructure Integrity (EII) risk and the Employee Safety risk. However, the Company elected to assess the mitigation benefit as part of the EII risk to minimize double counting of benefits throughout this 2019 RAMP Report.[27] Thus, the risk reduction within the Employee Safety risk is underestimated, since the mitigation was assessed against the EII risk. This is another instance of RSEs not being able to capture the entire picture when it comes to the costs and benefits of mitigations or controls.

Non-Asset Mitigations/Controls: Non-Asset mitigations also do not lend themselves well to evaluation by RSEs. Because such mitigations do not clearly lend themselves well to being broken down into discrete data points, trying to force them into a quantitative analysis is challenging. For example, the benefit of training or public awareness efforts for third party dig-ins is challenging to quantify because these non-asset mitigations rely on a variety of sources and indirect measurements related to the risk. There are a substantial number of mitigations that

[27] Additional discussion on the Treatment of Risk Mitigating Activities Presented in Risk Chapters is in Section III.B.4 of Chapter RAMP-A.

utilities pursue and implement which are not asset based. Determining how to assess them within an RSE-driven framework continues to be problematic.

RSEs Do Not Reflect Reality of Utility or Commission Priorities: Although there are several shortcomings in the RSEs that are primarily data driven, perhaps one of the most challenging to quantify is related to valuing mitigations that are strongly supported by the Commission and IOUs' strategic efforts and priorities. Certain mitigations are recognized by essentially all interested parties to be important – yet their RSEs would suggest they should be treated as lower priority work. For example, in the high-pressure pipeline incident risk, the valve automation mitigation had a relatively low RSE, yet valve automation was required by the Commission in D.14-06-007. The rankings of RSEs shown in Appendix D-1 contain other examples of these types of mitigations. Because there are so many mitigations like this, it becomes difficult to accept the results of other less unanimously supported mitigations (or any of the RSEs, for that matter).

Cannot be Used to Prioritize: Another shortcoming of RSEs is that they are not particularly effective at their presumed purpose: to rank mitigations. When SCE first proposed the use of RSEs in August 2015, they recognized it would take time to develop them and they were, at best, only one of many factors to be taken into consideration in measuring mitigation effectiveness.[28] PG&E and SED went further in concluding that RSEs cannot be used to compare RSEs across risks or across utilities.[29] Based on all the shortcomings noted above, the conclusions reached by SED, SCE, and PG&E regarding whether RSEs can be used to simply rank mitigations are correct. There are too many shortcomings and variables to be able to use RSEs in their current format to determine whether an investment should or should not be made relative to another risk.

---

28 Southern California Edison Company, *SMAP Workshop* (August 3, 2015), *available at* https://www.cpuc.ca.gov/General.aspx?id=9099.

29 D.16-08-018 at 164.

III. CONCLUSION AND POTENTIAL NEXT STEPS

SoCalGas and SDG&E, PG&E and SCE have all included RSE calculations in their respective RAMP Reports; however, as noted in numerous S-MAP Workshop documents and SED briefings, RSEs are flawed and provide imperfect results. While there is a belief that RSEs can be used as an input into investment decision making, neither SED nor the utilities believe RSEs can be used to prioritize investments or that they should be the determining input into decision making.

In conclusion, for RSEs to be of increased value in investment decision making, then RSEs specifically:

1. Must provide insights into mitigation selection but cannot be the only criteria used to prioritize mitigation investments.
2. Need further study and methodological development to address the complexity of deciding which mitigations are best implemented to address a risk.
3. Cannot address all the factors that go into determining which mitigations can be implemented (*e.g.,* resource availability and scheduling/permitting issues cannot be taken into consideration in developing RSEs).
4. Require historic data in addition to SME insights to be of most value.
5. May not provide an optimized portfolio of mitigations.
6. Need a better understanding of each stakeholders' risk tolerance for RSEs to be valuable.
7. Are of limited value when evaluating the effectiveness of non-asset mitigations.
8. Should be the subject of additional investigation in future S-MAPs.

The Company is hopeful that an exploration of how to strengthen RSEs can be included in future S-MAP proceedings. This exploration could include, but not be limited to, a determination of a risk tolerance methodology, RSEs and risk mitigation effectiveness and the access to historic data that goes well beyond subject matter expertise. This will likely mean that RSEs will have limited use for future GRC cycles while the methodology is refined, and data is improved and collected.

Risk Assessment Mitigation Phase

(RAMP-F)

Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This Chapter provides supplemental information regarding SoCalGas' organizational structure, programs, culture and compensation as they relate to safety, as required by D.16-08-018.[1] The Commission has stated that "[a]n effective safety culture is a prerequisite to a utility's positive safety performance record,"[2] and has defined "safety culture" as follows:

> An organization's culture is the collective set of that organization's values, principles, beliefs, and norms, which are manifested in the planning, behaviors, and actions of all individuals leading and associated with the organization, and where the effectiveness of the culture is judged and measured by the organization's performance and results in the world (reality). Various governmental studies and federal agencies rely on this definition of organizational culture to define "safety culture."[3]

The Commission has further stated that, under the above definition, a positive safety culture includes "a clearly articulated set of principles and values with a clear expectation of full compliance," and "effective communication and continuous education and testing."[4] SoCalGas has a robust safety culture embedded in its values, goals, operations and practices, including advancing programs, policies, procedures, guidelines, and best practices, and engaging employees to improve the safety of our operations.[5]

II. BACKGROUND

Following issuance of D.16-08-018, SoCalGas has described the elements of its safety culture in various proceedings. For example, numerous SoCalGas witnesses in the test year (TY) 2019 general rate case (GRC) testified regarding safety culture, as it related to the witness'

---

1 D.16-08-018 at 140-42 (Inclusion of Safety Culture and Organizational Structure in RAMP Filings). Additionally, the Commission stated, "[t]he company's compensation policies related to safety also should be included in the RAMP filing." *Id.* at 141. *See also*, I.19-06-014 at 3.

2 I.15-08-019 (Order Instituting Investigation of Pacific Gas and Electric Company's Safety Culture, August 27, 2015) at 4.

3 I.19-06-014 at 3.

4 *Id.*

5 *See, e.g.,* A.17-10-008, Diana Day direct testimony (Exh. SCG-02-R) at DD-28.

subject matter area.[6] Testimony that was sponsored by approximately 50 witnesses, including by the President and Chief Operating Officer (COO) of SoCalGas, detailed the Company's safety culture and safety management practices and based the GRC funding requests on key safety and risk-informed RAMP risks and mitigations. SoCalGas also provided TY 2019 GRC testimony and information regarding their governance, safety record, and safety culture,[7] pursuant to Commission direction in D.16-06-054.[8]

SoCalGas' testimony chapters in the TY 2019 GRC proceeding outlined various safety programs as well as new and evolving initiatives to build safety management systems. Furthermore, as described in SoCalGas' response to the safety culture order instituting investigation (OII),[9] following the formal release in July 2015 of American National Standards Institute/American Petroleum Institute Recommended Practice 1173 (API 1173), SoCalGas voluntarily adopted and began to implement the foundational principles of safety management systems therein and is encouraging its pipeline construction contractors to also do the same.[10]

In addition to addressing safety as an integral component of all of the risk assessments and mitigations outlined in each of the chapters of this RAMP report, the Commission has instructed the utilities to include specific discussion in this filing regarding the following:[11]

- Safety culture and organizational structure;
- Compensation policies related to safety;
- Executive and senior management engagement in the risk assessment, prioritization, mitigation, and budgeting process; and

---

6 *See generally* A.17-10-008 (witness direct testimony submitted and entered into the proceeding record) and Exh. SCG-250 Safety Policy Testimony of David Buczkowski and David Geier.

7 A.17-10-008, Exhs. SCG-02-R, SCG-30.

8 D.16-06-054 at 154.

9 Southern California Gas Company's Response to Order Instituting Investigation I.19-06-014 (July 29, 2019).

10 SoCalGas Response to I.19-06-014 at 3.

11 *See* D.16-08-018 at 140-42.

- Utility board engagement and oversight over safety performance and expenditures.

This chapter addresses each of these topics in the following sections.

III. SAFETY ORGANIZATIONAL STRUCTURE AND CULTURE

This section provides an overview of how safety is incorporated into the Company's organizational structure and is an integral part of its culture. Detailed descriptions of SoCalGas' safety organization can be found within the Employee, Contractor, and Customer and Public Safety Chapters included in this RAMP Report.

In SoCalGas' TY 2019 GRC proceeding, several executive witnesses testified to SoCalGas' longstanding commitment to operating a safe utility and enhancing the focus placed on the implementation of effective safety risk mitigations, including asset health and safety. For example, SoCalGas' then-Chief Operating Officer J. Bret Lane testified regarding "SoCalGas' deep-seated culture of employee/contractor, customer/public, and system safety," and how SoCalGas' TY 2019 GRC proposals would allow the company "to continue to invest to enhance safety and thereby mitigate risks that could impact our employees, customers, and/or system."[12] The following subsections further describe SoCalGas' safety organizational structure and culture.

A. Organizational Structure

SoCalGas' Chief Operating Officer also serves as the Company's Chief Safety Officer (CSO), with direct oversight of the operations of the Company. The CSO is supported by dedicated teams embedded within the organization whose primary roles are the management of safety and risks. These include SoCalGas' Enterprise Risk Management organization, Integrity Management organization, and Safety Management Systems organization. Each of these organizations is further described below.

In addition to these centralized functions that promote safety and risk management consistently across the Company, SoCalGas embeds safety into all of its functional areas. This is done in the form of safety processes and procedures, initiatives, and policies that are driven by

---

[12] A.17-10-008, Exh. SCG-01-2R (Lane) at JBL-1.

various employees across the Company. SoCalGas utilizes a variety of engagement initiatives to bring management, front-line personnel, and contractors together in forums to discuss safety concerns from the perspective of those closest to the risks. These include the Executive Safety Council engagement, Employee Safety & Health Congresses, Safety Standdowns, local safety committees, safety culture surveys, the Safety (Management/Union) Leadership Team, the Contractor Safety Congress, and Stop the Job/Near Miss reporting tools.

1. Enterprise Risk Management Organization

The Enterprise Risk Management organization is composed of a Chief Risk Officer/vice president, directors, and risk managers whose roles are dedicated to implementing the risk management process across the Company. This includes the development of transparent, repeatable, and consistent processes that are quantitative and data-driven, facilitating an annual identification and evaluation of risk, as well as supporting operational areas across the Company in the assessment of their risks and development of associated risk mitigations. SoCalGas' Enterprise Risk Management organization oversees the development and refinement of the annual Enterprise Risk Registry process, as described in Chapter RAMP-B. This organization also supports functional areas across the Company in the assessment of risks and development of risk mitigations, including, for example, by creating risk registers for operating units.

2. Integrity Management Organization

SoCalGas' Integrity Management organization is comprised of dedicated directors, managers, and staff whose roles focus on the development and implementation of processes and procedures to manage transmission, distribution, and storage well integrity in compliance with regulatory requirements. This organization continues to advance the approach to data management, data governance and risk assessment in connection with the Company's transmission, distribution and storage assets. This organization enables SoCalGas to place the safe and effective management of the Company's pipeline assets at the center of the Company's operations.

3. Safety Management Systems Organization

In 2015, when the American Petroleum Institute Recommended Practice (API 1173) was published, SoCalGas began to review the potential benefits of this new system. SoCalGas engaged with its peers, the American Gas Association (AGA) member companies, to better understanding how API 1173 could benefit SoCalGas with respect to the management of its pipeline safety risks. Subsequently, the Company took a more expansive view to other industries and how the principles of API 1173 could be applied beyond pipelines and into multiple assets and functions. From 2015 through 2018, SoCalGas took several key steps towards formally adopting the principles of API 1173, harmonizing them with the structures already in place, and enhancing and expanding the same. SoCalGas takes a broad, holistic view of safety management and plans to continue to benchmark its practices against those of its peer companies as well as best practices in other industries to adopt a more expansive view of Safety Management Systems (SMS).

Earlier this year, SoCalGas created a dedicated Safety Management Systems organization, reporting directly to the CSO. The Safety Management Systems organization was established to more clearly and transparently align employee safety, contractor safety, pipeline safety and compliance, quality management, and emergency management. The purpose of this new organization is to develop and implement a comprehensive set of safety management systems, incorporating the principles of API 1173 but expanding the scope of the system to address all aspects of safety relevant to the Company's business. This includes not only pipeline safety risks, but also occupational safety and health risks of its employees and contractors, customer safety risks, infrastructure safety risks, and public safety risks. The Safety Management Systems organization at SoCalGas is comprised of a team of directors, managers, supervisors, and subject matter experts who have the centralized authority, accountability, and responsibility for the full execution of the Company's SMS, including designing, developing, implementing, and continuously improving the Company's SMS across three primary categories: employee and contractor safety, public and customer safety, and system safety. The responsibilities include:

- Providing strategic guidance and establishing appropriate policies, standards, procedures and key performance indicators, as well as technology and data analytics tools and platforms and reporting capabilities, for various elements of the Company's SMS to promote its consistent implementation and effectiveness across organizations;

- Leading incident investigations and sharing lessons learned with stakeholders to demonstrate risk reduction and improvement;
- Leading the annual management review and safety assurance functions; and
- Collaborating with employees to provide safety and compliance support, emergency preparedness and response support, capabilities to benchmark against best practices, and to conduct periodic SMS conformance reviews to measure progress.

The Safety Management Systems organization includes the dedicated teams for strategy, technology and analytics, and continuous improvement. More particularly, the organization includes the Safety department, which holds a director, managers, and subject matter experts. These individuals oversee the implementation of the Company's various safety policies, trainings, and programs, including: the Environmental & Safety Compliance Management Program (ESCMP), the Behavior Based Safety programs, Industrial Hygiene programs, "Stop the Job," the Close Call/Near-Miss reporting program, Incident Investigations, Safety Culture Assessments, and Contractor Safety programs. These programs are described within the Employee Safety Chapter of this RAMP Report (Chapter SCG-2). This organization also oversees the Emergency Management team who coordinates safe, effective and risk-based emergency preparedness and response to safely and efficiently prepare for, respond to, and recover from an emergency or disaster. The Emergency Management team sustains quality assurance and improvement processes through strategic planning, training, simulation exercises, and a comprehensive After-Action Review and Improvement program. The Emergency Management team includes: 1) business resumption, 2) emergency preparedness and response operations, 3) information and technical services, and 4) operational field emergency readiness.

The Safety Management Systems organization is structured around the "PLAN-DO-CHECK-ACT" model and a robust Management of Change component and is expected to integrate over time the various existing safety management systems at the Company under one umbrella system called the Company's Safety Management Systems.

Figure 1: The "Plan-Do-Check-Act" Cycle[13]

An SMS Executive Steering Committee was established and is led by SoCalGas' CSO and includes other SoCalGas executives representing company operating groups. The Executive Steering Committee has the responsibility to provide oversight, guidance, and direction to the Safety Management Systems organization for the development, implementation, ongoing maintenance, and continuous improvement of the Company's SMS. This committee also has the responsibility to establish high-level performance measures to help assess the effectiveness of the Company's SMS, and to conduct the annual management review of the Company's SMS.

13 Pipeline SMS, *Fact Sheet: RP 1173 Pipeline Safety Management Systems* (April 16, 2018), *available at* http://pipelinesms.org/fact-sheet-rp-1173-pipeline-safety-management-systems/.

SoCalGas
A Sempra Energy utility

4. Safety Management System Implementation

The Company's journey of formalizing its SMS began more than a decade ago, when it first implemented its Environmental & Safety Compliance Management Program (ESCMP) to enhance the management of its environmental and occupational health and safety risks. ESCMP is conceptually based on the International Standards Organization (ISO) 14001 Environmental Management Systems standard and includes safety components that are unique to SoCalGas. ESCMP addresses compliance requirements, awareness, goals, monitoring and verification related to all applicable environmental, health and safety laws, rules and regulations, and company standards. SoCalGas also has an annual ESCMP Certification process, which involves submittal of information into the database used to collect and record employee and facility compliance. In January of each year, ESCMP information is submitted into an online system for year-end approval and certification for the prior calendar year. ESCMP has been refined and improved, and has matured over the years, but is still in place across the enterprise.

In 2017 SoCalGas began its Pipeline Safety Management Systems (PSMS) initiative to align the Company's practices with American Petroleum Institute's Recommended Practice 1173 (API RP 1173) and reinforce the Company's safety culture through the integration of business needs and operational risks in a systematic manner.

Safety Policy witnesses David Buczkowski testified in SoCalGas' TY 2019 GRC proceeding regarding the elements and varying maturity levels of the PSMS that SoCalGas had implemented to date. More specifically, SoCalGas, in its implementation of API 1173 for gas pipeline operations, has adopted a three-pronged approach that requires vigilant attention to:

a. Employee and Contractor Safety;
b. Customer and Public Safety; and
c. Safety of SoCalGas' gas delivery systems.[14]

Each of these categories is addressed in SoCalGas' risk management policies, processes, and practices, as well as through day-to-day operations. Moreover, these areas are all reflected in the various risk chapters of this RAMP Report.

---

[14] A.17-10-008, Exh. SCG-01-2R (Lane) at JBL-5.

As discussed in Omar Rivera's testimony in the TY 2019 GRC, API RP 1173 is a structured way to identify hazards and control risks while validating that the risk controls are effective. This includes increased interdepartmental integration of all pipeline safety-related programs and risk management, development and monitoring of leading and lagging indicators, implementation of reporting and oversight processes, continuous program monitoring and improvement, enhanced incident investigation and lessons learned, safety culture evaluation, improved management of change and recordkeeping, enhanced emergency preparedness, and application of competence training.

SoCalGas' SMS is based on the following seven Safety Values:

Leadership Commitment

- SoCalGas leadership is fully committed to safety as a core value. SoCalGas' Executive Leadership is responsible for overseeing reported safety concerns and promoting a strong, positive safety culture and an environment of trust that includes empowering employees to identify risks and to "Stop the Job."

Employee Engagement

- Employees are encouraged and expected to take ownership, to actively engage in safety practices, and to openly share and receive information with one another, our contractors, and our external stakeholders, to continuously enhance our safety practices.

Risk Management

- SoCalGas manages risk through a structured, data-driven approach that identifies threats and hazards, assesses and prioritizes risks, implements mitigation efforts, and engages in assessments and reviews to understand risk mitigation effectiveness.

Safety and Compliance Assurance

- SoCalGas maintains operational policies and procedures that document safety practices and standards and compliance with applicable regulations and follows a “management of change” process to structure change when new policies and procedures are implemented.

Continuous Improvement

- SoCalGas strives to continuously improve and strengthen its safety performance and culture by setting clear and measurable goals, assessing safety performance through audits and self-assessments, inviting employee feedback, and applying lessons learned from incidents and near miss events. SoCalGas also shares safety best practices with peer gas utilities and best-in-class companies in other industries.

Emergency Preparedness & Response

- SoCalGas maintains readiness to promptly respond to emergency incidents and events through an Incident Command System that incorporates response planning, training and equipping of personnel and coordination with first responders and external stakeholders.

Competence, Awareness & Training

- SoCalGas is committed to providing employees the proper tools, resources, training, and oversight to promote safe operations. This includes training tailored to specific roles and educating employees on why our training, policies, and procedures are important to safety.

To appropriately embed these safety values within the entire organization, SoCalGas is formalizing two new anchor policies: (1) the SMS Policy, and (2) the SMS Responsibilities Policy. The SMS Policy formally establishes leadership commitment to SMS, and the SMS Responsibilities Policy formally establishes responsibilities at various levels of the Company to promote, support, develop, implement, and continuously improve SMS in an effective and efficient manner.

The Company’s goal is to continually strengthen our safety culture by following the values of the SMS. To that end, SoCalGas is also formalizing (1) an internal Standard that clearly defines SoCalGas’ Safety Management System, and (2) SoCalGas’ first annual SMS Plan that assesses how SoCalGas is adhering to safety values, policies, and standards, and how it plans to continue to implement SMS going forward.

The Company takes a broad, holistic view to safety management and plans to continue to benchmark its practices against those of its peer companies (such as AGA and Western Energy Institute member companies). As its SMS matures, SoCalGas expects to learn from benchmarking efforts and aspires to adopt and apply other industry frameworks as applicable to continue enhancing its SMS into the future.

5. Leadership Commitment

In the Company's TY 2019 GRC proceeding, several executive witnesses testified to the Company's longstanding commitment to operating a safe utility and enhancing the focus placed on the implementation of effective safety risk mitigations, including asset health and safety.[15] As noted above, then-Chief Operating Officer J. Bret Lane testified in the last GRC about "SoCalGas' deep-seated culture" of safety. The SoCalGas leadership's commitment to safety is evidenced in a number of ways.

The Company has established an Executive Safety Council chaired by the Company's Chief Safety Officer and the Company also has safety advisors, supervision, and various local safety committees to help inform, educate and engage employees about safety values, policies, programs and initiatives throughout the Company. Also, as discussed above, the SMS Executive Steering Committee has involvement from several executives to oversee and guide the implementation of SMS.

The leadership commitment is also advanced by the support for forums to raise concerns to leadership. The Company has processes, programs, and committees in place that welcome feedback on safety from employees on the management of risks and unsafe practices or incidents. To promote these principles and to foster a culture of continuous safety improvement, SoCalGas continuously strives for a work environment where employees at all levels can raise pipeline infrastructure, customer safety, and employee safety concerns and offer suggestions for improvement. SoCalGas has an open-door policy that promotes open communication between

---

15 A.17-10-008, Exh. SCG-02-R, Chapter 1 (Day) at DD-26.

employees and their direct supervisors. The Company also has Safety Congresses for contractors and employees, as well as safety meetings for field employees that provide safety training, share best practices, and promote leadership and employee engagement.

6. Employee and Stakeholder Engagement

SoCalGas encourages two-way formal and informal communication between the company and the public, employees and management, and contractors and the company. Safety is communicated daily by supervisors in the morning before the field crews leave for work. The Company's safety department regularly issues employee safety communications to provide supervisors with safety-related information in a timely manner regarding standards and safe work practices to be communicated and shared with their employees. These safety communications are a tool used to inform employees about safety hazards and exposures, hazard mitigation, rules, regulations, warnings, goals, and progress reports through an array of media. Safety is also communicated on a weekly basis among operations directors at the beginning of each week during a Monday morning safety call. During that call, they also review all incidents from the previous week and share best practices. SoCalGas communicates information through safety bulletins, emails, newsletters, electronic bulletin boards (*e.g.,* digiboards), posted signage throughout the workplace, tailgate meetings and reports.

SoCalGas conducts public awareness efforts through education and outreach to enhance the safety of its customers and the general public. These efforts are designed to engage with our customers and the public to inform them about our shared safety responsibilities. Of equal importance are outreach activities with local first responder agencies, county coordinators (emergency management), and other public officials which occur on a yearly basis, focusing on how we can partner during an emergency incident response, including a review of infrastructure location information, hazard awareness and prevention, leak recognition and response, emergency preparedness and communications, damage prevention and integrity management. In addition, the Company also partners with these stakeholders throughout the year on joint drills, exercises, tabletops, and preparedness fairs in order to enhance our coordination and response during emergencies. SoCalGas also attends California Independently Owned Utility (IOU) and Municipality annual meetings to discuss employee and contractor safety. This dedicated forum is a utility benchmarking initiative addressing new regulations, legislation, best management practices, and other safety topics of interest.

To regularly engage more broadly with employees, the Company assesses and ranks itself relative to other similar companies through the Employee Engagement Survey and the National Safety Council (NSC) Safety Barometer Survey. As described by TY 2019 GRC witnesses Diana Day and Mary Gevorkian, the Safety Barometer Survey assesses overall safety climate health and identifies areas of opportunity to eliminate injuries and improve focus and commitment to safety.[16] David Buczkowski provided the following reasons for SoCalGas' belief that the NSC Safety Barometer Survey is a leading practice approach to evaluating safety culture:

1. NSC's mission is safety – eliminating preventable deaths, through leadership, education and advocacy;
2. The NSC Safety Barometer Survey is led by third-party experts;
3. The practices included in the survey are the leading practices drawn from survey participants, allowing SoCalGas to compare themselves to almost 1,000 other Companies; and
4. The survey goes well beyond the utility industry and includes other industries.[17]

Through regular participation in the surveys, the Company shares results, develops targets, implements plans, and measures progress, with the goal of increasing employee participation in, and contribution to, improvements in safety performance.

The Company began conducting safety culture assessments in 2013, using NSC's Safety Barometer Survey. The NSC Safety Barometer survey is an employee perception survey that engages employees and asks for their anonymous feedback on safety by measuring elements of safety excellence in the following areas:

16 A.17-07-008, Exhs. SCG-02, SCG-32.

17 A.17-10-008, Exh. SCG-250 at DLB-12.

- Organizational Climate – Probes general conditions that interact with the safety program to affect its ultimate success, such as teamwork, morale, and employee turnover;
- Management Participation – Describes ways in which top and middle management demonstrates their leadership and commitment to safety in the form of words, actions, organizational strategy, and personal engagement with safety;
- Supervisory Participation – Considers six primary roles through which supervisors communicate their personal support for safety: leader, manager, controller, trainer, organizational representative, and advocate for workers;
- Safety Support Climate – Asks employees across an organization for general beliefs, impressions, and observations about management's commitment and underlying values about safety;
- Employee Participation – Specifies selected actions and reactions that are critical to making a safety program work. Emphasis is given on personal engagement, responsibility, and compliance; and
- Safety Support Activities – Probes the presence or quality of various safety program practices. This focuses on communications, training, inspection, maintenance, and emergency response.

The NSC Barometer Survey provides information and insight in the six critical areas of safety culture described above. Furthermore, NSC's rich database provides SoCalGas the ability to benchmark the results with hundreds of other companies who have conducted similar surveys with NSC and gives a comparative analysis of relative strengths and potential opportunities for organizational improvements as well as for individual work locations and departments.

SoCalGas has now completed three cycles of the NSC Safety Barometer Survey (in 2013, 2016, and 2018) and, when compared to 580 other companies who have gone through similar surveys, SoCalGas consistently ranked high. In all three cycles, SoCalGas ranked above the 90th percentile. More important than the ranking, the NSC survey tool has helped identify safety areas of strength and alignment with other high performers, as well as opportunities for potential improvement.

As a result of NSC survey feedback from employees, both positive and constructive, the Company has made many improvements in recent years. For example, as a result of the 2013 NSC survey results, despite already having a "Stop the Job" policy, the Company worked with its union leadership and enhanced communication on that policy. The Company raised awareness about this policy to emphasize that if an employee does not feel safe or if they see another employee or contractor being unsafe, all employees, regardless of rank or title, are empowered to stop the work being performed to address the safety concern without fear of retribution. SoCalGas also enhance its communication to employees about the value and importance of learning from close calls. Subsequent NSC survey results demonstrated that employees now have more confidence to "Stop the Job" and report close calls, near misses, and unsafe conditions.

7. Risk Management

Effective risk management practices help to reinforce a strong and positive safety culture. SoCalGas has undertaken a thoughtful and measured approach to the adoption of risk management structures and processes at all levels, to further the development of a risk-aware culture. As described in (then-Vice President, Enterprise Risk Management for SoCalGas) Diana Day's testimony in the TY 2019 GRC, SoCalGas's Enterprise Risk Management organization facilitates the identification, analysis, evaluation and prioritization of risks, with an emphasis on safety, to ultimately inform the investment decision-making process, and works to integrate risk management with asset and investment management through the creation of governance structures, competencies, and tools.[18] The Enterprise Risk Management practices and processes are continuing to be used by SoCalGas different operational and functional departments to identify safety risks, thus providing a critical element of SoCalGas' SMS.

SoCalGas' risk management framework is consistent with the Cycla Corporation 10-step Evaluation Method adopted in D.16-08-018. Risk identification, as defined by ISO 31000, is the

[18] A.17-07-007, Exh. SCG-02, Diana Day Direct Testimony at DD-2.

process of finding, recognizing, and describing risks. It includes the identification of risk sources, events, their causes and potential consequences. On an annual basis, SoCalGas's Enterprise Risk Management Organization facilitates the enterprise risk identification process through interviews and meetings with risk owners and managers to review and discuss potential changes to the Company's Enterprise Risk Registry. SoCalGas has developed several operating unit risk registries in different operating areas of the Company, including but not limited to gas controls, high pressure gas system, medium pressure gas system, advance meters and customer services field, and continues to expand their use and refinement of the process. SoCalGas is leveraging the operating unit risk registries to inform internal asset management strategies and integrity management to continue the integration of risk and asset management. SoCalGas' risk management framework is further discussed in Chapter RAMP-B.

8. Safety and Compliance Assurance

SoCalGas employs a number of mechanisms for reviewing and confirming that safety and compliance requirements are being met.

Operational Controls – SoCalGas clearly communicates its processes and documents how we operate safely. SoCalGas has a comprehensive set of operational controls executed through a framework of policies, training, documentation, and recordkeeping. This includes operational activities to maintain compliance with applicable local, state and federal laws and regulations, and is accomplished through dedicating resources and subject matter expertise in various disciplines with the intent to track, understand, and implement regulatory requirements through developing formalized company standards.

The policies dictate the standards, training, resources, and programs on how employees are to conduct their day-to-day tasks in a compliant and safe way. Compliance requirements that SoCalGas employees have to follow are prescribed in written company standards to facilitate compliance with regulatory requirements, bring about more efficient operations, and promote both employee and public safety. All standards are housed in a centralized SoCalGas Document Library for easy access by employees and are reviewed at a designated frequency to stay current with pertinent regulations and laws, and with changing business needs.

To further assist with effective implementation, the company standards are consolidated into Manuals or Plans or Programs for each distinct compliance discipline. For example, the three principal categories of regulatory requirements that SoCalGas has to comply with are the CPUC/DOT/PHMSA pipeline safety regulations, the federal and California OSHA for employee safety, and DOGGR for underground natural gas storage safety.

Specifically, the pipeline safety standards for operations and maintenance activities are consolidated into SoCalGas' Operations & Maintenance Plan, the employee safety standards are consolidated into SoCalGas' Injury & Illness Prevention Program, contractor safety requirements are consolidated into SoCalGas' Contractor Safety Manual, and underground storage safety standards are grouped into SoCalGas' SIMP Plan. These are in addition to related compliance programs, such as the TIMP, DIMP, and SIMP, as well as procedures for material specifications and traceability, design and purchase specifications, and construction, inspection and testing procedures, as needed. Operational controls also include a Management of Change (MOC) process, which is established locally within various programs. An effort is underway by the SMS organization to consolidate the various MOC processes into one electronic platform that is currently in developmental stage.

Audits & Evaluations – Regularly scheduled internal audits are performed by Sempra Energy Audit Services which works directly with Company management to assist in assessing risks and evaluating business controls needed to enable SoCalGas to achieve its objectives. Audit Services has full access to all levels of management, and to all organizational activities, records, property, and personnel relevant to activities under review. Audit Services is authorized to select activities for audit, allocate resources, determine audit scope, and apply techniques required to accomplish audit objectives. Audit Services is authorized to obtain the necessary direct access of personnel in units of the organization where they perform audits, as well as other specialized services from within or outside the organization. The scope of work conducted by Audit Services is to review: (1) that processes and business controls, as designed and maintained by management, are adequate and functioning in compliance with policies, plans, procedures, laws, regulations and contracts; (2) the safeguarding of assets; (3) the effectiveness and efficiency of operations; and (4) the reliability and integrity of operating and financial information. Business controls are actions that increase the likelihood of achieving the above objectives. SoCalGas' management is responsible for taking ownership of, and being accountable for, understanding, establishing, and maintaining effective business controls. Through this effort, Audit Services can effectively work with management to determine whether business controls are designed and functioning properly. These collective efforts provide a basis for Audit Services to provide an independent evaluation to management and the Board of Directors as to the adequacy of the Company's overall system of business control. Management will address any identified deficiencies by Audit Services and develop management corrective actions to resolve the findings. Management corrective actions are assigned a completion date and Audit Services conducts reviews to determine if identified findings are resolved prior to closing out the audit.

Executive Safety Council Team Meeting Dialogues – The Executive Safety Council is the governing body for all safety committees. Led by SoCalGas's Chief Safety Officer and the directors of Safety Management Systems and Safety and Wellness, this is a roundtable with company officers to advance the company safety culture, address enterprise-wide safety strategy, and give employees an opportunity to share their safety experiences with company leadership. The Executive Safety Council represents SoCalGas' labor and represented workforce.

Gas Safety Subcommittee – This committee brings represented employee representatives from each district and management together monthly to discuss concerns and address potential gas operations safety hazards. The objective is to reduce unnecessary risk, resolve gas safety issues/concerns, and communicate information back to frontline employees.

Pipeline Safety Oversight Committee – This high-level internal committee comprising executives and directors that oversees pipeline safety programs and activities, including oversight over compliance activities and contractors. This committee meets periodically and reviews the progress made in the pipeline compliance activities and in the contractor safety area and provides direction on steps needed to be taken to continue to reduce the identified safety risks. This program serves as a proactive approach to have a senior level committee overseeing the development, implementation and growth of the contractor safety program to address the overall safety risk associated with hiring contractors and strengthening public trust.

Field and Office Safety Committees (site-specific) – These committees (approx. 50) are actively engaged in safety awareness through education, promoting a healthy lifestyle, encouraging work-life balance and always maintaining a safe work environment. To keep the committees connected, quarterly meetings are held with committee chairpersons and co-chairpersons. During these meetings safety updates are shared, training is provided, and action planning steps are identified. Like SoCalGas' other safety committees, site committees roll up to the Executive Safety Council as the governing body.

Behavior Based Safety Program – SoCalGas's Behavior Based Safety Program is a leading proactive approach to safety and health management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. Behavior Based Safety is the "application of science of behavior change to real world safety problems." This process is a safety partnership between management and employees that continually focuses attention and actions on daily safety behavior, to identify safe and at-risk behaviors. Through a job observation program, supervisors observe employees working using a critical behavior inventory checklist to track safety behaviors and have a dialog on safe and at-risk behaviors, then recommended behavioral safety changes. Field supervisors conduct documented observations with their employees to address at-risk behaviors and to attempt to modify an individual's actions and/or behaviors through these interactions. Supervisors provide quality feedback during these positive interventions aimed at developing safe work habits and improving safety culture. The purpose is to reduce recurrences of at-risk behaviors by modifying an individual's actions and/or behaviors through observation, feedback, and positive interventions aimed at developing safe work habits.

Safety Congress and Leadership Awards – Held annually, the Safety Congress provides a forum for safety committee members, safety leaders and others to share and exchange information and ideas through networking and workshops. At this event, safety leaders are recognized for living by the company's safety vision, turning that vision into action, embracing the SoCalGas safety culture and demonstrating safety leadership.

The National Safety Council (NSC) Barometer Survey – As noted above, the NSC Barometer Survey is used to assess the overall health of the safety climate and helps to identify areas of opportunity to eliminate injuries and improve focus and commitment to safety. The survey is administered to employees every other year. All organizations interpret their results using a three-step process to investigate, discuss, and understand where the improvement opportunities are. Organizational leaders work with their employees and decide where the attention is needed. After analysis, they identify and implement specific action-oriented strategies within their organization and carry out action plans to completion.

Environmental & Safety Compliance Management Program (ESCMP) – SoCalGas's comprehensive health and safety risk management organization and framework establishes and carries out SoCalGas's health and safety risk management policies, including SoCalGas's ESCMP. ESCMP is an environmental, health and safety management system to plan, set priorities, inspect, educate, train, and monitor the effectiveness of environmental, health and safety activities conceptually based on the internationally accepted standard, ISO 14001. ESCMP addresses compliance requirements, awareness, goals, monitoring and verification related to all applicable environmental, health and safety laws, rules and regulations, and company standards. SoCalGas also has an annual ESCMP Certification process, which involves submittal of information into the database used to collect and record employee and facility compliance. In January of each year, ESCMP information is submitted into an online system for year-end approval and certification for the prior calendar year. ESCMP has been refined, improved and matured over the years and is still in place at SoCalGas.

9. Management Review and Continuous Improvement

As noted above, SoCalGas's management review and continuous improvement efforts begin with the continuous assessment of risks identified through the Enterprise Risk Registry and the operating unit risk registries. The observations and information captured through the ERR are used to develop the strategic risk mitigations. The mitigations are implemented though operating and functional units. The implementation status, results and lessons learned are captured though on-going managerial oversight throughout all layers of management. The results of these oversight efforts are reviewed with the SoCalGas's leadership on a regular basis.

Management Review of Performance – Safety metrics provide a baseline for how well our organization is performing. Tracking both leading and lagging indicators and comparing historical results provides a baseline for continuous improvement and offers the ability to identify improvement opportunities. Common metrics (*e.g.,* Occupational Safety and Health Administration (OSHA) reportables such as Lost Time Injury (LTI), Days Away, Restricted, or Transferred (DART), Controllable Motor Vehicle Incident (CMVI), and Near Miss incident rates) are tracked and analyzed and recommendations for safety performance improvement are made, including training, tools, equipment, processes and procedures.

Continuous Improvement – As described above, management reviews results from a variety of safety metrics, including injuries, motor vehicle accidents, near miss incidents, safety observations, and is actively involved in evaluating risk and developing necessary action plans. Safety goals are set with continuous improvement in mind, by focusing on increasing current goals and developing new leading indicators. The SoCalGas Injury and Illness Prevention Programs (IIPP) describe procedures and responsibilities for incident and injury reporting and the steps involved to conduct an incident evaluation. Employees are required to report all work-related incidents and injuries promptly to their supervisor. The incident evaluation process includes proper notification, visiting the incident scene, interviewing employee(s) and witnesses involved, examining the factors associated with the incident, determining the contributing factors of the incident, developing and implementing corrective actions to prevent reoccurrence and documenting findings and corrective actions using the incident evaluation form (or safety information management system). Through the incident evaluation process, SoCalGas develops and communicates lessons learned from both internal and external incidents and investigations and makes recommendations for safety performance improvement, including changes to training, processes and procedures. This program allows potential hazards to be investigated, mitigated, and communicated. Reporting near misses also reduces risk by promoting a safety culture that establishes opportunities to review safety systems and hazard control and to share lessons learned. SoCalGas has a Close Call (or Near Miss) Reporting portal where employees can report an incident on-line. Additionally, this portal allows for employees to print the form and anonymously submit to their supervisor or the Safety Department. Further discussion on these programs can be found in the Employee Safety Chapter of this RAMP Report (SCG-3).

Records Management – For safety and compliance purposes, SoCalGas has implemented various recordkeeping controls for its system in accordance with applicable rules and regulations. SoCalGas' records management policies include, but are not limited to, processes and systems containing records, definition and identification of records, organizational records (both paper and electronic) and document retention and disposal policy. The goal of records management policies and practices is to provide consistent responsibilities for records management, and to require the assignment of specific accountability for oversight and administration of records management. SoCalGas also has record coordinators across the company. These record coordinators manage records and related issues and are based within each of their respective business areas. The purpose is to give each operational area day-to-day control over records for which it has responsibility and knowledge. While not their primary job function, the record coordinators work closely with Financial Systems to promote and support the Company's records policies and procedures. In effect, this means that the management of operational asset records is decentralized. Sempra Energy's Audit Services group performs periodic audits to verify compliance with policies related to records management and retention. SoCalGas management will address any identified deficiencies by Audit Services and develop management corrective actions to resolve the findings. Historically, these audits have occurred approximately every three years. Lastly, SoCalGas uses physical storage space, both on-site and off-site, for records. SoCalGas manages the records storage so that it complies with SoCalGas' policies related to retention and disposal.

10. Emergency Preparedness and Response

SoCalGas conducts public awareness efforts through education and outreach to enhance the safety of its customers and general public. These efforts are designed to engage with our customers and the public to inform them about our shared safety responsibilities. For example, SoCalGas's Public Safety campaigns focus on informing and educating the public about the danger of digging, planting or doing demolition work that could impact underground pipelines. The outreach campaign focuses on encouraging anyone planning such work to call 811 before digging so that the Company can identify pipelines and pipe material before work occurs. Of equal importance are outreach activities with local first responder agencies, county coordinators (emergency management), and other public officials which occur on a yearly basis, focusing on how we can partner during an emergency incident response, including a review of infrastructure location information, hazard awareness and prevention, leak recognition and response, emergency preparedness and communications, damage prevention and integrity management. In addition, we also partner with these stakeholders throughout the year on joint drills, exercises, tabletops, and preparedness fairs to enhance our coordination and response during emergencies. SoCalGas has also established liaisons with appropriate fire, police, and other public officials across its service territory, which includes over 100 fire agencies. Recently, SoCalGas deployed emergency response services to northern and southern California following weather-related events, and also sent assistance to the Boston area following a pipeline overpressure occurrence.

SoCalGas developed and maintains an Emergency Operations Center (EOC) for use during significant emergencies to allow Company employees to efficiently collaborate and take appropriate action for the response and mitigation of that emergency. During an EOC activation, over 50 subject matter experts may be brought into the EOC, from across the Company, to provide strategic direction, coordination and to facilitate all aspects of the emergency response through event duration. When activated, some basic responsibilities of the EOC include:

- Acquire and allocate critical resources;
- Consistent and aligned internal and external Communications;
- Manage crisis information;
- Strategic and policy-level decision-making; and
- Provide centralized coordination of all aspects of the emergency.

The EOC is the hub from which all incident management, response, and communication is coordinated and/or directed. As such, the EOC serves a critical support function to allow SoCalGas to respond effectively and efficiently to any hazard it may encounter, thereby protecting the safety of its employees, stakeholders, customers, the public, contractors, and any other resources or individuals in its service territory. After Action Reviews (AAR) are core to our Continuous Quality Assurance and Improvement process in Emergency Management.

Following an incident or an emergency, AAR's are developed and facilitated to identify the following:

- What went well;
- What needs improvement; and
- Specific Action Items toward improvement (these are entered into a data base and tracked to completion).

11. Competence, Awareness and Training

SoCalGas' employees and contractors receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. Front-line employees are trained on behavior-based safety program, such as "Stop the Job." A strong safety culture requires the right people at the right job with the right skills. The Human Resources function, with support from various operating organizations and the Safety Management Systems organization at SoCalGas, supports the safety culture by attracting, developing, training, and retaining employees who have the skills and abilities to perform their jobs safely. To achieve the accountability of enhancing the safety culture, the SMS organization, various operating organizations, and the Human Resources function are responsible for performance management, organizational effectiveness and safety. SoCalGas develops training plans by job classification that include courses required to perform certain work, meet company objectives, and satisfy required compliance training. Training plans are maintained in SoCalGas' Learning Management System (cornerstone) and accessed by supervisors and employees through the MyInfo application. Each department is responsible for maintaining training plans and ensuring employees complete initial and periodic refresher training requirements. Further details about SoCalGas' training programs and competence assessment can be found in the Employee Safety Chapter of this RAMP Report (SCG- 2).

IV. COMPENSATION POLICIES RELATED TO SAFETY

SoCalGas' strong safety culture is demonstrated through use of compensation metrics and key performance indicators to drive improved safety performance. As the Commission stated in D.16-06-054:

> One of the leading indicators of a safety culture is whether the governance of a company utilizes any compensation, benefits or incentive to promote safety and hold employees accountable for the company's safety record.[19]

Benefit programs that promote employee health and welfare also contribute to SoCalGas' safety performance and culture.

In her TY 2019 GRC testimony, Compensation and Benefits witness Debbie Robinson explained how SoCalGas' compensation and benefits programs are designed to focus employees on safety, and SoCalGas' increased emphasis on employee and operational safety measures in their variable pay plans, commonly referred to as the Incentive Compensation Plans (ICP), thus bolstering their already strong safety culture and safety performance.[20] Ms. Robinson testified that SoCalGas has increased the weighting of the employee and operational safety measures in their variable pay plans since the TY 2016 GRC, such that safety and operational excellence measures comprised 70% of the Company performance component by the time the TY 2019 GRC was submitted, which is an increase from the 20% reflected in the 2015 ICP plan, which was reflected in TY 2016 GRC.[21] Providing even stronger alignment between SoCalGas' safety programs and the ICP helps to strengthen the Company's safety culture and signals to employees that safety is the number-one priority.

Figure 2, below, taken from Ms. Robinson's TY 2019 GRC Testimony,[22] shows that as of the TY 2019 GRC, the ICP weighting for performance measures related to safety more than tripled since 2015:

---

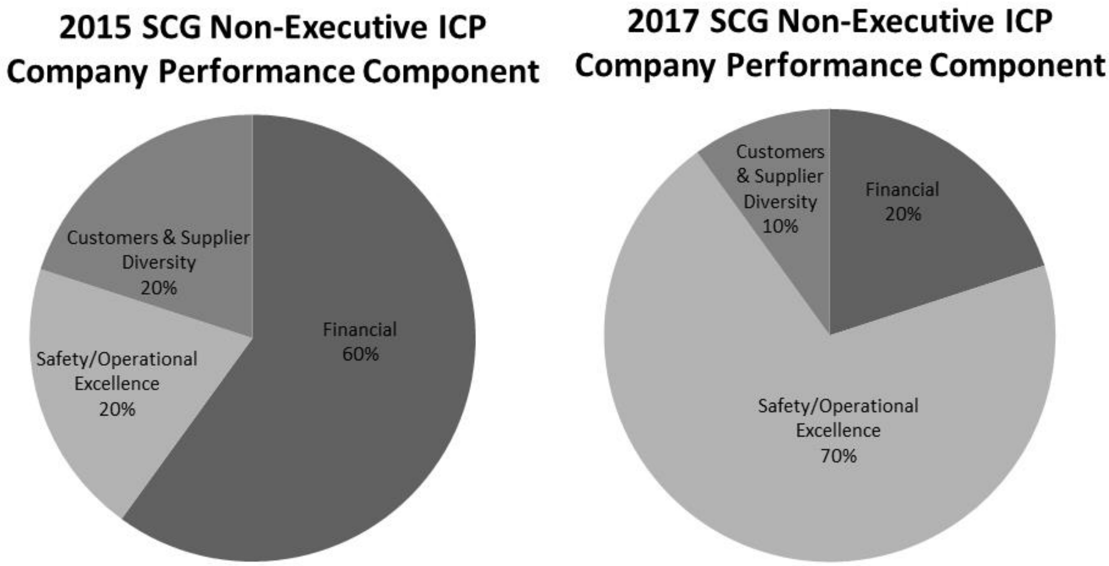
[19] D.16-06-054 at 153.

[20] A.17-10-008, Exh. SCG-30 at DSR-10.

[21] A.17-10-008, Exh. SCG-30 at DSR-11.

[22] A.17-10-008, Exh. SCG-30.

Figure 2: Comparison of ICP Safety Weighting



V. EXECUTIVE AND SENIOR MANAGEMENT ENGAGEMENT IN THE RISK ASSESSMENT, PRIORITIZATION, MITIGATION AND BUDGETING PROCESS

In the Company's TY 2019 GRC testimony, witness Diana Day testified that SoCalGas' executive management, and specifically the Company's Executive Safety Council, is committed to and accountable for the development and maintenance of safety culture, and that SoCalGas' leadership holds regular safety meetings at many levels, including Executive Safety Council meetings, which have been in place for over a decade, and annual Contractor Safety Congress, which have included hundreds of participants, representatives from other California utilities and the Safety and Enforcement Division of the CPUC. SoCalGas' Executive Safety Council, comprised of top company leadership, meets quarterly to engage directly with front-line employees and supervisors, including especially SoCalGas's labor and represented workforce, to listen and reinforce key safety tenets and have an open dialogue on safety issues, performance and culture.

Senior management at SoCalGas is engaged in the risk assessment and mitigation process for the Company. Appendix E to Diana Day's direct TY 2019 GRC testimony describes how SoCalGas' risk management framework and the annual development and updating of the enterprise risk registry provides a structured way for the organization to reflect on different types of risk and the strategies to control or mitigate those risks, as both a “bottom up” and a “top down” process. Subject matter experts and risk managers from throughout the organization provide insight on risk drivers, impacts, and mitigants for risks that are being assessed. Risk owners and the senior management team at each utility then discuss enterprise level risks and mitigants for those risks. Risk owners and risk managers then have the opportunity to confirm that mitigations for top risks are transparent in the business process and are prioritized in decision making.

The Enterprise Risk Registry (ERR) is a communication tool that is shared amongst the management team and with employees. Periodically, the Vice President of Enterprise Risk Management & Compliance provides the SoCalGas Board with a risk update of its operating risks and also an updated focus on key enterprise-level risks and associated mitigants. The Sempra Energy Board of Directors also receives periodic risk updates based on the written reports and management presentations from its operating subsidiaries, including SoCalGas. Training and education regarding management of risks is an ongoing endeavor. Risk topics are discussed at the monthly Senior Management Team meeting and Senior executives continue to be involved in at least three executive risk sessions each year to review top risks identified for the utilities, ranking and prioritization of the risks, and funding for the mitigations.

Senior management at SoCalGas is engaged in the planning process at the Company. The involvement of leadership in the capital planning process was described in the TY 2019 GRC testimony of Patrick Moersen, as follows:

For non-balanced base capital, the Executive Finance Committee (EFC) establishes a total annual capital expenditure target consistent with our authorized GRC funding for that period. From this total allocation, funding is prioritized based on risk-informed priorities and continuous input from operations.

- Step 1 – Initial capital allocations begin with input from Functional Capital Committees (FCCs), which are organized by the nature and type of capital investment or function. These teams of managers and subject matter experts perform a high-level assessment of the capital requirements for serving customers to determine whether infrastructure is maintained and developed to provide safe, reliable service with the highest risk mitigation at the lowest attainable cost. Each FCC elicits broad input for developing each function's capital plan and formulates a prioritized grouping of annual spending requirements.

- Step 2 – The capital requirements identified by the FCCs are provided to the Capital Planning Committee (CPC), a cross-functional team of directors representing each operational area with capital requests. The CPC reviews the FCC submissions, cross-prioritizes projects among the FCCs, and establishes a final ranking for proposed capital work. Projects determined to have the highest ratings on key priority metrics will receive the highest priority for funding. These key priority metrics include: safety, cost effectiveness, reliability, security, environmental, and customer experience.
- Step 3 – The CPC presents its recommendations for capital spending consistent within each functional area and consistent with the overall funding target to the EFC, which reviews the recommendations and either approves the proposed capital funding allocations or requests changes.

Once the capital allocations are approved, the individual operating organization is chartered to manage its respective capital needs within the allotted capital. The real-time prioritization of work within the context of the budget allocations is completed by the front-line and project managers on an ongoing and continuous basis. Regulatory compliance deadlines, customer scheduling requirements, and overall infrastructure condition are all factors taken into consideration as work elements are prioritized. Progress on existing capital projects is monitored and reviewed on a monthly basis by the CPC and EFC, and any new projects stemming from incremental Commission directives or changing business needs are evaluated and assessed throughout the year to determine whether current capital allocation should be reprioritized. Before starting a project or making any commitments, the project manager must secure specific project approval signatures in accordance with the Companies' Internal Order process and approval and commitment policies.

Significant senior management engagement exists, and documented processes are also followed for SoCalGas' Operation and Maintenance (O&M) allocations. SoCalGas' O&M plan is a compendium of over 140 policies that meet the requirements 49 CFR § 192.605 "Procedural manual for operations, maintenance, and emergencies." The O&M plan is reviewed annually to verify that the referenced documents containing policies and procedures remain in compliance with the requirements of the relevant CFR sections. The policies and procedures referenced are updated throughout the year in response to new information or regulations, technology, or other items that drive improvement to the policy. Individual documents referenced by the O&M plan undergo full functional reviews at least every five years. Training programs are reviewed in the same timeframe as associated gas standards, so employees are aware of and perform tasks according to the current requirements.

VI. SOCALGAS BOARD ENGAGEMENT AND OVERSIGHT OVER SAFETY PERFORMANCE

SoCalGas' Board of Directors (Board) determine safety performance measures and targets to be included in each year's ICP and review and approve the results. The Board meets on a quarterly basis where meetings begin with a safety briefing and include a regular review of year-to-date safety performance as well as current safety and risk-related topics. The members of the Board have extensive safety and employee safety processes experience. As a part of their oversight roles, the Board may exercise discretion to reduce or eliminate any payout for employee and/or contractor safety measures in the event of a work-related fatality or serious injury.

In Appendix E to her TY 2019 GRC testimony, witness Diana Day described the Sempra Energy Board of Directors' (Sempra Board) formation of the Environmental, Health, Safety and Technology Committee (the EHS&T Committee), which is responsible for:

- Assisting the board in overseeing the company's programs and performance related to environmental, health, safety, and technology matters;
- Reviewing environmental, health and safety laws, regulations and developments at the global, national, regional and local level and

evaluating ways to address these matters as part of the company's business strategy and operations; and

- Reviewing cybersecurity programs and issues.[23]

When a particular matter or project requires additional attention from the Sempra Board, it may establish, and has established, ad hoc committees. Management reports on significant operations, performance and safety incidents at meetings of the EHS&T Committee and provides updates to the Sempra Board as necessary. Furthermore, the EHS&T Committee Chair reports directly to the Sempra Board on matters reviewed and discussed at committee meetings.

On a monthly basis, SoCalGas also compiles information regarding safe operations, operational performance metrics and safety-related incidents, which is reported to the Sempra Board. Through the EHS&T and these monthly reports, Sempra's Board routinely stays informed on the safety-related business and operations of SoCalGas.

VII. CONCLUSION

Safety is a core value at SoCalGas. We have a strong safety culture imbedded in the organization that fosters transparency, engagement, and commitment. SoCalGas strives to continually improve processes and procedures that further enhance employee, contractor, customer and public safety. Nothing is more important than keeping our employees, contractors and the public safe. As demonstrated throughout the chapters of this RAMP Report, SoCalGas is making strategic investments in culture, technology, system upgrades, and community partnerships to enhance the safety of our employees, contractors, customers, and the communities we serve.

---

[23] The EHS&T Committee charter is available at https://www.sempra.com/investors/governance.

Risk Assessment Mitigation Phase

(RAMP-G)

Lessons Learned

November 27, 2019

SoCalGas
A Sempra Energy utility®

TABLE OF CONTENTS

I. INTRODUCTION

Southern California Gas Company (SoCalGas or Company) puts forth these lessons learned, in accordance with Decision (D.) 16-08-018, which can potentially be incorporated in future Risk Assessment Mitigation Phase (RAMP) Reports, including those of the other California investor-owned utilities (IOUs).[1] The lessons learned herein illustrate improvement opportunities that may be incorporated into future RAMP planning efforts, risk processes, and/or other longer-term goals.

As discussed in Chapter RAMP-A, the Company's 2019 RAMP Report vastly differs from its 2016 RAMP Report, as it implements the methodology and processes adopted in D.18-12-014[2] with the Safety Model Assessment Proceeding (SMAP) Settlement Agreement Decision (SA Decision), including developing and applying a new Multi-Attribute Value Function (MAVF).[3] This 2019 RAMP Report[4] also reflects lessons learned from the Company's 2016 RAMP Report[5] and incorporates certain feedback from the California Public Utilities Commission's (CPUC or Commission) Safety and Enforcement Division (SED), and the RAMP filings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). While the 2019 RAMP Report represents a prudent step forward in implementing a quantitative risk management framework, the Company is committed to continuously improving

---

[1] D.16-08-018 at 151. "Lessons learned by one company will also inform the RAMP filings of the other companies."

[2] D.18-12-014 contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[3] The MAVF is discussed further in Chapter RAMP-C.

[4] This 2019 RAMP Report will be incorporated into SoCalGas' Test Year (TY) 2022 General Rate Case (GRC).

[5] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation, Investigation (I.) 16-10-015/-016 (cons.) (November 30, 2016).

by incorporating best practices and lessons learned, and to collaborating and sharing knowledge with the Commission, IOUs, and other stakeholders.

II. OVERALL LESSONS LEARNED FROM THE 2016 RAMP REPORT

The Company's 2019 RAMP Report improves upon its 2016 RAMP Report by, among other things, implementing feedback provided in SED's Risk Assessment and Safety Advisory Report (SED RAMP Safety Advisory Report).[6] Improvements include reviewing and developing some risk definitions, providing more detail on how programs correlate to the stated risk, advancing probabilistic and quantitative approaches to risk management (including alternatives), more closely aligning the identification of costs with the Company's General Rate Case (GRC) presentation, and producing workpapers concurrently with the RAMP Report.

A. Modification of Risks

The Company received feedback on its 2016 RAMP Report that its Employee, Contractor, Customer, and Public Safety risk was overly broad.[7] In response, the Company has separated these into three distinct risks: Employee Safety (Chapters SCG-2 and SDG&E-3), Contractor Safety (Chapters SCG-3 and SDG&E-2), and Customer and Public Safety (Chapters SCG-4 and SDG&E-5). The Company found other risks which, if broken up, could be more effective risk assessment and alignment of mitigations. For example, in the 2016 RAMP Report, Third Party Dig-in was an individual risk chapter for both SoCalGas and SDG&E. In this 2019 RAMP Report, the risk of incidents resulting from a Third Party Dig-in has been further refined into two separate risk chapters, a Third Party Dig-in on a High Pressure Pipeline chapter and a Third Party Dig-in on a Medium Pressure chapter for each Company, for additional granularity and mitigations that are more specific to the type of pipeline. The decision to separate these risks was driven by the fact that there are vast differences in the quantity of the two asset classes, the

---

[6] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016 (SED RAMP Safety Advisory Report) (March 8, 2017).

[7] SED RAMP Safety Advisory Report at 41; I.16-10-015/I.16-10-016; Opening Comments of the Office of Safety Advocate (OSA) (April 17, 2017) at 6.

volume of tickets impacting each class, the damages to each class, the potential consequences of each risk, some risk drivers, and while a majority of the Controls and Mitigations are common, there are some that are different.

Given that risks are dynamic and revisited at a minimum annually, risks may be modified as necessary with some being separated for additional granularity and others being combined. For additional examples, please refer to the Appendix B-1.

B. Correlation of Controls and Mitigation to Risk

The SED RAMP Safety Advisory Report commented that "for several mitigations, there needs to be more effort in showing the correlation between the risk and the mitigations proposed."[8] To respond to this critique, the Company provides in this 2019 RAMP Report a detailed description of the Control or Mitigation in Section V of the respective risk chapters, as well as additional explanation in Section VI of how the Control or Mitigation impacts the risk (*see* Sections VI(a) and (b) of individual risk chapters).

C. Quantitative Framework

Generally, concerns were raised in the 2016 RAMP proceeding with respect to the Company's heavy reliance on subject matter expertise to determine risk reduction,[9] and, because of that reliance, the usefulness of Risk Spend Efficiency (RSEs).[10] While SED stated that RSEs are "admittedly an evolving area," SED has indicated a preference for "quantified data."[11] SED also recommended that "in the future" the Company "need[s] to do a better job clarifying and

---

8 SED RAMP Safety Advisory Report at 6.

9 *Id.* at 14.

10 I.16-10-015/I.16-10-016. *See* Reply Comments of SDG&E and SoCalGas (May 9, 2017) at 5-6; Opening Comments of the Office of Safety Advocate (April 17, 2017) at 13; Comments of the Indicated Shippers and Southern California Generation Coalition (April 24, 2017) at 3; Opening Comments of the Coalition of California Utility Employees (April 17, 2017) at 4; Comments of the Utility Consumers' Action Network (April 24, 2017) at 14; and Comments of the Office of Ratepayer Advocates (April 24, 2017) at 2-3, 26.

11 SED RAMP Safety Advisory Report at 18.

ranking the risk mitigations that are measured by the RSE and at the same time do a better job identifying metrics that correlate with the performance of the respective risk mitigation."[12]

Similarly, in the TY 2019 GRC, the California Public Advocates Office (CalPA)[13] recommended that the Companies "focus on quantitativeness and comparability"[14] for future RAMP filings. CalPA cautioned the Companies about the continued use of the 7x7 matrix, stating that it was "largely based on subjective judgement and does not provide [a] quantifiable, clear, and appropriate way of measuring and comparing risks."[15] Therefore, CalPA recommended that the 7x7 be phased out by the next RAMP filing.[16] Via discovery, CalPA asked the Company when it anticipated it could implement some of CalPA's recommendations, such as the following: comparing RSE scores across risks; reducing groupings of mitigations for purposes of calculating RSEs; calculating RSEs for alternatives; including the timeframe over which risks/mitigations are measured; producing complete, unlocked RAMP workpapers at the time of RAMP submission; reporting of added, removed, or changed risks since the last RAMP filing; and identifying of subject matter expert (SME) input used and any supporting metrics/data.[17] The Company noted in response that "many of the recommendations are anticipated to be included in the next RAMP."[18]

The SA Decision and the methodologies therein create a process that makes considerable strides toward a more quantitative risk approach compared to the Company's 2016 RAMP Report. In particular, the 7x7 matrix was not used for determining the pre-mitigation or post-

---

12 *Id.* at 6.

13 Formerly the Office of Ratepayer Advocates (ORA).

14 A.17-10-007/-008 (cons.). Exhibit (Ex.) 398 (ORA/Stannik Direct Testimony) at 11.

15 A.17-10-007/-008 (cons.). Ex. 398 (ORA/Stannik Direct Testimony) at 5.

16 *Id.* at 1 and 5.

17 *Id.* at 10-11 and footnote 20.

18 *Id.* at 10 and 11.

mitigation risk scores in this 2019 RAMP Report. Instead, the Company implemented the methods from the SA Decision, including statistical distributions and Monte Carlo simulations to help quantify risk events. Further, the Company has also leveraged quantifiable data where such data existed, whether its own or from a third-party, and verified the appropriateness of the results with its subject matter experts. Where no data existed or was incomplete, subject matter expertise was necessary. However, the SA Decision acknowledges the fact that subject matter expertise has value and plays a role in risk analysis,[19] and eliminating it entirely would hurt the value and accuracy of the quantitative analysis. With more reliable, quantitative data, the comparability of RSEs across risks has increased. As shown in Appendix D-1 and as required by the SA Decision,[20] the Company is providing a ranking of all programs by RSE, effectively comparing programs across risks.

Moreover, the Company has progressed in this RAMP Report on all the items noted by CalPA in the GRC. When performing RSEs, the Company made a concerted effort to calculate RSEs for each program and grouped or "bundled" activities, only when needed. For example, many of the activities in the Wildfire risk chapter provide SDG&E with more knowledge of its systems or local conditions – for example, situational awareness tools and inspections. These activities alone may not reduce the risk in a quantifiable manner. In order to quantify the risk reduction benefits, such activities need to be grouped with others. It is the Company's intention to minimize grouping activities together for purposes of calculating an RSE.

Additional information is included in the workpapers accompanying this RAMP Report. Information regarding the length of time used for measurement of program risk reduction benefits is provided in the risk chapters' RSE-related workpapers. Identification of data sources used for purposes of risk quantification are also provided in the RSE-related workpapers, as well as in Section IV and in the individual risk chapters. Changes to risks since the last Company's

---

19 D.18-12-014 at Attachment A, A-8-A-9 (Identification of Potential Consequences of Risk Event and Identification of the Frequency of the Risk Event).

20 D.18-12-014 at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

2016 RAMP filing is provided in Appendix B-1. Improvements related to alternatives, workpapers, and data collection are further discussed below.

D. Alternative Analysis

The SED RAMP Safety Advisory Report offered the feedback that, although the Company met the CPUC requirements related to providing alternatives in its last RAMP Report, an expanded discussion of alternative mitigations should include estimates of risk reduction and RSE.[21] Given this feedback, the Company is presenting more information in this 2019 RAMP Report regarding its alternative analysis. In Section VIII of the respective risk chapters, the Company puts forth, at a minimum, two alternatives. Section VII of each risk chapter describes the alternative and why it will not be pursued as well as the costs, risk reduction, and RSE. For these identified alternatives, the Company endeavored to provide new ideas and programs rather than relying on changing the pace and/or scope of the Risk Mitigation Plans. This exercise was challenging at times, for several reasons; for example, in instances where most or all mitigations and controls are mandated in a prescriptive manner, or where the Company already has an expansive or longstanding set of controls and/or mitigations.

E. Costs Presentation

Determination of costs presented in this 2019 RAMP Report was highly influenced through lessons learned from the Company's 2016 RAMP Report, its TY 2019 GRC, and its overall configuration of internal accounting and tracking systems.

Generally, the Company records operations and maintenance (O&M) costs in cost centers and capital expenditures on a budget code basis. This method is not mitigation-focused, but rather is organization-based for O&M and total project-based for capital. The Company presents its GRCs consistent with this approach. Internal labor costs are recorded in this manner and, for the most part, are not tied specifically to mitigation activities. Accordingly, additional granularity is largely unavailable without making a series of assumptions. Therefore, to identify

---

21 SED RAMP Safety Advisory Report at 6.

costs for certain RAMP controls related to employee time and associated labor costs, many assumptions are required.

For example, in the 2016 RAMP Report, the Company estimated labor-related costs for controls.[22] To do so, the Company gathered information related to how many employees took a given training class and multiplied that by the duration of the class and an average labor rate. This estimation method was used because the exact costs are not available in this manner in the Company's accounting systems. However, using this approach became problematic when the Company integrated this assumption-based forecast into the GRC, because the Company then had to similarly estimate the costs in a given cost center or workpaper (a group of one or more cost centers), associated with the internal labor activity.

Based on the foregoing, the Company took a different approach for this RAMP Report. As discussed in Chapter RAMP-A, internal labor for these certain controls (*e.g.*, internal labor to attend training, adhering to internal protocols or standards, internal time spent at meetings, etc.) is generally excluded from the baseline and forecasted cost estimates for Controls and Mitigations in the 2019 RAMP Report. While costs are not identified herein, the activities are discussed since they are associated with mitigating the RAMP risk.

Further, costs presented here are those the Company expects to include in its TY 2022 GRC application, as compared with the 2016 RAMP Report. Costs requested and recovered through regulatory means outside of the GRC, such as separate applications or from the Federal Energy Regulatory Commission (FERC), are generally not identified in the 2019 RAMP Report. While the Company discusses activities that mitigate the risk in an effort to provide a complete risk mitigation plan herein, associated costs for these non-GRC costs are not included herein.

Another lesson learned from its prior RAMP filing is the need to attempt to show activities and corresponding cost forecasts in this 2019 RAMP Report, either within a single risk

---

[22] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation, Lessons Learned (RAMP-F) I.16-10-015 and I.16-10-016 (November 30, 2016) at 2-3.

chapter and/or allocated between risks.[23] In the 2016 RAMP filing, the Company did not attempt to split or apportion the costs of an activity to each risk. Rather, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters.

While the costs may reside within the risk chapter of primary benefit in this RAMP Report, other risk chapters may qualitatively discuss how the activity affects the risk in the chapter receiving the indirect benefit. Alternatively, for some activities, an allocation was determined and the applicable risk chapters each took a portion of the activity and associated cost. For purpose of moving towards probabilistic RSE calculations, the Company aimed to present costs in a single instance, even though these activities may provide risk mitigation benefits to multiple risks. That said, the Company did include activities and costs on a limited basis in a few risk chapters where the costs could not be attributed to simply one risk. An example includes the Company's safe driving program, which mitigates both the risks of Employee Safety and Customer and Public Safety. It should be noted that although activities and costs may be included in multiple risk chapters, they will only be included once in the GRC. All these cost-related changes between the Company's 2016 RAMP Report and the 2019 RAMP Report are to improve upon prior showing as well as to better align with the presentation of the Company's GRC.

F. Workpapers

SED recommended that in the future "all utilities provide similar information in workpapers as part of their RAMP filings,"[24] and that technical documentation of risk modeling should be provided.[25] The Company followed SED's recommendations and is submitting workpapers for costs and modeling for RSEs concurrently with this RAMP Report. Further, the

---

23 *Id.* at 3-4.

24 SED RAMP Safety Advisory Report at 5.

25 I.16-10-015/-016 (cons.). Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company (March 15, 2017) at 20.

Company reviewed the workpapers of SCE and followed a similar format for purposes of consistency and ease of review by the Commission and intervenors.

III. LESSONS LEARNED FROM SED'S FEEDBACK ON OTHER IOU RAMP REPORTS

The RAMP Reports of PG&E and SCE further improved upon the Company's first RAMP Report. Both PG&E and SCE provided quantitative models and new value-added aspects. PG&E and SCE utilized the common risk terms of "Controls" and "Mitigations" and made certain determinations based on those distinctions, for purposes of calculating RSEs. PG&E limited their RSE calculations to Mitigations, rather than also including Controls.[26] SCE performed RSE calculations on non-compliance[27] Controls and Mitigations.

SED's evaluation reports on PG&E's and SCE's RAMP Reports provided information that the Company used to inform aspects of this 2019 RAMP Report. With respect to PG&E, SED "strongly recommend[ed] that PG&E provide MARS [Multi-Attribute Risk Scores] and RSE for all controls on the same basis developed for mitigations for their future RAMP filings"[28] and expressed concerns with PG&E's approach to cross-cutting risk modeling, stating "the cross-cutting model [should be] reviewed within the S-MAP."[29] SED also concluded that PG&E's risk "evolution [] brought additional complexity…[with] refined attempts to illustrate how the components of the analysis fit together."[30] For SCE's RAMP, SED was concerned that SCE

---

26 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (PG&E's RAMP Report) (November 30, 2017) at A-6.

27 SCE defined "compliance" as "currently established measure that is modifying or reducing risks, which is required by law or regulation." SCE Workshop Presentation (December 14, 2018) at 10.

28 California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003 (March 30, 2018) at 4.

29 *Id.* at 133.

30 *Id.* at 3.

submitted two different conflicting proposals in the WMP [Wildfire Mitigation Plan] and RAMP filings.[31]

Based on SED's feedback towards PG&E's and SCE's approaches to calculating RSEs, the Company attempted to perform RSEs on individual programs, regardless of whether they were controls, mitigations, and whether they were mandated or not. However, establishing an appropriate methodology for longstanding mandated activities posed challenges, in many cases. Therefore, the Company performed RSEs on Mitigations, non-mandated Controls, and mandated Controls, where practical. The Company also provides several chapters in this RAMP Report (Chapters RAMP-C, RAMP-D, and RAMP-E) related to RSEs, their underlying assumptions, and an evaluation of RSEs at this stage. These chapters are provided in an effort to clearly explain the determinations on conducting RSEs.

SDG&E also attempted to address the feedback SCE received on its WMP. SDG&E filed its first Wildfire Mitigation Plan in February 2019. In the Wildfire risk chapter in SDG&E's RAMP Report (Chapter SDG&E-1), SDG&E transparently noted if activities therein were also included in SDG&E's 2019 WMP. Further, there have been considerable developments from a regulatory perspective regarding general wildfire risk. For example, the CPUC has initiated several wildfire-related proceedings including but not limited to Rulemaking (R.) 18-10-007 (WMP OIR), R.18-12-005 (De-Energization OIR), and R.19-07-017 (Wildfire Fund OIR). Given the level of activity and potential impacts from other regulatory proceedings, considerable coordination is necessary. It remains unclear as to how these coordinated efforts will be addressed. For example, SDG&E is submitting its RAMP Wildfire chapter in November 2019 and will likely be filing its second WMP in early 2020. However, it is also highly likely that SDG&E will not receive feedback from the CPUC's SED on the Wildfire Risk Mitigation Plan presented herein until after the next WMP is submitted. While these issues with overlap

---

[31] California Public Utilities Commission, Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001 (January 31, 2017) at 8.

and timing may decrease over time, heavy coordination is needed and takes a considerable effort to confirm alignment.

IV. LESSONS LEARNED THROUGHOUT THE COURSE OF PREPARING THE TY 2022 RAMP REPORT

Through the course of preparing this RAMP Report, the Company identified additional lessons learned for future RAMP submissions. Although many of these must be addressed as longer-term goals, the Company is beginning to plan for such efforts.

A. Scoping of Risks

The Company's risk evaluation and registry process, facilitated by the Enterprise Risk Management organization, continues to evolve. Throughout the RAMP process and as discussed in the workshop held on March 5, 2019, pursuant to the SA Decision (Pre-RAMP Workshop),[32] the scoping and definitions applied in each risk are the foundation for determining how to conduct the required safety, reliability, and financial assessments. Although the Company annually reevaluates its risks through its Enterprise Risk Management process, it also recognizes room for continuous improvement. Accordingly, the Company has reviewed its risks to clarify the scope of each risk for analysis in the RAMP Report, after the Pre-RAMP Workshop. Based on the data used to determine the pre-mitigation risk score, the risk scope for purposes of the RAMP Report may have been refined, as necessary. This is further discussed in Chapter RAMP-C. Going forward, the Company will determine how best to address aligning availability of data and the scoping of the risks in the Enterprise Risk Register (ERR).

B. MAVF

The Company's approach to developing a multi-attribute value function (MAVF) for purposes of RAMP Report analysis is described in Chapter RAMP-C. The Company found it challenging to develop a MAVF, within the requirements of the SA Decision, that is useful for analyzing every activity it performs. Conceptually, a MAVF should be designed to apply to everything from assessing a new billing system, to hydrotesting, to facilities upgrades, to hiring

---

32 D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP).

more staff. In reality, this is a substantial and complex undertaking. And, the Company had a limited time to develop, test, and implement a MAVF for purposes of this filing. Accordingly, the Company adhered to the minimum top-level attributes of Safety, Reliability, and Financial in this RAMP Report.[33] However, the Company will continue to learn from experience and refine its MAVF over time.

It may be possible in the future to add complexity to the Safety attribute, perhaps by considering additional lower-level attributes such as illness, lost time of employment, or mental health. Additionally, the Company is aware that some organizations differentiate between safety incidents in some manner, such as incidents that impact employees versus those that impact the general public. The Company did not feel that a consensus was reached on how to differentiate between safety incidents. Future regulatory proceedings and RAMP Reports, including those from other utilities, may help with progress in this area.

In addition to the attributes presenting challenges, determining scaled units and the relative importance for the MAVF was also difficult. There are available studies that help guide decision-making on the relative importance between certain attributes. For example, as described in Chapter RAMP-C, studies exist that evaluate electric reliability in terms of dollars, the financial attribute. However, doing so would require a determination between reliability, financial, and safety attributes, consistent with the MAVF principles in the SA Decision. A range of potential scaled units were therefore determined for the Safety attribute, demonstrating the Company's belief that there is not one right answer to these questions. Rather, there is a range of potential possibilities that the Company should consider to inform its risk mitigation assessments. The Company believes that direction from the Commission on appropriate weights and scales for presenting risks in the RAMP Report could be helpful in future RAMP filings. The range of scaled units for the Safety attribute is discussed in greater detail in Chapter RAMP-C.

---

[33] *Id.*

C. Tranches

This is the first RAMP Report to include the concept of tranching. While the Company understood and could identify different risk profiles among its activities, costs were largely not available in that manner. For example, for the risk of a Third Party Dig-in on a High Pressure Pipeline (Chapters SCG-7 and SDG&E-9), mitigations such as the Public Awareness Compliance could potentially have been tranched by geographical areas or demographics.

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing risk of injuries or fatalities to the public, employees, and contractors. Given the vast number of activities SoCalGas performs to mitigate the Third Party Dig-in on a Medium Pressure Pipeline risk, SoCalGas grouped like activities with like risk profiles into mitigation programs. The Company tracks costs for these activities consistent with Title 49 CFR § 192.616, which identifies the following four groups: the affected public, emergency officials, local public officials, and excavators. In order to have identified costs at the tranches for geographical area or demographics, considerable assumptions would have been required; thus, the Company elected to tranche based on the four categories outlined in the code, which are representative of homogeneous risk profiles within this activity. The Company will evaluate how to improve upon this in the future.

D. Data Collection

The Commission identified the need for RAMP filings to include information regarding steps to "improve the collection of data and provide a timeframe for improvement" for business areas with less data, so that "the utilities can position themselves to make major improvements in risk assessment" for later S-MAP filings.[34] Quantitative risk analysis relies heavily on data. Therefore, the ability to locate and use meaningful data will always be in consideration. Although many data sources are available for a wide array of uses, it is common to find data that is not precisely of the type that is desired or needed at a particular point. The Company strives to add new data sources as needs arise and attempts to look ahead to what kind of data will be

[34] D.16-08-018 at 146. *See also* Conclusions of Law (COL) at 38.

needed in the future. Throughout the creation of this RAMP Report, several instances arose where data was either unavailable or incomplete. Therefore, the Company used a combination of its own data and national data in this RAMP Report. When national or external data was used, the Company attempted to apply company-specific characteristics and supplemented it with subject matter expertise, consistent with the SA Decision,[35] as explained in Chapter RAMP-A. Although national data was scaled to the characteristics of the Company's system or service territory, the Company will look for ways to further customize the use of national data, going forward.

Where data or metrics do not exist to track the performance of the activities presented in this RAMP Report, the Company seeks to develop such metrics for future applicability. For the Third-Party Dig-ins risk, for example, the Company is examining whether its existing data collection systems allow for the tracking of a more granular locate and mark process, to enable more precise identification of root causes and provide a better understanding of process improvements that may be necessary.

The Company believes this data is needed to evaluate the program's effectiveness as well as to meet future CPUC reporting requirements. To that end, the Commission and stakeholders have taken several steps to increase transparency and the availability of information. Specifically, the Commission instituted the Safety Performance Metrics Report[36] and the Risk Spending Accountability Report[37] requirements. Both of these reports are due annually on March 31, going forward. The Safety Performance Metrics Report will provide "26 safety performance metrics to measure achieved safety improvements."[38] This report will also summarize "how reported data reflect[s] progress against the risk mitigation and management

[35] *Id.* at Attachment A, A-8 – A-9 (Identification of Potential Consequences of Risk Event, Identification of the Frequency of the Risk Event).

[36] *See* D.19-04-020.

[37] D.14-12-125 (as modified by D.19-04-020).

[38] D.19-04-020 at 2.

goals approved in the applicable Risk Assessment Mitigation Phase filing and General Rate Case (GRC) application and to identify and provide additional information for any metrics that may be linked to financial incentives."[39] As part of the efforts related to the Safety Performance Metrics Report, the Company is reviewing available data and is actively participating in the S-MAP Metrics Technical Working Group to refine and develop metrics. Regarding the Risk Spending Accountability Report, the report was established in D.14-12-025 to "improve utility accountability of ratepayer money spent on risk mitigation."[40] In D.19-04-020, the Commission added the requirement to report on work units as part of the Risk Spending Accountability Report.[41] With the requirement of work units, the Company will provide more data in future GRCs and Risk Spending Accountability Reports.

E. Secondary Impacts

As discussed in Chapter RAMP-A, for this RAMP Report, the Company generally excluded secondary impacts from its risk quantification assessments. Secondary impacts are "downstream" of the initial risk event. These impacts are challenging to quantify, as there are data limitations and overlaps between multiple risks. The Company will continue collaborating with stakeholders to continue to refine processes and develop improved methodologies for capturing data to support quantifying secondary impacts.

The Office of Safety Advocates (OSA) provided feedback that it would like to see Electric Grid Failure and Restoration (Blackout/Failure to Black Start) included in this RAMP Report. Electric Grid Failure and Restoration is the risk of a blackout or the loss of electric service throughout the SDG&E service territory and the inability to restore electric services. While the Electric Grid Failure and Restoration risk was included in SDG&E's 2018 annual risk registry assessment cycle, it was not selected as a RAMP risk for two reasons. First, OSA's feedback was provided several months after the Company had presented its proposed risks at a

---

39 *Id.*

40 *See* D.14-12-025.

41 D.19-04-020 at 36, 38-39, Findings of Fact 27 and 28, COL 15, and Ordering Paragraphs 10 and 11.

public workshop and consequently had made the determination of what risks to include in RAMP. There was not adequate time to conduct the extensive RAMP analysis adopted in the SA Decision. Second, the safety elements of this risk are largely related to secondary impacts. For example, a prolonged outage could be attributed to an extended Public Safety Power Shutoff event. In that scenario, the primary reason for the outage was to minimize the likelihood of a wildfire event. The secondary impact was the prolonged outage for customers.

F. Risk Reduction and RSEs

Estimating risk reduction generally presents various challenges, which also are present in calculating RSEs. These challenges are further discussed in Chapter RAMP-E. A methodology to estimate risk reduction was determined based on available data. This required the Company to evaluate risk reduction and RSEs on a case-by-case basis. The methodology required understanding how the activity impacted the risk and the effectiveness of a certain program. When data was available, less subjectivity was applied. Nevertheless, subject matter expertise is required to derive estimates for risk reduction benefits. Amongst the challenges, assessments of human-based activities, such as training and communicating with the public, were particularly difficult to estimate. As experienced by PG&E in its 2017 RAMP Report (described above), the Company has not identified a precise method of predicting future benefits for human-based activities. It is difficult to estimate how effective training is, because it is frequently difficult to ascertain if one or more risk events were caused by, or prevented due to, training. In some cases, the impact is clear; but in the majority of cases, the conclusions are largely speculative. It is also not easy to surmise the duration for which training is considered effective.

As stated in the Data Collection section above, most RSE calculations required an extensive evaluation of company data. In many cases, the data necessary to support RSE calculations with a high level of confidence was often unavailable (*i.e.*, data was not currently collected) and/or difficult to find and obtain. This process required a high level of involvement of entire teams of individuals from across the organization, which was the case among all the risk chapters. As a result of these considerations, the RSE process was lengthier than initially predicted. This process, however, has identified opportunities for the Company to improve data collection and aggregation, which will support better business operations and make data readily available for future RAMP filings.

Risk Assessment Mitigation Phase

(Chapter SCG-1)

Medium Pressure Gas Pipeline Incident

(Excluding Dig-in)

November 27, 2019

TABLE OF CONTENTS

Risk: Medium Pressure Gas Pipeline Incident

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas or Company) Medium Pressure Gas Pipeline Incident risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in the 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (SMAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout the 2019 RAMP Report, activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Medium Pressure Gas Pipeline Incident risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code (PUC) statute, or General Order (GO). Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated

---

[3] *Id.* at 16.

[4] *Id.* at 17.

costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

SoCalGas and San Diego Gas & Electric Company (SDG&E), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' gas pipeline incident related chapters.[5]

A. Risk Definition

For purposes of this RAMP Report, the Medium Pressure Gas Pipeline Incident risk is the risk of damage, caused by a medium pressure pipeline[6] event, which results in serious injuries or fatalities. This risk concerns a gas public safety event on a medium-pressure distribution plastic or steel pipeline and/or its appurtenances (e.g., valves, meters, regulators, risers).

---

[5] The other gas pipeline incident related chapters in the 2019 RAMP Report include: SCG-5 – High Pressure Gas Pipeline Incident; SDG&E-6 – Medium Pressure Gas Pipeline Incident; and SDG&E-8 – High Pressure Gas Pipeline Incident.

[6] Maximum Allowable Operating Pressure (MAOP) at or lower than 60 psig.

B. **Summary of Elements of the Risk Bow Tie**

Pursuant to the SA Decision,[7] for each control and mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger & Potential Consequence
DT.1	Corrosion
DT.2	Natural forces (natural disasters, fires, earthquakes)
DT.3	Other outside force damage (excluding dig-in)
DT.4	Pipe, weld, or joint failure
DT.5	Equipment failure
DT.6	Incorrect operations
DT.7	Incorrect/inadequate asset records
PC.1	Serious injuries and/or fatalities
PC.2	Property damage
PC.3	Adverse litigation
PC.4	Penalties and Fines
PC.5	Erosion of public confidence

C. **Summary of Risk Mitigation Plan**

Pursuant to the SA Decision,[8] SoCalGas has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP, as further

[7] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

[8] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

described below. SoCalGas' baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-1-C1	Cathodic Protection (CP)
SCG-1-C2	Valve Inspections and Maintenance
SCG-1-C3	Meter and Regulator (M&R) Maintenance
SCG-1-C4	Meter Set Assembly (MSA) Inspection and Maintenance
SCG-1-C5	Pipeline Patrol
SCG-1-C6	Gas Infrastructure Protection Project (GIPP)
SCG-1-C7-T1	DREAMS: Vintage Integrity Plastic Plan (VIPP)
SCG-1-C7-T2	DREAMS: Bare Steel Replacement Program (BSRP)
SCG-1-C8	Sewer Lateral Inspection Project (SLIP)
SCG-1-C9	Distribution Riser Inspection Project (DRIP)
SCG-1-C10	Distribution Operations Control Center (DOCC)
SCG-1-C11	Leak Survey
SCG-1-C12	Bridge & Span Inspections
SCG-1-C13	Unstable Earth Inspection

The drivers/triggers identified for the Medium Pressure Gas Pipeline Incident risk are addressed through the 2018 baseline controls listed in the above table, and SoCalGas will continue said controls. Although SoCalGas has considered alternatives to these controls, no new mitigations are projected to be implemented. However, additional activities are being forecasted within the existing controls for Cathodic Protection and Regulator Stations, and SoCalGas is also forecasting to increase annual activity levels within existing controls.

Finally, pursuant to the SA Decision,[9] SoCalGas presents in Section VIII considered alternatives to the described mitigation plan for this risk and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VII.

II. RISK OVERVIEW

Typically, medium-pressure distribution systems use a series of mains (pipes with larger diameter) to feed service lines, regulator stations, meters, and other appurtenance piping. Service lines are smaller diameter pipes which feed customer homes, businesses, and some commercial applications. Medium-pressure pipelines are made of steel or plastic material.

For safety and compliance, Title 49 of the Code of Federal Regulations (CFR) 192, General Order (GO) 58, and GO 112 are the leading sources of requirements for SoCalGas' medium-pressure pipelines (among other legal and regulatory provisions). 49 CFR 192 prescribes safety requirements for pipeline facilities and the transportation of gas at the federal level. GO 112 and GO 58 complement and enhance the requirements of 49 CFR 192 at a state level.

SoCalGas currently operates over 47,000 miles of medium pressure mains with over 22,000 miles being steel and approximately 25,000 made of plastic. These medium-pressure pipelines serve over 21.8 million SoCalGas consumers.

Table 3: Medium-Pressure Pipelines

Medium Pressure Pipelines	SoCalGas Mains	SoCalGas Services
Miles of Steel	22,785	31,694
Miles of Plastic	24,886	18,604
Total Miles Medium Pressure Pipelines	47,671	50,298

[9] *Id.* at 34.

Various causes and events can lead to medium pressure pipeline incidents. Drivers can range from natural forces (such as natural disasters, fires, earthquakes.), improper installation techniques, material defects, aging/environmental factors such as corrosion and material fatigue, improper operations, and inadequate maintenance of the pipeline infrastructure. For the purposes of this chapter, the Medium-Pressure Pipeline Incident risk focuses on risk events that result in serious injuries or fatalities.

SoCalGas notes that when the loss of gas cannot be resolved by lubing, tightening or adjusting, it is defined as a "leak." A leak in and of itself may cause little-to-no risk of serious injury or fatality. Risk to the public and employees can increase when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate into a confined space. The safety concern of the leak is addressed by SoCalGas' leak indication prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in American Society of Mechanical Engineering (ASME) B31.8S.[10]

Additionally, although not included in this RAMP filing, SoCalGas is currently in the very preliminary stages of organizing and modeling a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association (CEPA) and the Pipeline Research Council International (PRCI). The FIMP is not intended to duplicate any systems, processes, or information that may already exist, but rather to supplement the already existing programs to enhance the safety and integrity of the integrated gas pipeline

---

10 American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. AMSE B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes.

system.[11] FIMP will be a documented program, specific to the facilities portion of a pipeline system,[12] that identifies the practices used by the operator for purposes of "safe, environmentally responsible, and reliable service."[13] While SoCalGas is currently in the preliminary stages of organizing and modeling a FIMP approach based on the principles of CEPA, FIMP is anticipated to be included in the next GRC. Although this concept of an overarching program is still maturing in the industry, SoCalGas' intention of a FIMP is to better identify and reduce risks of facility assets, extend the life of assets, and achieve operational excellence, in alignment with both the principles of RAMP and the Company's existing Transmission, Distribution, and Storage Integrity Management Programs (TIMP, DIMP, and SIMP, respectively).[14] Consistent with the SA Decision, a supplemental analysis will be conducted in the GRC for FIMP if it ultimately meets the criteria for inclusion in that proceeding.

III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Medium Pressure Gas Pipeline Incident risk.

---

11 SoCalGas notes that there are certain facilities management systems and processes in place, for example Pipeline Research Council International (PRCI) – Facility Integrity Management Program (FIMP) Guidelines – PRCI IM-2-1 Contract PR-186-113718.

12 "Pipeline system" is defined by Pipeline Research Council International (PRCI) - Facility Integrity Management Program (FIMP) Guidelines – PRCI IM-2-1 Contract PR-186-113718 as "*Pipeline System is comprised of pipelines, stations, and other facilities required for the measurement, processing, gathering, transportations, and distribution of oil or gas industry fluids*."

13 Canadian Energy Pipeline Association (CEPA), Facilities Integrity Management Program, Recommended Practice, 1st Edition (May 2013) at 7-8.

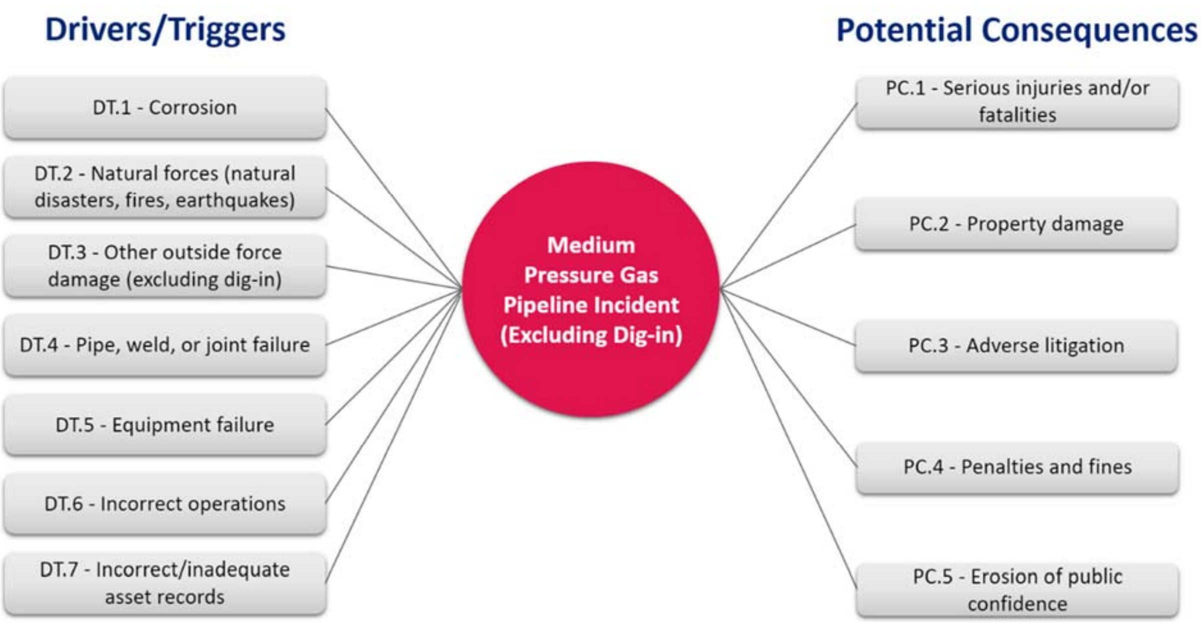
14 Based on industry definitions, there are a variety of types of facilities; facilities are highly complex; a variety of equipment/asset types exist within facilities; and in this context facilities are not considered building structures.

15 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[16] directs the utilities to endeavor to identify all asset groups or systems subject to the risk.

16 D.18-12-014, Attachment A, Item No. 14 ("Definition of Risk Events and Tranches").

The Natural Gas Pipeline Distribution System consists of SoCalGas' medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and its appurtenances (e.g., meters, regulators, risers). As discussed in RAMP-G, the tracking of costs by SoCalGas is not logically disaggregated by high/medium pressure, and therefore costs with some controls for high pressure assets are captured within this chapter.

SoCalGas' Medium Pressure Gas Pipeline Incident risk impacts all of SoCalGas' natural gas infrastructure and assets in the medium pressure pipeline system. The medium pressure pipeline system is comprised of approximately 100,000 miles of plastic and steel pipelines and its appurtenances (e.g., valves, meters, regulators, risers) operating at or less than 60 psig.[17] The large size of the system means a high volume of related appurtenances for example the system includes more than 5 million meters and approximately 2,000 regulator stations to distribute and regulate pressure.

C. Risk Event Associated with the Risk

The SA Decision[18] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[19]

The SA Decision[20] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for High Pressure Gas

---

[17] Due to cost tracking limitations, the cost reflects a small percentage of miles of high-pressure pipelines maintained by Distribution Operations.

[18] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

[19] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[20] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

Pipeline Incident, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – Corrosion:** External corrosion is a naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[21] External corrosion occurs to the outside of a pipe. Internal corrosion is the deterioration of metal that results from an electrochemical reaction. This reaction causes the iron in the steel pipe or other pipeline appurtenances to oxidize (rust). Internal corrosion results in metal loss in the inside of the pipe. The loss of material from corrosion can eventually result in "pinhole" leakage, or a crack, split, or rupture of the pipeline unless the corrosion is repaired, the affected pipe section is replaced, or the operating pressure of the pipeline is reduced.[22] Because corrosion can occur internally and/or externally, both potentially resulting in a pipeline incident, both will be referred to as "corrosion" for the remainder of this chapter, unless otherwise specified.
- **DT.2 – Natural forces (natural disasters, fires, earthquakes):** Attributable to causes not involving humans, but includes effects of climate change, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, wildfires and high winds.
- **DT.3 – Other outside force damage (excluding dig-in):** Attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck, or motorized equipment not engaged in excavation.

---

[21] L.S. Van Delinder, *Corrosion Basics, An Introduction* (1984); *see also* U.S. Department of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

[22] U.S. Department of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

- **DT.4 – Pipe, weld, or joint failure:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, improper construction or fabrication, or in-service stresses such as vibration, fatigue and environmental cracking.
- **DT.5 – Equipment failure:** Similar to DT.4, but unrelated to pipe (main and services). These failures are attributable to the malfunction of a component including, but not limited to, regulators, valves, meters, flanges, gaskets, collars, and couples. This driver/trigger is specific to the material properties related to the manufacturing process or post installation of the equipment.
- **DT.6 – Incorrect operations**: May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.7 – Incorrect/inadequate asset records**: The use of inaccurate or incomplete information that could result in the failure to (1) construct, operate, and maintain SoCalGas' pipeline system safely and prudently, or, (2) to satisfy regulatory compliance requirements.

E. Potential Consequences

If one of the drivers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

- PC.1 – Serious injuries and/or fatalities;
- PC.2 – Property damage;
- PC.3 – Adverse litigation;
- PC.4 – Penalties and fines; and
- PC.5 – Erosion of public confidence.

These potential consequences were used in the scoring of the Medium Pressure Gas Pipeline Incident risk during the development of SoCalGas' 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION FRAMEWORK

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[23] including enhancements to Interim Decision 16-08-018.[24] SoCalGas used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[25]

Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	315	**1581**	3692
LoRE		**542**	
CoRE	1	**3**	7

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[26] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

---

23 D.18-12-014 at Attachment A.

24 *Id.* at 2-3.

25 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

26 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

In Scope for purposes of risk quantification:	The risk of damage, caused by a medium pressure pipeline (maximum allowable operating pressure - MAOP at or lower than 60 psig) failure event, which results in consequences such as injuries or fatalities or outages.
Out of Scope for purposes of risk quantification:	The risk of damage caused by a non-medium-pressure pipeline failure event or third-party dig-ins which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration (PHMSA) data).[27]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SoCalGas, the national average incident rate per mile per year was applied to the medium-pressure pipeline miles at SoCalGas.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA medium-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

[27] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

B. Sources of Input

The SA Decision[28] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Annual Report Mileage for Gas Distribution Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SoCalGas medium-pressure pipeline miles
  - 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SoCalGas end user natural gas customers

---

[28] *Id*. at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Source: SNL (2016Y, from the FERC Form 2/2-F, 3/3-A or EIA 176)
- Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[29] This section describes SoCalGas' Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control.

As stated above, the Medium Pressure Gas Pipeline Incident risk is the risk of damage, caused by a medium pressure pipeline event, which results in serious injuries or fatalities. The Risk Mitigation Plan includes current controls that are expected to continue for the period of SoCalGas' TY 2022 GRC cycle. The controls are those activities that were in place as of 2018, most of which are compliance driven and have been implemented over decades plus the addition of the Distribution Integrity Management Programs (DIMP) that has been developed over recent years, to address this risk. SoCalGas' mitigation plan for this risk consists of controls based on 42 CFR Part 192, GO 58, GO 112-F and forecasted enhancements within existing controls. Overall the compliance requirements are set forth within the regulations (although considered minimum requirements.) The compliance requirements are robust in that they provide prescriptive preventative and maintenance guidance for the medium pressure assets. In addition, the DIMP regulations have allowed operators to identify risks specific to their system and address them through additional controls and mitigations.

For this RAMP chapter, the makeup of the portfolio of controls is a combination of compliance requirements and additional programs implemented by DIMP within the last 7 years. The DIMP is continually evaluating the system threats and risk to determine if additional

---

29 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

mitigations are appropriate. The threat and risk evaluation leverages leak repair, incident data and SME input to evaluate and rank risk. As programs are developed, available data sets are leveraged to develop specific risk rankings for each, which allows higher priority remediations to be completed first. For example, the Distribution Risk Evaluation and Monitoring System (DREAMS) steel replacement programs utilize a relative risk model which includes leak rates, condition of the pipe, soil and other factors to prioritize medium pressure segments for replacement. An example is the introduction of the Damage Program Analyst specifically covered within the Third Party Dig-In on a Medium Pressure Pipeline Chapter SCG-6. The incremental request within existing controls for Cathodic Protection and Meter and Regulations[30] are the first steps to evaluating the need for larger programs and further analysis will aid in the overall prioritization given the size of the system.

Other programs and activities also mitigate the Medium Pressure Gas Pipeline Incident risk, but they are not included in this Risk Mitigation Plan. For example, the Mobilehome Park Utility Upgrade Program ("MHP") is converting master-metered/sub-metered natural gas and/or electric services to direct utility services in mobile home parks and manufactured housing communities to improve the safety and reliability of service for residents of mobile home parks currently served by master-metered gas systems. The MHP is not included in this mitigation plan because MHP costs are not anticipated to be forecasted in SoCalGas' next GRC.[31]

Another example is SoCalGas' methane emissions reduction activities in compliance with Senate Bill (SB) 1371 and the resulting Gas Leak Abatement OIR (R.15-01-008). In addition to the federally mandated leak survey requirements described in the Pipeline Monitoring Control (SCG-1-C5) below, SoCalGas proposed transitioning pre-1986 plastic to annual survey as part of the GRC and also bare steel to an annual survey per the SB 1371 proceeding. SB 1371

---

30 Continued incremental request since because GRC requested funding to increase regulator replacement programs.

31 The Mobile Home Park Conversion Program is a pilot program authorized by and discussed in D.14-03-021 and Resolutions E-4878 (September 28, 2017) and E-4958 (March 14, 2019).

requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code section 961(d) and 49 CFR sections 192.703(c). SoCalGas has been an active participant in the rulemaking and has provided comments as well as met the reporting requirements set forth under SB 1371. SoCalGas' first Leak Abatement Compliance Plan and accompanying Advice Letter were approved in 2018 and the Plan is being implemented by the Emissions Strategy Project Management Organization to implement 26 Mandatory Best Practices. Although the focus of SB 1371 activities is to reduce methane emissions, the activities may result in collateral safety benefits as a reduction in the number of leaks reduces the potential opportunity for ignition. However, the risk reduction analysis and the costs tied to the implementation of SB 1371 are not reflected in the Mitigation Plan for this chapter because the intent of SB 1371 best management practice activities is to reduce methane emissions (and thus it is not primarily focused on addressing safety risk).

A. SCG-1-C1: Cathodic Protection

Corrosion is a natural process that can deteriorate steel assets and potentially lead to leaks or damage. If a leak migrates to a confined space and an ignition source is introduced, there is the potential for injuries. Although the SoCalGas operations groups immediately respond to these leak situations, they have the potential to lead to a pipeline incident. Cathodic Protection (CP), coating and monitoring can protect and extend the life of a steel asset by mitigating corrosion. The application of a Cathodic Protection current is necessary to overcome local corrosion currents along the pipeline, that left unabated would result in localized corrosion at anodic sites. Cathodic Protection can be achieved by the installation of sacrificial anodes or impressed current systems.[32]

32 SoCalGas utilizes both impressed current and magnesium anode (galvanic) systems to provide CP to existing pipelines. Impressed current systems utilize a rectifier for the generation of the direct current. Both systems utilize sacrificial anodes as a primary component in the system. Anodes are

The directives prescribed by 49 CFR 192 Subpart I, include the monitoring of CP areas, remediation of CP areas that are out of tolerance,[33] and preventative installations to avoid out of tolerance areas. The following summarizes the required intervals for completing these preventative measures as prescribed in 49 CFR § 192.465 External Corrosion Control (Monitoring):

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

- Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.[34]

SoCalGas plans to continue with work according to this schedule.

In addition to meeting these federal and state requirements, based on feedback from the Commission's Safety and Enforcement Division (SED) during a 2018 Safety Audit, and upon further review, SoCalGas issued new guidelines requiring the re-evaluation of existing 100 mV

---

installed in wells drilled into the surrounding soil by third-party drilling contractors. Each protected pipe segment requires multiple anodes, collectively referred to as an "anode bed." The number of anodes needed to achieve the desired level of protection and the average life of the anode bed can vary based on pipeline length, coating effectiveness, soil conditions and interference that may occur on the system.

33 Out of tolerance areas are defined as areas where CP measures are not efficiently mitigating the effect of the corrosive environment on steel assets.

34 49 CFR § 192.465(a) and (b).

polarization shift areas[35] at least every 10 years to verify their effectiveness as a measurement for adequate Cathodic Protection of an area. A pipeline utilizing the 100 mV polarization shift criteria must achieve a minimum of 100 mV of polarization along its entirety through the application of Cathodic Protection. SoCalGas will re-evaluate 75 CP packages in 2018 and 175 CP packages annually starting in 2019. SoCalGas is forecasting to also expand this CP control by creating a sampling program of CP Areas that fall within the 10-year monitoring interval requirement to determine if a shorter interval would provide a benefit and reduce risk. This incremental work activity supports the safety and integrity of the system and mitigates risks defined in this RAMP chapter.

B. SCG-1-C2: Valve Inspections & Maintenance

Valve maintenance is a program that validates that the valves within the system operate at optimum effectiveness, enhancing public safety by providing SoCalGas with the ability to control the pressure and flow of gas in the system. The maintenance activities vary by type of valve, and may include flushing, lubrication, parts replacement, cleaning and testing of operability.

Valves are installed for control of pressure and flow of gas. Their location and purpose determine their criticality: fire valves at regulator stations isolate the high- and medium-pressure systems; emergency valves isolate segments of pipelines in case of pipe damage or for operational purposes; and isolation valves segment portions of the system in the event of a widespread emergency, such as an earthquake and reduce the impact of resulting pipeline damage. A valve that is operating at its optimum effectiveness means that, for example, in the case of an earthquake or fire where an area needs to be isolated to reduce the risk of incident, these valves will operate as intended and fully isolate the area. A second example, which happens more frequently, when third-party damage occurs, these valves can be operated to allow for a safe environment to complete the repairs and minimize the risk of furthering the incident.

---

[35] 49 CFR Part 192, Appendix D (Criteria for Cathodic Protection and Determination of Measurements).

The following summarizes the requirements for completing these preventative measures as prescribed within the 49 CFR § 192.747:

> (a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.
>
> (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

C. SCG-1-C3: Meter & Regulator (M&R) Maintenance

Regulator stations reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure to be used on the distribution pipeline system. A failure of a regulator station due to mechanical failure, corrosion, contamination or other cause could result in over-pressurization of the gas distribution system, which may compromise the integrity of medium-pressure pipelines and/or jeopardize public safety as evident by recent over-pressure events in the industry. The medium and large customers meter set assemblies (MSAs) require routine inspection/maintenance of the meters, regulators, and other components to meet customers' capacity requirements and to measure gas volume accurately.

Regulator stations are critical control elements in the gas distribution system. 49 CFR § 192.739 requires inspections/tests to be conducted done annually, not to exceed 15 months to maintain these devices in good mechanical condition. Functional tests of regulator stations are performed as part of inspections. The pressure checks are done to verify that the station's pressure protection devices perform as designed. If a station does not perform properly, internal maintenance and inspections are conducted. This consists of disassembling the regulator devices and inspecting the internal components for worn or damaged parts. The regulator is cleaned and inspected for corrosion and any faulty parts are replaced.

As regulator stations age, their parts and equipment can begin to wear, malfunction, and become harder to disassemble, increasing maintenance requirements. Modern regulator stations are beginning to be designed with dual-run feeds to maintain continued safe and reliable operation of the station in the event of a failure within either of the two runs. Annual maintenance and inspections are used to record the condition of each station and identify items that require immediate and long-term action. The overall inspection of the station is leveraged to prioritize future regulator station replacement projects. The assessment includes evaluation of the design, condition of the equipment, valves and vaults, and exposure to other outside forces including flooding and traffic conditions.

SoCalGas' operating and maintenance practices allow stations to exceed their useful lives. However, it is prudent to proactively replace regulator stations prior to the end of their design life in order to reduce the overall system risk. This risk reduction is achieved through improved station design of dual-run regulators which will reduce the risk of over-pressure and the stations location can be evaluated to reduce the risk of vehicular damage (outside force) or vandalism. SoCalGas operates and maintains approximately 1,357 regulator stations, of which, on average, 10 stations are replaced or added to the system each year. SoCalGas plans to expand this control by accelerating the rate at which it replaces regulator stations by replacing an incremental 8 in 2019 (0.6%) in addition to the base forecast. SoCalGas will prioritize the replacement of district regulator stations (DRS) across operating regions while continuing to enhance the prioritization methodology to validate the starting point of 10 regulator stations a year is enough or should be increased. SoCalGas relies heavily on SME input from the operating districts to determine prioritization of regulator station replacements. This combined with expanding datasets surrounding condition and performance of stations throughout the service territory will support the evolution of the prioritization methodology. This regulator station replacement program is an example of addressing SoCalGas' aging infrastructure and will be used as a model to review other facilities and equipment in a similar fashion. The following summarizes the requirements for completing these preventative measures as prescribed within the 49 CFR § 192.739 Pressure limiting and regulating stations: Inspection and testing:

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is-

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

D. SCG-1-C4: Meter Set Assembly (MSA) Inspection and Maintenance

Meter and regulator activities include maintaining and operating approximately 102,000 medium and large customer MSAs in the SoCalGas service territory. The MSAs reduce the pressure of natural gas and measure the volume of natural gas delivered to the customer. General Order 58-A requires that meters, regulators, and other components be maintained, repaired, and tested periodically to meet customers' capacity requirements, measure gas volume accurately and deliver natural gas at an adequate pressure for the houseline and home appliances. Additionally, if MSAs are housed in vaults, the vaults must be inspected and repaired, if necessary, to protect the MSA. Should the regulators fail a household could potentially see a much higher pressure of natural gas and may lead to an incident. Scheduled inspections of meter set assemblies proactively target the risk of equipment failures, corrosion and outside force before operation and safety issues arise. In addition, as required by 49 CFR § 192.481, above ground piping facilities such as MSAs must be inspected for atmospheric corrosion no less than once every three calendar years and at intervals not to exceed 39 months.

E. SCG-1-C5/C11/C12/C13: Pipeline Monitoring (Pipeline Patrol, Leak Survey, Bridge & Span Inspection, Unstable Earth Inspection)

SoCalGas conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include pipeline patrols, leak surveys, bridge and span inspections, and unstable earth inspections. These inspections are critical since they are intended to observe assets over time to determine if abnormal conditions exist prior to becoming a concern. For example, a span that no longer is coated appropriately due to recent weather conditions can be identified for re-coating before corrosion begins that could lead to a leak. The leak survey monitoring identifies leaks that require repair.

The monitoring and inspections must follow certain prescribed processes included in the Code of Federal Regulations.[36]

F. SCG-1-C6: Gas Infrastructure Protection Project (GIPP)

The Gas Infrastructure Protection Project (GIPP) addresses prevention of potential third-party vehicular damage associated with above-ground pressurized natural gas facilities. An incident involving vehicular damage of a distribution facility can cause serious injuries or fatalities due the possibility of ignition. The GIPP is an additional control developed and managed as part of the DIMP. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the DIMP.[37] Although the DIMP guidelines do not prescribe what programs operators should implement the prescriptive sections results in the need to take action to reduce system risk.

GIPP identifies, evaluates, recommends, and implements damage prevention solutions for at risk above-ground pressurized gas facilities that are exposed to vehicular impacts. The

---

36 49 CFR § 192.721.

37 https://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/Pipeline/DIMP_Enforcement_Guidance(1_29_2014).pdf.

solutions reduce the number of incidents to pressurized piping and/or reduce the potential consequences caused from escaping natural gas after vehicular collisions. Major actions include: investigating historical claims data and developing risk assessment algorithms, conducting record reviews and physical inspections of facilities, developing risk exposure categories, identifying and implementing mitigation measures, updating policies/practices/procedures, and developing performance measures and program tracking.

GIPP remediation measures include the construction of barriers between facilities and vehicular traffic (bollards or block wall), relocation of a facility, or installation of an excess flow valve. Barriers are intended to be a visual, not a structural deterrent. They are not intended or capable of stopping all vehicular traffic, particularly large vehicles. The installation of excess flow valves can aid in the reduction of unrestrained gas flows. The types of considerations for the relocation of a facility include the type of road nearby, the volume of traffic, and the type of area (e.g., commercial or residential). The prioritization of GIPP inspections and remediations is based on field assessments.

Among MSAs, which is the largest population facility type, the most vulnerable are high pressure residential first stage regulation meter sets and commercial and industrial MSAs. GIPP is focusing on these facilities, which account for 352,000 at SoCalGas. Since the development and implementation of the program in 2011, approximately 468,000 sites with above-ground distribution facilities have been inspected and over 38,000 sites have been remediated. The GIPP Program forecast for remediation is 5,000 sites a year.

G. SCG-1-C7: Distribution Risk Evaluation and Monitoring System (DREAMS)

The DREAMS program is an additional control developed and managed as part of the DIMP. Within DIMP, the DREAMS tool is used to prioritize risk mitigation on early vintage plastic and steel pipeline segments. The risk algorithm includes pipe attributes, operational conditions, and impact on population. The results of the analysis determine appropriate action to address risk for the segment and prioritize replacement investments based on a leakage root-cause analysis.

For 2019, SoCalGas is on target to replace 48 miles of mains and associated services for replacement above and beyond routine replacements in accordance with DIMP regulations for the replacement of vintage plastic. For 2019, SoCalGas is on target to replace 24 miles of mains and associated services and targeted replacement of 300 – 500 services for replacement above and beyond routine replacements in accordance with DIMP regulations for the replacement of vintage steel. As SoCalGas' infrastructure continues to age and more leak data is accumulated through annual inspections, SoCalGas anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through the replacement program through indicators such as leak repair and incident rates related to early vintage plastic as part of DIMP regulations. Although the initial outlook is for a continued increase in scope for DREAMS (as previously stated), program metrics will be monitored on a continual basis to determine increase or decrease levels in scope.

As RAMP continues to mature it is expected that the results will also influence scope and investment levels, as outlined later in this chapter the DREAMS steel and plastic programs have a positive RSE. In addition, when expanding the program, consideration will be given to resources and contractor availability so that contractors can adequately meet the increase scope while maintain safety at the forefront with qualified and experienced workers. The increased replacement rate is associated with the number of incidents related to Aldly-A in recent years. Since DIMP's inception in 2010, SoCalGas has continued to prioritize and adjust scope of the program as the inputs to the risk algorithms change annually. This anticipated increase in scope over the 6-8 years can be considered dynamic; however, is not considered a new mitigation activity, and it is still within the scope of a control activity that has been active for near a decade. DREAMS assessment proactively identifies the risk factors for remediation before operation and safety issues arise.

1. SCG-1-C7-T1: Vintage Integrity Plastic Plan (VIPP)

The Vintage Integrity Plastic Plan (VIPP) falls within the umbrella of DREAMS. Plastic pipe manufactured and used for gas service from the 1960s through the early 1980s (8,200 miles) exhibit brittle-like cracking characteristic that could cause a leak to grow and release additional natural gas than would normally be released, increasing the risk of natural gas gathering and igniting, causing injuries and/or fatalities. Given the potential for a higher release of gas, the leak survey frequency has been increased to yearly versus every five years for plastic pipelines within this vintage. The initial focus of the VIPP is early vintage plastic manufactured pre-1973. This vintage of plastic exhibits the brittle-like cracking characteristics discussed, but also exhibits a Low Ductile Inner Wall (LDIW) issue that further exacerbates the brittle-like cracking issues since it expedites crack initiation when external loads are applied. This issue in the manufacturing practice has been the focus of earlier notices as issued by the manufacturer DuPont and PHMSA. Therefore, the focus will be a wholesale replacement of pre-1973 plastic pipe with a priority given to poor performing segments by utilizing a relative risk model and dynamic segmentation. The secondary focus will be to leverage the same relative risk model and dynamic segmentation to continue to focus on the replacement of poor performing early vintage plastic for all pre-1986 plastic pipe.

As mentioned, for 2019 SoCalGas plans to target 50 miles of plastic mains and associated services for replacement above and beyond routine replacements. SoCalGas anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through VIPP through indicators such as leak repair and incident rates related to early vintage plastic. In the early 1970s and 1980s, SoCalGas proactively took this similar approach with replacing the cast iron pipe within the system, completing the removal in 1993. This contributed to California being one of 21 states that eliminated cast iron from the system.

2. SCG-1-C7-T2: Bare Steel Replacement Program (BSRP)

The Bare Steel Replacement Plan (BSRP) falls within the umbrella of DREAMS will continue to focus on the replacement of bare steel with highest leak rates. Starting in 2019, SoCalGas plans to target 21 miles of steel mains and associated services and targeted replacement of 300 – 500 services for replacement above and beyond routine replacements.

SoCalGas anticipates continuing to increase the level of replacement over the next 6-8 years, while monitoring performance to continually review the benefits and risk reduction accomplished through BSRP through indicators such as leak repair and incident rates related to bare steel. The lack of protective coating makes steel a high-risk family of pipe and has been identified by DOT and PHMSA as a family of pipe that should be evaluated for an accelerated replacement program.

H. SCG-1-C8: Sewer Lateral Inspection Project (SLIP)

The SLIP project is an additional control developed and managed as part of the DIMP. SLIP addresses the concerns PHMSA expressed under the DIMP regulations that require operators to address identified threats of low frequency, but potentially high consequence events concerning pipeline damage within sewer laterals. Threats to pipeline integrity can occur if the trenchless installation inadvertently crosses a sewer line (or "lateral") and penetrates, or bores, through the sewer line, creating what is referred to as a "cross bore." For instance, through the SLIP, SoCalGas is proactively inspecting gas services for points of intrusion into house sewer lines. Should an intrusion be found, the service is remediated, which mitigates the potential of an incident due to a homeowner or plumber attempting to clear a house sewer line when a clog is present. For example, a plumber or the property owner then unknowingly uses a cleanout technology, such as a sewer-line auger, to clean out what is seemingly normal sewer debris and blockage. Following this work, the sewer line appears to be unclogged, but in reality, the sewer-line auger has pierced the gas line. Depending on how extensive the damage caused by the sewer-line auger, the gas line, which has now been breached, will leak gas into the sewer line and elsewhere. This unwanted gas migration can pose significant risks of bodily injury and damage to property.

Since the start of the program in 2010, approximately 2 million services have been reviewed and over 240,000 services inspected in the field. The SLIP PAAR forecast for records review is another 2 million services; the services left to inspect are dependent on the findings of the records review and should be in the vicinity of another 300,000-350,000 services based on initial findings. At the current rate, the records research is anticipated to be completed by 2022.

SoCalGas
A Sempra Energy utility

I. SCG-1-C9: Distribution Riser Inspection Project (DRIP)

The Distribution Riser Inspection Project (DRIP) Programs and Activities to Address Risk (PAAR) addresses the threat of failure of anodeless risers due to corrosion. Anodeless risers (ALRs) are service line components that have shown a propensity to fail before the end of their useful lives. ALRs were first introduced in the 1970s as a new technology replacing steel risers to transition from the underground plastic pipe to the above ground steel meter set. When an ALR was originally installed, it was set at a height where the gas carrying portion of the ALR was above ground. However, as grade conditions change due to landscaping and hardscaping, this gas carrying portion may no longer be at the proper height above the ground. When the gas carrying portion of the ALR is buried or set too low it can potentially corrode due to contact with the soil. The consequence of this component failing can be significant in that risers are attached to the meter set assembly, which is usually located next to a residence.

In addition, SoCalGas has been involved in research to develop an effective means of mitigating above-ground and ground level corrosion on anodeless risers. This effort has led to the implementation of the epoxy composite wrap, which provides a protective barrier for the above-ground section of the riser under the environmental conditions that are typical of riser installations, in lieu of replacement of the riser.

J. SCG-1-C10: Distribution Operations Control Center (DOCC)

The DOCC and related system of field sensors and control assets will strengthen SoCalGas and SDG&E's ability to manage their distribution pipeline operations system in real-time by use of modern technology including remote and automated controls and the co-location of a constantly-staffed DOCC facility with Gas Control operations. The DOCC will allow integrated operation of the distribution and existing high-pressure transmission pipeline systems. A modernized DOCC will increase operational efficiency, swiftness of response and ability to manage unplanned pipeline incidents and associated emergencies on both high- and medium-pressure distribution pipeline systems. Moreover, the DOCC will allow the Company to shift toward real-time monitoring and control from our point-of-receipt for gas supplies through our transmission and distribution systems and, ultimately, to our 6.4 million metered customers. Additionally, the DOCC will allow for centralized change management for planned pipeline operations, including the central coordination of operational information. Some examples of the summary features of the DOCC and system of field monitoring and control assets include the following:

- Remote Control of over 200 distribution regulator stations
- Data connectivity with SoCalGas and SDG&E Emergency Operations Center
- At least one real-time pressure measurement and trending data station in each pressure district/zone trending data station in each pressure district/zone
- Monitoring over 2,500 additional system points using alarm-based notification DOCC
- Hourly consolidated flow information from up to 5,000 core and non-core metering sites

Once implemented the Distribution Operations Control Center will be responsible for the continuous electronic pressure monitoring and oversight of its gas distribution pipeline system into the Gas Control SCADA system. The DOCC will strengthen the ability to manage the distribution pipeline operations system in real-time by use of modern technology including remote and automated controls. This type of monitoring and control will facilitate faster response times to incidents that occur and reduction of severity of incidents that occur due to its ability to monitor and respond to unfolding incidents in real time.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Unless otherwise specified, all elements of the bow tie concerning Potential Consequences are assumed to be addressed by the below mentioned controls. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[38] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. Risk reduction from mitigations and RSEs are determined at the tranche level. For purposes of the risk analysis, each tranche is considered to have homogeneous risk profiles (i.e., the same LoRE and CoRE). SoCalGas' rationale for the determination of tranches is presented below.

SoCalGas' comprehensive integrity and maintenance programs consist of policies, programs, and efforts designed to reduce the probability of a pipeline incident. The extensive activities SoCalGas performs to mitigate pipeline risks have been grouped into the controls presented herein based on the similarity of their risk profiles.

SoCalGas does differentiate some programs by asset type (e.g. steel vs plastic); however, as discussed in RAMP-G, costs are not tracked at a level of detail to allow for the logical disaggregation of assets or systems at a more granular level than the controls described in the mitigation plan.

Table 5: Summary of Tranches

ID	Control	Tranche	Tranche ID
SCG-1-C7	Distribution Risk Assessment and Monitoring Service (DREAMS)	DREAMS: Vintage Integrity Plastic Plan	SCG-1-C7-T1
		DREAMS: Bare Steel Replacement Program	SCG-1-C7-T2

[38] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

B. Post-Mitigation/Control Analysis Results

As described in RAMP-D and Section 4 above, SoCalGas utilized both internal data/modeling as well as PHMSA data to build RSEs for the pipeline incident risk areas. In the determination of inputs for the RSE calculations, SMEs were heavily utilized to confirm and provide data to perform the RSE calculations. Such input included the effectiveness of each control. The effectiveness percentages shown below are the results of discussions with SMEs whose knowledge of the control heavily dictated the values selected.

The below sections detail the Risk Reduction Benefits of each control/mitigation as well as specifically outline the data used in conjunction with said SME input to develop the RSE values

1. SCG-1-C1: Cathodic Protection (CP)

a. Qualitative Description of Risk Reduction Benefits

A steel pipeline can corrode externally and experience a degradation process that can lead to a structural incident. Corrosion control activities, like Cathodic Protection (CP), should manage or arrest structural changes. CP is a method to mitigate external corrosion on steel pipelines thereby extending the life of a steel asset. The activities associated with CP include installation, monitoring, and remediation. SoCalGas has installed CP on 66% of its 22,785 miles of steel gas mains and 42% of its 17,593 miles of steel gas services. Given the mandated requirement to continuously monitor and evaluate the CP areas, the management of this control is cyclical in nature. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

CP will reduce safety risks by controlling pipeline corrosion rates thus reducing the frequency of corrosion-related incidents. Minimizing corrosion will have the additional benefits of reducing reconstruction costs from pipeline incidents, reducing risk to property, and the potential benefit of improved service reliability. SoCalGas exceeds the minimum safety requirements for CP prescribed by 49 CFR 192 Subpart I, which includes monitoring of CP areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance.

b. Elements of the Bow Tie Addressed

CP addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.4] – Pipe, weld, or joint failure

c. RSE Inputs and Basis

Scope	The cathodically protected distribution system running at a pressure of 60 psi or lower.
Effectiveness	Per internal SME assessment, we assume 95% effectiveness. Based on SME analysis, vintage steel segments replaced are 13.2 times more likely to have an incident occur than modern plastic pipe over a lifecycle. We assume a similar deterioration proportion were cathodic protection discontinued.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 41 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 1 out of the 41 SoCalGas and SDG&E incident samples were corrosion-related events (2%). Using these assumptions, this mitigation could improve safety risk by up to 30% of the current residual risk. **Reliability**: Using these assumptions, this control for this tranche can improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 30% of the current residual risk. **Financial**: Using these assumptions, this control for this tranche improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 30% of the current residual risk.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	**LoRE**		**707.77**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	410.72	**2064.67**	4821.26
	RSE	1.01	**5.06**	11.81

2. SCG-1-C2: Valve Inspections and Maintenance

a. Qualitative Description of Risk Reduction Benefits

Valves provide the ability to control the pressure and flow of gas in SoCalGas' system. Valves are controlled locally or remotely from a central control system. Valve inspections and maintenance validate that the valves within the system operate at optimum effectiveness by detecting and addressing emerging equipment issues. Valve inspections and maintenance will continue to be conducted in accordance with 49 CFR 192 Subpart M, which require that each valve must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. Given the mandated requirement to complete valve inspections and maintenance, the management of this control will continue in a cyclical nature. Distribution Operations will manage the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

Valves that are operating appropriately enhance public safety by providing SoCalGas with the ability to control the pressure and flow of gas in the system. Valve inspections and maintenance activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident. Valve inspections and maintenance should increase public and employee safety by mitigating various risk sources, primarily corrosion and degradation. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Valve Maintenance addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.5] – Equipment failure

[DT.6] – Incorrect operations

3. SCG-1-C3: Meter and Regulator (M&R) Maintenance

a. Qualitative Description of Risk Reduction Benefits

Regulator stations will reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure used on the distribution pipeline system. A failure of a regulator station due to mechanical failure, corrosion, contamination, or other cause could result in over-pressurization of the gas distribution system, which may compromise the integrity of medium-pressure pipelines and/or jeopardize public safety. Meter & Regulator (M&R) maintenance activities are cyclical in nature and are conducted in accordance with 49 CFR 192 Subpart M which require the annual inspection and maintenance of all of the approximately 1,357 regulator stations operated by SoCalGas in order to maintain these devices in good mechanical condition.

M&R maintenance activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident by detecting and addressing emerging equipment issues. In addition to addressing emerging issues, M&R maintenance activities will provide an opportunity for SoCalGas to identify equipment that is at risk of deterioration in the future and procure equipment to address said equipment during the next inspection cycle. Distribution

Operations will manage the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

M&R maintenance will increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. When a regulator station is replaced as part of M&R maintenance, there are additional safety benefits that improve safety and reliability. The design of new regulator stations includes dual-run feeds which provide redundancy. Modern regulator stations have more monitoring points that feed into the Distribution Operations Control Center (DOCC) which improves response time in the event of an incident. Additionally, there is a financial benefit with the installation of new regulator stations related to ease of maintenance compared to older model regulator stations and better availability of parts when maintenance is required. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Meter & Regulator Maintenance addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.5] – Equipment failure

[DT.6] – Incorrect operations

c. RSE Inputs and Basis

Scope	SoCalGas is replacing approximately 30 regulator stations out of 1,970 total regulator stations in the system (1.5%).
Effectiveness	Per internal SME assessment, replacing regulator stations could reduce safety, reliability, and financial risk associated with this asset type by up to 100%. Replacing stations with a potentially higher risk of incident,

	has a 5x risk reduction impact versus replacing the average regulator station in the system, per internal SME assessment.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 26 out of 427 significant incident samples were attributed to regulator stations at the national level. This ratio (6%) is used as a proxy for the portion of SoCalGas Medium Pressure safety, financial, and reliability risk associated with this mitigation. Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident safety risk by up to 0.5%. **Reliability**: Using these assumptions, this mitigation could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 0.5%. **Financial**: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 0.5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**544.52**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	315.99	**1588.44**	3709.19
	RSE	0.47	**2.35**	5.50

4. SCG-1-C4: Meter Set Assembly (MSA) Inspection and Maintenance

a. Qualitative Description of Risk Reduction Benefits

Meter and regulator activities include maintaining and operating approximately 102,000 medium and large customer Meter Set Assemblies in the SoCalGas service territory. The medium and large customer MSAs require routine maintenance of the meters, regulators, and other components to meet customers' capacity requirements and to measure gas volume accurately. MSA inspection and maintenance activities are conducted in accordance with General Order 58-A which requires routine maintenance on medium and large MSAs. Given the mandated requirement to conduct MSA inspections and maintenance, the management of this control is cyclical in nature.

MSA inspection and maintenance activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent equipment issues. In addition to addressing emergent issues, MSA inspection and maintenance activities will provide an opportunity for SoCalGas to identify equipment that is at risk of deterioration in the future and procure equipment to remediate or replace that equipment during the next inspection cycle. Distribution Operations will manage the implementation of the work associated with this control with engineering oversight.

MSA inspection and maintenance activities will increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

MSA Inspection and Maintenance addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.5] – Equipment failure

[DT.6] – Incorrect operations

5. SCG-1-C5/C11/C12/C12: Pipeline Monitoring (Pipeline Patrol, Leak Survey, Bridge & Span Inspection, Unstable Earth Inspection)

a. Qualitative Description of Risk Reduction Benefits

SoCalGas conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include bridge and span inspections, unstable earth inspections, pipeline patrols, and leak surveys. These inspections are critical since they are intended to observe assets over time to determine if abnormal conditions exist prior to becoming a concern. For example, a span that no longer is coated appropriately due to recent weather conditions can be identified for re-coating before corrosion begins that could lead to a leak. The leak survey monitoring identifies leaks that require repair.

SoCalGas will conduct pipeline monitoring and inspections to proactively target risk factors before operational and safety issues arise. Pipeline monitoring activities include bridge and span inspections, unstable earth inspections, pipeline patrols, and leak surveys. Distribution pipeline spans, pipe supported on bridges, aboveground (or jacketed) pipelines, and all other exposed pipeline (as installed) are inspected for atmospheric corrosion or abnormal conditions: Onshore, at least once every 2 calendar years, but with intervals not exceeding 27 months. Offshore, at least once each calendar year, but with intervals not exceeding 15 months. SoCalGas will proactively survey its gas distribution system for leakage at frequencies determined based on the pipe material involved, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities as prescribed within CFR § 192.723. Distribution Operations will manage the implementation of the work associated with this control with engineering oversight.

Pipeline monitoring activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent issues. Pipeline monitoring activities should increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. Safety risks will be proactively reduced on a regular basis as result of the continual, ongoing nature of pipeline monitoring activities. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Pipeline Monitoring addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.5] – Equipment failure

6. SCG-1-C6: Gas Infrastructure Protection Project (GIPP)

a. Qualitative Description of Risk Reduction Benefits

The Gas Infrastructure Protection Project addresses prevention of potential third-party vehicular damage associated with above-ground pressurized natural gas facilities. An incident involving vehicular damage of a distribution facility can cause serious injuries or fatalities due to the possibility of ignition. Vehicular impacts have been one of the highest sources of significant incident risk due to the volume of incidents. The GIPP focuses on damage prevention with the following remediation measures: construction of barriers between the facility and vehicular traffic (bollards or block wall); relocation of the facility; or installation of an excess flow valve. The installation of various kinds of barriers can prevent some contacts from vehicular impacts, especially those done at low speed. The installation of excess flow valves can aid in the reduction of unrestrained gas flows.

GIPP activities will increase public safety by mitigating risk associated with above-ground distribution facilities located near vehicular traffic. GIPP remediation measures are preventative in nature and will reduce conditions that might lead to an incident.

b. Elements of the Bow Tie Addressed

Gas Infrastructure Protection Project addresses the following elements of the bow tie:

[DT.3] – Outside forces

[PC.1] – Serious injuries and/or fatalities

[PC.2] – Property damage

[PC.5] – Erosion of public confidence

c. RSE Inputs and Basis

Scope	The GIPP involves the inspection and remediation (i.e., installing bollards, relocating meters, service alterations, and abandonments) of 22,275 of 27,600 total commercial and industrial locations on the SoCalGas medium pressure system (81%).
Effectiveness	Per internal SME assessment, this tranche can reduce safety, reliability, and financial risk associated with this asset type by up to 95%.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 41 significant incidents occurred at SoCalGas and SDG&E since year 2010. Of these 41 incidents, 9 were attributed to "other outside force damage - car, truck, other vehicle." This ratio (22%) is used as the portion of SoCalGas Medium Pressure safety, financial, and reliability risk associated with this tranche. Using these assumptions, this control for this tranche could improve SoCalGas Medium Pressure Gas Incident safety risk by up to 17%. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 17%.

	Financial: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 17%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**633.22**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	367.46	**1847.19**	4313.42
	RSE	63.58	**319.61**	746.34

7. SCG-1-C7: Distribution Risk Evaluating and Monitoring System (DREAMS)

a. Qualitative Description of Risk Reduction Benefits

The Distribution Risk Evaluating and Monitoring System tool, developed and managed as part of the DIMP, will prioritize risk mitigation on early vintage plastic and steel pipeline segments. SoCalGas will utilize a relative risk model in order to rank and prioritize the risk for both plastic and steel pipeline. As noted in Section 5.G., for 2019, SoCalGas is on target to replace 78 miles of mains and associated services for replacement above and beyond routine replacements in accordance with DIMP regulations for the replacement of vintage plastic as part of the Vintage Integrity Plastic Plan (VIPP). For 2019, SoCalGas is on target to replace 29 miles of mains and associated services and targeted replacement of 2,000 – 4,000 services for replacement above and beyond routine replacements in accordance with DIMP regulations for the replacement of vintage steel as part of the Bare Steel Replacement Plan (BSRP).

SoCalGas
A Sempra Energy utility

SoCalGas anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through the replacement program through indicators such as leak repair and incident rates related to early vintage plastic. DREAMS, inclusive of the VIPP and BSRP, are conducted in accordance with 49 CFR Part 192. Distribution Operations will manage the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

Significant reductions in safety risks will be achieved with the replacement of vintage plastic and steel pipeline with new plastic pipe. Newly installed plastic pipe has a very low leak rate and is not subject to corrosion. A newly installed pipeline has a lower residual risk level and its risk rises on a different path than that of vintage pipe. The difference in deterioration paths is the performance benefit derived from reconstruction. This directly translates into a decrease in safety risk. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability over time.

b. Elements of the Bow Tie Addressed

DREAMS, inclusive of VIPP and BSRP, addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.4] – Pipe, weld or joint failure

[DT.5] – Equipment failure

[DT.7] – Incorrect/inadequate asset records

c. RSE Inputs and Basis

i. SCG-1-C7-T1: Vintage Integrity Plastic Plan (VIPP)

Scope	The VIPP involves replacing, mitigating, and remediating 560 miles of plastic pipe out of 8,680 identified miles (6.4%).
Effectiveness	Per internal SME assessment, we assume 100% effectiveness because failure rate of modern PE plastic pipe is very low. Based on SME analysis, replaced plastic segments are 12.5 times more likely for an incident to occur than modern plastic pipe over a lifecycle.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 41 natural gas incidents occurred at SoCalGas and SDG&E starting in year 2010. 7 out of the 41 SoCalGas and SDG&E incident samples were plastic pipeline events (17%). Using these assumptions, this tranche could improve safety risk by up to 14%. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 14%. **Financial**: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 14%.

ii. SCG-1-C7-T2: Bare Steel Replacement Program (BSRP)

Scope	The BSRP involves replacing, mitigating, and remediating 114 miles of steel pipe out of 7,855 identified miles (1.5%).
Effectiveness	Per internal SME assessment, we assume 100% effectiveness because the failure rate of replacement PE steel pipe is very low. Based on SME

	analysis, steel segments that are being replaced are 13.2 times more likely for an incident to occur than the modern steel pipe over a lifecycle.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 41 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 3 out of the 41 SoCalGas and SDG&E incident samples were steel pipeline events (7%). Using these assumptions, this control for this tranche could improve safety risk by up to 1.4%. **Reliability**: Using these assumptions, this tranche could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 1.4%. **Financial**: Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 1.4%.

d. Summary of Results

i. SCG-1-C7-T1: Vintage Integrity Plastic Plan (VIPP)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**616.57**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	357.80	**1798.63**	4200.02
	RSE	2.68	**13.45**	31.40

ii. SCG-1-C7-T2: Bare Steel Replacement Program (BSRP)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**549.60**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	318.93	**1603.26**	3743.79
	RSE	0.64	**3.20**	7.48

8. SCG-1-C8: Sewer Lateral Inspection Project (SLIP)

a. Qualitative Description of Risk Reduction Benefits

SLIP addresses identified threats of low frequency, but potentially high consequence events related to pipeline damage within sewer laterals. The program should find instances in which a gas service has penetrated a sewer lateral upon installation thereby having the potential to cause incident from work such as auger or rooter operations in said lateral. It is a latent risk that exists in any gas system using directional boring technologies (boring through an existing sewer pipe creates a conflict which may lead to an incident). An inspection and the subsequent remediation, if necessary, eliminates the risk from a subject location. The potential migration of unwanted gas into a sewer line and elsewhere can pose significant risks of bodily injury and damage to property. The SLIP control will provide safety benefits by mitigating the risks to public safety and property damage.

b. Elements of the Bow Tie Addressed

SLIP addresses the following elements of the bow tie:

[DT.3] – Outside forces

[PC.1] – Serious injuries or fatalities

[PC.2] – Property damage

[PC.5] – Erosion of public confidence

c. RSE Inputs and Basis

Scope	165,000 locations out of 1,140,000 (14.5%) are scheduled for inspection as part of SLIP.
Effectiveness	Per internal SME assessment, inspection and remediation of these locations could reduce safety, reliability, and financial risk associated with this asset type by up to 100%.
Risk Reduction	Safety: Based on PHMSA information, 3 out of a 426 significant incident samples at the national level are due to sewer conflicts. Using these assumptions, this mitigation could improve safety risk by up to 0.1%. Reliability: Using these assumptions, this mitigation could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 0.1%. Financial: Using these assumptions, this mitigation could improve SoCalGas Medium Pressure Gas Incident financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**542.55**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.85	**1582.70**	3695.80
	RSE	0.89	**4.46**	10.43

9. SCG-1-C9: Distribution Riser Inspection Project (DRIP)

a. Qualitative Description of Risk Reduction Benefits

The Distribution Riser Inspection Project (DRIP) PAAR will address the threat of failure of anodeless risers (ALRs) due to corrosion. ALRs are service line components that have shown a propensity to fail before the end of their useful lives. ALRs are located next to buildings or residences therefore the potential gas migration path is short and can present a safety risk. Where the threat of failure of an ALR is present, SoCalGas will remediate the issue by implementing an epoxy composite wrap, providing a protective barrier for the above-ground section of the ALR. The epoxy composite wrap is completed during all inspections Replacement of the equipment may be considered if the implementation of the epoxy composite wrap is not effective or possible. DRIP is conducted in accordance with 49 CFR Subpart P. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group. The DRIP PAAR will reduce the likelihood of failure of ALRs thus reducing risk to public safety and property.

b. Elements of the Bow Tie Addressed

DRIP addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

[DT.5] – Equipment failure

c. RSE Inputs and Basis

Scope	570,000 out of 1,700,000 locations (33.5%) are identified to be inspected and remediated as part of DRIP.

Effectiveness	Per internal SME assessment, inspection of the remaining locations could reduce safety, reliability, and financial risk associated with this asset type by up to 100%.
Risk Reduction	**Safety**: Based on PHMSA information, 3 out of a 426 significant incident samples at the national level are due to riser issues. Using these assumptions, this mitigation could improve safety risk by up to 0.2%. **Reliability:** Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident reliability risk by up to 0.2%. **Financial:** Using these assumptions, this control for this tranche could improve the SoCalGas Medium Pressure Gas Incident financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	**LoRE**		**543.28**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	315.27	**1584.83**	3700.75
	RSE	1.23	**6.21**	14.49

10. SCG-1-C10: Distribution Operations Control Center (DOCC)

a. Qualitative Description of Risk Reduction Benefits

The DOCC will continue to provide the ability to manage distribution pipeline operations system in real-time via the use of modern technology, including remote and automated controls and the co-location of a constantly-staffed DOCC facility with Gas Control operations. The DOCC allows for the integrated operation of the distribution and existing high-pressure transmission pipeline systems. The DOCC is managed by the Gas Control group in accordance with CFR 192.631 (Control Room Management). The DOCC is not mandated by state or federal regulations, but individual aspects of DOCC operations are regulated. The DOCC will provide multiple safety and reliability benefits, including but not limited to:

- Faster response times to incidents and the reduction of severity of incidents due to the ability to monitor and respond to unfolding incidents in real time
- Increased operational awareness through the implementation of centralized management of change
- Improved technology that allows for more effective system controls and the ability to aggregate, streamline, and analyze inputs from multiple data sources

A centralized and modernized DSS will increase operational efficiency and improve the speed and ability to manage incidents which will directly translate to improvement in public and employee safety. The commission recognized the DOCC as an important mitigation to the Medium Pipeline Incident Risk and in authorizing SoCalGas' proposed capital expenditures in the TY 2019 GRC.[39]

b. Elements of the Bow Tie Addressed

Distribution Operation Control Center addresses the following elements of the bow tie:

[DT.1] – Corrosion

[DT.2] – Natural forces

[DT.3] – Outside forces

---

[39] D.19-09-051 at 131 ("The system also supports mitigation of a key risk identified during the RAMP process and we find that the real time monitoring to be provided by the system supports our policy of reducing gas leaks more quickly.")

[DT.4] – Pipe, weld or joint failure

[DT.5] – Equipment failure

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

As discussed, the existing controls outlined within the Chapter will continue and certain controls will increase in scope or at an accelerated pace. However, as a diligent operator the controls will be monitored to determine if any adjustments are needed during the implementation period. The programs could be influenced as additional information is gathered or understanding of risk and controls relationship changes. Should controls need to change, consideration will be given to available technology, labor resources, planning and construction lead time, compliance requirements, and operational and execution considerations.

The table below provides a summary of the Risk Mitigation Plan, including controls, associated costs and the RSEs by tranche. SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in the table were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Overview[40]

(Direct 2018 $000)[41]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-1-C1	Cathodic Protection	T1	7,100	17,000	30,000 – 38,000	17,000 – 22,000	47,000 – 60,000	1.01 – 11.81
SCG-1-C2	Valve inspection & Maintenance	T1	0	900	0	900 – 1,100	900 – 1,100	--

40 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

41 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

42 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

43 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

44 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

45 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-1-C3	Meter & Regulator (M&R) Maintenance	T1	5,800	15,000	7,500 – 9,600	21,000 – 27,000	30,000-37,000	0.47 – 5.50
SCG-1-C4	Meter Set Assembly (MSA) Inspection and Maintenance	T1	19,000	10,000	24,000 – 31,000	10,000 – 13,000	34,000 – 44,000	-
SCG-1-C5	Pipeline Patrol	T1	0	90	0	190 - 250	190-250	-
SCG-1-C6	Gas Infrastructure Protection Plan (GIPP)	T1	6,700	1,800	15,000 – 19,000	750 - 950	16,000 – 20,000	63.58 – 746.34
SCG-1-C7	DREAMS - Vintage Integrity Plastic Plan	T1	100,000	1,600	410,000 – 520,000	660 - 850	410,000 – 520,000	2.68 – 31.40
SCG-1-C7	DREAMS - Bare Steel	T2	44,000	680	170,000 – 220,000	280 - 360	170,000 – 220,000	0.64 – 7.48

SoCalGas
A Sempra Energy utility

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
	Replacement Program							
SCG-1-C8	Sewer Lateral Inspection Plan (SLIP)	T1	0	9,600	0	9,100 – 12,000	9,100 – 12,000	0.89 – 10.43
SCG-1-C9	Distribution Riser Inspection Project (DRIP)	T1	0	15,000	0	15,000 – 19,000	15,000 – 19,000	1.23 – 14.49
SCG-1-C10	Distribution Operations Control Center (DOCC)	T1	720	0	65,000 – 83,000	0	65,000 – 83,000	-
SCG-1-C11	Leak Survey	T1	0	9,700	0	11,000 – 14,000	11,000 – 14,000	-
SCG-1-C12	Bridge & Span Inspections	T1	0	78	0	64 – 82	64 – 82	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-1-C13	Unstable Earth Inspection	T1	0	8	0	9 – 12	9 – 12	-
TOTAL COST			**180,000**	**81,000**	**720,000 – 920,000**	**86,000–110,000**	**810,000 – 1,000,000**	-

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan but is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

Control ID	Control Name	Reason for No RSE Calculation
SCG-1-C2	Valve Inspections and Maintenance	Mandated activity per 49 CFR 192 Subpart M § 192.7245 and § 192.747.
SCG-1-C4	Meter Set Assembly (MSA) Inspection and Maintenance	Mandated activity per 49 CFR 192 Subpart H
SCG-1-C5/C11/C12/C13	Pipeline Monitoring (Pipeline Patrol, Leak Survey, Bridge & Span Inspection, Unstable Earth Inspection)	Mandated activity per 49 CFR § 192.722, § 192.705, § 192.722, § 192.723 and § 192.935.
SCG-1-C10	Distribution Operations Control Center (DOCC)	The TY2019 SoCalGas/SDG&E GRC Decision recognized and approved the benefits of the DOCC, effectively establishing activities surrounding the DOCC as a control with funding approved from 2017 through 2019.[46]

[46] D.19-09-051 at 128-130 ("The [DOCC] system is proposed to be built in phases from 2017 to 2021 with an estimated total capital cost of $108 million.…we find that the real time information and monitoring of gas distribution pipelines that will be provided by the system as described in Exhibit 50 showing the features and other capabilities of the DOCC, provide meaningful safety benefits.")

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the described mitigations for the Medium Pressure Gas Pipeline Incident risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, including but not limited to operational, compliance and resource constraints.

A. SCG-1-A1 – Assessment and Replacement of 10-year Cycle Cathodically Protected Services (CP10s)

SoCalGas considered replacing the 325,349 CP10 services rather than continuing to monitor, inspect and maintain them on ten-year cycle. CP10 services are separately protected service lines that are surveyed on a sampling basis where at least 10% of system inventory are sampled each year, so that the entire system is tested in a 10-year period. However, due to the number of CP10 services in the system, a program targeting complete replacement of CP10 services would exceed $2 Billion and likely take many decades to complete. As complete replacement is not feasible, further evaluation of CP10 services is required to evaluate and quantify the risk reduction benefits, and potentially develop a risk based targeted replacement program. In the interim CP10s will be replaced based on performance history and current protection levels.

Scope	Per SME input, scope is 0.9% or a replacement of 3,000 units out of 325,349.
Effectiveness	Per internal SME assessment, the effectiveness of this mitigation is 95%.
Risk Reduction	Based on historical information reported to PHMSA, risk addressed is 2%. Using these

	assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.02%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	LoRE		**541.88**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.46	**1580.75**	3691.25
	RSE	0.06	**0.29**	0.67

B. SCG-1-A2 - Soil Sampling Program

SoCalGas considered expanding its collection of soil property information. SoCalGas collects soil properties (rocky, clay, sandy) during excavations and repairs along its pipelines. These soil properties are an element within the relative risk models used for prioritization process of the vintage replacement program for plastic. Expanding the collection of soil properties beyond leak repair excavations may allow SoCalGas to further refine its replacement efforts. The cost estimate of sampling the 54,479 miles of distribution pipe is $88.1 million; on average, 14 samples per day will be tested at intervals of 2 samples per mile. SoCalGas has not initiated an expanded soil sampling program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature for the corrosion threat the benefit of additional information can be better understood. In the interim SoCalGas will be researching available data sets and determining the benefit of additional soil property information.

Scope	Assuming 100% of soil would be sampled, as a one-time effort: once the soil is sampled, it does not need to be resampled.
Effectiveness	Per internal SME assessment, effectiveness of having additional data for making better pipe replacement decisions will be minimal, at 1%.[47]
Risk Reduction	Per SME guidance, risk addressed is 17%, same as plastic DREAMS program. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.2%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**542**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	314.53	**1581.09**	3692.04
Post-Mitigation	**LoRE**		**541.07**	
	CoRE	0.58	**2.92**	6.81
	Risk Score	313.99	**1578.39**	3685.73
	RSE	0.01	**0.03**	0.07

47 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

Table 8: Alternative Mitigation Summary

(Direct 2018 $000)[48]

ID	Mitigation	2020-2022 Capital[49]	2022 O&M	Total[50]	RSE[51]
SCG-1-A1	Assessment and Replacement of 10-year Cycle Cathodically Protected Services (CP10s)	30,000 – 38,000	0	30,000 – 38,000	0.06 – 0.67
SCG-1-A2	Soil Sampling Program	0	1,700 – 2,200	1,700 – 2,200	0.01 – 0.07

48 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

49 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

50 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

51 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control Name	Drivers/Triggers/Potential Consequences Addressed
SCG-1-C1	Cathodic Protection (CP)	DT.1, DT.4
SCG-1-C2	Valve Inspections and Maintenance	DT.1, DT.2, DT.3, DT.5, DT.6
SCG-1-C3	Meter and Regulator (M&R) Maintenance	DT.1, DT.2, DT.3, DT.5, DT.6
SCG-1-C4	Meter Set Assembly (MSA) Inspection and Maintenance	DT.1, DT.2, DT.3, DT.5, DT.6
SCG-1-C5	Pipeline Patrol	DT.1, DT.2, DT.3, DT.5
SCG-1-C6	Gas Infrastructure Protection Project (GIPP)	DT.3; PC.1, PC.2, PC.5
SCG-1-C7-T1	DREAMS: Vintage Integrity Plastic Plan (VIPP)	DT.2, DT.3, DT.4, DT.5, DT.7
SCG-1-C7-T2	DREAMS: Bare Steel Replacement Program (BSRP)	DT.1, DT.2, DT.3, DT.4, DT.5, DT.7
SCG-1-C8	Sewer Lateral Inspection Project (SLIP)	DT.3; PC.1, PC.2, PC.5
SCG-1-C9	Distribution Riser Inspection Project (DRIP)	DT.1, DT.2, DT.3, DT.5
SCG-1-C10	Distribution Operations Control Center (DOCC)	DT.2, DT.3, DT.5
SCG-1-C11	Leak Survey	DT.1, DT.2, DT.3, DT.5
SCG-1-C12	Bridge & Span Inspections	DT.1, DT.2, DT.3, DT.5
SCG-1-C13	Unstable Earth Inspection	DT.1, DT.2, DT.3, DT.5

Risk Assessment Mitigation Phase

(Chapter SCG-2)

Employee Safety

November 27, 2019

SoCalGas
A Sempra Energy utility

TABLE OF CONTENTS

Risk: Employee Safety

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas' or Company's) Employee Safety risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 and the Settlement Agreement included therein (the SA Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in this 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this RAMP Report are those costs which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Employee Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), California Code of Regulations (CCR), Public Utilities Code, or General Order. Activities with no RSE score presented in the 2019 RAMP Report are identified in Section VI, below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V, below. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

A. Risk Definition

For purposes of this RAMP Report, SoCalGas' Employee Safety risk is defined as the risk of an employee safety incident that causes serious injuries[3] or fatalities while on duty.

---

[3] As defined by Cal/OSHA, as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger/Potential Consequence
DT.1	Employees deviate from company policies or procedures
DT.2	Hazards in the work environment or within the pipeline system
DT.3	Drug/alcohol use or undisclosed prescriptions or medical restrictions
DT.4	Non or improper use of personal protective equipment
DT.5	Employees are not prepared to respond to emergencies
DT.6	Effective corrective actions are not instituted following an incident to prevent reoccurrence
DT.7	Unsafe operation of equipment or motor vehicles
PC.1	Serious injuries[5] and/or fatalities
PC.2	Property damage
PC.3	Operational and reliability impacts
PC.4	Adverse litigation
PC.5	Penalties and fines
PC.6	Erosion of public confidence

hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) § 330(h).

4 *Id.* at Attachment A, A-11 ("Bow Tie").

5 8 CCR § 330(h).

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[6] SoCalGas has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP, as further described below. SoCalGas' baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-2-C1	Mandatory employee health and safety training programs and standardized policies
SCG-2-C2	Drug and alcohol testing program
SCG-2-C3	Employee wellness programs
SCG-2-C4	Employee safety training and awareness programs
SCG-2-C5	Safe driving programs
SCG-2-C6	Personal protection equipment (PPE)
SCG-2-C7	Near Miss, Stop the Job and jobsite safety programs
SCG-2-C8	Safety culture
SCG-2-C9	Utilizing Occupational Safety and Health Administration (OSHA) and industry best practices and industry benchmarking

SoCalGas will continue the baseline controls identified above and puts forth additional projects and/or programs (*i.e.*, mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SCG-2-M1	OSHA 30-hour construction certification training

[6] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SCG-2-M2	Industrial hygiene program refresh
SCG-2-M3	Establish proactive monitoring for indoor air quality and chemicals of concern
SCG-2-M4	Creation of a safety video library
SCG-2-M5	Expanded Safety Congress and expanded Executive Safety Council
SCG-2-M6	Expanded Safety Culture Assessments

Finally, pursuant to the SA Decision,[7] SoCalGas presents considered alternatives to its Risk Mitigation Plan for the Employee Safety risk and summarizes the reasons that the alternatives were not included into the Risk Mitigation Plan in Section VIII.

II. RISK OVERVIEW

At SoCalGas, the safety of employees is a core value. SoCalGas' approach to safety is built on our tradition of providing safe and reliable service for 150 years and is summarized in our Commitment to Safety statement, which is embraced and endorsed by every member of our senior management team:

> SoCalGas' longstanding commitment to safety focuses on three primary areas employee/contractor safety, customer/public safety and the safety of gas delivery system. This safety focus is embedded in what we do and is the foundation for who we are from initial employee training, to the installation, operation and maintenance of our utility infrastructure, and to our commitment to provide safe and reliable service to our customers.[8]

To promote these principles throughout, and to foster a culture of continuous safety improvement, "[t]he company continuously strives for a work environment where employees at all levels . . . can raise pipeline infrastructure, customer safety, and employee safety concerns and offer suggestions for improvement."[9] SoCalGas encourages two-way formal and informal

---

7 *Id.* at 33.

8 Southern California Gas Company, SoCalGas' Natural Gas System Operator Safety Plan (March 15, 2019) at 6, available at https://www.socalgas.com/regulatory/documents/r-11-02-019/2019_SoCalGas_Gas_Safety_Plan-FINAL.pdf.

9 *Id.*

communication between its employees and management, and in order to identify and manage safety risks before incidents occur, as further described below in SCG-2-C8 and Chapter RAMP-F. SoCalGas endeavors to foster a work environment where employees are focused on and engaged in sustaining a culture that emphasizes safety and encourages its employees at all levels to raise pipeline infrastructure, customer safety, and employee safety concerns and to offer suggestions for improvement.

The Employee Safety risk was included in SoCalGas' 2018 ERR and is defined as the risk of an employee safety incident that causes serious injuries or fatalities while on duty. This Employee Safety risk chapter focuses on mitigations that address safety, education, training, and other internal procedural enhancements. This safety focus is embedded in what we do and is the foundation for who we are. Our safety efforts start at the top with appropriate safety governance. SoCalGas' board includes senior officers with extensive operational and safety experience specific to a natural gas utility and provides oversight at the highest level. At SoCalGas, each officer and director is responsible for safety. As further described below, SoCalGas has an Executive Safety Council (ESC), which is chaired by the Chief Operating Officer, who is also the Chief Safety Officer. The ESC sets goals and direction, provides resources, and reviews results of direct feedback from the frontline employees.

While the Employee Safety risk scope is limited for purposes of this Chapter, it is important to note that the operational risks addressed in this RAMP Report[10] can result in an incident where an employee is seriously injured, or a fatality occurs. The risk mitigation activities presented in other Chapters of this RAMP Report also address the Employee Safety risk.[11] Following the SA Decision and our risk methodology, a potential risk scenario of SoCalGas' Employee Safety risk is an employee not following a company policy or procedure being severely injured and causing a disruption of service to a small number of customers.

[10] *See,* SCG-1, Medium Pressure Gas Pipeline Incident (Excluding Dig-in); SCG-5, High Pressure Gas Pipeline Incident (Excluding Dig-in); SCG-6, Third Party Dig-in on a Medium Pressure Pipeline; and SCG-7, Third Party Dig-in on a High Pressure Pipeline. *See also*, Appendix A-3 to Chapter RAMP-A.

[11] *Id*.

In addition to promoting employee safety within the Company, SoCalGas also seeks to supplement its workforce by using contractors who are also committed to safety and employ numerous mitigation measures to protect the safety of SoCalGas' customers and the public at large. The contractor safety and customer and public safety mitigations are discussed in the separate, respective chapters of this RAMP report. While this chapter focuses on Employee Safety risk, many of the activities described herein also help to mitigate these other risks.

III. RISK ASSESSMENT

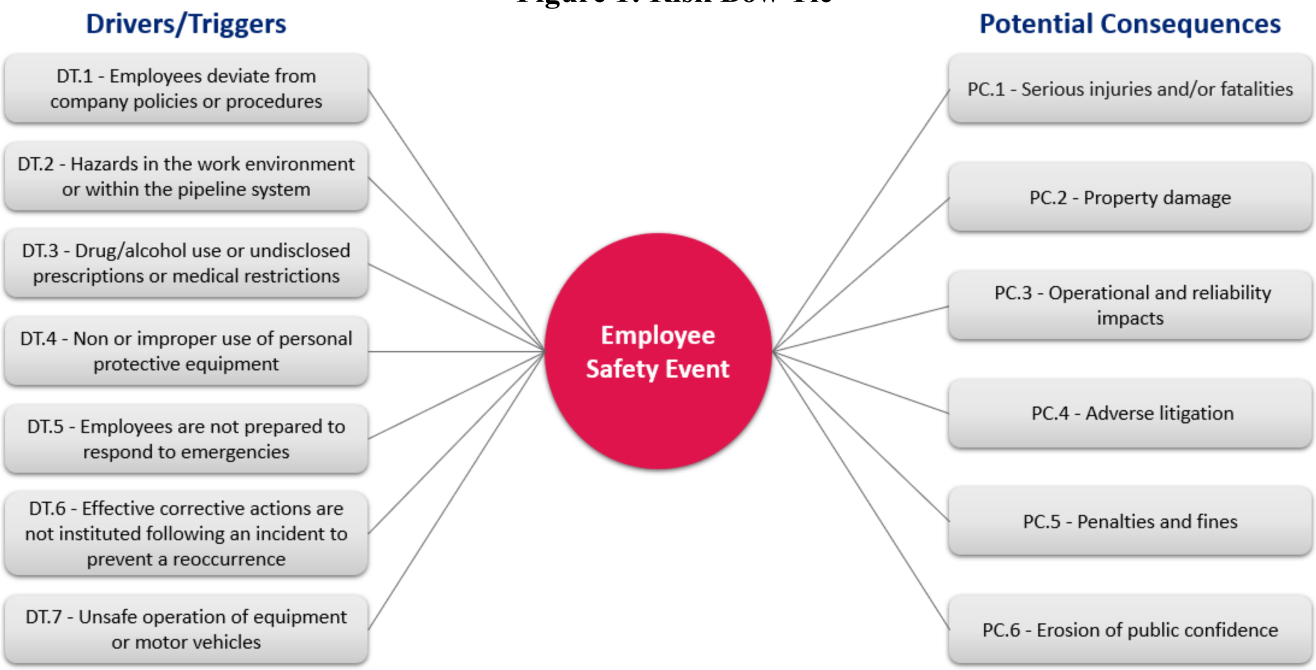
In accordance with the SA Decision,[12] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the Employee Safety risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1 below is a commonly used tool for risk analysis. The left side of the Risk Bow Tie illustrates the Drivers/Triggers that lead to a risk event and the right side shows the Potential Consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

12 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[13] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. This is a "cross-cutting" risk and therefore is associated with human systems, rather than particular asset groups.

C. Risk Event Associated with the Risk

The SA Decision[14] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the Bow Tie) is an employee safety event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

---

13 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

14 *Id.* at Attachment A, A-11 ("Bow Tie").

1. Potential Drivers/Triggers[15] of Risk Event

The SA Decision[16] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Employee Safety, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT.1 - Employees deviate from company policies or procedures:** SoCalGas' Company policies and procedures are defined in Gas Standards. Similarly, the Company's general safety rules are defined in the Employee Responsibilities section of the Illness and Injury Prevention Program (IIPP). An employee not adhering to such Company safety policies and procedures could result in a safety-related event.
- **DT.2 - Hazards in the work environment or within the pipeline system:** Unsafe work environments, including work locations, roadways and parking places, customer premises, gas equipment condition, lead from paint, asbestos, fumigation chemicals, for example, could lead to a safety event.
- **DT.3 - Drug/alcohol use or undisclosed prescriptions or medical restrictions:** Unknown drug/alcohol use while on the job or medical restrictions can impede the safe conduct of work which could lead to a safety event.
- **DT.4 – Non-use or improper use of personal protective equipment:** Safety equipment serves to protect employees and contractors from avoidable injuries. Failure to wear personal protection and safety equipment can lead to a safety incident.
- **DT.5 – Employees are not prepared to respond to emergencies:** Failure to respond accordingly during an emergency may increase the likelihood of serious injuries and/or fatalities.

---

15 An indication that a risk could occur. It does not reflect actual or threatened conditions.

16 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.6 – Effective corrective actions are not instituted following an incident to prevent a reoccurrence:** Lessons learned, and the appropriate follow-up actions or training, can help prevent future safety events from occurring. The failure to implement corrective actions following an event can lead to the recurrence of safety events.
- **DT.7 – Unsafe operation of equipment or motor vehicles:** Non-adherence to motor vehicle laws or not utilizing equipment according to safety standards could result in serious injuries and/or fatalities.

2. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one of the drivers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries and/or fatalities;
- Property damage;
- Operational and reliability impacts;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of Employee Safety that occurred during the development of SoCalGas' 2018 ERR.

IV. RISK QUANTIFICATION

A. Summary

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[17] including enhancements to the Interim Decision 16-08-018.[18] SoCalGas used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below.

---

[17] *Id.* at Attachment A.

[18] *Id.* at 2-3.

Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[19]

Employee Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	117	**1112**	2771
LoRE		**1.5**	
CoRE	80	**765**	1907

B. Risk Scope and Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[20] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk assessment:	The risk of an employee safety incident that causes serious injuries or fatalities while on duty.
Out-of-Scope for purposes of risk assessment:	The risk of a safety incident (outside of OSHA regulation; not work-related) involving an employee that causes injuries or fatalities while <u>not</u> on duty.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (*e.g.,* Pipeline and Hazardous Materials Safety Administration

[19] The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

[20] D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

data).[21] SoCalGas' safety risk assessment primarily utilized data from the Bureau of Labor Statistics (BLS), OSHA, and the Department of Labor (DOL).

Calculating serious injury and fatality incidence rates required data on total employment by sector. The BLS Employment and Earnings data was used to determine total employment by sector. The data was filtered on NAICS (North American Industry Classification System) subsector code "2212 Natural Gas Distribution" to represent SoCalGas.

Injuries, Illnesses, and Fatalities Program (IIF) historical data from the BLS was used to determine the serious injury and the fatality incidence rates per year. From this data, for the serious injury rate, it was calculated that 0.5% of recordable incidents are serious injuries for gas-related employees. This serious injury assumption is calculated as the ratio of serious injuries to recordable incidents during 2015-2016, by sector.

The OSHA Enforcement Data from the DOL was used to determine the distribution of injuries or fatalities resulting from a single employee safety incident. The data was supplemented with data from OSHA Severe Injury Reports. The NAICS code structure used in the data from the BLS is consistent with the NAICS codes in the OSHA enforcement data used for determining the distribution.

A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences. The safety consequence scoring was based on a publication from the Federal Aviation Administration (FAA): a fatality is represented by 1.000 and a serious injury is represented by 0.253. Internal SME input was provided to estimate the financial consequence of employee safety incident. Based on SME input, reliability is not impacted by employee safety.

C. Sources of Input

The SA Decision[22] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Injuries:

---

21 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

22 *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
- Link: https://www.bls.gov/iif/oshsum.htm#15Summary_Tables
- Report Title: TABLE Q1. Incidence rates of total recordable cases of nonfatal occupational injuries and illnesses by quartile distribution and employment size, 2009-2016, All establishment sizes

- Fatalities:
  - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
  - Link: https://www.bls.gov/iif/oshcfoi1.htm#2015
  - Report Title: Census of Fatal Occupational Injuries-TABLE A-3. Fatal occupational injuries to private sector wage and salary workers, government workers, and self-employed workers by industry, all United States

- Distribution Fitting Data:
  - Agency: Department of Labor (DOL)
  - Link: https://enforcedata.dol.gov/views/data_catalogs.php
  - Report Title: OSHA Enforcement Data: osha_accident, osha_accident_injury, osha_inspection

- Severe Injury Assumption:
  - Agency: Occupational Safety and Health Administration (OSHA)
  - Link: https://www.osha.gov/severeinjury/index.html
  - Report Title: Severe Injury Reports

- Support Data:
  - Agency: Bureau of Labor Statistics- Office of Publications & Special Studies
  - Link: https://www.bls.gov/opub/ee/archive.htm
  - Report: Employment & Earnings- Table B-1b. Employees on nonfarm payrolls by industry sector and selected industry detail, not seasonally adjusted, 2011-2016

- North American Industry Classification System - NAICS
  - Agency: US Census Bureau
  - Link: https://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart_code=22&search=2017%20NAICS%20Search

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[23] This section describes SoCalGas' Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SoCalGas' Employee Safety risk is defined as the risk of a work-related employee safety incident that causes serious injuries or fatalities. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SoCalGas' TY 2022 GRC cycle.[24] The controls are those activities that were in place as of 2018 to address this risk (most of which have been developed over many years) and include work to comply with laws that were in effect at that time.

SoCalGas' Employee Safety risk encompasses the Drivers/Triggers outlined above that result in a safety-related incident. The baseline controls discussed below include the current evolution of SoCalGas' risk management of its employee safety risk. These baseline controls have been developed over many years to address this risk. As further described below, SoCalGas' current controls include provisions to comply with laws and regulations currently in effect and, in some instances, go above and beyond mandated compliance in line with industry best practices (*e.g.*, safety culture assessments, safety congresses, executive safety council) to further reduce employee safety risk.

SoCalGas' Safety and Wellness department, which is part of the Safety Management Systems organization, is responsible for positioning SoCalGas employees to lead healthy, safe, and productive lives. The services provided by the department include but are not limited to: physical and mental wellness education; safety and industrial hygiene education and compliance; and incident prevention, analysis and reporting. There are two distinct work units within SoCalGas' Safety and Wellness department 1) Health and Safety, and 2) Employee Assistance

---

23 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

24 *Id.* at 16 and 17. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

Program (EAP) and Wellness. The Health and Safety group is responsible for ensuring SoCalGas is, at a minimum, in compliance with all required health and safety regulations (*e.g.,* Department of Transportation (DOT) and OSHA regulations) and is responsible for positively influencing the SoCalGas safety culture and working closely with SoCalGas personnel to provide education and training that can result in an incident-free workplace. The Health and Safety group reviews incidents and shares lessons learned with management, safety committees, and other departments within SoCalGas to prevent incidents and injuries from occurring. The staff also provides safety leadership training to frontline supervisors to make the safety culture more relevant and effective, benchmarks its safety practices against those of other companies in the industry, and identifies improvement potential. The Health and Safety work unit also participates in incident analysis and reporting and facility inspections and administers numerous facets of the SoCalGas occupational health and safety program. The work unit oversees the DOT-required programs of SoCalGas contractors to verify they are also in compliance with the DOT drug and alcohol testing regulations and submits annual contractor drug testing program statistical reports to federal agencies, as required by DOT regulations.

The EAP and Wellness group promotes adoption of a safe and healthy lifestyle to employees and their families by promoting health and wellness, substance abuse education and intervention, and mental health programs. The work unit educates the SoCalGas workforce and works to motivate employees to make positive behavioral changes to improve their health, safety, and well-being through onsite wellness events and programs, and regular distribution of educational tips and resources. The EAP and Wellness staff:

- Educates employees in topics such as proper hydration, nutrition, sleep, and activities that can contribute to preventing workplace injuries;
- Manages and administers the Company's non-regulated and DOT-regulated drug and alcohol testing programs and EAP;
- Provides oversight and administration of pre-employment, random, reasonable cause and other DOT required drug and alcohol testing of employees in safety sensitive positions, regulated by the Pipeline Hazardous Materials Safety Administration (PHMSA) and Federal Motor Carrier Safety Administration (FMCSA) drug and alcohol testing program regulations;

- Refers employees to substance abuse treatment for drug and alcohol testing violations, and case manages these and other unique and sometimes complex employee issues (*i.e.*, mental health behaviors affecting job performance, workplace violence threats or critical incidents requiring EAP or other intervention); and
- Provides guidance and support to HR departments, employees, supervisors, and managers regarding employee substance abuse, mental health and workplace violence issues, and supports organizational safety events and meetings with coordination of wellness services (*i.e.*, health screenings, flu shots, health fairs, educational presentations).

SoCalGas establishes leading indicators to support injury prevention. An example of a program that captures leading indicators is the Safety Barometer Survey SoCalGas performs to assess the overall health of our safety climate and identify areas of opportunity that can help eliminate injuries and improve our focus and commitment to safety. Periodic application of the survey allows SoCalGas to compare results between different time periods and assess areas experiencing progress or a need for improvement. The goal of this assessment is to increase employee participation in, and contribution to, SoCalGas' ongoing efforts to continually improve its safety performance. The Safety Services department:

- Interprets and advises field operations regarding safety-related rules and regulations;
- Provides review and analysis of potential legislation that would impact the Company and develops policies to enforce them;
- Provides operational support by conducting compliance audits, sponsoring company-wide safety programs, developing and conveying safety communications, managing incidents, and performing statistical analysis;
- Conducts job observations, incident investigation and root cause analysis;
- Promotes defensive driver training, body mechanics training, and ergonomics training;

- Works with field operations to prevent incidents, perform self-audits; identify corrective actions following incidents, and conduct safety training;
- Is responsible for compliance with safety regulations, as well as establishing and managing programs, policies, and guidelines for the safety of employees; and
- Manages company-wide Occupational Health Nurse (OHN) services. The OHN is a specialty practice that delivers health and safety programs and services to employees. The practice focuses on promotion and restoration of health, prevention of illnesses and injuries, and protection from work-related and environmental hazards.

As discussed in Chapter RAMP-A, certain internal labor costs are not reflected in Section VII, below. While the costs presented herein may therefore appear lower than those presented in SoCalGas' TY 2019 RAMP Report, it is important to note that this does not reflect a drop in SoCalGas' employee safety risk mitigation efforts. The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not currently track labor in this manner. Therefore, in order to aid RAMP to GRC integration efforts, and Risk Spending Accountability Reporting requirements, SoCalGas has not captured certain internal labor costs (e.g., time spent to attend training) in this 2019 RAMP Report but continues to perform these risk mitigation activities as described herein.

A. SCG-2-C1: Mandatory Employee Health and Safety Training Programs and Standardized Policies

Our employees receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. SoCalGas' Mandatory Employee Health and Safety Training Programs and Standardized Policies comprise the following elements, as required by the California Code of Regulations (CCR) and/or Cal/OSHA:

<u>Injury Illness Prevention Plan (IIPP)</u>: In California, every employer is required by law to provide a safe and healthful workplace for its employees.[25] Further, Title 8 of the California

[25] Cal. Labor Code § 6400.

Code of Regulations[26] requires every employer to have an effective IIPP. SoCalGas' IIPP is a written plan for preventing injury and illness that includes procedures. The elements included in SoCalGas' IIPP are:

- Management commitment/assignment of responsibility;
- Safety communication system with employees;
- System for assuring employee compliance with safe work practices;
- Scheduled inspections/evaluation system;
- Accident investigation;
- Procedures for correcting unsafe or unhealthy conditions;
- Safety and health training instruction;
- Recordkeeping and documentation; and
- Safety programs.

Employee Safety Standards: The employee safety standards are a collection of information, instructions, policies, and procedures intended to promote safe work practices. The purpose of the Health and Safety policies and procedures is to guide and direct all employees to work safely and prevent injury to themselves and others.

Safety standards are specifications designed to promote the safety of work activities or processes. Standards are rules that describe the methods that employers use to protect their employees from hazards. They are used to communicate policy to the workforce as well as key stakeholders and others at SoCalGas.

Industrial Hygiene Program: SoCalGas has a robust Industrial Hygiene program in compliance with Cal/OSHA regulations. Industrial Hygienists are responsible for monitoring changes in employee safety and health regulations, developing internal safety policies and procedures to promote compliance with the applicable regulations, and managing company-wide implementation of key industrial hygiene programs, such as Hazard Communications, Hearing Conservation, Respiratory Protection, Mold, Asbestos, and Lead Exposure Management.

[26] 8 CCR § 8350.

B. SCG-2-C2: Drug and Alcohol Testing Programs

SoCalGas has implemented an employee drug and alcohol testing program managed in accordance with state and federal regulations. SoCalGas' Substance Abuse Prevention policy prohibits the use and/or possession of alcohol during working hours or reporting to work with alcohol, illegal drugs, or impairing prescribed controlled substances in their system. All employees are responsible for knowing and complying with Company policy. Violations are cause for disciplinary action up to and including termination of employment.

In compliance with the Drug-Free Workplace Act of 1988[27] (which requires SoCalGas, as a federal contractor and grant recipient, to implement a comprehensive drug and alcohol-free workplace policy (DAFWP)), SoCalGas has a longstanding commitment to provide a safe and productive work environment for our employees, and safe and efficient service for our customers and the public. Because alcohol and drug abuse pose a threat to the health and safety of SoCalGas employees and the public and to the security of the Company's equipment and facilities, SoCalGas is committed to providing a drug and alcohol-free workplace. The use of illegal drugs, impairing prescribed controlled substances, and the misuse of alcohol is contrary to these high standards. All employees in non-safety-sensitive and safety-sensitive positions are subject to the Company's DAFWP. Testing under this policy is limited to only Pre-employment and Reasonable Cause, Return-to-duty, and Follow-up testing (when applicable). Under the DAFWP, SoCalGas tests for additional (*e.g.*, generally prescribed) impairing drugs not tested for under the DOT testing program. This Policy also requires employees to pre-duty disclose their use of impairing medications that may affect their ability to safely perform safety-sensitive duties.

In addition, SoCalGas also complies with the DOT drug and alcohol program requirements[28] and implemented a Drug and Alcohol Misuse Prevention Plan and Policy (DAMPPP) for employees in safety-sensitive positions, subject to these regulations and testing requirements. The purpose of the DAMPPP is to reduce accidents and injuries that may result

---

27 41 United States Code Service (U.S.C.) § 81.

28 49 CFR Part 40.

from the use of illegal drugs, impairing prescribed controlled substances, and misuse of alcohol, thereby reducing fatalities, injuries and property damage, and to comply with federal and state regulations. To comply with the DOT regulations, the Company implemented two random testing pools as required by 49 CFR Part 199 (Drug and Alcohol Testing Procedures and regulations for PHMSA-covered employees) and Part 382 (Drug and Alcohol Testing Procedures for FMCSA-covered employees (applicable to Commercial Motor Vehicle Drivers). PHMSA-covered employees are those employees who perform operations, maintenance, or emergency response functions associated with gas pipeline or LNG facilities and regulated by 49 CFR Part 192, 193 and 195. FMCSA-covered employees are commercial motor vehicle drivers required to hold a commercial Class A, Class B, or commercial C driver's license. Each of these agencies established its own additional testing policies and regulations to comply with the 49 CFR Part 40 testing procedures and set their testing rates annually. For example: PHMSA only requires random testing for drugs (current annual test rate for 2019 is 50% of the pool), while FMCSA requires testing for both drugs and alcohol (current annual test rate for 2019 is 25% of the pool for drugs and 10% for alcohol). In addition to random testing, both agencies require testing (as needed) for: Pre-employment/Pre-Assignment, Reasonable Cause, Post-Accident, Return-to-Duty and Follow-up testing, and require a drug and alcohol background history check be conducted prior to placing employees in safety-sensitive functions.

C. SCG-2-C3: Employee Wellness Programs

SoCalGas' Employee wellness program objectives are to design comprehensive "Wellbeing" programs that reflect the Company's commitment to employees and their social communities. Further, it builds a culture of health and safety at work and in personal life that has a positive impact on our medical plan populations' morbidities and creates an understanding of the incremental impact that a collective wellbeing program presence can have on helping SoCalGas continue its high performance and achievement of organizational goals.
SoCalGas' Wellbeing Program goals are to:

- increase employee awareness of personal health and safety;
- empower and educate employees about making healthy lifestyle choices; and

- improve employee and their social communities' quality of living.

According to the CDC, preventable chronic conditions are a major contributor to the costs of insurance premiums and employee medical claims and lost productivity. Effective worksite wellness programs can result in significant, positive outcomes such as:

- Better employee health;
- Less absenteeism and sick leave;
- Higher job performance and productivity;
- Lower health insurance costs;
- Fewer safety incidents and workers' compensation claims; and
- Happier, more satisfied employees.
- The Company Wellbeing programs strive to offer programs under the following wellness pillars:
- Move More (Physical Fitness and Activity);
- Eat Right (Healthy Eating and Weight Management);
- Prevent It. Manage It. (Disease Prevention and Mgmt., Biometric Screenings);
- Stress Less. Focus More. (Mental/Emotional Wellbeing);
- My Money (Financial Wellbeing and Saving);
- My Community (Giving Back – Engagement, Volunteerism and Awareness);
- At Your Fingertips (Interactive Tools, Guides & Resources); and
- Achieve It! (Incentives and recognition).

In addition, based on medical plan utilization and experience, our educational programs target the following areas:

- Diabetes;
- Cancer;
- Heart Disease;
- Obesity;
- Stress;
- Coronary Arterial Disease (CAD);
- Asthma and Chronic Obstructive Pulmonary Disease (COPD); and

- Tobacco Cessation.

D. SCG-2-C4: Employee Safety Training and Awareness Programs

Training, education and awareness are elements of a strong Injury and Illness Prevention Program. As stated above in SCG-2-1, our employees receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. Front-line employees are trained in behavior-based safety programs. At SoCalGas, safety is a core value, so we provide all employees with the training necessary to safely perform their job responsibilities.

A strong safety culture requires the right people at the right job with the right skills. The Human Resources function, with support from the operating organizations and the Safety Management Systems (SMS) organization at SoCalGas, supports the safety culture by attracting, developing, training and retaining employees who have the skills and abilities to perform their jobs safely and operate and maintain a safe and reliable system. To achieve the accountability of enhancing the safety culture, the SMS organization, the operating organizations, and the Human Resources function are responsible for performance management, organizational effectiveness and safety. SoCalGas develops training plans by job classification that include courses required to perform certain work, meet company objectives, and satisfy required compliance training. Training plans are maintained in SoCalGas' Learning Management System (cornerstone) and accessed by supervisors and employees through the MyInfo application. Each department is responsible for maintaining training plans and ensuring employees complete initial and periodic refresher training requirements. Contractor compliance, maintenance of DOT-required programs, improving driver safety via training, and in-vehicle instruction are also top priorities for SoCalGas.

SoCalGas deploys a "Safety Essentials for Supervisors" training program which is a 1-day workshop developed for new and existing supervisors to provide a comprehensive understanding about safety culture and leadership for supervisors to effectively manage safety programs at their respective work location. This training is mandatory for all new supervisors and is offered as a refresher to existing supervisors. Safety and Wellness execute these programs to maintain employee safety.

SoCalGas also has a Safety-First program. This program involves the rollout of safety committee member training to prepare safety committee members to better influence the safety culture. The focus of this training is to enhance the skills of safety committee members, so safety improvement projects and person-to-person interaction are more effective. SoCalGas seeks to enhance the mindset that employees are "one-another's keeper" when it comes to safety. SoCalGas provides initial and refresher safety leadership training to safety committee members. The safety committee members include Union employees, and in the operating organizations, the safety committees typically consist of mostly Union employees. The training is available to all job classifications. These individuals are safety advocates and are in safety leadership roles. They help define and instill the safety culture at their respective work location.

SoCalGas uses an Environmental and Safety Compliance Management Program (ESCMP) to track and document completion of the above-noted training courses, as well as compliance requirements, awareness, goals, monitoring, and verification related to all applicable environmental, health and safety laws, rules and regulations, and Company standards. SoCalGas' annual ESCMP certification process involves submittal of information into a database used to collect and record employee and facility compliance. For this submittal, two types of checklists are available and completed in the online system: An employee-based checklist and a facility-based checklist. Through this process, the Environmental and Safety departments can review submittals in the online system and confirm all required inspections were completed, assigned training was done, and all corrective actions were addressed.

E. SCG-2-C5: Safe Driving Programs

SoCalGas' safe driving programs aim to increase a driver's safety awareness to prevent and minimize the risk of motor vehicle incidents. With senior management's commitment and employee involvement, SoCalGas is driving a safety culture committed to safe driving. This commitment includes written policies and procedures and the following program elements:

Alert Driving Program: FleetDefense® by AlertDriving is a state-of-the-art online Driving Safety Program designed to increase skills that will help keep employees safe and reduce traffic incidents. The FleetDefense web-based training uses targeted defensive driving courses to assess employees' safe driving behaviors and evaluate drivers' defensive skills using actual footage of near-collision situations. The training features an online hazardous driving assessment called the Hazard Perception Evaluation (HPE). Once the HPE is completed, each driver is assigned monthly online training modules.

DMV Drivers' License Pull Program: The California DMV Pull Notice Program allows SoCalGas to monitor driver's license records of employees who drive on the Company's behalf. SoCalGas is enrolled in the Class A Pull Notice Program, which also enrolls the employee in the random alcohol and drug testing program, per Company policy, which is managed by the Employee Care Services department.

The ability to monitor driving records assists the Company in improving employee and public safety and helps minimize overall risk and liabilities. The Program automatically sends a notice when an employee has an action against their license, such as a suspension or a DUI. This information also helps to reveal problem drivers or driving behavior with notice of accidents and failures to appear.

Commercial Drivers' License Program: In accordance with the FMCSA Drug and Alcohol Testing Regulations,[29] SoCalGas' EAP and Wellness department must subject the Company's commercial drivers who operate a commercial motor vehicle (*i.e.*, vehicles with a GVWR of 26,001+ pounds, or are placarded for hazardous materials) to random drug and alcohol testing. Details of this program are outlined under the Drug and Alcohol Testing section above (*see*, SCG-2-C2). To manage this pool, the EAP and Wellness department collaborates with the Gas Systems Integrity Staff and Programs department (who manages the DMV Pull Notice Program) to determine that each commercial driver in the random testing pool has a valid commercial driver's license and medical card. In addition, this group also provides the information on new drivers that need to be added to the pool, or inactive drivers that need to be removed from the pool. The EAP and Wellness team closely monitors this pool by gathering driver data monthly, from the DMV Pull Notice department, and prior to the next month's random selection, to determine that the pool is not diluted with inactive drivers and/or that new employees are promptly added to the pool. EAP and Wellness also conducts required DOT drug and alcohol history background checks for all new drivers that enter the CMV driver pool.

[29] 49 CFR Part 382.

Effective January 4, 2020, FMCSA will require that the Company also register with their FMCSA Driver National Clearinghouse. The EAP and Wellness team will now be required to check the Clearinghouse for drug and alcohol violations prior to hiring new drivers, and thereafter on an annual basis. The team must also report violations to this Clearinghouse within three days of any driver drug and alcohol program violations.

F. SCG-2-C6: Personal Protective Equipment (PPE)

The purpose of SoCalGas' PPE Program is to protect employees from the risk of injury by creating a barrier against workplace hazards. The PPE Program addresses eye, face, head, foot, and hand protection. OSHA standards require employers to conduct and certify workplace hazard assessments for the use of PPE at facility locations that are representative of the types of ongoing work operations. SoCalGas does not have to perform a hazard assessment at each location, but if a hazard assessment is performed, for example, at a transmission facility, then that assessment is representative of other similar transmission facilities and would also apply to those locations. SoCalGas provides its employees with the PPE required to safely perform work (*e.g.*, flame-retardant suits, eye protection, and gloves). The Company maintains processes and procedures so that employee hearing and respiratory functions are not impaired due to exposure to harmful environmental conditions. When work is performed that could expose customers or the public to injury, controls are implemented to mitigate risk. The costs associated with equipment and specific occupational safety programs are included in this category.

G. SCG-2-C7: Near Miss, Stop the Job and Jobsite Safety Programs

All SoCalGas employees, regardless of rank or title, are given the authority to "stop a job" at any time if they identify a safety hazard and are encouraged to raise a red flag whenever they feel it is needed. SoCalGas recognizes the importance of learning from close calls and near-misses to reduce the potential for a serious incident or injury in the future.[30] We encourage employees to report close calls. The information is submitted to Safety Services for review and may be shared with other employees, so they understand and benefit from lessons learned.

---

30 The National Safety Council describes a close call or near-miss as an unplanned event that did not result in injury, illness, or damage, but had the potential to do so.

Front-line employees are trained to "Stop the Job," a SoCalGas safety best practice that empowers anyone to stop the job at any time, without fear of retaliation, if they see a condition that might be unsafe. Following invocation of "Stop the Job," the job can only resume once all concerns have been addressed and safety precautions have been taken.

SoCalGas maintains a Quality Assurance (QA) program to assess the work quality of many of its field personnel. Job observations and field rides are conducted by management personnel based upon Behavior Based Safety (BBS) principles. SoCalGas' BBS program is a proactive approach to safety and health management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. The purpose of the job observation and field ride process is to reduce the occurrence of at-risk behaviors by modifying an individual's actions through observation, feedback, and positive interventions aimed at developing safe work habits. Employees are also provided feedback and coaching so that their work conforms to policy and procedure.

H. SCG-2-C8: Safety Culture

SoCalGas promotes a vigilant focus among all employees by investing in regular events on safety issues and facilitating discussion of safety practices. Safety meetings are important to SoCalGas and, therefore, are scheduled on a regular basis. These meetings include: weekly reviews of relevant policies and procedures; safety tailgates to discuss workplace hazards, work plans, and responsibilities; safety stand-downs to discuss safety incidents, close calls, bulletins or other safety topics; safety committee meetings to develop and present material on various safety topics; annual safety stand-downs at its operating districts; annual safety congresses for employees and contractors; and dialogue meetings with Company and department leadership.

Since 1999 SoCalGas has held annual Safety and Health Congresses to provide a forum for local safety committee members (composed of represented employees) to share and exchange safety information and ideas. Recipients of the Individual and Committee Safety Excellence Awards are announced at the events, recognizing safety stand-outs who embrace the safety culture and demonstrate safety leadership.

Safety Culture Survey: SoCalGas regularly assesses its safety culture and encourages two-way communication between employees and management as a means of identifying and managing safety risks. SoCalGas conducts and invites/encourages all employees to participate in the National Safety Council (NSC) Barometer Survey every two to three years (Safety Culture Survey). The first survey was conducted in 2013, followed by two more surveys in 2016 and 2018. Safety Culture Survey results are shared with all employees, improvement opportunities are identified, corrective actions implemented, and progress measured by comparing results from survey to survey. We look to continually improve our safety program and culture using a variety of means, including using the Safety Culture Surveys.

Safety Stand-downs: A Safety Stand-down is a voluntary event for employers to talk directly to employees about safety. These events provide an opportunity to discuss hazards, protective methods, and the company's safety policies, goals and expectations. SoCalGas has about five dozen operating districts and each district typically conducts a safety stand-down every year. The purpose of these safety stand-downs is to bring district employees together to raise awareness about safety, health and wellness. Local management and the local safety committees select topics of interest to the district and the topics change from year to year. This practice has been in place for more than a decade.

Safety Congress and Leadership Awards: Since 2002 this event has been held annually, providing a forum for safety committee members, safety leaders, and others to share and exchange information and ideas through networking and workshops. At this event, safety leaders are recognized for living by the company's safety vision, turning that vision into action, embracing the SoCalGas safety culture, and demonstrating safety leadership.

Safety Tailgates: Safety tailgate talks are short informational meetings held with employees to discuss work-site related safety. The purpose of a tailgate is to inform employees of specific hazards associated with a task and the safe way to do a job. Tailgate talks also serve as a reminder to employees of what they already know while establishing the supervisor's credibility and conscientiousness about his role related to safety and work oversight.

Safety Meetings: The main objective of a safety meeting is to remind employees of safe practices they have already learned or to introduce and build awareness of new techniques, new equipment, or new regulations that must be observed.

I. SCG-2-C9: Utilizing OSHA and Industry Best Practices and Industry Benchmarking

SoCalGas collaborates with high-performers in environmental, health and safety across industry sectors and regions of the world through the Campbell Institute at the NSC, benchmarking with other utilities, industries, and leaders in safety performance. SoCalGas benefits from building relationships with other safety leaders, accessing best practices on employee and contractor safety, and benchmarking on leading indicators and key safety program elements.

SoCalGas participates in safety benchmarking forums to compare our health and safety processes, performance against others to learn how to reduce incidents, improve compliance, and discuss best management practices as efforts to improve the safety health of our organization. Our end goal is to send every employee home safely every day by targeting zero. Some of the key organizations the Company benchmarks against are the American Gas Association (AGA), the Campbell Institute, the Bureau of Labor Statistics, and other partners.

Additionally, SoCalGas attends the California Independently Owned Utility (IOU) and Municipality bi-annual meeting to discuss employee and contractor safety. This dedicated forum is a utility benchmarking initiative addressing new regulations, legislation, best management practices, and other safety topics of interest.

Of equal importance are outreach activities with local first responder agencies, county coordinators (emergency management), and other public officials which occur on a yearly basis, focusing on how the Company can partner during an emergency incident response, including a review of infrastructure location information, hazard awareness and prevention, leak recognition and response, emergency preparedness and communications, damage prevention and integrity management. In addition, SoCalGas partners with these stakeholders throughout the year on joint drills, exercises, tabletops, and preparedness fairs to enhance our coordination and response during emergencies. SoCalGas has also established liaisons with appropriate fire, police, and other public officials across its service territory, which includes over 100 fire agencies. Recently, SoCalGas deployed emergency response services to northern and southern California following weather-related events, and also sent assistance to the Boston area following a pipeline overpressure occurrence.

J. SCG-2-M1: OSHA 30-hour Construction Certification Training

The OSHA 30-hour construction training is part of OSHA's Outreach Training Program, which is a voluntary training program started by OSHA in 1971. According to OSHA, its purpose is to promote workplace safety and health and to make workers more knowledgeable about workplace hazards and their rights. The OSHA Outreach Training Program alone does not, however, fulfill the training requirements found in OSHA standards. For example, there are separate OSHA standards for energy isolation programs (*i.e.,* Lock-out and Tag-out programs), the confined space program, the lead standard, and the asbestos standard. There are specific compliance training requirements for employees who are involved in these activities. The Outreach 30-hour training covers many of those hazards, but it is considered non-mandatory training and is over and above the compliance training mandated by OSHA standards. Therefore, employers are responsible for providing additional training for their employees on the specific hazards of their job, as noted in many OSHA standards. OSHA's Outreach Training Program provides training on the recognition, avoidance, abatement, and prevention of workplace hazards. Through its national network of OSHA Training Institute (OTI) Education Centers, qualified individuals become authorized OSHA Outreach trainers and deliver 30-hour outreach classes to workers. According to OSHA, between FY 2012 and FY 2016, more than 3.94 million workers were trained in job hazard recognition and avoidance through the program.

SoCalGas plans to add this new training for employees involved in construction jobs. This mitigation would provide the 30-hour training to all field supervisors and field employees involved in construction and operations activities (*e.g.*, Gas Operations, Gas Transmission Operations, Customer Services Field, Storage Operations, Construction Projects/Programs (like PSEP, MHP, PI, and TIMP)). The purpose of providing employees with this new training is to further enhance their skills in hazard identification and help them gain certification that is recognized by regulatory agencies nationwide. By becoming better at identifying hazards, employees are expected to contribute to reducing the risk of injuries.

K. SCG-2-M2: Industrial Hygiene Program Refresh

An important component of the industrial hygiene program is to conduct exposure assessments for issues of concern to employee health and safety and to establish appropriate mitigation measures and controls. SoCalGas has been conducting such assessments for over three decades, in conjunction with the various industrial hygiene programs, to promote employee health and safety as well as compliance with various Cal/OSHA regulations.

An important component of conducting exposure assessments is to review these assessments and periodically refresh or update them to confirm that they still support the decisions made on mitigation controls to promote employee health and safety. There are no specific regulatory requirements defining a frequency at which the initial assessments should be reviewed and updated, except when the conditions of exposure have significantly changed. SoCalGas recognizes the need to review all past records and identify records that are older than 10 years or more to assess whether those assessments need to be refreshed and updated.

SoCalGas plans to take a proactive approach in conducting additional assessments in areas where regulations may become more stringent in the future and gradually work towards achieving compliance prior to new requirements coming into play.

For example, noise generating equipment and machinery at many facilities have changed since SoCalGas originally conducted noise surveys for employees to assure compliance with the Hearing Conservation Program. Obtaining more current data through implementation of this program will help to document the noise levels for employee job tasks and alert SoCalGas to any new areas of concern. It should also be noted that noise dosimetry monitoring technology has also significantly advanced, improving the accuracy of the data collected and method of documentation. Implementation of this program will include a re-sampling that will assist us in ensuring our data has been collected and documented in sync with best practices.

Cal/OSHA is proposing regulation changes for occupational lead exposure. One of the changes will be a lower Permissible Exposure Limit (PEL): down to 10 ug/m3 from 50 ug/m3, and a lower Action Limit (AL): down to 2 ug/m3 from 30 ug/m3. Most of our industrial hygiene exposure assessment data for lead removal tasks was gathered before 2012 and was based on complying with the current exposure limits. Employee tasks will need to be monitored again to determine if they can comply with the proposed lower exposure limits. The tasks may need to be modified or deleted depending on the air monitoring results.

L. SCG-2-M3: Establish Proactive Monitoring for Indoor Air Quality and Chemicals of Concern

SoCalGas historically has addressed indoor air quality (IAQ) issues when they are raised by employees as safety concerns. Such issues have been brought up typically at large headquarters facilities. Most recently in 2019, a concern was brought up regarding mold at the Compton headquarters facility. The issue was resolved by abating the areas contaminated by mold growth and conducting a thorough IAQ investigation, which created a lot of anxiety amongst several hundred employees working at the facility. One of the biggest takeaways from the incident was to consider a proactive approach to evaluating IAQ on a routine basis at a representative number of SoCalGas office-type facilities where employees work indoors on a full-time basis. Thus, SoCalGas is proposing to begin this new Proactive Monitoring program to conduct annual IAQ assessments at the six large headquarters facilities in its service territory. This mitigation measure, in combination with other existing and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend.

M. SCG-2-M4: Creation of a Safety Video Library

SoCalGas has a safety video library comprised of training videos on a variety of safety topics. The collection consists of several hundred titles covering around 50 primary safety topics, with typically a single copy available for physical checkout by SoCalGas employees. The collection is outdated with virtually all titles available only in a format that is no longer useful, and the video check-out and check-in process is cumbersome, disincentivizing its use.

To streamline the library, SoCalGas plans to subscribe to a third-party online streaming service provider to get access to the latest safety training materials from a reputable training source. This will tremendously help our employees and supervisors to have 24/7 ready access to the relevant and most updated safety training materials to use during their safety stand-downs, daily morning safety meetings, daily tailgate meeting for field crews, and other safety events.

N. SCG-2-M5: Expanded Safety Congress and Expanded Safety Council

As stated above, since 1999, SoCalGas has held annual Safety and Health Congresses to provide a forum for safety committee members (composed of represented employees) to share and exchange safety information and ideas. Recipients of the Individual and Committee Safety Excellence Awards are announced at the events, recognizing safety stand-outs who embrace the safety culture and demonstrate safety leadership. There are two congress events scheduled every year principally benefiting the transmission, distribution, customer services, underground and aboveground storage and other operating organizations.

Beginning in 2019, SoCalGas added an additional safety congress event for the benefit of the multitude of staffing/office organizations located at SoCalGas' Gas Company Tower in Los Angeles. This milestone event took place in Sept. 2019. This expansion is expected to further improve the safety awareness and ownership amongst office employees and help reduce ergonomic and other office related injuries and incidents. This mitigation measure, in combination with other existing and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last 5 years' historical trend.

SoCalGas Executive Safety Council (ESC) has been in place for well over a decade and its purpose is to provide safety oversight and executive interactions with employees over safety matters. The ESC is led by the Chief Safety Officer of SoCalGas and includes all executives with operations responsibilities. The ESC meets on a quarterly basis at various operating locations to engage with represented employees, supervisors, and managers associated with an operating district or a region. Unique and separate employee dialogue sessions are held to provide a forum for employees to share their candid feedback on what is going well in safety and what needs to be improved. Issues brought up are discussed and resolved during the dialogue session or carried forward as action items for later resolution. These sessions, which have been well-received by employees, enable executives and employees to share their perspectives on safety successes, challenges, and opportunities.

Beginning in 2019, SoCalGas expanded the frequency of these interactions from quarterly to monthly to enable reaching out to more operating districts and more employees in the Company. The four quarterly sessions will continue as is, but the supplemental monthly sessions will be less structured and more integrated with local safety stand-downs managed by each operating district. In the monthly sessions, executives actively participate in the operating district's routine safety stand-down activities. The primary goal with the monthly interactions is to demonstrate support by executives for our front-line employees (management and represented) and local safety committees to learn how executives can better support safety.

O. SCG-2-M6: Expanded Safety Culture Assessments

As stated above (SCG-2-C8), since 2013, SoCalGas has retained the NSC to use its Safety Barometer Survey to engage our employees to provide input on safety, gain benchmarking insight, and identify improvement opportunities (Safety Culture Survey). SoCalGas has now completed three cycles of the Safety Culture Survey (2013, 2016, and 2018) and has ranked consistently high, above the 90th percentile of 580 similarly surveyed companies. More important than the ranking, the Safety Culture Survey has helped to identify safety areas of alignment and strength as well as opportunities for potential improvement.

Moving forward, SoCalGas plans to expand the assessments to include focus group discussions, employee interviews and field observations of employee job activities to view safety culture in action and further supplement the feedback received from the Safety Culture Surveys. SoCalGas also plans to tap into grass-roots activities of its local safety committees and integrate that insight into safety culture assessment. The purpose of these additional methods and approaches is to gain further insight in areas of success and potential weakness within the safety management system or programs and identify more relevant and specific opportunities of improvement. This mitigation measure, in combination with other existing and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. SoCalGas has not calculated an RSE for activities beyond the requirements of the S-MAP SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[31] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. As defined in the SA Decision, a tranche is "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment."[32] Therefore, risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE).

SoCalGas' comprehensive Employee Safety program consists of training courses, policies, programs, and efforts aimed to reduce risk of injury or fatality to employees while on duty. Given the vast number of activities SoCalGas performs to mitigate Employee Safety risk, SoCalGas grouped similar activities with similar risk profiles into mitigation programs. Since each of SoCalGas' Employee Safety risk mitigations have the same goal of reducing employee risk of injury or fatality, all controls and mitigations have the same risk profile and are not further tranched.

B. Post-Mitigation/Control Analysis Results

For this post-mitigation and post-control analysis, SoCalGas evaluated the historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. Historically, SoCalGas has routinely improved existing mitigations and/or added new mitigations to continue enhancing safety. As such, for existing and new programs, we expect to get similar level of reduction (3.33% per year) based on the last 5 years (2014 through 2018) of historical trend in OSHA recordable injury rates. This equates to 10% reduction over the 3-year GRC cycle. This 10% reduction, when equally allocated to each of the controls identified below, results in a 0.33% annual risk reduction benefit over the 3-year GRC cycle by continuing the activities. For SoCalGas' new programs/activities

---

31 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

32 *Id*. at A-4.

(*i.e.,* mitigations), SoCalGas has applied an incremental effectiveness of 0.06% annual risk reduction benefit.

1. SCG-2-C1: Mandatory employee health and safety training programs and standardized policies

a. Description of Risk Reduction Benefits

Safety programs and standards help decrease employee safety risk by providing information in policy and procedure formats used to guide and direct all employees to work safely and prevent injury, to themselves and others. Injury and illness prevention programs can substantially reduce the number and severity of workplace injuries and illnesses while reducing costs to employers. OSHA mandatory employee health and safety training programs and standardized policies help reduce SoCalGas employee risk by providing a framework for working safely while addressing safety and health issues in the workplace. They serve as a proactive approach to manage workplace safety and health by educating employees and at times the public (*e.g.*, SoCalGas informs employees and the public about natural gas leak abatement). These guidelines recognize that finding and correcting hazards before an injury or illness occurs is far more effective than an after-the-fact response.

Industrial hygiene programs anticipate, recognize, evaluate and correct workplace conditions that may cause workers' injury or illness. These programs include, but are not limited to Hearing Conservation, Respiratory, Hazard Communication – Chemical, and Asbestos/lead/mold Abatement. Industrial hygiene programs use environmental monitoring and analytical methods to detect the extent of worker exposure and employ engineering, work practice controls, and other methods to control potential health hazards. Developing and complying with mandatory occupational safety and health standards involves determining the extent of employee exposure to hazards and deciding what is needed to control these hazards, thereby protecting the workers. Industrial hygienists, or IHs, are trained to anticipate, recognize, evaluate, and recommend controls for environmental and physical hazards that can affect the health and well-being of workers.

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-2-C1 because the program elements are mandated by law and/or regulation.[33] SoCalGas must comply with all applicable laws/regulations, and thus it is not feasible for SoCalGas to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. This well-established program serves as a proactive approach to address potential workplace safety and health hazards and therefore reduce Potential Consequences by identifying potential hazards and developing training, policies and programs designed to avoid those hazards. SoCalGas' mandatory health and safety training programs and standardized policies therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); hazards in the work environment or within the pipeline system (DT.2); non or improper use or undisclosed prescriptions or medical restrictions (DT.4); employees not prepared to responds to emergencies (DT.5); effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6); and unsafe operation of equipment or motor vehicles (DT.7). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); and property damage (PC.2). As stated above, this program is mandated by state and federal regulation. SoCalGas complies with all applicable laws and regulations and implements the various elements of this program in aim to reduce its Employee Safety risk.

2. SCG-2-C2: Drug and Alcohol Testing Program

a. Description of Risk Reduction Benefits

Drug testing and substance abuse prevention training in the workplace connects to occupational safety as a key component in protecting the safety, health, and welfare of employees and the public. Drug testing programs can contribute to the reduction of employee injury- and illness-related by providing a powerful deterrent to on-the-job drug use. Employers

[33] Cal. Labor Code § 6400; *see also* 8 CCR § 8350.

who are drug testing are committed to having sober employees in the workplace, thereby reducing occupational injuries and illnesses and to sending a clear signal they care about their employees. In addition, reasonable suspicion drug testing is a critical safety measure. An employee that may be impaired while working and must be taken out of his or her work position; the drug and/or alcohol test will verify that the employee may have used drugs or alcohol while at work or before coming to work, which in turn decreases the likelihood of an at work injury.

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-2-C2 because the program elements are mandated by law and/or regulation.[34] SoCalGas must comply with all applicable laws/regulations, and thus it is not feasible for SoCalGas to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. This program represents both a proactive approach (*e.g.*, policy, procedures, training) and a reactive approach (*e.g.*, post-accident testing, disciplinary action) to address potential safety hazards related to the potential for employee drug and/or alcohol use. SoCalGas' drug and alcohol testing program therefore addresses the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); drug/alcohol use or undisclosed prescriptions or medical restrictions (DT.3); employees not prepared to responds to emergencies (DT.5); effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6); and unsafe operation of equipment or motor vehicles (DT.7). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2); operational and reliability impacts (PC.3); adverse litigation (PC.4); penalties and fines (PC.5); and erosion of public confidence (PC.6). While this risk is covered in this Employee Safety chapter, this program also provides risk benefit to SoCalGas' Customer and Public Safety risk (SCG-4).

[34] 41 U.S.C. § 81; 49 CFR Parts 40, 192, 193, 195, 199 and 382.

3. SCG-2-C3: Employee Wellness Programs

a. Description of Risk Reduction Benefits

Comprehensive wellness programs that encourage healthy lifestyles and provide wellness resources help employees reduce health risks and promote disease management and decrease distraction that can lead to injury. SoCalGas' approach to a healthy workplace has evolved from solely the physical work environment (primarily on-the-job safety concerns) to a more holistic concept that encompasses psychosocial and personal health factors. This focus is comprehensive in scope, encompassing assessment of employees' overall well-being in addition to injury prevention. It includes an increasing emphasis on programs supporting safety that is inclusive of physical, mental, and social well-being.

With an integrated program in place that encompasses health promotion, occupational health and safety, the Company can break down silos to promote a healthy workplace. For example, if musculoskeletal disorders are occurring among employees, SoCalGas can examine the ergonomics of the work process/station and correct any hazardous physical conditions.

For purposes of RSE analysis, SoCalGas applied a 0.33% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.33% reduction for continuous implementation of this activity. As a current control, SoCalGas expects to receive a reduction in further risk benefit for continuing this activity but also took into account the expected rise in health and safety incidents if this activity was no longer performed.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas' wellness programs serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential Consequences. SoCalGas' employee wellness programs therefore address the following elements of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2); and drug/alcohol use or undisclosed prescriptions or medical restrictions (DT.3). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4577**	
	CoRE	80.246	**765.29**	1907.02
	Risk Score	116.97	**1115.54**	2779.81
	RSE	0.12	**1.10**	2.75

4. SCG-2-C4: Employee Safety Training and Awareness Programs

a. Description of Risk Reduction Benefits

At SoCalGas, safety starts with the individual. Accordingly, the Company trains and equips every employee to work safely, respond during an emergency and live a healthy lifestyle. SoCalGas believes that making sure employees have information, tools and training to do their jobs safely will reduce the potential for injury. Training includes safety hazard identification and mitigation for the various job activities employees perform. Lack of training may result in employees not understanding safety hazards of their work environment and increase the likelihood of injury. With safety as the core value of its operations, SoCalGas chooses to integrate these fundamentals into the Company's safety programs and worksites.

Each Director and Manager who reports to a Vice President (VP) or Senior VP (SVP) is assigned the role of "Responsible Person" (RP) for an Employee-Based Checklist as part of SoCalGas' Environmental and Safety Compliance Management Program (ESCMP). A RP is tasked with entering ESCMP information into the online system and submitting the checklist electronically to his/her VP/SVP for approval. This process provides oversight to verify that applicable safety compliance requirements are completed by employees.

SoCalGas

A Sempra Energy utility

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-2-C2 because the program elements are mandated by law and/or regulation.[35] SoCalGas must comply with all applicable laws/regulations, and thus it is not feasible for SoCalGas to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas' employee safety training and awareness programs aim to proactively train employees on topics necessary to safely perform their job and communicate topics of importance for safety best practices. These programs are a proactive approach aimed to minimize and help prevent Potential Consequences, including serious injury or fatality. SoCalGas' employee safety training and awareness testing programs therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); hazards in the work environment or within the pipeline system (DT.2); drug/alcohol use or undisclosed prescriptions or medical restrictions (DT.3); non or improper use of personal protective equipment (DT.4); employees not prepared to responds to emergencies (DT.5); and unsafe operation of equipment or motor vehicles (DT.7). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1).

5. SCG-2-C5: Safe Driving Programs

a. Description of Risk Reduction Benefits

Implementation of driver safety programs helps SoCalGas keep employees safe by educating them on driving techniques and principles that decrease the risk of motor vehicle incidents, collisions, and traffic violations. These programs teach drivers to improve their driving skills by reducing their driving risk by anticipating situations and making informed decisions. The Department of Motor Vehicle (DMV) Drivers' License (DL) Employer Pull Notice (EPN) program allows SoCalGas to electronically receive employees' driving records of employees who drive on behalf of our organization and are subject to Department of

35 29 CFR § 1910 *et. seq.*

Transportation regulations. The monitoring allows SoCalGas to determine if each driver has a valid drivers' license, reveal problem drivers or driving behavior, and improve public safety. The EPN automatically generates a driver record when there is a conviction, failure to appear, accident, driver license suspension or revocations, or any other actions taken against the driving privilege addended to an employee's drivers record. These notifications allow SoCalGas to stay up-to-date with drivers' records and reduce the likelihood of accidents by monitoring the status/validity of current licenses and provides information about potential issues that may need to be reviewed for action.

For purposes of RSE analysis, SoCalGas applied a 0.33% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.33% reduction for continuous implementation of this activity. As a current control, SoCalGas expects to receive a reduction in further risk benefit for continuing this activity but also took into account the expected rise in health and safety incidents if this activity was no longer performed.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas' safe driving programs serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential Consequences. SoCalGas' safe driving programs therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); hazards in the work environment or within the pipeline system (DT.2); drug/alcohol use or undisclosed prescriptions or medical restrictions (DT.3); effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6); and unsafe operation of equipment or motor vehicles (DT.7). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4577**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.97	**1115.54**	2779.81
	RSE	0.41	**3.90**	9.72

6. SCG-2-C6: Personal Protection Equipment (PPE)

a. Description of Risk Reduction Benefits

Controlling exposures to occupational hazards is the fundamental method of protecting workers. These controls include elimination, substitution, engineering and can be administrative in an effort to minimize hazard exposures in the workplace. When such controls are not practical or applicable, PPE is employed to reduce or eliminate personnel exposure to hazards. PPE is worn to minimize exposure to hazards that cause serious workplace injuries and illnesses. These injuries and illnesses may result from contact with chemical, physical, mechanical, or other workplace hazards. SoCalGas' PPE program, together with employee safety training, reduces risk to employees by ensuring the proper use and fitting of PPE.

Per OSHA standards,[36] prior to requiring employees to wear PPE, SoCalGas is required to:

- Perform hazard assessments and determine the PPE needed to protect workers;
- Provide training on the proper use of PPE for working on or near exposed energized parts;
- Discuss PPE needs during required job briefings; and

[36] *Id.* at § 1910.269.

- Inspect and test certain PPE to determine that they are not damaged or defective and will provide the needed protection.

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-2-C2 because the program elements are mandated by law and/or regulation.[37] SoCalGas must comply with all applicable laws/regulations, and thus it is not feasible for SoCalGas to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Mandatory use of PPE aims to keep employees safe and prevent Potential Consequences from workplace hazards possibly resulting in serious injury or fatality. SoCalGas' required use of PPE therefore addresses the following elements of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2); non or improper use of personal protective equipment (DT.4). This program aims to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1).

7. SCG-2-C7: Near Miss, Stop the Job and Jobsite Safety Programs

a. Description of Risk Reduction Benefits

Near-miss reporting helps prevent incidents by alerting the Health and Safety department of an event that did not result in injury, illness, or damage but had the potential to do so. This program allows potential hazards to be investigated, mitigated, and communicated. Reporting near-misses also reduces risk by promoting a culture of safety and establishing opportunities to review safety systems and hazard controls and share lessons learned.

Every employee at SoCalGas has the authority to stop the job or stop a task that they believe is unsafe or requires a pause for clarification, regardless of level. This action is supported by management, the union, and the Health and Safety department.

Jobsite safety programs are about an understanding of the work being performed and potential hazard exposure. Planning and understanding the work being performed are key to

---

[37] *Id.* at § 1910 *et. seq.*

understanding and mitigating the risks associated with job site safety. Jobsite safety programs define the task and hazard descriptions, how risk exposure can arise, contributing factors, consequences, and hazard controls.

A job hazard analysis (JHA) or job safety analysis (JSA) is a technique used to identify the hazards/dangers of specific tasks in order to reduce the risk of injuries to workers. It focuses on the relationship between the worker, the task, tools, and work environment. Simply put, a hazard is the potential for harm often associated with a condition or activity that, if left uncontrolled, could result in injury or illness. Identifying hazards, eliminating them, or controlling them as early as possible will help prevent injuries and illnesses.

In addition to eliminating, controlling, and preventing hazards in the workplace, JHAs are a valuable tool for training employees about the steps required to perform their jobs safely. JHAs are often done for jobs with the highest injury or illness rates, jobs with the potential to cause severe incidents, jobs where one human error could lead to a serious incident or fatality, jobs that are new to the operation, or changed and complex jobs.

It is important to review JHAs when jobs change or if an incident occurs, so that the JHA can be updated to prevent injuries. When changes are made, or the JHA is affected by new job methods, equipment, or procedures, for example, updates should be made, and training should be given to all employees affected by the changes.

For purposes of RSE analysis, SoCalGas applied a 0.33% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.33% reduction for continuous implementation of this activity. As a current control, SoCalGas expects to receive a reduction in further risk benefit for continuing this activity but also took into account the expected rise in health and safety incidents if this activity was no longer performed.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas' Near Miss, Stop the Job, and jobsite safety programs serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential Consequences. SoCalGas' jobsite safety programs therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); hazards in the work environment or within the pipeline system (DT.2); drug/alcohol use or undisclosed prescriptions or medical restrictions (DT.3); non or improper use of personal protective equipment (DT.4); effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6); and unsafe operation of equipment or motor vehicles (DT.7). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4577**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.97	**1115.54**	2779.81
	RSE	1.31	**12.48**	31.10

8. SCG-2-C8: Safety Culture

a. SoCalGas-2-C8-T1

i. Description of Risk Reduction Benefits

Governed by the Executive Safety Counsel and led by SoCalGas' Chief Operating Officer, who is also the Chief Safety Officer, SoCalGas' various safety committees help inform and educate employees about safety and health issues throughout all levels of the Company and set meaningful and attainable safety goals throughout the organization. Safety committees provide the following benefits:

- support a positive safety culture;
- reduce the risk of workplace injuries and illnesses;
- encourage employees to participate in the Company safety programs;
- confirm compliance with state and federal health and safety regulations;

- provide feedback on safe work practices;
- develop safety programs tailored to individual departments;
- lead safety training;
- communicate about safety and health issues; and
- provide a forum where employees and company leadership can discuss, identify and collaborate on safety solutions.

For purposes of RSE analysis, SoCalGas applied a 0.33% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.33% reduction for continuous implementation of this activity. As a current control, SoCalGas expects to receive a reduction in further risk benefit for continuing this activity but also took into account the expected rise in health and safety incidents if this activity was no longer performed.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C8 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas' safety culture initiatives create constant awareness, dialog, and means for employees to express questions, concerns and lessons learned. Though these activities, SoCalGas encourages two-way formal and informal communication between employees to identify and manage safety risks before incidents occur. Employee feedback from these meetings/events help lead constant improvement across the company. SoCalGas' safety culture programs therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6). These programs aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2); and erosion of public confidence (PC.6) by raising questions, addressing issues, communicating safety issues, and demonstrating SoCalGas' safety-first culture.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4577**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.97	**1115.54**	2779.81
	RSE	0.70	**6.69**	16.66

9. SCG-2-C9: Utilizing OSHA and Industry Best Practices and Industry Benchmarking

a. Description of Risk Reduction Benefits

Benchmarking allows SoCalGas to capture views from a wide range of industries that provide insight about programs that allow the Company to identify strengths and opportunities and compare SoCalGas' safety programs against others. This provides an opportunity for SoCalGas to review its programs, reassess or confirm its approach to safety and review programs from others to continue moving our safety culture and programs forward. For example, comparing our safety performance (lagging safety indicators) with that of other companies helps identify what areas should be targeted for improvement. Another example is the benefit of using the AGA peer review program for the experts from other companies to come in and critically review safety programs and identify strengths and potential weaknesses resulting in enhancing safety programs and contributing to injury reductions.

For purposes of RSE analysis, SoCalGas applied a 0.33% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.33% reduction for continuous implementation of this activity. As a current control, SoCalGas expects to receive a reduction in further risk benefit for continuing this activity but also took into account the expected rise in health and safety incidents if this activity was no longer performed.

b. Elements of the Risk Bow Tie Addressed

SCG-2-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Utilizing OSHA and industry best practices and industry benchmarking helps SoCalGas learn how to reduce incidents, improve the safety health of our organization and therefore reduce Potential Consequences. SoCalGas' use of best practices and industry benchmarking therefore addresses the following elements of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2). This program aims to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); and erosion of public confidence (PC.6).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4577**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.97	**1115.54**	2779.81
	RSE	0.33	**3.15**	7.85

10. SCG-2-M1: OSHA 30-hour Construction Certification Training

a. Description of Risk Reduction Benefits

Providing and requiring health and safety training helps develop a positive health and safety culture, keeps safety professionals up-to-date on regulatory safety changes, and imparts knowledge about safety systems and processes. Training is important to building a knowledge set required for employees and management to identify safe and at-risk behaviors. Additionally, it helps in risk management, enhances innovation, and allows employees to acquire and sharpen skill sets. Regular education and training provide employees with the skills needed to do their work and creates an awareness and understanding of workplace hazards and how to identify, report, control and mitigate them. SoCalGas believes that being educated, making sure employees have information, tools and training to do their jobs safely will reduce the potential for injury. As stated above in Section V, the purpose of providing employees with this additional 30-hour construction certification training is to further enhance employee skills in hazard identification. By becoming better at identifying hazards, employees are expected to contribute to reducing the risk of injuries.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M1 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An enhanced OSHA construction training program would aim to further educate and inform our employees, in order to reduce Potential Consequences. SoCalGas' OSHA 30-hour construction certification training would therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); and hazards in the work environment or within the pipeline system (DT.2). This program would aim to reduce the following Potential Consequences identified in the right side of the Bow Tie: serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	0.68	**6.47**	16.13

11. SCG-2-M2: Industrial Hygiene Program Refresh

a. Description of Risk Reduction Benefits

Like SoCalGas' current industrial hygiene programs, the aim of the Industrial Hygiene Program Refresh is controlling workplace conditions that may cause workers' injury or illness. This program will review and analyze data collected by SoCalGas to update and improve the current programs. Further developing and complying with mandatory occupational safety and health standards involves determining the extent of employee exposure to hazards and deciding what is needed to control these hazards, thereby protecting workers. Industrial hygienists are trained to anticipate, recognize, evaluate, and recommend controls for environmental and physical hazards that can affect the health and well-being of workers. This mitigation measure, in combination with other existing and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M2 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An Industrial Hygiene program refresh would allow SoCalGas to proactively address regulation changes and monitor and implement findings to further protect employees from acute and long-term injuries or illnesses. SoCalGas' Industrial Hygiene Program refresh program would therefore address the following element of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2). This program would aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); adverse litigation (PC.4); and penalties and fines (PC.5).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	0.19	**1.80**	4.48

12. SCG-2-M3: Establish Proactive Monitoring for Indoor Air Quality and Chemicals of Concern

a. Description of Risk Reduction Benefits

Implementation of a proactive program for indoor air quality and chemicals of concern would allow SoCalGas to reduce the potential for employee injury or illness. As stated above, a mold concern has been raised just this year. Implementation of a proactive program to address findings would further protect employees, especially those who work indoors on a full-time basis, from acute and long-term injury or illness.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M3 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Establishing proactive monitoring for IAQ would allow SoCalGas to proactively monitor and implement findings to further protect employees from acute and long-term injuries or illness. SoCalGas' program to establish proactive monitoring for IAQ and chemicals of concern would therefore address the following element of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2). This program would aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); adverse litigation (PC.4); and penalties and fines (PC.5).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.246	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	1.02	**9.71**	24.19

13. SCG-2-M4: Creation of a Safety Video Library

a. Description of Risk Reduction Benefits

Safety training in general has a large impact on employee safety risk reduction efforts. Implementing a program to allow for SoCalGas' safety video library to be accessible to more employees would provide further risk reduction benefits. This mitigation would greatly help our employees and supervisors to have 24/7 ready access to the relevant and most updated safety training materials to use during their safety stand-downs, daily morning safety meetings, daily tailgate meeting for field crews, and other safety events.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M4 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Creation of an electronic video library would provide employees with greater access to safety training and therefore would aim to further educate and inform our employees, to reduce Potential Consequences. SoCalGas' program presented herein to create an electronic safety video library would therefore address the following elements of the left side of the Risk Bow Tie: Employees deviating from company policies or procedures (DT.1); and hazards in the work environment or within the pipeline system (DT.2). This program would aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	1.22	**11.65**	29.03

14. SCG-2-M5: Expanded Safety Congress and Expanded Executive Safety Council

a. Description of Risk Reduction Benefits

SoCalGas believes that its Safety Congress and Executive Safety Council provides significant benefits to employees and help reduce employee safety risk. As such, an expanded Safety Congress and expanded Safety Council would result in greater communication and safety messaging to employees. Enhancing SoCalGas' safety culture by this expanded program would provide employees with more safety-related contact and communication and therefore would aim to further educate and inform our employees, to reduce Potential Consequences.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M5 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An expanded Safety Congress and expanded Safety Council would result in greater communication and safety messaging to employees. Enhancing SoCalGas' safety culture by this expanded program would provide employees with more safety-related contact and communication and therefore would aim to further educate and inform our employees, to reduce Potential Consequences. SoCalGas' expansion of its Safety Congress and Executive Safety Council would therefore address the following elements of the left side of the Risk Bow Tie: Hazards in the work environment or within the pipeline system (DT.2); and effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6). This program would aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2); and erosion of public confidence (PC.6).

c. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	1.74	**16.64**	41.46

15. SCG-2-M6: Expanded Safety Culture Assessments

a. Description of Risk Reduction Benefits

The purpose of expanded safety culture assessments is to gain further insights in areas of potential weaknesses within the safety management system or programs and identify more relevant and specific opportunities of improvement. This mitigation measure, in combination with other existing and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. Enhancing SoCalGas' safety culture by this program expansion would provide SoCalGas with additional areas on which to focus in an effort to further reduce risk and potential consequences.

This mitigation measure, in combination with other existing controls and new mitigation measures, is expected to reduce SoCalGas' occupational injury rates based on the last five years' historical trend. For purposes of RSE analysis, SoCalGas applied a 0.06% annual risk reduction benefit to the RSE formula. SoCalGas' health and safety subject matter experts reviewed historical data, trends and averages to derive this 0.06% reduction for implementation of this incremental activity into its overall risk mitigation portfolio. As an incremental mitigation, SoCalGas expects to receive a reduction in further risk benefit by implementing this activity.

b. Elements of the Risk Bow Tie Addressed

Implementation of SCG-2-M6 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An expanded safety culture assessment would allow for further follow-up and action as a result of employee feedback. Enhancing SoCalGas' safety culture by this expanded program would therefore aim to further educate and inform our employees, in order to reduce Potential Consequences. SoCalGas' expansion of its Safety Culture assessments would therefore address the following element of the left side of the Risk Bow Tie: Effective corrective actions are not instituted following an incident to prevent reoccurrence (DT.6) and aim to reduce the following Potential Consequences identified in the right side of the Risk Bow Tie: serious injuries or fatalities (PC.1); property damage (PC.2); and erosion of public confidence (PC.6).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.52	**1111.21**	2769.04
	RSE	1.22	**11.65**	29.03

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SoCalGas' Risk Mitigation Plan takes into account recent data and trends related to Employee Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SoCalGas has performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors, including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigations activities, associated costs, the RSEs by tranche. SoCalGas does not account for and track costs by activity; rather SoCalGas accounts for and tracks costs by cost center and capital budget code. The costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[38]
(Direct 2018 $000)[39]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[40]	2018 Baseline O&M	2020-2022 Capital[41]	2022 O&M[42]	Total[43]	RSE[44]
SCG-2-C1	Mandatory employee health and safety training programs and standardized policies	T1	0	740	0	700-810	700-810	-
SCG-2-C2	Drug and alcohol testing program	T1	0	630	0	600-710	600-710	-
SCG-2-C3	Employee wellness programs	T1	0	2,230	0	3,000-3,500	3,000-3,500	0.12 – 2.75

38 Recorded costs and ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.
39 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.
40 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.
41 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.
42 As previously stated, internal labor (*e.g.,* employee time spent to complete training courses, employee time spent to perform inspections) are not included in some of SoCalGas' risk mitigation activity O&M cost forecasts since these costs would rely on cost assumptions (*e.g.*, number of employees, x length of training course, x average hourly wage). Further, SoCalGas does not currently track labor in this manner and thus would not be able to include such internal labor costs in future spending accountability reports.
43 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.
44 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[40]	2018 Baseline O&M	2020-2022 Capital[41]	2022 O&M[42]	Total[43]	RSE[44]
SCG-2-C4	Employee safety training and awareness programs	T1	0	7,370	0	7,900 – 8,900	7,900 – 8,900	-
SCG-2-C5	Safe driving programs	T1	0	900	0	850 - 980	850 - 980	0.41 – 9.72
SCG-2-C6	Personal Protection Equipment (PPE)	T1	0	1,170	0	1,200-1,400	1,200-1,400	-
SCG-2-C7	Near Miss, Stop the Job and jobsite safety programs	T1	0	280	0	270-310	270-310	1.31 – 31.10
SCG-2-C8	Safety Culture	T1	0	520	0	500-570	500-570	0.70 – 16.66
SCG-2-C9	Utilizing OSHA and industry best practices and industry benchmarking	T1	0	1,110	0	1,100 – 1200	1,100-1,200	0.33 – 7.85
SCG-2-M1	OSHA 30-hour construction certification training	T1	0	0	0	90-110	90-110	0.68 – 16.13
SCG-2-M2	Industrial Hygiene Program refresh	T1	0	0	0	290-390	290-390	0.19 – 4.48

ID	Mitigation/Control	Tranche	2018 Baseline Capital[40]	2018 Baseline O&M	2020-2022 Capital[41]	2022 O&M[42]	Total[43]	RSE[44]
SCG-2-M3	Establish proactive monitoring for indoor air quality and chemicals of concern	T1	0	0	0	50-70	50-70	1.02 – 24.19
SCG-2-M4	Creation of a safety video library	T1	0	0	0	50-60	50-60	1.22 – 29.03
SCG-2-M5	Expanded Safety Congress and expanded Executive Safety Council	T1	0	0	0	30-40	30-40	1.74 – 41.46
SCG-2-M6	Expanded Safety Culture Assessments	T1	0	0	0	50-60	50-60	1.22 – 29.03
TOTAL COST			**0**	**15,000**	**0**	**17,000 – 19,000**	**17,000 – 19,000**	-

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SoCalGas notes that there are activities related to this Employee Safety risk that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.*, employee time spent for internal training, performing inspections or monitoring). The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not currently track labor in this manner. The inclusion of these internal labor costs in SoCalGas' 2016 RAMP Report required the use of assumptions. Additionally, since these costs are not tracked, it would impede SoCalGas' ability to report in future spending accountability reports. These activities are continuing to be performed but, as a result of the exclusion of internal labor, forecasted costs for these activities may appear lower in this RAMP Report. The activities related to this risk that have not captured internal labor costs are:

- SCG-2-C1: OSHA mandatory employee health and safety training programs and standardized polices;
- SCG-2-C4: Employee safety training and awareness programs;
- SCG-2-C5: Safe driving programs; and
- SCG-2-C7: Near Miss, Stop the Job and jobsite safety programs.

While all the controls, mitigations, and respective costs presented in Table 6 mitigate Employee Safety risk, some of these activities also mitigate other risks presented in this RAMP Report, including: Contractor Safety, Customer and Public Safety, Catastrophic Damage Involving High-Pressure Pipeline Failure and Catastrophic Damage Involving Medium-Pressure Pipeline Failure. Employee Safety is a "cross-cutting" risk that impacts employees across the entire business. While the controls and mitigations identified herein may provide risk reduction benefits to other RAMP risks, where employee safety is the primary driver of a given activity, it may be referenced elsewhere in this RAMP filing, but the control/mitigation and associated costs and RSE analysis are captured within this chapter.

SoCalGas has not calculated RSEs on the following activities:

Table 6: Summary of RSE Exclusions

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SCG-2-C1	OSHA mandatory employee health and safety training programs and standardized policies	Mandated compliance activity per Cal. Labor Code § 6400, 8 CCR § 8350
SCG-2-C2	Drug and alcohol testing program	Mandated compliance activity per 41 USC § 81, 49 CFR Parts 40, 192, 193, 195, 199 and 382
SCG-2-C4	Employee Safety Training and Awareness Programs	Mandated compliance activity per 29 CFR Part 1910 *et. seq*
SCG-2-C6	Personal Protection Equipment (PPE)	Mandated compliance activity per 29 CFR Part 1910 *et. seq*

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the Risk Mitigation Plan for the Employee Safety risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SCG-2-A1 – Develop internal expertise for expanded safety culture assessment

As an alternative to the mitigation included in SoCalGas' Risk Mitigation Plan (SCG-2-M6), SoCalGas considered adding two full-time internal resources to conduct periodic safety culture assessments as an alternative to utilizing a third-party consulting firm. SoCalGas has concluded that the alternative of adding professionals with specialized expertise is just as expensive as our current option of using the National Safety Council but comes with less credibility and independence and lack of benchmarking abilities. SoCalGas also considered utilizing vendors other than the National Safety Council who are generally competitive in their costs and concluded that the benefit of using the non-profit and nationally renowned National Safety Council with their extensive benchmarking capabilities outweighs the potential benefits of using other similar assessment methodologies. Therefore, SoCalGas is not seeking additional internal resources to conduct Safety Culture Surveys at this time but will continue to evaluate the cost and effectiveness of the use of the National Safety Council.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.51	**1111.16**	2768.91
	RSE	0.30	**2.89**	7.21

B. SCG-2-A2: OSHA Voluntary Protection Program

The Federal and California Voluntary protection programs (Cal/VPP) is a labor-management-government cooperative program designed to recognize workplaces that manage outstanding health and safety management systems for protection of workers and go beyond minimal compliance with the Federal and Cal/OSHA Title 8 California Code of Regulations. OSHA's Voluntary Protection Programs[45] (VPP) recognize employers who have implemented effective safety and health management systems and maintain injury and illness rates below national BLS averages for their respective industries. In VPP, management, labor, and OSHA work cooperatively and proactively to prevent fatalities, injuries, and illnesses through a system focused on: hazard prevention and control; worksite analysis; training; and management commitment and worker involvement. To participate, employers must submit an application to OSHA and undergo a rigorous onsite evaluation by a team of safety and health professionals. VPP participants are re-evaluated every three to five years to remain in the programs.

Implementation of an OSHA VPP serves as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential

[45] United States Department of Labor, *Voluntary Protection Programs*, *available at* https://www.osha.gov/dcsp/vpp/.

Consequences. OSHA's VPP assessments are a proactive way to identify strengths and opportunities for enhancing safety. VPP physical inspections, document reviews, and interviews are components in this process. Sites with VPP work together in partnership with Federal OSHA and Cal/OSHA to systematically identify and correct hazards. VPP assessments provide insight into baseline safety and health hazards to establish initial levels of exposures for comparison to future levels so change can be identified. Implementing findings/results and acting on results helps move safety from its current "as is" state to the desired future state.

SoCalGas is not proposing implementation of a VPP program as part of its Risk Mitigation Plan included herein but may present this program in a future GRC. SoCalGas is in the initial stages of its assessment of this program and will weigh the anticipated costs and benefits before deciding to move forward with implementation of this program.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.51	**1111.16**	2768.91
	RSE	0.19	**1.81**	4.51

C. SCG-2-A3: Additional Industrial Hygienist

SoCalGas considered the alternative of adding an industrial hygienist to support the Industrial Hygiene program refresh (SCG-3-M2) included as part of SoCalGas' Risk Mitigation Plan. This alternative would include adding another internal resource to support the industrial hygiene data refresh initiative and take on new industrial hygiene issues. Recently, there have been industrial hygiene issues identified which add to the existing workload of the industrial hygiene staff. However, SoCalGas is not proposing this alternative in its Risk Mitigation Plan because it is currently premature to judge the need of a full-time staff position being added. We may still include this proposal in SoCalGas' GRC as more insight is gained and if the long-term need of an additional industrial hygienist internal resource is recognized.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.453**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.58	**1111.83**	2770.58
Post-Mitigation	LoRE		**1.4520**	
	CoRE	80.25	**765.29**	1907.02
	Risk Score	116.51	**1111.16**	2768.91
	RSE	0.63	**6.03**	15.02

Table 7: Alternative Mitigation Summary
(Direct 2018 $000)[46]

ID	Mitigation	2020-2022 Capital[47]	2022 O&M	Total	RSE[48]
SCG-2-A1	Develop internal expertise for expanded safety culture assessment	0	200-250	200-250	0.30 – 7.21
SCG-2-A2	OSHA Voluntary Protection Program	0	300-400	300-400	0.19 – 4.51
SCG-2-A3	Additional Industrial Hygienist	0	80-120	80-120	0.63 – 15.02

46 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

47 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total.

48 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
SCG-2-C1	Mandatory employee health and safety training programs and standardized policies	DT.1, DT.2, DT.4, DT.5, DT.6, DT.7 PC.1, PC.2
SCG-2-C2	Drug and alcohol testing program	DT.1, DT.3, DT.5, DT.6, DT.7 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SCG-2-C3	Employee wellness programs	DT.2, DT.3 PC.1
SCG-2-C4	Employee safety training and awareness programs	DT.1, DT.2, DT.3, DT.4, DT.5, DT.7 PC.1
SCG-2-C5	Safe driving programs	DT.1, DT.2, DT.3, DT.6, DT.7 PC.1, PC.2
SCG-2-C6	Personal protection equipment (PPE)	DT.2, DT.4 PC.1
SCG-2-C7	Near Miss, Stop the Job and jobsite safety programs	DT.1, DT.2, DT.3, DT.4, DT.6, DT.7 PC.1, PC.2
SCG-2-C8	Safety culture	DT.1, DT.6 PC.1, PC.2, PC.6
SCG-2-C9	Utilizing Occupational Safety and Health Administration (OSHA) and industry best practices and industry benchmarking	DT.2 PC.1, PC.6
SCG-2-M1	OSHA 30-hour construction certification training	DT.1, DT.2 PC.1
SCG-2-M2	Industrial hygiene program refresh	DT.2 PC.1, PC.4, PC.5
SCG-2-M3	Establish proactive monitoring for indoor air quality and chemicals of concern	DT.2 PC.1, PC.4, PC.5
SCG-2-M4	Creation of a safety video library	DT.1, DT.2 PC.1
SCG-2-M5	Expanded Safety Congress and expanded Executive Safety Council	DT.2, DT.6 PC.1, PC.2, PC.6
SCG-2-M6	Expanded Safety Culture Assessments	DT,6 PC.1, PC.2, PC.6

Risk Assessment Mitigation Phase

(Chapter SCG-3)

Contractor Safety

November 27, 2019

TABLE OF CONTENTS

Risk: Contractor Safety

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas or Company) Contractor Safety risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 (and the Settlement Agreement included therein (SA Decision)).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, operations and maintenance (O&M) costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is consistent with the

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Contractor Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code (PUC) statute, or General Order (GO). Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

For purposes of this RAMP Report, SoCalGas' Contractor Safety risk is defined "as the risk of a safety event, caused by a contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company."

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[3] for each control and mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Deviation from policy/procedure, inadequate reporting of near misses
DT.2	Inexperience or lack of training
DT.3	Inadequate oversight
DT.4	Inadequate use of Job Site Safety Plans or Job Safety Analysis
DT.5	Inadequate utility and/or substructure location information
DT.6	Unsafe operation of equipment or motor vehicle
DT.7	Contractor crew fatigue or complacency, or impairment
PC.1	Serious injuries[4] and/or fatalities
PC.2	Property damage
PC.3	Additional compliance safety inspections
PC.4	Operational and reliability impacts
PC.5	Adverse litigation
PC.6	Penalties and fines
PC.7	Additional regulations

3 D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

4 A "serious injury" is defined in the California Code of Regulations as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) § 330(h).

PC.8	Erosion of public confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SoCalGas has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SoCalGas' baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-3-C1	Contractor Safety Oversight
SCG-3-C2	Contractual Requirements
SCG-3-C3	Stop the Job/Near Miss/Close Call Reporting Program
SCG-3-C4	Third-Party Administration Tools
SCG-3-C5	Contractor Engagement

SoCalGas will continue the baseline controls identified above and identifies one mitigation project/program as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SCG-3-M1	Expanded Contractor Safety Oversight

Finally, pursuant to the SA Decision,[6] SoCalGas presents considered alternatives to the Risk Mitigation Plan for the Contractor Safety risk and summarizes the reasons that the alternatives were not included into the Risk Mitigation Plan in Section VIII.

---

5 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

6 *Id.* at p. 33.

II. RISK OVERVIEW

The Contractor Safety risk was included in SoCalGas' 2018 ERR and for purposes of this RAMP filing is defined as the risk of a safety event, caused by a contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company. While 2018 is used as the base year for mitigation planning presented in the RAMP, risk management has been occurring, successfully, for many years within the Company and is continuously evolving. SoCalGas takes compliance and managing risks seriously as evidenced by the many actions taken to mitigate each risk. The baseline mitigations are determined based on the relative expenditures during 2018; however, SoCalGas does not currently track expenditures in this way, so the baseline amounts reflect the best effort of SoCalGas to benchmark both capital and O&M costs during a year.

The Commission has ordered that RAMP be focused on safety-related risks and mitigating those risks.[7] For many risks, safety and reliability are inherently related and cannot be separated, and the mitigations reflect that fact. Compliance with laws and regulations is also inherently tied to safety and SoCalGas takes those activities very seriously. In all cases, the 2018 baseline mitigations include activities and amounts necessary to comply with the laws in place at that time. Laws can rapidly evolve, however, and if new laws have been passed since September 2018 the RAMP baseline has not taken these into account.

As noted above, the purpose of RAMP is not to request funding. Any funding requests will be made in the TY 2022 GRC. The forecasts for mitigation are therefore not for funding purposes but are rather to provide an anticipated range of costs for the future GRC filing. This range will be refined with supporting testimony in the GRC.

This Contractor Safety risk chapter focuses on mitigations that address safety, education, training, and other internal procedural enhancements, whereas SoCalGas' High- and Medium-Pressure Pipeline chapters focus on pipeline infrastructure improvements and thus the risk is more appropriately captured within those chapters. Thus, not included in the Contractor Safety risk is the risk of potential injuries or fatalities associated with medium-pressure or high-pressure natural gas pipelines. While the

---

[7] D.16-08-018.

consequences of those risk events could fall under the risk definition here, those risk events are captured in the High-Pressure Gas Pipeline Incident (SCG-5) and the Medium-Pressure Gas Pipeline Incident (SCG-6) chapters of this report.

Finally, this RAMP Report is the first instance where SoCalGas has had to apply the SA Decision to its risk analysis of this risk (and all of its risks in RAMP). SoCalGas looks forward to feedback from the Commission on its application of the SA Decision to this risk.

III. RISK ASSESSMENT

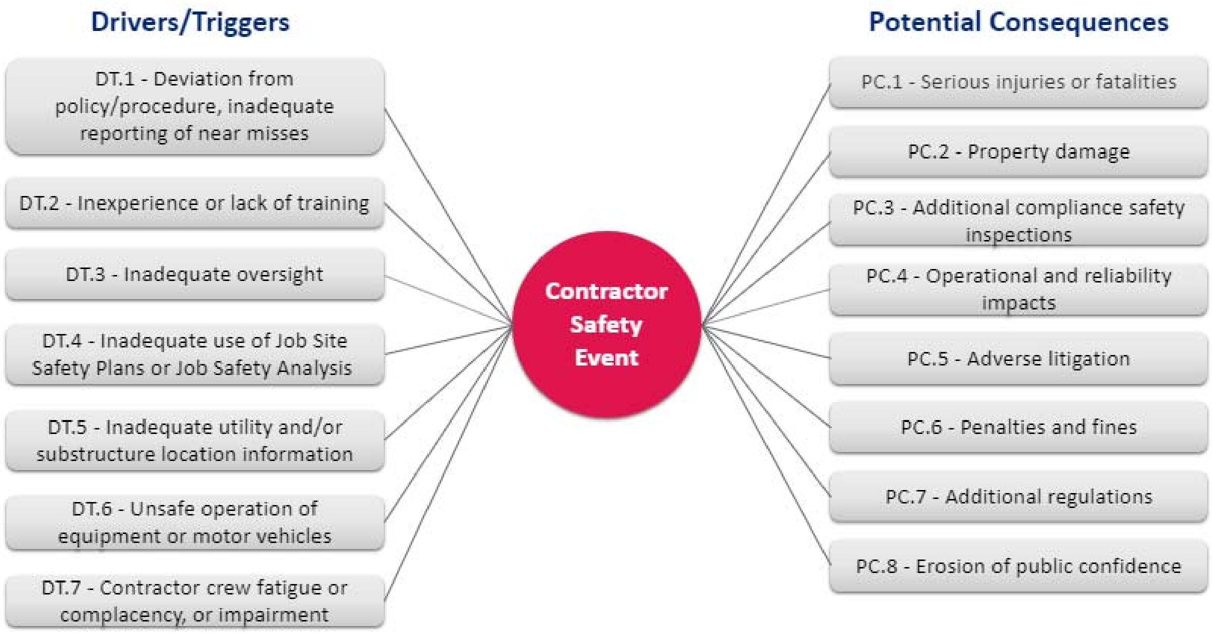
In accordance with the SA Decision,[8] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Contractor Safety risk.

A. Risk Bow-Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

[8] D.18-12-014 at 16 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups of Systems Subject to the Risk

The SA Decision[9] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. This is a "cross-cutting" risk and therefore is associated with human systems, rather than particular asset groups.

C. Risk Event Associated with the Risk

The SA Decision[10] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the Risk Bow Tie) is a contractor safety event that results in a serious injury or fatality along with any of the Potential

---

[9] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[10] *Id.* at Attachment A, A-11 ("Bow Tie").

Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[11]

The SA Decision[12] instructs the utility to identify which element(s) of the associated Risk Bow Tie each mitigation addresses. When performing the risk assessment for Contractor Safety, SoCalGas identified potential leading indicators, referred to as Drivers or Triggers. These include, but are not limited to:

- **DT.1 – Deviation from policy/procedure, inadequate reporting of near misses:** SoCalGas has many safety-related policies and procedures for contractors to follow. Failure of a contractor to adhere to a Company safety policy or procedure could result in a safety-related event. In addition, contractors failing to report near misses and sharing lessons learned with SoCalGas can result in the incident occurring again with potentially more significant results.
- **DT.2 – Inexperience or lack of training:** Contractors and sub-contractors used by SoCalGas are expected to hire experienced employees and provide adequate training to perform the work required. Failure of contractors to hire experienced employees as well as a failure to provide training for the jobs they are required to perform may lead to an increase in the occurrence of a safety-related event.
- **DT.3 – Inadequate oversight –** Oversight is an integral part of managing work performed by contractors, not only from a quality of work perspective, but also to verify that safe work practices are being followed. The lack or failure to engage in overseeing the work of a contractor can lead to departures from safe work practices that could result in a safety-related event.
- **DT.4 – Inadequate use of Job Site Safety Plans of Job Safety Analysis –** Insufficient knowledge of the work environment or improper planning for potential job hazards may lead to contractors sustaining a safety-related event while on the job.

---

11 An indication that a risk could occur. It does not reflect actual or threatened conditions.

12 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.5 – Inadequate utility and/or substructure location information –** Contractors need to have the proper information about the assets, systems or infrastructure that are part of the SoCalGas facilities they are contracted to work on, but also the auxiliary substructures in the vicinity of their work activities. Inadequate or inaccurate utility and/or substructure information can lead to instances of serious injuries to contractor employees.
- **DT.6 – Unsafe operation of equipment or motor vehicle –** Contractors may utilize their own company vehicles/equipment or vehicles/equipment owned by SoCalGas. The unsafe operation of such may lead to consequences such as serious injuries or fatalities.
- **DT.7 – Contractor crew fatigue or complacency, or impairment –** Contractors working excessive hours can create unsafe work environments. Complacency may reduce the level of awareness to hazards which can lead to a safety-related event. Also, factors such as heat, night work, high-risk work locations (e.g. busy roadways), etc. may lead a contractor becoming impaired and increase the likelihood of being seriously injured.

E. Potential Consequences

Potential Consequences are listed to the right side of the Risk Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries and/or fatalities;
- Property damage;
- Additional compliance safety inspections;
- Operational and reliability impacts;
- Adverse litigation;
- Penalties and fines;
- Additional regulations; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of the Contractor Safety risk that occurred during the development of SoCalGas' 2018 Energy Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[13] including enhancements to the Interim Decision 16-08-018.[14] SoCalGas used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Risk Quantification Scores[15]

Contractor Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	109	**1037**	2582
LoRE		**1.1**	
CoRE	104	**984**	2451

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[16] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

---

13 *Id.* at Attachment A.

14 *Id.* at 2-3.

15 The term "pre-mitigation analysis," in the language of the SA Decision (at Attachment A A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

16 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of a work-related as defined by Occupational Safety and Health Administration (OSHA) safety incident involving a Class 1 contractor(s) which causes serious injuries or fatalities while conducting work on behalf of SoCalGas. SoCalGas is focusing its Contractor Safety Program on Class 1 Contractors. Class 1 Contractors are: *"A Class 1 Contractor is a Contractor engaged by the Company to perform work that can reasonably be anticipated to expose the Contractor's employees, subcontractors, SoCalGas employees, or the general public to one or more hazards that, if not properly mitigated, have the potential to result in Serious Safety Incident. Examples of a Class 1 Contractor include contractors that are subject to and covered by the Operator Qualification Program and contractors performing construction, repair, or maintenance work on any aspects of SoCalGas' natural gas pipeline system and appurtenances, including gas distribution, transmission, or storage systems or any building construction, repair, or maintenance work involving elevated work surfaces, confined space, energized equipment, hazardous chemicals, or other similar hazards."*
Out-of-Scope for purposes of risk quantification:	The risk of a work-related safety incident involving a non-Class 1 contractor(s), or the risk of a work-related safety-incident involving a Class 1 Contractor(s) while conducting work for a company other than SoCalGas. Safety incidents involving a Class 1 contractor(s) that are not work-related (as defined by OSHA regulation) and impacts to the public resulting from work-related safety incidents involving Class 1 contractor(s).

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data.)[17] SoCalGas' safety risk assessment primarily utilized data from the Bureau of Labor Statistics (BLS), OSHA, and the Department of Labor (DOL).

Calculating serious injury and fatality incidence rates required data on total employment by sector. Therefore, the BLS Employment & Earnings data was used to determine total employment by sector. This data was filtered by NAICS (North American Industry Classification System) sector codes which were determined by analyzing SoCalGas Class 1 Contractor data from ISN (ISNetworld, a third-party administrator of the SoCalGas contractor safety program) to find the NAICS codes for companies

[17] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

contracted with SoCalGas. Based on this data and subject matter expert (SME) input from the Contractor Safety Programs and Safety Compliance groups, total hours of Class 1 Contractor work for SoCalGas were estimated at 4.750 million hours per year.

From the BLS industry data, total employees per sector were converted to total hours per sector using the following guidance from the BLS: Total hours by Sector = Total Employees by sector * 40 hours per week * 50 weeks per year. The total contractor hours were then allocated to the Class 1 Contactor sectors contracted by SoCalGas.

Injuries, Illnesses, and Fatalities (IIF) program historical data from the BLS was used to determine the serious injury and the fatality incidence rates per year. From this data, the serious injury frequency was calculated as the ratio of serious injuries to recordable incidents by sector during 2015-2016. Industry serious injury and fatality rates were applied to total SoCalGas Class 1 Contractor work hours to obtain the respective incidence rates for SoCalGas.

OSHA Enforcement Data, supplemented with OSHA Severe injury Reports, from the DOL was used to determine the distribution of safety consequence resulting from a single safety event. The NAICS code structure used in the data from the BLS is consistent with the NAICS codes in the OSHA enforcement data used for determining the distribution.

A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences. The safety consequence scoring was based on a publication from the Federal Aviation Administration (FAA): a fatality is represented by 1.000 and a serious injury is represented by 0.253. Internal SME input was provided to estimate the financial consequence of a contractor safety incident. Based on SME input, reliability is not directly impacted by contractor safety related incidents.

B. Sources of Input

The SA Decision[18] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

---

18 *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Injuries:
    - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF);
    - Link: https://www.bls.gov/iif/oshsum.htm#15Summary_Tables;
    - Report Title: TABLE Q1. Incidence rates of total recordable cases of nonfatal occupational injuries and illnesses by quartile distribution and employment size, 2009-2016, All establishment sizes.
- Fatalities:
    - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF);
    - Link: https://www.bls.gov/iif/oshcfoi1.htm#2015;
    - Report Title: Census of Fatal Occupational Injuries-TABLE A-3. Fatal occupational injuries to private sector wage and salary workers, government workers, and self-employed workers by industry, all United States.
- Distribution Fitting Data:
    - Agency: Department of Labor (DOL);
    - Link: https://enforcedata.dol.gov/views/data_catalogs.php;
    - Report Title: OSHA Enforcement Data: osha_accident, osha_accident_injury, osha_inspection.
- Severe Injury Assumption:
    - Agency: Occupational Safety and Health Administration (OSHA);
    - Link: https://www.osha.gov/severeinjury/index.html;
    - Report Title: Severe Injury Reports.
- Support Data:
    - Agency: Bureau of Labor Statistics- Office of Publications & Special Studies;
    - Link: https://www.bls.gov/opub/ee/archive.htm;
    - Report: Employment & Earnings- Table B-1b. Employees on nonfarm payrolls by industry sector and selected industry detail, not seasonally adjusted, 2011-2016.
- North American Industry Classification System - NAICS

- Agency: US Census Bureau;
- Link: https://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart_code=22&search=2017%20NAICS%20Search

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[19] This section describes SoCalGas' Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SoCalGas' Contractor Safety Risk is defined as the risk of a safety event, caused by a Class 1 Contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SoCalGas' TY 2022 GRC cycle.[20] The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SCG-3-C1: Contractor Safety Oversight

SoCalGas's Contractor Safety Oversight consists of contractor safety program policies and procedures, Contractor Safety Manual for Class 1 Contractors, field inspections and oversight, post-job safety evaluation, stop-the-job, near-miss and close-call reporting, internal audits, enforcement actions, and management of the pipeline safety risk by the pipeline safety oversight committee. The purpose of having these key controls in place is to enhance the safety of SoCalGas construction projects from inception to completion. Each specific control is further described below:

<u>Internal Contractor Safety Standard</u>

---

[19] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

[20] *Id.* at 33. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

SoCalGas has formalized its contractor safety program in the Company Operations Standard 167.04 – Contractor Safety Program. The standard is for internal use only and applies to SoCalGas employees who oversee Class 1 Contractors and subcontractors on behalf of the company. The standard establishes the policy, scope and approach used by SoCalGas to manage contractor safety, requirements for pre-qualification of contractors, roles and responsibilities for various employees who work with Contractors, and expectations on contractor oversight, periodic safety inspections, and investigations of contractor safety incidents.

SoCalGas's longstanding commitment to safety focuses on three primary areas: employee safety, customer safety, and public safety. This commitment to safety is embedded in what we do and is the foundation for who we are – from initial employee training, to the installation, operation, and maintenance of SoCalGas' infrastructure, to providing safe and reliable service to our customers. When working on SoCalGas projects, SoCalGas employees and Contractors are expected to adhere to SoCalGas' commitment to safety.

Contractor Safety Manual for Class 1 Contractors

In 2017, SoCalGas issued a contractor safety manual for use by all of SoCalGas' Class 1 contractors. This manual consolidated in one place all the safety requirements and expectations SoCalGas has established for Contractors working for SoCalGas. These include:

- The Contractor must comply with all applicable federal, state, regional, municipal, and local laws, ordinances, rules, codes, regulations, and executive orders, including all laws, ordinances, rules, codes, regulations, and executive orders applicable to health and safety, the SoCalGas Contractor Safety Manual, and all contract terms as set forth in the contract entered into with the Company, and must confirm that all employees and subcontractors working on Contractor's behalf meet or exceed these same requirements.
- Contractors must provide a safe working environment for their employees and subcontractors and make sure their operations do not adversely impact the safety of SoCalGas employees or the public. The personal safety of a Contractor's employees and subcontractors is the Contractor's responsibility.
- The Company reserves the right to take action, including, but not limited to, issue warnings, withhold payment, suspend work, require the removal of contractor personnel from the

project, notify enforcement agencies, and terminate the contract if the Contractor does not comply with applicable laws, all site and system-related safety requirements, the SoCalGas Contractor Safety Manual, and all terms and conditions required by the contract entered into with the Company.

- A process for pre-qualification of contractors for safety, including a defined set of pre-qualification criteria as listed below:

Criteria	Target	Below Target
3-Year TRIR (Total Recordable Incident Rate)	Equal to or less than BLS industry average for applicable NAICS code	Greater than BLS industry average for applicable NAICS code
3-Year DART (Days Away Restricted/Transfer Rate)	Equal to or less than BLS industry average for applicable NAICS code	Greater than BLS industry average for applicable NAICS code
EMR (Experience Modification Rate)*	Equal to or less than 1.1	Greater than 1.1
5 -Year Fatality Data	Zero (0) fatalities within the last five (5) years	One (1) or more fatalities within the last five (5) years
5-Year Non-Fatal, Serious Safety Incident Data (e.g., life altering/life threatening, including incidents affecting the public)	Zero (0) non-fatal, serious safety incidents within the last five (5) years	One (1) or more non-fatal, serious safety incidents within the last five (5) years
3-Year OSHA Serious, Willful, or Repeat Citations	Zero (0) serious, willful, or repeat OSHA citations within the last three (3) years	One (1) or more serious, willful, or repeat citations within the last three (3) years
3-Year OSHA Non-Serious Citations	Zero (0) non-serious OSHA citations within the last three (3) years	One (1) or more non-serious citations within the last three (3) years
Written Safety Programs	Company has comprehensive written safety programs that are in compliance with environmental, health, and safety laws and regulations and are specific to the hazards associated with the work to be performed	Company does not have comprehensive written safety programs that are in compliance with environmental, health, and safety laws and regulations and are specific to the hazards associated with the work to be performed
Drug and Alcohol Plan	Company has a comprehensive written drug and alcohol plan that is in compliance with applicable laws and regulations	Company does not have a comprehensive written drug and alcohol plan that is in compliance with applicable laws and regulations
Subcontractor Management Plan	Company has a written plan to monitor subcontractors and hold them accountable for the same requirements as themselves	Company does not have a written plan to monitor subcontractors and hold them accountable for the same requirements as themselves
Employee Disciplinary Action Plan	Company has a written employee disciplinary action plan	Company does not have a written employee disciplinary action plan
Safety Culture Evaluation	Company has a positive safety culture that it is working to advance	Company does not have a positive safety culture that it is working to advance

***** **Experience modification rate** (EMR) is a number insurance companies use to represent a business' prior workers' comp claims and potential for future injuries.

- The manual provides guidelines on the process to be followed in managing safety on construction projects, including reviewing applicable compliance requirements, providing appropriate oversight on contractor work, and reporting safety incidents.

<u>Construction Inspections and Contractor Performance Review</u>

SoCalGas requires its representatives overseeing contractors to conduct documented job-site safety inspections of Contractors working at a facility, property, or worksite owned, operated, or managed by the Company (including leased premises and rights-of-ways) on SoCalGas projects at a frequency of once per week per Contractor. When there are multiple crews for a specific Contractor working on similar projects, one safety inspection per Contractor per week meets this requirement. The Construction Inspection Report, Company Form 2849, built in ISNetworld, is used for documenting such inspections.

The SoCalGas Representative must also complete a post-job safety evaluation of Class 1 Contractors at the completion of every contract or annually, whichever is earlier, including the final at the end of the term for Master Services Agreements and multi-year contracts. Company Form #6350, Report of Contractor's Performance, built in ISNetworld, is used to appraise and document the safety performance of Contractors performing work for the Company.

The inspections and evaluations represent SoCalGas' oversight responsibilities and are designed to provide valuable feedback on contractors' overall performance on SoCalGas projects.

<u>Corporate Safety Audits, Ad Hoc Contractor Audits, and Enforcement Activities</u>

SoCalGas utilizes mechanisms to monitor and evaluate safety requirements for Class 1 Contractors, including conducting formal safety audits, requiring contractors to conduct their own evaluations, and imposing corrective actions in response to safety issues identified as a result of its oversight activities. For example, in 2018, based on observing several serious close call incidents associated with one prime contractor on a pipeline integrity project, SoCalGas utilized several measures to address the risk of a potential serious injury or fatality. This included stopping the job, putting the contractor on probation, conducting an audit of their safety program, asking the contractor to evaluate their safety culture, and following up on all the corrective actions resulting from this effort to elevate the importance of safety on SoCalGas projects.

Pipeline Safety Oversight Committee

SoCalGas has established a high-level internal committee comprising of executives and directors to oversee pipeline safety programs and activities, including oversight over contractors. This committee meets periodically and reviews the progress made in the contractor safety area and provides direction on steps needed to be taken to continue to reduce the contractor safety risk. This committee and its oversight serve as a proactive approach to have a senior level committee overseeing the development, implementation and growth of the contractor safety program to address the overall safety risk associated with hiring contractors and strengthening public trust.

B. SCG-3-C2: Contractual Requirements

The contractual requirements control is in place to add appropriate language to all contracts in order to hold all Class 1 Contractors accountable to follow the Class 1 Contractor Safety Manual. All new and existing contracts and Master Service Agreements between SoCalGas and a primary contractor include Contractor Safety Program related requirements as part of the contract terms and conditions. Moreover, contractors are made aware of the Class 1 contractor safety requirements upfront during the RFP process.

C. SCG-3-C3: Stop the Job/Near Miss/Close Call Reporting Program

SoCalGas requires all its Class 1 contractors to develop and implement Stop the Job policy on SoCalGas projects. Stop the Job is a critical process and gives authority to everyone onsite to stop a job or task if an unsafe work condition, behavior or activity is identified. All work must immediately cease in the area of concern once the Stop the Job is declared until site supervision and the involved Contractor(s) have done an investigation, the identified situation is abated, controlled, or otherwise determined to be safe and the situation and outcome are explained to affected personnel. SoCalGas also encourages its contractors to report near miss or close calls or good catch incidents so that everyone can learn from these incidents and prevent injuries and/or reduce/eliminate safety risks on the job and to our pipeline delivery system.

These incidents are shared with contractors so that SoCalGas and the contractors can learn from one another.

SoCalGas defines a Near Miss/Close Call as follows:

- Non-Serious Near Miss: A Work-Connected incident in which Property Damage less than $50,000 or an injury or illness (other than a Serious Safety Incident) could have occurred but did not.
- Serious Near Miss: A Work-Connected incident in which Property Damage, a Spill/Release resulting in damages of $50,000.00 or more, or a Serious Safety Incident could have occurred but did not.

D. SCG-3-C4: Third-Party Administration Tools

SoCalGas utilizes three best-in-class third-party tools to manage various aspects of its contractor safety. These are discussed below.

<u>ISNetworld</u>

The purpose of the ISNetworld platform (created and managed by ISN) is to pre-qualify, vet, and monitor Class 1 Contractors for safety. ISNetworld is an online contractor and supplier management platform of data-driven products and services that help manage risk through data collected across the contractors' operations nationally. ISNetworld helps reduce unnecessary duplication associated with traditional qualification processes. It streamlines the contractor pre-qualification process and is intended to improve workplace safety. Each Class 1 Contractor currently performing or seeking to perform work for SoCalGas must have an ISN account. Before performing any work for SoCalGas, Class 1 Contractors must upload the information specified in the SoCalGas Pre-Qualification Criteria to ISN. ISN's Review and Verification Services (RAVS) Team reviews self-reported information against regulatory our requirements. ISN safety experts also review contractor safety compliance programs and validates their accuracy and completeness. ISN uses an "A," "B," "C," and "F" grading system to measure Contractors' safety performance against criteria established by SoCalGas. Contractors who receive an "A" or "B" grade and continue to maintain an "A" or "B" grade, are deemed qualified and are approved to work for SoCalGas. Contractors who receive a "C" or "F" grade, and those whose grade changes from an "A" or "B" to a "C" or "F," must be approved through SoCalGas's Variance Request Process. Variances are approved at the director and officer levels. This process promotes safer contractors to be used by SoCalGas and thereby reduces the risk of safety incidents on SoCalGas projects.

Veriforce

SoCalGas utilizes Veriforce® to centrally track records for covered task qualifications, along with related certifications and training. SoCalGas also utilizes Veriforce® to monitor contractors' compliance with PHMSA/DOT drug and alcohol program requirements. Veriforce® delivers a comprehensive solution for D&A compliance, combining software with audit services to help streamline management of contractor drug and alcohol compliance program and drive improvements that mitigate contractor risk. The purpose of utilizing the Veriforce® platform is to streamline Operator Qualification program administration and facilitate compliance with PHMSA OQ Rule requirements for Class 1 Contractors who work on safety sensitive tasks. Veriforce® delivers a comprehensive solution for DOT/PHMSA OQ Rule compliance that supports OQ processes from end to end, uniting software with audit, consulting, and training services to support the management of our OQ program.

Gold Shovel Standard

Gold Shovel Standard (GSS) is a nonprofit organization committed to improving workforce and public safety and the integrity of buried infrastructure. GSS believes that greater transparency in all aspects of damage prevention among buried-asset operators, locators and excavators is essential to drive continuous improvement, and vital to increasingly safe working conditions and communities. GSS works to prevent life-threatening damages, empower field teams to operate safely, and protect excavation crews and the public. SoCalGas utilizes the GSS platform to enhance excavation safety associated with its pipeline infrastructure projects. SoCalGas requires all of its prime gas infrastructure contractors to be members of the GSS and follow best practices in promoting excavation safety.

To obtain Gold Shovel Standard Certification, an excavator must have a complete Damage Prevention-Safety Management System (DP-SMS). This includes:

- A leadership and management commitment to infrastructure damage prevention

- Requiring specific training for all workers on jobs with excavation
- Enforcing whistleblower and stop work responsibility for workers
- Maintaining a policy to adhere to specialized best practices of excavation operations
- Maintaining a policy to hire Gold Shovel Standard subcontractors with few exceptions
- Using thorough investigation and corrective action procedures
- Using specialized software to track and manage their operations to prevent damages

In the past, businesses often learned about potential excavation risks by their occurrence. A quality DP-SMS reveals risks before they happen, giving businesses the opportunity to improve without catastrophic catalysts.

E. SCG-3-C5: Contractor Engagement

SoCalGas aims to reinforce our strong safety culture by engaging contractors in a variety of ways, including hosting an annual Contractor Safety Congress and three Quarterly Meetings with its Class 1 contractors.

SoCalGas' annual Contractor Safety Congress was initiated in 2015 as a way to share safety best practices and learn from one another's experiences. The event is expected to continue to further strengthen our collective "safety culture" and provide a foundation for safety improvement. Attendees include representatives from a wide variety of contractors, including diverse business enterprises, and select representatives from SoCalGas who oversee contractors. The forum provides an opportunity for SoCalGas executives to share their safety vision and expectations with contractors and offer opportunity for contractors to showcase their safety successes and challenges and share serious safety incidents and lessons learned so others can benefit from their experience and improve their safety performance.

The quarterly meetings on the other hand are limited to signatory contractors who perform the vast majority of pipeline construction work for the company. These meetings are established as a forum to give our contractors the opportunity to collaborate with SoCalGas on safety, share issues and challenges faced by contractors on SoCalGas projects, communicate new requirements, and overall foster an improved safety culture for contractors and the company.

F. SCG-3-M1: Expanded Contractor Safety Oversight

SoCalGas plans to add approximately seven safety advisors to conduct comprehensive safety audits of contractor construction projects to further improve the effectiveness of the oversight element in SoCalGas' Contractor Safety program. Safety advisors will perform detailed review of contractors' safety programs, audit pipeline contractors field crews, oversee contractor safety incident investigations, and share corrective actions and lessons learned from incidents and audits within SoCalGas and with other SoCalGas contractors to promote continual risk reduction and improvement. As a result of this program, SoCalGas will be able to assess contractors' adherence to SoCalGas' Contractor Safety Manual requirements, identify potential weaknesses in the contractors' safety programs, and assist with taking corrective actions to prevent incidents. This program will also benefit SoCalGas field supervisors who oversee contractors and manage construction projects to enable them to learn from the audits and integrate lessons learned into their routine oversight to prevent injuries associated with contractor construction projects.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the SA Decision. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[21] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk

[21] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SoCalGas's Contractor Safety risk is a "cross-cutting" risk that applies to contractors. Therefore, a single tranche is appropriate.

SoCalGas's comprehensive Contractor Safety program consists of the pre-qualification, oversight, observations, pre-work safety meetings and efforts all aimed to reduce risk of a safety event caused by Class 1 contractors while conducting work on behalf of SoCalGas. Given the vast number of activities SoCalGas performs to mitigate Contractor Safety risk, SoCalGas grouped similar activities with similar risk profiles into mitigation programs. Since all Class 1 contractors have the potential for serious safety incidents and fatalities, and each of SoCalGas' Contractor Safety risk mitigations have the same goal of reducing the frequency and consequence of safety events caused by contractors, all controls and mitigations have the same risk profile and are not further tranched.

B. Post-Mitigation/Control Analysis Results

For the post-mitigation and post-control analysis, SoCalGas reviewed the historical contractor OSHA injury rates for the time span beginning in 2015, which is when SoCalGas began tracking this metric. It was quickly recognized that fluctuations were occurring in the injury rates over the short term that were not a reliable predictor of the effectiveness of SoCalGas' evolving controls. SoCalGas attributes this to:

- The small data set associated with the short time span (only four years);
- Within those same four years, SoCalGas implemented several additional controls like ISNetworld which changed how Contractors reported their data;
- More positive emphasis placed on reporting safety incidents and encouraging learning from such incidents; and
- More and more Class 1 contractors and subcontractors being added to vetting, monitoring, and reporting via ISNetworld.

That said, SoCalGas used the results of a long-range study of another energy infrastructure company, Kinder Morgan, as a proxy to estimate the probable effectiveness of controls that can be anticipated to be achieved by utilizing ISNetworld along with other controls over a longer period of time. Kinder Morgan has been using ISNetworld in conjunction with its oversight program for more than a decade, and over the last 16 years (2002 through 2018), it has seen a reduction in its OSHA recordable injury rates of 79%. This equates to a compounded yearly reduction of 3.67%. For new and/or incremental mitigations, we expect to achieve further risk reduction.

Through the controls described below, SoCalGas is estimating a 3.67% overall decrease in OSHA recordables per year as the controls mature. Additional assumptions made in estimating the effectiveness include the following: Control SCG-3-C1, being the primary control covering internal oversight efforts of SoCalGas, is assumed to be twice as effective as each of the supporting controls SCG-3-C4 and SCG-3-C5. Furthermore, it is assumed that the new mitigation SCG-3-M1 adding substantial oversight will provide incremental benefit of half of the overall decrease of 3.67% allocated to the existing controls. The specific risk reduction benefit percentages used for each identified control/mitigation are included under each program heading below.

1. SCG-3-C1: Contractor Safety Oversight

a. Description of Risk Reduction Benefits

Through the Contractor Safety Program, and with introduction of ISNetworld use in 2017, SoCalGas has provided its Business Units using Class 1 Contractors with a consistent Contractor Safety Program that is easily understood by SoCalGas and its contractors. Each of the elements included in SCG-3-C1 supports SoCalGas not only in the selection/engagement of contractors with acceptable safety records, but also with the ongoing management of worksite safety and evaluation.

As noted previously, SoCalGas has formalized its contractor safety program through Company Operations Standard 167.04. The standard is for internal use only and applies to SoCalGas employees who oversee Class 1 Contractors and subcontractors on behalf of the Company. In 2017, SoCalGas issued a contractor safety manual for use by all of SoCalGas' Class 1 Contractors, which establishes the safety requirements and expectations SoCalGas has established for Contractors working for SoCalGas:

- Contractor must comply with laws and regulations;

- Contractors provide a safe working environment;
- Company has the right to take action;
- Contractors must be processed for pre-qualification; and
- Contractors must be processed for managing safety on construction projects.

Through the development and use of an internal contractor safety standard and the development and implementation of the contractor safety manual, which is considered an industry common practice, SoCalGas is able to effectively manage its Class 1 Contractors, provide consistent information to its employees on Class 1 Contractor safety policies and procedures, and further enhancing its safety-first culture.

SoCalGas requires its representatives overseeing contractors to conduct documented job-site safety inspections of Contractors working at a facility, property, or worksite owned, operated, or managed by the Company (including leased premises and rights-of-ways) on SoCalGas projects at a frequency of once per week per Contractor. The Construction Inspection Report, Company Form 2849, built in ISNetworld, is used for documenting such inspections. The SoCalGas Representative must also complete a post-job safety evaluation of Class 1 Contractors at the completion of every contract. The inspections and evaluations represent SoCalGas' oversight responsibilities and are designed to provide valuable feedback on contractors overall performance on SoCalGas projects. Through the use of these safety inspections, SoCalGas is able to demonstrate the importance and raise the level of awareness of safety amongst contractor crews at the construction job sites in a proactive way to prevent incidents.

SoCalGas utilizes a variety of ways to enforce safety requirements on Class 1 Contractors, including conducting formal safety audits, requiring contractors to do its own evaluations, and taking enforcement actions in response to safety issues identified as a result of its oversight activities. Sempra's Audit Services supports SoCalGas' quality assurance through random selection of projects to audit, including contractors. More specifically, Sempra's Audit Services has performed audits on Contractor projects managed by the Pipeline Safety Enhancement Program (PSEP), Pipeline Integrity (PIT), Underground Storage, Gas Storage, and Facilities departments and performed a construction contract and invoice compliance audit.

SoCalGas
A Sempra Energy utility

SoCalGas has established a high-level internal committee comprising of executives and directors to oversee pipeline safety programs and activities, including oversight over contractors. This committee meets periodically and reviews the progress made in the contractor safety area and provides direction on steps needed to be taken to continue to reduce the contractor safety risk. This committee not only provides oversight, but also demonstrates leadership involvement in contractor safety and executive commitment to SoCalGas' safety culture.

Through these oversight controls covered by SCG-3-C1, SoCalGas estimates that it will achieve a decrease of approximately 1.84% in the annual OSHA recordable incident rate. This is just about half of the overall reduction of 3.67% to be anticipated per year for all existing controls.

b. Elements of the Risk Bow Tie Addressed

SCG-3-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. The contractor oversight program is the way SoCalGas standardizes its approach to contractor safety. This oversight enhances the safety of SoCalGas construction projects from inception to completion. SoCalGas' contractor safety oversight program therefore addresses all elements of the left side of the Risk Bow Tie (DT.1 through DT.7), and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie (PC.1 through PC.8).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	**LoRE**		**1.0728**	
	CoRE	103.525	**983.99**	2451.43
	Risk Score	111.06	**1055.60**	2629.84

	RSE	1.06	**10.12**	25.22

2. **SCG-3-C2: Contractual Requirements**

a. **Description of Risk Reduction Benefits**

SoCalGas has updated the contractual requirements of all contract templates and Master Service Agreements for Class 1 work to include language that holds SoCalGas' Class 1 Contractors accountable for following the Company's policies, procedures, and safety practices. All Class 1 Contractors have executed contracts including the new language and without this control, SoCalGas may have difficulty enforcing its safety policies, procedures, and practices.

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-3-C2 because this control in itself does not have a monetary value/cost that could be calculated in any reasonable manner.

b. **Elements of the Risk Bow Tie Addressed**

SCG-3-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. The contractual requirement control is in place to add updated language to all contracts in order to hold all Class 1 Contractors accountable to follow SoCalGas' Class 1 Contractor Safety Manual. SoCalGas' contractor requirements therefore address elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1) and inadequate use of Job Site Safety Plans or Job Safety Analysis (DT.4), and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as adverse litigation (PC.5).

3. **SCG-3-C3: Stop The Job/Near Miss/Close Call Reporting Program**

a. **Description of Risk Reduction Benefits**

Stop the Job/Near Miss/Close Call reporting (SCG-3-C3) helps prevent future incidents by alerting SoCalGas of an event that had the potential to result in injury, illness, or damage but did not. Integrating Near Miss reporting into the Contractor safety culture provides SoCalGas with an opportunity to investigate, conduct lessons learned, mitigate, communicate and educate

Contractors about the risk/hazard, improve future practices, and avoid similar incidents – thereby reducing risk.

SoCalGas has not performed a Risk Spend Efficiency Evaluation on SCG-3-C3 because this control in itself does not have a monetary value/cost that could be calculated in any reasonable manner.

b. Elements of the Risk Bow Tie Addressed

SCG-3-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. The Stop the Job process is a protocol SoCalGas has established for all contractors. It gives authority to everyone onsite to stop a job or task if an unsafe work condition or activity is identified. SoCalGas requires its contractors to report all incidents per the Class 1 Contractor Safety Manual including Near Miss/Close Call incidents immediately. SoCalGas' initiatives to reduce incidents starts with identifying potential incidents in order to mitigate future incidents from occurring. SoCalGas' contractor requirements therefore address all elements of the left side of the Risk Bow Tie (DT.1 through DT.7), and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie (PC.1 through PC.8).

4. SCG-3-C4: Third-Party Administration Tools

a. Description of Risk Reduction Benefits

SoCalGas uses different third-party administration tools ISNetworld, Veriforce, and Gold Shovel Standard to manage contractor data and compliance in accordance with SoCalGas and applicable rules and regulations. The use of ISNetworld verifies Class 1 Contractor compliance with SoCalGas safety rules and regulations, maintenance of a safe record in compliance with OSHA requirements and regulations, and provides SoCalGas with a centralized system to house contractor documents, pre-qualification requirements, and communications, thereby reducing the risk of safety incidents on SoCalGas work. The benefit of Veriforce is to allow only OQ trained and certified contractor employees to work on OQ tasks associated with SoCalGas projects to prevent incidents. Furthermore, ISNetworld, Veriforce, and Gold Shovel Standard, which are all used by the majority of utilities in California and are considered common practices, support SoCalGas in proactive identification of safety trends, provide a centralized system to store and review safety data to validate compliance, and allow the Company to address Class 1 Contractor at-risk behavior before the occurrence of an incident. Finally, using third-party administration tools (rather than SoCalGas resources) allows the Company to verify Contractor data, conduct trend analyses, and manage safety compliance more cost-effectively.

All of SoCalGas' Class 1 Contractors involved in managing excavation activities (representing 100% of pipeline excavation work) are certified by Gold Shovel Standard, which certifies the Contractor as having best safety practices during excavations. The use of Gold Shovel certified companies for excavation work supports SoCalGas' safety program and prevents life-threatening damages and incidents, empowers field teams to operate safely, and protects excavation crews and the public. SoCalGas estimates that the use of these three administration tools combine to contribute to a 0.92% risk reduction. This is just about one-fourth of the overall reduction of 3.67% SoCalGas anticipates achieving per year for existing controls.

b. Elements of the Risk Bow Tie Addressed

SCG-3-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SoCalGas currently uses three third-party administration tools to confirm contractors comply with SoCalGas' established safety requirements according to the Class 1 Contractor Safety Manual and the contractual requirements. SoCalGas' use of third-party administrative tools reduce risk and give SoCalGas a way to verify contractor data in an effective manner. SoCalGas' third-party administration tools therefore address elements of the left side of the Risk Bow Tie such as DT.1 – DT.3 and DT.5 and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as PC.1, PC.2, PC.4, and PC.6

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	**LoRE**		**1.0631**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	110.06	**1046.08**	2606.12
	RSE	21.78	**207.00**	515.70

5. SCG-3-C5: Contractor Engagement

a. Description of Risk Reduction Benefits

The four annual meetings (three Quarterly Safety Meetings and one Contractor Safety Congress) create a forum in which SoCalGas and Contractors can share industry leading best practices, discuss new safety policies and regulations, discuss lessons learned and opportunities for improvement, and collaborate to improve the Company's and its Contractors safety culture. Having these meetings and the strong engagement shown in the same, is considered a leading practice and places emphasis on safety, demonstrates SoCalGas' engagement in supporting a safety culture, has resulted in identifiable enhancements in Contractor safety practices, and supports dialog between Contractors and the Company, providing a means for Contractors to express questions, concerns and lessons learned. SoCalGas estimates that the use of these three administration tools combine to contribute to a 0.92% risk reduction. This is just about one-fourth of the overall reduction of 3.67% SoCalGas anticipates achieving per year for existing controls.

b. Elements of the Risk Bow Tie Addressed

SCG-3-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. The quarterly and annual meetings for contractors create a proactive approach towards sharing industry-leading best practices, communicating new requirements and promoting a collaborative environment. These meetings promote a strong safety culture and greater opportunity to learn from one another. SoCalGas' contractor safety meetings therefore address all elements of the left side of the Risk Bow Tie (DT.1 through DT.7), and aim to reduce the Potential Consequences identified in the right side of the Risk Bow Tie (PC.1 through PC.8).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	**LoRE**		**1.0631**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	110.06	**1046.08**	2606.12
	RSE	25.47	**242.07**	603.08

6. SCG3-M1: Expanded Contractor Safety Oversight

a. Description of Risk Reduction Benefits

SoCalGas plans to add approximately seven safety advisors to conduct comprehensive safety inspections and audits of contractor construction projects to further improve the effectiveness of the oversight element of SoCalGas' Contractor Safety program. Expansion of the Company's Contractor Oversight Program is expected to result in a measurable impact on

Class 1 Contractor OSHA recordables and would allow SoCalGas to effectively oversee all Class 1 Contractor work and confirm compliance with contractor safety program enterprise-wide. Considering the types of work performed by the Class 1 Contractors that would be integrated in the expanded Program and the amount of work that would become subject to enhanced oversight, SoCalGas estimates a further 1.84% reduction in OSHA recordable rate through this new mitigation. This is just about half of the overall reduction of 3.67% SoCalGas anticipates achieving per year for existing controls.

b. Elements of the Risk Bow Tie Addressed

SCG-3-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Expanding SoCalGas' current Contractor Oversight program to include seven new advisors would aim to provide comprehensive inspections and audits of contractor construction projects. SoCalGas' expansion of its oversight program therefore addresses all elements of the left side of the Risk Bow Tie (DT.1 through DT.7), and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie (PC.1 through PC.8).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	LoRE		**1.0341**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	107.05	**1017.52**	2534.97
	RSE	2.26	**21.52**	53.63

VII. SUMMARY OF RISK MITIGTION PLAN RESULTS

SoCalGas's Risk Mitigation Plan takes into account recent data and trends related to Contractor Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SoCalGas has performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigation activities, associated costs, the RSEs by tranche.

SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[22]

(Direct 2018 $000) [23]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[24]	2018 Baseline O&M	2020-2022 Capital[25]	2022 O&M[26]	Total[27]	RSE[28]
SCG-3-C1	Contractor Safety Oversight	T1	0	950	0	1,600-2,400	1,600-2,400	1.06-25.22

22 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

23 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

24 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

25 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas's Test Year 2022 GRC Application.

26 As previously stated, internal labor (e.g., employee time spent to complete training courses, employee time spent to perform inspections) are not included in SDG&E's O&M cost forecasts since these costs would rely on cost assumptions (e.g., number of employees, x length of training course, x average hourly wage). Further, SDG&E does not track labor in this manner and thus would not be able to include such internal labor costs in future spending accountability reports.

27 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

28 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[24]	2018 Baseline O&M	2020-2022 Capital[25]	2022 O&M[26]	Total[27]	RSE[28]
SCG-3-C2	Contractual Requirements	T1	0	0	0	0-0	0-0	-
SCG-3-C3	Stop the Job/Near Miss/Close Call Reporting	T1	0	0	0	0-0	0-0	-
SCG-3-C4	Third-Party Administration Tools	T1	0	40	0	40-50	40-50	21.78-515.70
SCG-3-C5	Contractor Engagement	T1	0	20	0	35-40	35-40	25.47-603.08
SCG-3-M1	Expanded Contractor Safety Oversight	T1	0	0	0	750-960	750-960	2.26-53.63
		TOTAL COST	**0**	**1,010**	**0-000**	**2,425-3,090**	**2,425-3090**	

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SoCalGas notes that there are activities related to this Contractor Safety risk that will be carried over to the GRC for which the costs are a combination of external and internal labor (*e.g.*, employee time spent for internal training, performing inspections or monitoring). The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not track labor in this manner.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for No RSE Calculation
SoCalGas-3-C2	Contractual Requirements	Excluded internal labor ; no identified costs
SoCalGas-3-C3	Stop the Job Near Miss/Close Call	Excluded internal labor; no identified costs

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the mitigations for the Contractor Safety risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SCG-3-A1: Use Internal Resources and Tools to Vet Contractors For Safety

This alternative would involve developing an in-house electronic platform using internal Information Technology (IT) resources at a cost exceedingly greater than the subscription fees incurred for outside third-party platforms, like the ISNetworld. It would also result in time delays to develop such a platform. Furthermore, this alternative would require hiring several safety professionals (around

5 FTEs) at a cost exceedingly greater than the subscription fees incurred for third-party services, like the ISNetworld, to review contractor compliance programs on an on-going basis for accuracy and completeness for meeting the regulatory requirements. Based on our experience of over two years with using ISNetworld, this alternative was judged to be not a cost-effective option.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	**LoRE**		**1.0502**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	108.72	**1033.39**	2574.50
	RSE	0.62	**5.92**	14.76

B. SCG-3-A2: Use A Different Third - Party Administration Tool To Vet Contractors For Safety

SoCalGas utilizes another third-party electronic platform, Veriforce, for managing contractors for Operator Qualification and Drug & Alcohol program compliance. Veriforce also has the ability to vet contractors for employee safety and recently has strengthened its offering by merging with PEC Safety that provides services similar to ISNetworld. The cost of these third-party platforms is competitive, and SoCalGas ended up selecting ISNetworld in 2016 after a competitive bidding process. SoCalGas has had good experience and success with ISNetworld thus far, but as the landscape of third-party providers change, SoCalGas will consider this alternative through another round of competitive bidding process and make appropriate adjustments. As of now, switching to another provider may not save any money but may add costs to contractors for switching over to another platform. If we ever plan to switch the platforms, it must be done with long lead time to make it efficient all around.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.053**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	109.06	**1036.56**	2582.40
Post-Mitigation	LoRE		**1.0502**	
	CoRE	103.53	**983.99**	2451.43
	Risk Score	108.72	**1033.39**	2574.50
	RSE	9.89	**94.04**	234.27

Table 8: Alternative Mitigation Summary
(Direct 2018 $000) [29]

ID	Mitigation	2020-2022 Capital[30]	2022 O&M	Total[31]	RSE[32]
SCG-3-A1	Use internal resources and tools to vet contractors for safety	0	480-580	480-580	0.62-14.76
SCG-3-A2	Use a different third-party administration tool to vet contractors for safety	0	30-40	30-40	9.89-234.27

---

29 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

30 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

31 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

32 RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

A Sempra Energy utility

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
SCG-3-C1	Contractor Safety Oversight	DT.1 – DT.7 PC.1 – PC.8
SCG-3-C2	Contractual Requirements	DT.1, DT.4, PC.5
SCG-3-C3	Stop the Job/Near Miss/Close Call Reporting Program	DT.1 – DT.7, PC.1 – PC.8
SCG-3-C4	Third-Party Administration Tools	DT.1 – DT.3, DT.5, PC.1, PC.2, PC.4, PC.6
SCG-3-C5	Contractor Engagement	DT.1 – DT.7, PC.1 – PC.8
SCG-3-M1	Expanded Contractor Safety Oversight	DT.1 – DT.7, PC.1 – PC.8

SoCalGas

A Sempra Energy utility®

Risk Assessment Mitigation Phase

(Chapter SCG-4)

Customer and Public Safety

November 27, 2019

SoCalGas
A Sempra Energy utility®

TABLE OF CONTENTS

Risk: Customer and Public Safety

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas or Company) Customer and Public Safety risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in this 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from information in this 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (SMAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon.[3] A "Control" is defined as a "[c]urrently established measure that is modifying risk."[4] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[5] Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Customer and Public Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP

[3] *Id.* at Attachment A.

[4] *Id.* at 16.

[5] *Id.* at 17.

Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

A. Risk Definition

For purposes of this 2019 RAMP report, SoCalGas' Customer and Public Safety Risk is defined as "the risk of customer safety incidents, which results in fatality, serious injury[6] and/or facility damage."

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[7] for each Control and Mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Employees who deviate from Company policy or procedure
DT.2	Employee inexperience or lack of training
DT.3	Condition of customer premises or equipment
DT.4	Condition of Company facilities
DT.5	Distracted driving
PC.1	Serious injuries and/or fatalities
PC.2	Property Damage
PC.3	Adverse litigation
PC.4	Penalties and fines
PC.5	Erosion of public confidence

6 For purposes of this 2019 RAMP Report, a "serious injury" is defined as an injury that requires an overnight hospital stay.

7 *Id.* at Attachment A, A-11 ("Bow Tie").

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[8] SoCalGas performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP, as further described below. SoCalGas' baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Name
SCG-4-C1	Employee Formal Skills Training
SCG-4-C2	Natural Gas and Appliance Testing
SCG-4-C3	Leak and Emergency Order Response
SCG-4-C4	Gas Consumption Analytics
SCG-4-C5	Customer Services Field - Leak Detection Equipment
SCG-4-C6	Quality Assurance
SCG-4-C7	Policy, Procedures and Standards
SCG-4-C8	Collect Customer Contact Data for Safety Communication
SCG-4-C9	Safe Driving Programs
SCG-4-C10	Pole and Data Collector Unit (DCU) Inspections

8 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SoCalGas will continue the 2018 controls identified above and puts forth additional projects and/or programs (*i.e.*, mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SCG-4-M1	Underground Leak Detection Tool

Finally, pursuant to the SA Decision,[9] SoCalGas considered alternatives to the Risk Mitigation Plan for the Customer and Public Safety risk and summarizes the reasons that the alternatives were not included in the plan in Section VIII.

II. RISK OVERVIEW

SoCalGas' possesses a "safety-first" culture, which focuses on its employees, customers, and the public, and is embedded in every aspect of its work. As discussed in the Employee Safety chapter, SCG-2, SoCalGas employee safety programs are founded on proven employee-based programs, safety training, and workforce education. Many, if not all, of these employee safety programs also promote the safety of the public and our customers. While the costs and activities are presented in the operational risk chapters and the Employee Safety chapter of this 2019 RAMP Report, the benefits received by SoCalGas' customers and the public remain present.

The majority of risk mitigation activities presented in the various Chapters of this 2019 RAMP Report provide customer and public safety risk reduction benefits. For example, the mitigation activities presented in SoCalGas' medium- and high-pressure pipeline risk Chapters (SCG-1, SCG-5) that focus on reducing pipeline incidents are designed to protect the public but are more accurately captured in the respective pipeline infrastructure chapters of this RAMP Report since the activities focus on infrastructure protection. The same applies to SoCalGas' third party dig-in risk Chapters (SCG-6, SCG-7). Therefore, the definition of SoCalGas' Customer and Public Safety risk is very limited in scope.

SoCalGas' Customer and Public Safety risk also includes motor vehicle incidents. To mitigate this risk, SoCalGas utilizes a driver safety program as part of the employee safety efforts. This program includes a monthly training module that serves to remind and bolster safe driving practices to help

---

9 *Id.* at 33.

prevent motor vehicle incidents. The goal of this program is to help drivers see, think and act their way through various driving environments, challenges and changes that may exist or develop regardless of where they travel or the vehicles they operate. These principles enable employees to be better drivers, to keep themselves safe and, by extension, to keep the public safe as well (*see* Risk Bow Tie driver DT.5).

The last serious injury to a SoCalGas customer that occurred after-the-meter was related to a field service technician's performance in late 2014. Since then, there has been no reoccurrence of a similar incident. SoCalGas regularly assesses its policies, procedures and safety culture and encourages two-way communication between employees and management as a means of identifying and managing safety risks. Further, since 2014, management has created multiple methods for employees to report close calls/near misses, which has helped further mitigate this risk. Safety is a core value, so we provide all employees with the training necessary to safely perform their job responsibilities. SoCalGas has formal procedures, processes, and standards it maintains to provide guidance to employees and document the manner in which work is to be performed safely, which are continuously updated, in addition to training practices including module and skills testing, field evaluations for employees and a Quality Assurance Program that involves random testing. Strong continuous improvement practices result in periodic updates to these items.

An integrated approach to safety is taken by SoCalGas, and there is a multitude of safety practices infused in every aspect of the Company from its design and construction of facilities to the continuous evaluation and improvement of operation and maintenance activities. As further discussed in Chapter RAMP-F, SoCalGas is continually working to evolve and enhance its safety practices as illustrated in descriptions of the programs/activities below. SoCalGas addresses safety concerns through public communication and awareness, emergency response, safety programs and practices and fosters a workplace that encourages continual open and informal discussion of safety-related issues. For example, as discussed in the Employee Safety chapter (SCG-2), SoCalGas has meetings and campaigns that are founded on safety training and workforce education. These initiatives also reassure the safety of the public and our customers. Similarly, controls and mitigations that are discussed through-out the various chapters of this 2019 RAMP Report encompass initiatives and activities that also promote the safety of the public and our customers but are not discussed here (*e.g.,* Meter-Set Assembly inspections). *See* Appendix A of Chapter RAMP-A.

As further discussed in SoCalGas Chapter RAMP-F, the safety of employees, contractors, customers and the public in the communities it serves is a core value for SoCalGas. The Company endeavors to foster a work environment where employees are focused on and engaged in sustaining a culture that emphasizes safety; from initial employee training, to the installation, operation, and maintenance of utility infrastructure, and the commitment to provide safe and reliable service to customers.

III. RISK ASSESSMENT

In accordance with the SA Decision,[10] the following section describes the risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the Customer and Public Safety risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above.

[10] *Id.* at 33 and Attachment A, A-11 (“Bow Tie”).

Figure 1: Risk Bow Tie

B. Asset Groups or Systems Subject to the Risk

The SA Decision[11] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. This is a "cross-cutting" risk and therefore is associated with human systems, rather than particular asset groups.

C. Risk Event Associated with the Risk

The SA Decision[12] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the Risk Event (center of the Risk Bow Tie) is a Customer and Public Safety event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. The Risk Scenario (*i.e.*, a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency) is assessed for SoCalGas' 2018 Enterprise Risk Registry. This scenario does not

---

[11] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[12] *Id.* at Attachment A, A-11 ("Bow Tie").

necessarily address all Drivers/Triggers and Potential Consequences and does not reflect actual or threatened conditions.

D. Potential Drivers/Triggers[13]

The SA Decision[14] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for this risk, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – Employees who deviate from Company policy or procedure**: Failure of an employee to adhere to Company safety policies or procedures could result in a safety-related event.
- **DT.2 – Employee inexperience or lack of training**: Failure to use experienced employees or provide the proper training to perform the necessary work may lead to an increase in the occurrence of safety incidents.
- **DT.3 – Condition of customer premises/gas equipment poses hazard to customers**: Unsafe customer premises or equipment may increase the likelihood of a safety event.
- **DT.4 – Condition of Company facilities:** The state or condition of Company facilities, if not properly maintained, could lead to a safety event.
- **DT.5 – Distracted driving**: Use of cellphones or other types of distractions while driving can lead to serious injuries and/or fatalities

E. Potential Consequences

Potential Consequences are listed to the right side of the Risk Bow Tie illustration provided above. If one or more of the drivers or triggers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[15] and/or fatalities;

---

13 An indication that a risk could occur. It does not reflect actual or threatened conditions.

14 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

15 For purpose of this 2019 RAMP Report, "serious injury" is broadly defined as an injury that requires an overnight hospital stay.

- Property damage;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These potential consequences were used in the scoring of the Customer and Public Safety Risk that occurred during the development of SoCalGas' 2018 enterprise risk registry.

IV. RISK QUANTIFICATION FRAMEWORK

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[16] including enhancements to the Interim Decision 16-08-018.[17] SoCalGas used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[18]

Customer &Public Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	98	**765**	1875
LoRE	**0.5**		
CoRE	204	**1586**	3888

[16] D.18-12-014 at Attachment A.

[17] *Id.* at 2-3.

[18] The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[19] The section below provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of motor vehicle incidents or after-meter incidents, which results in significant consequences including injuries, fatalities and/or facility damage.
Out-of-Scope for purposes of risk quantification:	The risk of incidents that could affect customers and/or the public already captured in other RAMP risks, and other incidents not described as "In Scope."

Pursuant to Step 2A of the SA Decision,[20] the utility is instructed to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data). The SoCalGas Customer and Public Safety risk assessment identified two main risks: SoCalGas motor vehicle risk and SoCalGas after-meter risk. The motor vehicle risk assessment primarily utilized data from the Department of Transportation (DOT), National Highway Traffic Safety Administration (NHTSA), and Federal Highway Administration (FHA).

Fatality Analysis Reporting System (FARS) historical data from the DOT was used to determine the fatal accident rate per year by vehicle type. The General Estimates System (GES) historical data from the National Automotive Sampling System (NASS) was used to calculate nonfatal incident rates per year by vehicle type. To determine fatal and nonfatal incident rates per year for SoCalGas, the national average incident rate per mile per year was applied to the vehicle miles traveled (VMT) at the company. The safety and financial consequence distributions were generated based on both FARS and GES historical data. A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences for SoCalGas motor vehicle risk.

---

19 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

20 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

The safety and financial consequence of SoCalGas after-meter risk was estimated based on SME input.

B. Sources of Input

The SA Decision[21] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The inputs utilized as part of this assessment are listed below.

- Fatality Analysis Reporting System (FARS)
  - Agency: U.S. Department of Transportation
  - Link: https://www.nhtsa.gov/research-data/fatality-analysis-reporting-system-fars
- General Estimates System (GES) of National Automotive Sampling System (NASS):
  - Agency: U.S. Department of Transportation
  - Link: https://www.nhtsa.gov/research-data/national-automotive-sampling-system-nass
- The Economic and Societal Impact of Motor Vehicle Crashes, May 2015 (Revised)
  - Agency: U.S. Department of Transportation, National Highway Traffic Safety Administration
  - Link: https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/812013
- Shares of Highway Vehicle-Miles Traveled by Vehicle Type, 1970–2015
  - Agency: Oak Ridge National Laboratory
  - Link: https://tedb.ornl.gov/wp-content/uploads/2019/03/Edition36_Full_Doc.pdf

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[22] This section describes SoCalGas' Risk Mitigation Plan by each selected control and mitigation for this risk, including the rationale supporting each selected control and mitigation.

---

21 *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

22 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

As stated above, SoCalGas' Customer and Public Safety risk includes the in-scope motor vehicle incidents and after-meter incidents, as well as other customer safety incidents that result in fatality, injury, and/or facility damage. The Risk Mitigation Plan discussed below includes controls and mitigations that are expected to continue for the period of SoCalGas' Test Year 2022 GRC cycle.[23] Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SCG-4-C1 – Employee Formal Skills Training

Training is an integral part of how SoCalGas mitigates the Customer and Public Safety Risk. All field service technicians and call center customer service representatives (CSRs) must complete and pass mandatory training.

The Customer Contact Center (CCC) is generally the first point of Company contact for emergencies; as such it provides a critical support role in the safety of the SoCalGas system and the public's well-being. CSRs working in the CCC are trained to answer notifications for multiple types of emergencies in which gas leak calls are given top priority in the CSR call queue. This training is crafted to teach CSRs to discern different types of emergencies and manage calls to confirm appropriate field technician or emergency response personal are sent in response to the particular type of situation. Additionally, the CSRs at the CCC help mitigate risk to customer and public safety during non-emergency situations by issuing customer-requested appliance inspection and maintenance orders.

The orders taken in the CCC are prioritized and then completed by field service technicians. For field service technicians, training includes classroom and situational field exercises to educate employees on safety processes and procedures to perform work in a manner that meets all applicable rules, regulations and SoCalGas internal policies and procedures. Formal skills training reduces the likelihood of employees deviating from Company policy or procedure because field service technicians do not work customer orders on their own until they are fully trained to do their jobs adequately and

---

23 *Id.* at 16-17 and 33. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

safely. Additionally, field instructors provide field service technicians with formal field training and perform job observations. Once the field service employees successfully pass formal training, they are permitted to work customer orders on their own. A follow-on quality assurance assessment is then performed to confirm that the field service employees have retained the training knowledge and skills required to safely perform their duties.

B. SCG-4-C2 – Natural Gas and Appliance Testing

SoCalGas performs Natural Gas Appliance Testing (NGAT) in homes that receive air infiltration measures such as weather-stripping, caulking, or window and door repair as part of the services offered under the Energy Savings and Assistance Program (ESAP).[24] Following the completion of energy efficiency work, the SoCalGas contractor performing the ESAP service must inspect every natural gas appliance in the home to help mitigate exposure to carbon monoxide (CO). The inspection process involves an operational evaluation of each gas appliance as well as the measurement of carbon monoxide levels within the living space. This safety precaution is conducted to verify conditions are suitable for building occupants, which mitigates risk to customer and public safety.

C. SCG-4-C3 – Leak and Emergency Order Response

Customers call SoCalGas' CCC to request service for many different reasons, including potential gas leaks and other emergency orders. As previously stated, the CCC is generally the first point of Company contact for emergencies; as such it provides a critical support role in the safety of the SoCalGas system and the public's well-being. Gas leak calls are given top priority in the CSR call queue and CSRs are trained to discern the different types of emergencies and manage calls to see that appropriate field personnel are sent in an order prioritizing the necessary response in accordance with the Code of Federal Regulations (CFR) 49 Part § 192.615.[25]

---

24 *See* A.19-11-006, Application of Southern California Gas Company for Approval of its Energy Savings Assistance and California Alternate Rates for Energy Programs and Budgets for Program Years 2021-2026 (November 4, 2019).

25 *See* 49 CFR Part 192, § 192.615 Emergency Plans.

These types of requests include, but are not limited to:

- General Leaks – at appliances, at gas meters, inside structures-source unknown, ignited leaks;
- Outside Leaks- damaged gas lines or meter, dying vegetation;
- Carbon Monoxide (CO) – customer experiencing symptoms or not, CO safety checks, CO Alarm/Detectors activated or not;
- Miscellaneous Safety-Related issues – Odor Fade, appliance recalls; and
- Other Urgent Situations – water heater not cycling off (water steaming), bomb threats.

The CCC also helps to mitigate risk to customer and public safety during non-emergency situations by issuing customer requested appliance inspection and maintenance orders.

Field service technicians respond to the customer orders taken by the CCC. They are trained to rectify safety hazards on customer premises in order to maintain safe operations of Company facilities. Some of these customer requests are safety related, such as checking appliances upon move in. However, any customer call about a gas leak, both hazardous and non-hazardous, is dispatched to a field service technician to perform a gas leak investigation. SoCalGas requires that all hazardous and non-hazardous leak orders are responded to by a field technician within the same day of receiving the customer call, with the response to the highest priority gas leak orders within 30 minutes.

D. SCG-4-C4 – Gas Consumption Analytics

SoCalGas continuously analyzes and monitors gas consumption on all meters that have been advanced to identify any potentially unsafe anomalies in consumption. Prior to the installation of the Advanced Metering Infrastructure (AMI) technology, gas consumption at premises with installed security devices was identified as part of the billing exception processes by the Customer Information System (CIS). Billing analysts would be required to evaluate and schedule additional visits to the meter if there is unusual gas consumption that is not associated with the customer's historical usage patterns. With AMI, SoCalGas can now identify and investigate these possibly unsafe situations within the same day that unusual consumption is identified, reducing the risk of a customer or public safety incident.

Gas Consumption Analytics furthers the safe operation of SoCalGas and customer equipment (*e.g.,* meter, regulator) by allowing SoCalGas to actively recognize and investigate potentially unsafe conditions, such as equipment failures, gas leaks at unoccupied facilities, or unsafe natural gas diversion. Safety is a SoCalGas core value and strategies to address tampering of gas devices by non-SoCalGas personnel reduces the potential for hazardous conditions that could be detrimental to customers and/or to the public.

E. SCG-4-C5 – Customer Services Field - Leak Detection Equipment

Job-specific tools are required by service field technicians to perform work safely. SoCalGas provides specialized equipment to its field service technicians to detect leaks inside and outside customer homes and businesses.

A team is in place to review and evaluate proposed changes and support continuous improvement. The team works closely with potential suppliers, manufacturers and various departments within SoCalGas to verify that the functional requirements of the leak detectors are met. The costs associated with the leak detection equipment currently in use, are included in this category.

F. SCG-4-C6 – Quality Assurance and Control Programs

As referenced in Section SCG-4-C1, SoCalGas performs regular Quality Assurance (QA) checks to assess the work quality of its field and CCC personnel. The QA function regularly includes in-field sampling of completed customer service field orders to assess employee work quality and compliance with Company policies and procedures. QA Specialists receive random orders previously completed by customer service field representatives and make in-home visits. The purpose of the QA program is to have QA Specialists verify that customer service field representatives recognize and address safety issues with customer-owned appliances and Company-owned equipment.

The CCC QA program involves sampling voice calls to better assess employee work quality and compliance with Company policies and procedures. The efforts of both QA programs promote improved consistency in adherence to policies and processes and a reduction in work errors that may pose a risk to customer and public safety.

G. SCG-4-C7 – Policy, Procedures & Standards

SoCalGas develops and maintains formal written procedures, processes, and standards. These materials provide guidance to employees and document the manner in which work is to be performed. Systems are in place to track employee training (*e.g.*, DOT Operator Qualification (Op Qual) certification, facility site inspections (Uniform Building Code requirements per Assembly Bill (AB) 32) and administration of the Company's Environmental and Safety Compliance Management Program (ESCMP).

As discussed in further detail in the Employee Safety Chapter (SCG-2) and Chapter RAMP-F, ESCMP is an environmental, health, and safety management system to plan, set priorities, inspect, educate, train, and monitor the effectiveness of environmental, health, and safety activities in accordance with the internationally accepted standard, International Organization for Standardization (ISO) 14001. ISO 14001 is the international standard that specifies requirements for an effective environmental management system. Included in the ISO 14001 standards are Consumer Product Safety Commission published recalls on gas appliances and equipment. SoCalGas continually monitors the ISO 14001 standards to confirm that Company standards are current. Company policies, procedures and standards are always accessible to field service technicians on their Mobile Data Terminals,[26] enabling them to safely do their jobs with the most current information.

H. SCG-4-C8 – Collect Customer Contact Data

Customer Contact Center service representatives (CSRs) confirm and collect updated customer contact information during a service call. This data provides SoCalGas with contact information that allows it to call the customer ahead of a service call or to provide information in case of an emergency. On all calls that involve direct interaction between CSRs and customers, CSRs will collect/verify customer email addresses and mobile phone numbers. Gathering this additional information better enables SoCalGas to communicate with customers in the event of a natural disaster, emergency incident or when property access is required for conducting maintenance on company facilities.

---

[26] SoCalGas is currently in the process of transitioning from Mobile Data Terminals to iPhone technology.

I. SCG-4-C9 – Safe Driving Programs

SoCalGas' safe driving programs include the Employer Pull Notice (EPN) program and the AlertDriving® program. These two programs are discussed in greater detail in SoCalGas' Employee Safety Risk Chapter (SCG-2) but have relevancy to Customer and Public Safety risk. The California DMV Pull Notice Program allows employers to monitor driver's license records of employees who drive on the Company's behalf. The EPN is currently used to monitor the driving records of the Company's commercial (Class A) drivers. The EPN is designed to promote driver safety through the ongoing review of driver records.

The AlertDriving program is designed to enhance the driving skills of service technicians. The program teaches drivers to proactively see, think and act their way through various driving environments, challenges and changes that exist regardless of where they travel or the vehicles they operate. These principles enable employees to be better drivers to keep themselves safe and in doing so, the public safe as well.

J. SCG-4-C10 – DCU Pole Inspections

SoCalGas conducts cyclical inspections of Data Collector Units (DCUs) and poles to identify structural problems and/or hazards in support of public safety and a reliable network communication. Although SoCalGas is only mandated to inspect SoCalGas-owned poles, SoCalGas goes above and beyond and inspects all DCU units on an annual basis, including third party poles. The annual inspections support public safety. The pole inspection process identifies structural problems and/or hazards in support of public safety and system reliability.

Qualified SoCalGas field resources perform this work to comply with the CPUC's General Orders.[27] Inspection results are logged and maintained by the Network Maintenance & Construction team for compliance reporting.

K. SCG-4-M1 –Underground Leak Detection Tool

As previously stated for Customer Services Field - Leak Detection Equipment (SCG-4-C5), job-specific tools are required by service field technicians to perform work safely. SoCalGas customer

---

[27] CPUC General Orders 95 and 165.

service field employees currently utilize the Sensit G2 Multi-Gas Detector for indoor and outdoor leak detection and carbon monoxide detection. SoCalGas Gas Operations uses a different gas detection tool for underground detection purposes (GMI Gasurveyer 500). SoCalGas Customer Services is working to deploy a new underground leak detection tool **(**GMI Gasurveyor 700). Since both the Gas Surveyor 500 and 700 utilize the same detection principles, the new tool will provide greater consistency and reliability for company underground leak detection.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the SA Decision. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[28] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE).

SoCalGas' Customer and Public Safety program consists of programs aimed to reduce risk of injury or fatality to customers or the public. SoCalGas grouped similar activities with like risk profiles into mitigation programs. Since each of SoCalGas' Customer and Public Safety risk mitigation activities have the same goal of reducing the risk of injury or fatality to our customers and the public, all controls and mitigations have the same risk profile and are not further tranched. Further, a single tranche is appropriate for the Customer and Public Safety Risk event as there is no logical disaggregation of assets or systems related to the controls presented in the Risk Mitigation Plan.

---

[28] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

B. Post-Mitigation/Control Analysis Results

1. SCG-4-C1 – Employee Formal Skills Training

a. Description of Risk Reduction Benefits

The CCC helps to mitigate risk to customer and public safety during non-emergency situations by scheduling customer requested appliance inspection and maintenance orders. Training for CSRs is critical because the CCC is often the first point of contact during an emergency. With proper training, CSRs can better recognize and escalate public and employee safety issues. Training for field service technicians also helps to confirm that technicians operate in a safe and compliant manner.

Formal skills training must be completed and passed by all field service technicians and call center CSRs. Training gives CSRs the ability to identify different types of emergencies and determine the appropriate response to the situation. Training for field service technicians includes classroom and situational field exercises. After training is conducted, a QA process is performed to confirm that employees have retained their knowledge.

As further discussed in the Employee Safety Chapter (SCG-2), SoCalGas provides numerous employee safety training courses to educate employees across the entire Company how to safely perform their jobs.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C1 helps to address the following elements of the Risk Bow Tie: Employees who deviate from Company policy or procedure (DT.1), Employee inexperience or lack of training (DT.2), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4) and Erosion of public confidence (PC.5).

2. SCG-4-C2 – Natural Gas Appliance Testing

a. Description of Risk Reduction Benefits

SoCalGas conducts carbon monoxide (CO) testing on homes weatherized through the Energy Savings Assistance (ESA) Program in accordance with Statewide Energy Savings Assistance Program Installation Standards and the Statewide Energy Savings Assistance Program Policy and Procedures Manual. CPUC directives order SoCalGas to charge the costs for the Natural Gas and Appliance Testing (NGAT) program to base rates rather than to the public purpose funds. Additionally, the frequency of

NGAT is expected to increase in proportion to the forecast increase proposed in the 2019 Low Income Application (A.)19-11-006, subject to Commission Decision.

In order to help safeguard conditions for customers, NGAT involves an operational evaluation of each gas appliance and the measure of carbon monoxide level and is performed after the completion of energy efficiency work. NGAT is required on a residence due to weatherization measures, such as air sealing and increased home insulation, which increase the risk of CO exposure for customers. Inspection work is conducted by pre-qualified contractors on each home where weatherproofing work has been completed. These contractors are required to hold and maintain an active C-20 Warm-Air Heating, Ventilating, and Air-Conditioning license that is issued by the Contractors State License Board (CSLB).

b. Elements of the Risk Bow Tie Addressed

SCG-4-C2 helps to address the following elements of the Risk Bow Tie: Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4).

3. SCG-4-C3 – Leak and Emergency Order Response

a. Description of Risk Reduction Benefits

The SoCal Gas CCC is the first point of contact for potential gas-related emergencies, including gas leaks. If a gas leak is called in to the CCC, a CSR follows a script designed to obtain information that allows the location and the severity of the leak to be determined. The CSR will then generate a gas leak investigation order. The order will be worked within the same day by a SoCalGas Technician, as stated above in Section V.

Based on the information provided by the customer, CSRs determine whether a potential leak is an emergency. In 2018, emergency calls made up 11.9% of the total number of calls received by the CCC. The total number of emergency calls amounted to 518,086 that year. The average call answer time for emergency orders is 6 seconds with an average response time of field technicians to the gas leak at 22.7 minutes. This response time is faster than the company response time goal of 30 minutes. With efficient, trained and intelligent leak and emergency order response, SoCal Gas can help mitigate public and employee harm associated with gas emergencies.

b. Elements of the Risk Bow Tie Addressed

This control addresses the following elements of the Risk Bow Tie: Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4).

4. SCG-4-C4 – Gas Consumption Analytics

a. Description of Risk Reduction Benefits

With AMI technology, SoCalGas can monitor gas usage to identify irregular usage patterns and investigate potentially unsafe conditions more quickly. Elements of Gas Consumption Analytics include the comparison of real-time gas consumption with prior consumption patterns, customer behavior, and the results from prior field visits.

Gas Consumption Analytics improves SoCalGas' ability for prompt identification of gas leaks and can lead to a timelier response time for remediation. With AMI technology, SoCalGas can proactively identify potential leaks based upon gas usage spikes that may have otherwise been missed. In 2018, AMI technology identified 4,952 customer facilities with unusual gas consumption levels that were undetected by customers. Typically, these were facilities that were vacant with no customers on premise to smell a gas leaks or the customer was unaware that appliances were unintentionally left on. Once a facility with highly unusual gas consumption is identified by AMI technology, the customer is contacted, and a technician is dispatched for further investigation.

AMI technology can also detect potential gas diversion. In 2018, AMI technology identified 356 customer facilities investigated by CSF Operations technicians for tampering. When work on a customer facility by a non-SoCalGas technician is detected, an ETR (Gas Service Technician) is sent to the site within two business days for investigation and/or remediation. In many instances, situations were resolved that could have led to unsafe conditions for the customer and the public.

b. Elements of the Risk Bow Tie Addressed

The technology described within SCG-4-C4 helps reduce customer and public safety risk, and addresses the following elements of the Risk Bow Tie: Condition of customer premise or equipment

(DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4) and Erosion of public confidence (PC.5).

5. SCG-4-C5 – Customer Services Field – Leak Detection Equipment

a. Description of Risk Reduction Benefits

SoCalGas uses job-specific tools so that field technicians can perform work safely and efficiently. Leak detection equipment is used by field technicians at customer premises to detect natural gas leaks on the customers natural gas systems. Currently, the Company uses the Sensit G2 Multi-Gas Detector® for detection of indoor leaks and rotameter technology to test for leakage on customer natural gas systems.

As described previously, the Company is continually looking to identify new tools and technologies. SoCalGas is currently piloting Crystal Gauges technology to detect leaks on customer natural gas systems. The Crystal Gauges provide a greater level of accuracy than the rotameter technology. The preliminary results of the pilot are positive – not only was accuracy increased, but the Crystal Gauges were easier to use and to maintain than the rotameters.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C5 addresses the following elements of the Risk Bow Tie: Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4) and Erosion of public confidence (PC.5).

6. SCG-4-C6 – Quality Assurance and Control Programs

a. Description of Risk Reduction Benefits

Quality Assurance (QA) checks provide valuable information on the quality of service to customers in the field and on customer service calls in the CCC. In the Field QA Program, an "after-the-completion-of-the-order" assessment is made to verify that the field service technician completed field orders in accordance with Company policies and procedure. In 2018, Field QA Specialists inspected 11,877 field orders, which reflected 99.87% of the inspected orders without any hazardous safety errors.

The data obtained by the QA Program is reported on a monthly basis. Feedback is provided to the impacted employees so they can improve their performance. The data obtained is also analyzed for trends. The data trends are used to identify areas where additional training might be needed.

In the CCC, QA Specialists can listen to CSR/customer calls, making assessments on the quality of the service provided. CSR responses to safety related calls are assessed on key elements that include: accurate analysis of safety risks, providing customers with appropriate safety advice, and the CSR's adherence to the Customer Service Order (CSO) flow chart. The flow chart contains an established process outlining the requirements for handling customer calls by the CSRs. Like the Field QA program, the CCC QA Specialist provides feedback to the CSR so that performance can be improved.

For purposes of an RSE analysis, Company SMEs looked at existing controls, considered the historical improvement achieved as a result of performing these activities, and used that in considering the potential increase in safety incidents if those activities ceased to be performed. As such, the Company expects to continue to achieve higher levels of accuracy as a result of the QA program and therefore expects to receive an additional 12% risk reduction[29] by continuing to perform these activities. Further, without performing these activities, the Company could potentially see a decrease in other programs' effectiveness, such as the ability to deploy focused employee training where needed as a result of findings from the QA program.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C6 allows for increased consistency in adherence to policies and processes and a reduction in work errors that may risk customer and public safety. This control addresses the following elements of the Risk Bow Tie: Employees who deviate from Company policy or procedure (DT.1), Employee inexperience or lack of training (DT.2), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4) and Erosion of public confidence (PC.5).

---

29 Please refer to the accompanying RSE workpapers for additional detail.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.482**	
	CoRE	204	**1586**	3888
	Risk Score	98	**765**	1875
Post-Mitigation	LoRE		**0.494**	
	CoRE	207	**1588**	3890
	Risk Score	102	**785**	1924
	RSE	2.74	**15.06**	35.60

7. SCG-4-C7 – Policy, Procedures & Standards

a. Description of Risk Reduction Benefits

The purpose of policies, procedures, and standards is to guide and direct all employees to work safely and to prevent injury to themselves and others. The employee safety standards provide guidance on the manner in which work is to be performed and how to conduct work safely in the workplace. As new equipment is incorporated, or changes occur in the organization, policies and procedures are updated to reflect these adjustments. Updates to policies are performed by the Customer Service Field Department. The policies at SoCalGas are continuously updated, depending on how frequently changes are made in the organization, with all policies reviewed and updated as necessary at least every five years.

SoCalGas has created procedures, standards, and various programs to protect the safety of work activities. An example includes, the Environmental Safety Compliance Management Program (ESCMP), which is used to monitor the effectiveness of environmental, health and safety activities in accordance with ISO14001. SoCalGas also conducts self-assessments and inspections for hazardous environmental factors and monitors the compliance activities for Proposition 65.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C7 addresses the following elements of the Risk Bow Tie: Employees who deviate from Company policy or procedure (DT.1), Employee inexperience or lack of training (DT.2), Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Distracted Driving (DT.5), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2) and Erosion of public confidence (PC.5).

8. SCG-4-C8 – Update Customer Contact Data

a. Description of Risk Reduction Benefits

Customer contact data collected by CSRs provides SoCalGas with information that allows it to remind and contact the customer ahead of a service call or to contact customers in the event of an emergency. CSRs now solicit mobile phone information on all calls, both emergency and non-emergency. For example, communication with customers is important in the event of a natural disaster or other emergency situations. It can also provide customers with timely announcements of pipeline inspections, leakage surveys, and other safety-related activities. During live calls, CSRs will collect and verify mobile phone numbers and also email addresses. Accurate customer data obtained during these calls also provides contact information to technicians who may need access to facilities for safety-related maintenance activities.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C8 addresses the following elements of the Risk Bow Tie: Employees who deviate from Company policy or procedure (DT.1), Employee inexperience or lack of training (DT.2), Distracted Driving (DT.5), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2) and Erosion of public confidence (PC.5).

9. SCG-4-C9 – Safe Driving Programs

a. Description of Risk Reduction Benefits

Driver safety programs enable SoCalGas employees to be better drivers to keep themselves safe and by doing so, keep the public safe as well. The safety programs educate employees on driving techniques and the principles that decrease the risk of motor vehicle incidents and traffic violations. The AlertDriving program focuses on reducing service technicians' driving risk by enhancing their driving skills. This training involves practical exercises that require the technicians to think about the challenges that exist in various driving environments, helping them to make informed decisions and anticipate situations.

The Employer Pull Notice (EPN) program is another safe driving program. This program enables SoCalGas to electronically receive the driving records of the Company's commercial (Class A) drivers. This allows SoCalGas to monitor those people who drive on behalf of the organization. Monitoring the records of these employees helps SoCalGas to determine if there are any convictions, accidents, and/or unsafe driving behaviors. The EPN provides SoCalGas a way to stay up to day with drivers' records, notifying the Company if any issues arise. Access to these notices helps SoCalGas identify where the Company should take corrective measures with the particular employee driver to reduce the likelihood of incidents (*see* SoCalGas' Employee Safety Chapter, SCG-2, risk mitigation activity SCG-2-C5, for RSE analysis).

b. Elements of the Risk Bow Tie Addressed

SCG-4-C9 addresses the following elements of the Risk Bow Tie: Employees who deviate from Company policy or procedure (DT.1), Distracted Driving (DT.5), Serious injuries and/or fatalities (PC.1) and Property Damage (PC.2).

10. SCG-4-C10 – DCU Pole Inspections

a. Description of Risk Reduction Benefits

Annual inspections of Data Collector Units (DCUs) and poles are designed to identify structural problems or hazards and are performed to support public safety and the reliability of the system. Although SoCalGas is only responsible for inspecting company-owned poles, the Company has chosen to annually inspect its entire DCU infrastructure, including DCUs that are attached to third-party poles and indoor DCUs not attached to poles. Qualified field resources who perform the annual inspections log their inspection records. These records are maintained by the Maintenance & Construction team and are reported to the CPUC.

In 2018, SoCalGas inspected 4,323 DCU poles, which comprises 100% of the total DCU infrastructure. These inspections have helped SoCalGas proactively identify issues and hazards before the DCU stops communicating. Therefore, the DCU inspections are beneficial from a public safety, compliance, and network stability standpoint.

b. Elements of the Risk Bow Tie Addressed

SCG-4-C10 addresses the following elements of the Risk Bow Tie: Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2), Adverse litigation (PC.3), Penalties and fines (PC.4) and Erosion of public confidence (PC.5).

11. SCG-4-M1 –Underground Leak Detection Tool

a. Description of Risk Reduction Benefits

As previously stated, SoCalGas uses job specific tools that allow field technicians to perform their work safely. In addition to above-ground leak detection tools that are currently being utilized by technicians, SoCalGas is planning to upgrade the gas service technician's current underground leakage detection tool with the state of the art GMI Gasurveyor 700. The GMI Gasurveyor 700 is equipped with an intake pump and methane-specific infrared technology to detect leaks. The instrument is intended to be used for investigating all outdoor leakage orders.

The GMI Gasurveyor 700 meets all compliance safety and operational requirements and implementation of this unit supports the company's adherence to all FERC, PHSMA and CPUC rules and regulations. Upgrading to the GMI Gasurveyor 700 will provide customers and employees with consistent and safe leak detection.

b. Elements of the Risk Bow Tie Addressed

SCG-4-M1 will address the following elements of the Risk Bow Tie: Condition of customer premise or equipment (DT.3), Condition of Company facilities (DT.4), Serious injuries and/or fatalities (PC.1) and Property Damage (PC.2).

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SoCalGas' Risk Mitigation Plan considers recent trends related to Customer and Public Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SoCalGas has performed RSEs, in compliance with the SMAP decisions and the SA, however, selecting activities for mitigating risks can be influenced by other factors including funding, labor resources, technology, planning and construction lead time, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigation activities, associated costs, and the RSE.

SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 6 below were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[30]

(Direct 2018 $000)[31]

ID	Mitigation/Control	2018 Baseline Capital[32]	2018 Baseline O&M	2020-2022 Capital[33]	2022 O&M	Total[34]	RSE[35]
SCG-4-C1	Employee Formal Skills Training	-	3,400	-	3,400 - 4,000	3,400 - 4,000	-
SCG-4-C2	Natural Gas Appliance Testing	-	2,200	-	2,100 - 2,600	2,100 - 2,600	-

30 Recorded costs and forecasted ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

31 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

32 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

33 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

34 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

35 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	2018 Baseline Capital[32]	2018 Baseline O&M	2020-2022 Capital[33]	2022 O&M	Total[34]	RSE[35]
SCG-4-C3	Leak and Emergency Order Response	-	33,000	-	37,000 - 44,000	37,000 - 44,000	-
SCG-4-C4	Gas Consumption Analytics	-	500	-	700 - 900	700 - 900	-
SCG-4-C5	Customer Services Field – Leak Detection Equipment	-	4	-	10 - 14	10 - 14	-
SCG-4-C6	Quality Assurance	-	2,000	-	2,100 - 2,500	2,100 - 2,500	2.74 – 35.60
SCG-4-C7	Policy, Procedures & Standards	-	1,000	-	1,100 - 1,300	1,100 - 1,300	-
SCG-4-C8	Collect Customer Contact Data for Safety Communication	-	200	-	190 - 230	190 - 230	-
SCG-4-C9	Safe Driving Programs[36]	-	780	-	850 - 980	850 - 980	-

[36] These costs are also captured in the SoCalGas Employee Safety risk Chapter (SCG-2) of this RAMP Report; as discussed in Chapter RAMP-A, internal labor hours (*e.g.*, employee time to take training courses) are not captured in in the costs for this risk mitigation activity.

ID	Mitigation/Control	2018 Baseline Capital[32]	2018 Baseline O&M	2020-2022 Capital[33]	2022 O&M	Total[34]	RSE[35]
SCG-4-C10	DCU Pole Inspections	-	-	-	160 - 200	160 - 200	-
SCG-4-M1	Underground Leak Detection Tool	40	-	4,100 - 5,300	-	4,100 - 5,300	-
	TOTAL COST	**40**	**44,000**	**4,100 - 5,300**	**48,000 – 55,000**	**54,000 – 60,000**	

It is important to note that SoCalGas is identifying a range of potential costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SoCalGas also notes there are activities related to the Customer and Public Safety risk that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.,* time spent to perform training). The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not track training labor in this manner. These activities related to the Customer and Public Safety Risk are: Classroom time related to formal training and employee time for policy, procedures, and standards review.

SoCalGas is not calculating RSEs on the following activities:

Table 7: Summary of RSE Exclusions

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SCG-4-C1	Employee Formal Skills Training	Mandated activity per Cal. Labor Code § 6400, 8 CCR § 8350
SCG-4-C2	Natural Gas and Appliance Testing	Mandated activity per statewide policy[37]
SCG-4-C3	Leak and Emergency Order Response	Mandated activity per 49 CFR Part 192
SCG-4-C4	Gas Consumption Analysis	Non-scoped safety activity
SCG-4-C5	Customer Services Field – Leak Detection Equipment	Non-scoped safety activity
SCG-4-C7	Policy, Procedures & Standards	Mandated activity per 49 CFR Parts 192 and 195, CA Proposition 65
SCG-4-C8	Collect Customer Contact Data	Non-scoped safety activity

[37] Statewide Energy Savings Assistance Program 2017-2020 Cycle, Policy and Procedures Manual (September 2019), available at https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457425

SCG-4-C9	Safe Driving Programs	RSE analysis included in Employee Safety Chapter (SCG-2)
SCG-4-C10	DCU Pole Inspections	Mandated activity per CPUC General Orders 95 and 165
SCG-4-M1	Underground Leak Detection Tool	Non-scoped safety activity

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the Risk Mitigation Plan for the Customer and Public Safety Risk. Typically, analysis of alternatives occurs when implementing activities to obtain the most effective result. The alternatives analysis for this Risk Mitigation Plan also considered modifications to the plan and constraints, such as operating, compliance and resource constraints.

A. SCG-4-A1 – Technician Refresher Training

SoCalGas considered increasing the frequency of employee refresher training as an alternative to the training program put forth in SoCalGas' Risk Mitigation Plan, above (Employee Formal Skills Training, SCG-4-C1). Currently, SoCalGas reviews policies and procedures on a periodic basis. The time interval is dependent upon the nature of the policy/procedure. When policies and procedures are updated, the updates are shared with gas service technicians. As mentioned previously, Company policies, procedures and standards are accessible to field service technicians on their Mobile Data Terminals.

This alternative proposal considered that all field service technicians complete periodic refresher training sessions at the Company's training facility at Pico Rivera. The refresher training would provide greater reinforcement of the gas service technician job skills. The training would include both classroom and hands-on scenario-based modules reinforcing that policies and procedures are being followed and confirming that updates to policies and procedures are understood.

This alternative proposal is not currently being implemented. The high percentage results seen for the service technician QA program validate the adequacy of the current practice of periodic policy and procedure reviews. Expanding the scope of training by adding periodic refresher training would require additional resources. The cost of the increased resources was not projected to yield significant benefits.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.482**	
	CoRE	204	**1586**	3888
	Risk Score	98	**765**	1875
Post-Mitigation	**LoRE**		**0.482**	
	CoRE	204	**1586**	3888
	Risk Score	98	**764**	1874
	RSE	0.06	**0.31**	0.74

B. SCG-4-A2 –Post-Training Follow-Up Field Evaluations

Another alternative proposal considered by SoCalGas is for field service technicians to receive a scheduled, formal field evaluation with a QA Specialist 6-months after graduation from formal training. The QA Specialist would field ride with the employee to observe the employee's adherence to Company policies and procedures after their formalized training. Any deficiencies would be addressed with the employee. The findings from the field rides would be compiled to determine if formal training enhancements are needed and/or if the system wide refresher training is needed.

This alternative proposal is not currently being implemented. Like the previous proposal, the high percentage results seen for the service technician QA program validate the adequacy of the current practice of periodic policy and procedure reviews. Implementing the QA Program field rides would require additional resources. The cost of the increased resources was not projected to yield significant benefits.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.482**	
	CoRE	204	**1586**	3888
	Risk Score	98	**765**	1875
Post-Mitigation	LoRE		**0.482**	
	CoRE	204	**1586**	3888
	Risk Score	98	**764**	1874
	RSE	0.26	**1.40**	3.31

Table 8: Alternative Mitigation Summary

(Direct 2018 $000)[38]

ID	Mitigation	2020-2022 Capital[39]	2022 O&M	Total[40]	RSE[41]
SCG-4-A1	SCG-4-A1 – Technician Refresher Training	-	466 - 595	466 - 595	0.06 – 0.74
SCG-4-A2	SCG-4-A2 –Post-Training Follow-Up Field Evaluations	-	104 - 132	104 - 132	0.26 – 3.31

38 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

39 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

40 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

41 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Name	Elements of the Risk Bow Tie Addressed
SCG-4-C1	Employee Formal Skills Training	DT.1, DT.2, PC.1, PC.2, PC.3, PC.4, PC.5
SCG-4-C2	Natural Gas and Appliance Testing	DT.1, DT.2, DT.3, DT.4, PC.1, PC.2, PC.3, PC4
SCG-4-C3	Leak and Emergency Order Response	DT.1, DT.2, DT.3, DT.4, PC.1, PC.2,PC.3, PC.4
SCG-4-C4	Gas Consumption Analytics	DT.3, DT.4, PC.1, PC.2,PC.3, PC.4, PC.5
SCG-4-C5	Customer Services Field - Leak Detection Equipment	DT.3, DT.4, PC.1, PC.2,PC.3, PC.4, PC.5
SCG-4-C6	Quality Assurance	DT.1, DT.2, PC.1, PC.2,PC.3, PC.4, PC.5
SCG-4-C7	Policy, Procedures & Standards	DT.1, DT.2, DT.3, DT.4, DT.5, PC.1, PC.2, PC.5
SCG-4-C8	Collect Customer Contact Data for Safety Communication	DT.1, DT.2, DT.5, PC.1, PC.2, PC.5,
SCG-4-C9	Safe Driving Programs	DT.1, DT.5, PC.1, PC.2
SCG-4-C10	Pole and Data Collector Unit (DCU) Inspections	DT.3, DT.4, PC.1, PC.2, PC.3, PC.4, PC.5
SCG-4-M1	Underground Leak Detection Tool	DT.3, DT.4, PC.1, PC.2

Risk Assessment Mitigation Phase

(Chapter SCG-5)

High Pressure Gas Pipeline Incident

(Excluding Dig-in)

November 27, 2019

TABLE OF CONTENTS

Risk: High Pressure Gas Pipeline Incident

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation plan for Southern California Gas Company's (SoCalGas or Company) High Pressure Gas Pipeline Incident risk. Each chapter in the Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in in Chapter RAMP-B of this RAMP Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. The 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

---

[1] D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[2] *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk.[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.[4] Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' High Pressure Gas Pipeline Incident risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue,

---

[3] *Id*. at 16.

[4] *Id*. at 17.

even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

SoCalGas and San Diego Gas & Electric Company (SDG&E), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' gas pipeline incident related chapters.[5]

A. Risk Definition

For purposes of this RAMP Report, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure – Maximum Allowable Operating Pressure (MAOP), greater than 60 psig) failure event, which results in serious injuries or fatalities. For purposes of this testimony, the failure event is when a high-pressure pipe ruptures as a result of eight threats identified by the Department of Transportation Pipeline and Hazardous Materials and Safety Administration. The medium pressure assets operating at a pressure of 60 psig and less are included in the Risk Assessment Mitigation Phase (RAMP) chapter for incidents involving medium pressure pipelines. Similarly, events caused by third party damage are included in their own RAMP chapters.

---

[5] The other gas pipeline incident related chapters in the 2019 RAMP Report include: SCG-5 – High Pressure Gas Pipeline Incident; SDG&E-6 – Medium Pressure Gas Pipeline Incident; and SDG&E-8 – High Pressure Gas Pipeline Incident.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[6] for each control and mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger or Potential Consequence
DT.1	External corrosion
DT.2	Internal corrosion
DT.3	Stress corrosion cracking
DT.4	Manufacturing defects
DT.5	Construction and fabrication
DT.6	Outside forces (natural disaster, fire, earthquake)
DT.7	Incorrect operations
DT.8	Equipment failure
DT.9	Third party damage (except for underground damages)
DT.10	Incorrect /inadequate asset records
PC.1	Serious Injuries and/or fatalities
PC.2	Property damage
PC.3	Operational and reliability impacts
PC.4	Adverse litigation
PC.5	Penalties and fines
PC.6	Erosion of public confidence

6 D.18-12-014 at Attachment A, A-11 (“Bow Tie”).

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[7] SoCalGas has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP. SoCalGas' baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-5-C1	Gas Infrastructure Protection Plan (GIPP)
SCG-5-C2	Cathodic Protection
SCG-5-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A
SCG-5-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B
SCG-5-C3-T3	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 2A
SCG-5-C4-T1	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 1A
SCG-5-C4-T2	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 1B
SCG-5-C4-T3	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 2A
SCG-5-C5	Pipeline Safety Enhancement Plan – Valve Automation
SCG-5-C6	Transmission Integrity Management Program (TIMP)
SCG-5-C7	Valve Maintenance
SCG-5-C8	Gas Control supervisory control and data acquisition (SCADA) Operation
SCG-5-C9	Right of Way
SCG-5-C10	Pipeline Maintenance

The drivers/triggers identified for High Pressure Gas Pipeline Incident risk are addressed through the 2018 baseline controls listed in the above table, and SoCalGas will continue said

7 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

regulatory compliance driven controls. Although SoCalGas has considered alternatives to these controls, no new mitigations are projected to be implemented. The Commission's focus in addressing pipeline safety risk has resulted in robust regulations that guide SoCalGas' efforts in addressing the safety of gas pipeline infrastructure. Although no new mitigations are projected, SoCalGas is forecasting to increase annual activity levels within existing controls.

Finally, pursuant to the SA Decision,[8] SoCalGas presents in Section VIII alternatives to the described mitigations for this risk and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VII.

II. RISK OVERVIEW

The SoCalGas transmission and distribution system operates in 12 different counties and spans from the California-Arizona border to the Pacific Ocean and from the California-Mexico border to Fresno County. SoCalGas is the largest gas distribution operator in the nation and the second largest transmission operator in High Consequence Area (HCA) miles, with approximately 1,100 miles out of 3,509 miles of pipelines defined as transmission by the United States Department of Transportation (DOT). In total, SoCalGas operates 6,719 miles of high-pressure pipelines in its service territory, which includes the 3,509 miles of transmission defined pipelines. The number of miles operated by operating unit is listed in the table below.[9]

---

8 *Id.* at 34.

9 The miles are based on DOTs definition of "transmission" whereas the table defines miles by department operating pipelines.

Table 3: SoCalGas Assets (>60 psig)

Operating Unit	Total High Pressure Miles (>60psig)	Number of High Consequence Area Miles
Transmission	3398	1120
Distribution	3286	5
Storage	35	8
Total	6719	1133

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and American Society of Mechanical Engineers (ASME) B31.8S, "Managing System Integrity of Gas Pipelines" categorizes eight types of threats that could lead to a high-pressure pipeline incident. They include:

1) External Corrosion
2) Internal Corrosion
3) Stress Corrosion Cracking
4) Manufacturing Defect
5) Construction & Fabrication
6) Outside Forces
7) Incorrect Operation
8) Equipment Threat

These factors, also known as potential risk drivers, can work independently and/or interactively together.

When a gas pipeline has a loss of product, PHMSA categorizes it as a non-hazardous release of gas or a leak. Specifically, when the loss of gas cannot be resolved by lubing, tightening or adjusting, it is defined as a "leak." A leak in and of itself may cause little-to-no risk of serious injury or fatality. Risk to the public and employees can increase when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate into a confined space. The safety concern of the leak is addressed by SoCalGas' leak indication prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in ASME B31.8S.[10]

However, in some instances a pipeline may be weakened to the extent that the pipe can overload and "break open" or burst apart. This is referred to as a pipeline rupture and considered a failure of the pipeline as it can no longer function as intended. This type of failure could release a high level of energy, and sometimes ignite, resulting in damage to the surrounding area, injury, and/or loss of life.

The leak verses rupture failure mode is generally dependent on the stress to the pipe, the pipe material properties and the geometry of the latent weak point on a pipeline. As a general rule, the rupture failure mode does not occur on a pipeline operating under 30% of Specified Minimum Yield Strength (SMYS), unless there is an egregious pipe anomaly acting as an initiation growth point and there are interacting threats involved.

Due to the nature of a potential rupture failure mode, this risk category discusses the potential consequences of a rupture event occurring on the Company's high-pressure gas system. The extent of damage of an incident can be modeled through the use of a potential impact radius (PIR) around a pipe. PHMSA has incorporated the PIR into its methods for determining a high consequence area (HCA) along the pipeline right-of-way.

The presence of HCA miles in a transmission system provides an indication of the potential consequences of an incident to the public because HCA's consist of highly populated areas and identified sites where people regularly gather or live. Applying mitigative measures as outlined in Title 49 of the Code of Federal Regulations (CFR) Section (§) 192.935, such as increased inspections and assessments, additional maintenance, participation in a one-call system, community education and consideration of the installation of additional remote-

---

[10] American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes.

controlled valves, can help reduce the likelihood or consequence of a rupture event in both high consequence and lesser populated areas.

The SoCalGas High Pressure Gas Pipeline Incident risk is similar to the SDG&E High Pressure Gas Pipeline Incident risk because the threats are the same and the system is managed in an integrated manner. The chapter is also similar in nature to the Medium Pressure Gas Pipeline Incident risk because the threats are comparable. The biggest differences are the threats of plastic pipeline since plastic is only used in medium pressure systems and high pressure has an increased potential for injuries and fatalities due to its operating pressure and defined potential impact areas. Since the high pressure gas pipeline asset is managed by two Operating departments (Transmission and Distribution) it is difficult to identify costs solely dedicated to high pressure pipelines managed by Distribution Operations. Therefore, the costs are primarily related to the Transmission Operations department.

Additionally, although not included in this RAMP filing, SoCalGas is currently in the very preliminary stages of organizing and modeling a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association (CEPA) and the Pipeline Research Council International (PRCI). The FIMP is not intended to duplicate any systems, processes, or information that may already exist, but rather to supplement the already existing programs to enhance the safety and integrity of the integrated gas pipeline system.[11] FIMP will be a documented program, specific to the facilities portion of a pipeline system,[12] that identifies the practices used by the operator for purposes of "safe, environmentally

---

11 SoCalGas notes that there are certain facilities management systems and processes in place, for example Pipeline Research Council International (PRCI) – Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718.

12 "Pipeline system" is defined by Pipeline Research Council International (PRCI) - Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718 as "*Pipeline System is comprised of pipelines, stations, and other facilities required for the measurement, processing, gathering, transportations, and distribution of oil or gas industry fluids*."

responsible, and reliable service."[13] While SoCalGas is currently in the preliminary stages of organizing and modeling a FIMP approach based on the principles of CEPA, FIMP is anticipated to be included in the next GRC. Although this concept of an overarching program is still maturing in the industry, SoCalGas' intention of a FIMP is to better identify and reduce risks of facility assets, extend the life of assets, and achieve operational excellence, in alignment with both the principles of RAMP and the Company's existing Transmission, Distribution, and Storage Integrity Management Programs (TIMP, DIMP, and SIMP, respectively).[14] Consistent with the SA Decision, a supplemental analysis will be conducted in the GRC for FIMP if it ultimately meets the criteria for inclusion in that proceeding.

III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the High Pressure Gas Pipeline Incident risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

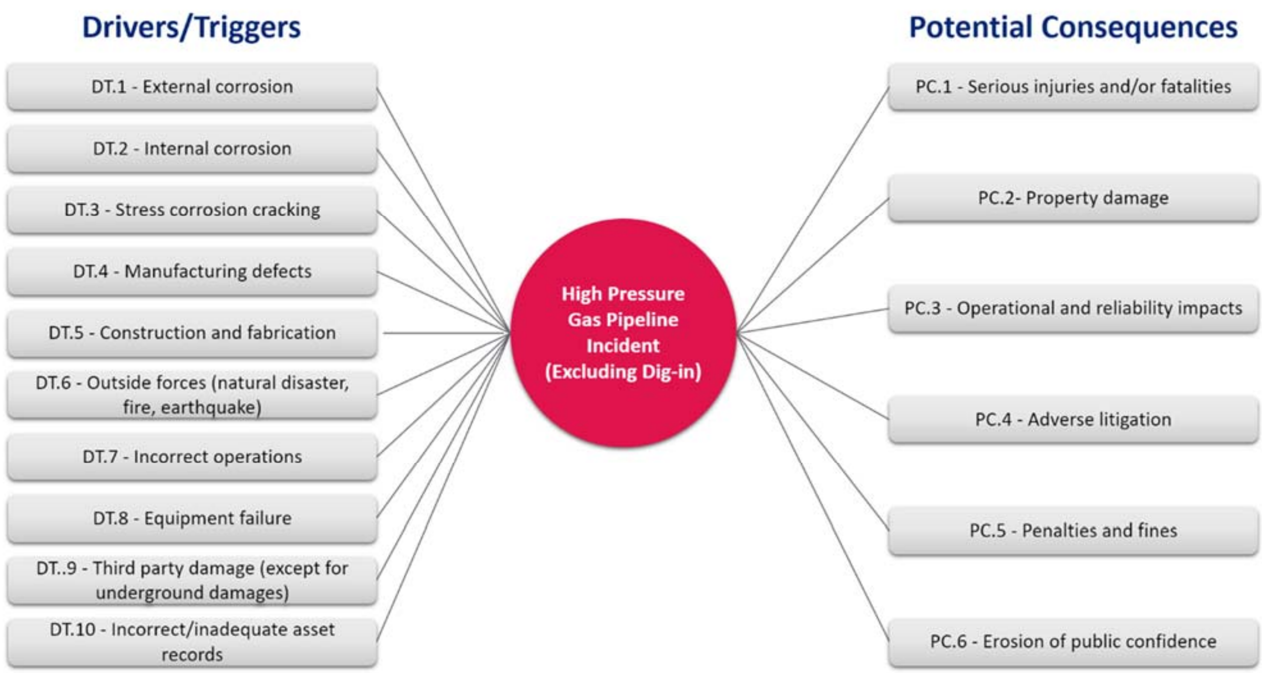
---

13 Canadian Energy Pipeline Association (CEPA), Facilities Integrity Management Program, Recommended Practice, 1st Edition (May 2013) at 7-8.

14 Based on industry definitions, there are a variety of types of facilities; facilities are highly complex; a variety of equipment/asset types exist within facilities; and in this context facilities are not considered building structures.

15 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[16] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. SoCalGas' High Pressure Incident risk impacts all of SoCalGas' high-pressure natural gas infrastructure and assets.

Natural Gas Pipeline Distribution System - SoCalGas' medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and their appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength, and they are considered to be transmission pipelines. By definition, however, these assets are operated by Distribution Operations.

---

16 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Natural Gas Pipeline Transmission System – SoCalGas' high-pressure transmission pipeline system is comprised of steel pipelines and its appurtenances (e.g., meters, regulators, risers) operating over 20% of the pipeline's SMYS.

C. Risk Event Associated with the Risk

The SA Decision[17] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a pipeline failure event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[18]

The SA Decision[19] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for High Pressure Gas Pipeline Incident, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – External Corrosion:** A naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[20]
- **D.T2 – Internal Corrosion:** Corrosion is the deterioration of metal that results from an electrochemical reaction with its immediate surroundings. This reaction

---

[17] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

[18] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[19] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

[20] L.S. Van Delinder, *Corrosion Basics, An Introduction* (1984); *see also* U.S. Dept. of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

causes the iron in the steel pipe or other pipeline appurtenances to oxidize (rust). Corrosion results in metal loss in the pipe. Over time, corrosion, if left unmitigated, can cause the steel to lose its strength and possibly render it unable to contain the fluid in the pipeline at its operating pressure. The loss of material from corrosion can eventually result in "pinhole" leakage, or a crack, split, or rupture of the pipeline unless the corrosion is repaired, the affected pipe section is replaced, or the operating pressure of the pipeline is reduced.[21]

- **DT.3 – Stress Corrosion Cracking:** A form of corrosion that produces a marked loss of pipeline strength with little metal loss. A type of environmentally assisted cracking usually resulting from the formation of cracks due to various factors in combination with the environment surrounding the pipeline that together reduces the pressure-carrying capability of the pipe.[22]
- **DT.4 – Manufacturing defects:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue and environmental cracking.
- **DT.5 – Construction and fabrication:** Attributable to the construction mythology applied during the installation of pipeline components specifically based on the vintage of the construction standards, fabrication technics (welding, bending, etc.) and overall guiding regulations.
- **DT.6 – Outside forces (natural disaster, fire, earthquake):** Attributable to causes not involving humans, but includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, and high winds.

---

[21] *Id*.

[22] *Id*.

- **DT.7 – Incorrect operations**: May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.8 – Equipment failure:** Attributable to malfunction of component including but not limited to regulators, valves, meters, flanges, gaskets, collars, couples, etc.
- **DT.9 – Third party damages (except for underground damages[23]):** Attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck or motorized equipment not engaged in excavation, etc.
- **D.T10 – Incorrect /inadequate asset records:** The use of inaccurate or incomplete information that could result in the failure to (1) construct, operate, and maintain SoCalGas' pipeline system safely and prudently; or, (2) to satisfy regulatory compliance requirements.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the bow tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- PC.1 – Serious injuries and/or fatalities;
- PC.2 – Property damage;
- PC.3 – Operational and reliability impacts;
- PC.4 – Adverse litigation;
- PC.5 – Penalties and fines; and
- PC.6 – Erosion of public confidence.

These potential consequences were used in the scoring of the High Pressure Gas Pipeline Incident risk that occurred during the development of SoCalGas' 2018 enterprise risk registry.

[23] Underground damage would fall under the Third-Party Dig-In risk chapters in the RAMP report.

IV. RISK QUANTIFICATION FRAMEWORK

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[24] including enhancements to the Interim Decision 16-08-018.[25] SoCalGas used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[26]

High Pressure Gas Pipeline Incident (Excluding Dig-in)	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	51	**321**	772
LoRE		**4**	
CoRE	12	**76**	182

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[27] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

---

24 D.18-12-014 at Attachment A.

25 *Id.* at 2-3.

26 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

27 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

In-Scope for purposes of risk quantification:	The risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure - MAOP greater than 60 psig) failure event, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification:	The risk of damage caused by a non-high-pressure pipeline failure event or third-party dig-ins which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results and available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data).[28]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SoCalGas, the national average incident rate per mile per year was applied to the high-pressure pipeline miles at SoCalGas.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA high-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

[28] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

B. Sources of Input

The SA Decision[29] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Link: Annual Report mileage for Gas Distribution Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: Pipeline and Hazardous Materials Safety Administration
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SoCalGas high-pressure pipeline miles
  - 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SoCalGas end user natural gas customers

[29] *Id.* at Attachment A, A-8-A-9 ("Identification of the Frequency of the Risk Event").

- Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
- Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations." [30] This section describes SoCalGas' Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected Control.

As stated above, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline failure event, which results in serious injuries or fatalities. The Risk Mitigation Plan discussed below includes controls that are expected to continue and for the period of SoCalGas' Test Year 2022 GRC cycle.[31] While there are no mitigations identified SoCalGas is forecasting to expand the level of activity for certain controls as further described below.

The controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with compliance requirements that were in effect at that time.

This section describes SoCalGas' Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control. Overall, the compliance requirements set forth within the regulations (although considered minimum requirements) are robust in that they provide prescriptive preventative and maintenance guidance for high pressure assets. In addition, the Transmission Integrity Management Program (TIMP) regulations guide

---

30 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

31 *Id.* at 16and 17. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

operators in completing enhanced assessment of transmission pipelines in high consequence areas. More recently, Public Utility Code 957 and 958 have been an additional layer to evaluate construction and manufacturing related threats through pressure testing and mitigation of additional threats through full replacement. To date, PSEP has pressure tested over 111 miles, replaced over 105 miles and completed 306 valve project bundles for SoCalGas and SDG&E. Within the RAMP chapter, the makeup of the portfolio is a healthy mix of compliance requirements and additional programs implemented by TIMP and PSEP within the last 7 years. The TIMP is continually evaluating the system threats and risk to determine if additional mitigations are required like the introduction of the Damage Program Analyst specifically covered within the Third Party Dig-In on a High Pressure Pipeline chapter.

These controls focus on safety-related impacts per guidance provided by the Commission in Decision (D.) 16-08-018 as well as controls and mitigations that may address reliability. SoCalGas will continue its 2018 baseline controls. In addition, based on the foregoing assessment, SoCalGas projects to expand its current/existing control activities to survey and maintain the Company's Right of Way (ROW) to increase span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and ROW maintenance.

A. SCG-5-1: Gas Infrastructure Protection Plan (GIPP)

The Gas Infrastructure Protection Project (GIPP) addresses prevention of potential third-party vehicular damage associated with above-ground pressurized natural gas facilities. An incident involving vehicular damage of a distribution facility can cause serious injuries or fatalities due the possibility of ignition. The GIPP is an additional control developed and managed as part of the DIMP. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the DIMP. Although the DIMP guidelines do not prescribe what program operators should implement the prescriptive sections result in the need to take action to reduce system risk.

GIPP identifies, evaluates, recommends, and implements damage prevention solutions for at risk above-ground pressurized gas facilities that are exposed to vehicular impacts. The solutions reduce the number of incidents to pressurized piping and/or reduce the potential consequences caused from escaping natural gas after vehicular collisions. Major actions include: investigating historical claims data and developing risk assessment algorithms, conducting record reviews and physical inspections of facilities, developing risk exposure categories, identifying and implementing mitigation measures, updating policies/practices/procedures, and developing performance measures and program tracking.

GIPP remediation measures include the construction of barriers between facilities and vehicular traffic (bollards or block wall), relocation of a facility, or installation of an excess flow valve. Barriers are intended to be a visual, not a structural deterrent. They are not intended or capable of stopping all vehicular traffic, particularly large vehicles. The installation of excess flow valves can aid in the reduction of unrestrained gas flows. The types of considerations for the relocation of a facility include the type of road nearby, the volume of traffic, and the type of area (e.g., commercial or residential). The prioritization of GIPP inspections and remediations is based on field assessments.

Among meter set assemblies (MSAs), which is the largest population facility type, the most vulnerable are high pressure residential first stage regulation meter sets and commercial and industrial MSAs. GIPP is focusing on these facilities, of which SoCalGas has 352,000. Since the development and implementation of the program in 2011, approximately 468,000 sites with above-ground distribution facilities have been inspected and over 38,000 sites have been remediated. The GIPP Programs and Activities to Address Risk (PAAR) forecast for remediation is 6,000 sites a year.

B. SCG-5-C2: Cathodic Protection

Corrosion is a natural process that can deteriorate metal assets and potentially lead to leaks or damages. Cathodic Protection coating and monitoring is key to protecting and extending the life of a steel asset by keeping corrosion at bay. The ongoing compliance controls for the threat of corrosion are prescribed by 49 CFR 192 Subpart I – Requirements for Corrosion Control Operations. The requirements include monitoring of cathodic protection areas, remediation of CP areas that are out of tolerance and preventative installations to avoid areas out of tolerance. These activities are intended to address threats as identified by PHMSA specifically external corrosion. These preventive measures provide an opportunity to address issues that otherwise could lead to a serious incident or failure. The following details the required intervals for completing these preventative measures as prescribed in 49 CFR § 192 Subpart I:

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463.
- Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months, to ensure that it is operating.

In addition to meeting these federal and state requirements, based on feedback from the Commission's Safety and Enforcement Division (SED) during a 2018 Safety Audit, and upon further review, SoCalGas issued new guidelines requiring the re-evaluation of existing 100 mV polarization shift areas[32] at least every 10 years to verify their effectiveness as a measurement for adequate Cathodic Protection of an area. A pipeline utilizing the 100 mV polarization shift criteria must achieve a minimum of 100 mV of polarization along its entirety through the application of Cathodic Protection.

C. SCG-5-C3/C4: Pipeline Safety Enhancement Plan – Pipeline Replacement/Pressure Testing

The primary objectives of the Pipeline Safety Enhancement Plan (PSEP) are to enhance public safety, comply with Commission directives, maximize cost effectiveness, and minimize

[32] 49 CFR § 192 at Appendix D – Criteria for Cathodic Protection and Determination of Measurements.

customer impacts from safety investments. PSEP comprises Pipeline Replacement and Pressure Testing components. As directed by the Commission, the program includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels.

The PSEP is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B:

1. Phase 1A

Phase 1A encompasses replacing or pressure testing pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in HCAs that do not have sufficient documentation of a pressure test to achieve at least 125% of the maximum allowable operating pressure (MAOP) of the pipeline. For reference, determination of the Class of a pipeline is dependent on the type and density of dwellings and human activity within 220 yards of the pipeline.

2. Phase 1B

The scope of Phase 1B, is to replace pipelines incapable of being assessed via inline smart inspection tools (non-piggable pipelines), installed prior to 1946, with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards.

3. Phase 2A

Phase 2A replaces transmission pipelines that do not have sufficient documentation of a pressure test to achieve at least 125% of MAOP and are located in Class 1 and 2 of non-HCAs.

4. Phase 2B

Phase 2B pipelines are those that have documentation of a pressure test that predates the adoption of federal testing regulations in 1970, specifically, Part 192 Subpart J of Title 49 of the

CFR. There are no standalone Phase 2B projects[33] anticipated to begin within the next GRC cycle, and therefore none are associated with this control.

As PSEP continues into less populated areas (Phase 2A) with the conclusion of Phase 1A it will primarily include transmission pipelines that transport natural gas from the receipt points into the basin of the system. Due to their remote location these transmission pipelines have been tested to a hydrostatic pressure of 110% of MAOP per regulation requirements, however, as part of PSEP they need to be tested to 125% of MAOP to address the manufacturing threats. These transmission pipelines include, for example, Lines 235, 3000 and 4000 located in the Northern Desert area. These pipelines will be evaluated through the PSEP Decision Tree analysis with updated information regarding the pipeline's condition and operating history provided by recent TIMP assessment. In addition, insight gained regarding desert pipelines provided by the Root Cause analysis of Line 235 will be incorporated when developing test/replace options.

D. SCG-5-C5: Pipeline Safety Enhancement Plan – Valve Automation

Separate from the testing or replacing of pipeline, PSEP also includes a Valve Enhancement Plan, as required by the Commission in D.14-06-007. The plan focuses on the enhancement of valve infrastructure to identify, isolate, and contain transmission pipelines from escaping gas in the event of a pipeline rupture. The valve automation is intended to provide an opportunity for a shorter response time should a failure occur due to natural forces (such as natural disasters, fires, earthquakes, landslides), third party damage, vandalism or other causes.

The enhancement includes modifications of 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of "first responders" into the area surrounding a substantial section of ruptured pipe.

---

[33] To date, SoCalGas has solely addressed Phase 2B segments within the scope of Phase 1 or Phase 2A projects for constructability and/or cost efficiency reasons. This is referred to as "accelerated" Phase 2B pipeline segments.

E. SCG-5-C6: Transmission Integrity Management Program (TIMP)

Through the TIMP, per 49 C.F.R. 192, Subpart O, SoCalGas is federally mandated to identify threats to transmission pipelines in HCAs, determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, and take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure. At a minimum of every seven years transmission pipelines located within HCAs are assessed using In-Line-Inspection (ILI), Direct Assessment or Pressure Test and remediated as needed.

Detected anomalies are classified and addressed based on severity with the most severe requiring immediate actions. Remediations reduce risk by addressing areas where corrosion, weld or joint failure, or other forces are occurring or has occurred. Post-assessment pipeline repairs, when appropriate, and replacements are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident. ILI is the primary assessment method used to identify potential pipeline integrity threats. When a threat is identified, SoCalGas might take immediate action to reduce risk until a repair is completed. These actions involve removing a pipeline from service or reducing operating pressure. In cases where the assessment involves a pressure test, immediate remediation is also required as the pressure test cannot be completed until the pipeline is repaired.

TIMP reduces the risk of failure to the pipeline transmission system and on a continual basis evaluates the effectiveness of the program and scheduled assessments. TIMP Risk Assessment evaluates the Likelihood of Failure (LOF) using the nine threat categories (External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force) for transmission pipelines located within a HCA. Pipeline operational parameters and the area near the pipeline are considered to evaluate Consequence of Failure (COF). The LOF multiplied by the COF produces the pipelines Relative Risk Score. Further information is collected about the physical condition of transmission pipelines through integrity assessments. Action is taken to address applicable threats and integrity concerns to increase the safety and preclude pipeline failures.

The numbers and types of TIMP activities vary from year to year and are based on the timing of previous assessments done on the same locations. Approximately 1,120 miles out of 3,398 miles of SoCalGas' transmission pipelines are located in HCA areas. SoCalGas is the second largest transmission operator in the nation in terms of miles of transmission pipeline located in HCA areas.

F. SCG-5-C7/C10: Transmission Operations Maintenance (Valve Maintenance and Pipeline Maintenance)

Gas Transmission is responsible for the safe day-to-day operation and maintenance of gas transmission pipeline facilities and related infrastructure. Their specific responsibilities for this operation and maintenance include gas measurement, pressure regulation, non-core customer equipment and facilities, instrumentation, cathodic protection, locate-and-mark activities, standby to monitor construction activity, patrol, leakage survey, class location survey, bridge and span inspections and valve inspections. In addition, pipeline and valve maintenance validates that the pipelines within the system operate appropriately which enhances public safety. Valve inspections may include flushing, repair or replacement, function test, and other activities (and should the valve be inoperable it needs to be addressed promptly.) The valve inspections are to be conducted once a year and not to exceed 15 months between inspections. Both valve and pipeline maintenance control activities have costs that are tracked separately and provide similar risk reduction profiles within each asset group. However, for ease of review and because both O&M activities are done under the same operating umbrella, the activities are grouped together here.

G. SCG-5-C8: Gas Control Supervisory Control and Data Acquisition (SCADA) Operation

The safety and reliability of SoCalGas' transmission system is dependent on the meter and regulator equipment that is used to control the flow of natural gas in transmission pipelines through the use of valves and regulator stations. This equipment is controlled locally or through remote commands from a central Supervisory Control and Data Acquisition (SCADA) system. The communication equipment includes programmable logic controllers, pressure transmitters, uninterruptible power supply systems, temperature probes, gas quality sensors, and communication/interface technologies. This type of monitoring and control facilitates response times to incidents and may reduce the severity of incidents due to its ability to monitor and respond to unfolding incidents in real time. The costs associated to this control include 24/7 staffing for control room monitoring and the remote control of pipeline and compression facilities on the SoCalGas & SDG&E transmission system. These costs include the management of planning, operations and maintenance of the SCADA system which provides for remote monitoring and operation of valves, compressors, pressure regulation equipment, and gas flow across the system. Finally, these costs include compliance with Control Room Management – PHMSA rule 49 CFR § 192.63111 regarding alarm management, system change management, fatigue mitigation, system operating experience, and personnel training requirements.

H. SCG-5-C9: Right of Way

The Land and Right-of-Way group is responsible for managing the necessary property rights that allow for the access, operation, and maintenance of our pipeline infrastructure on public and private properties. Right of way (ROW) access is critical for the overall general safety of employees and the public and includes span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and right-of-way maintenance. Maintenance of access roads is critical to allow pipelines to be accessed in a timely manner, minimizing third-party pipeline damage and prevention of wildfire damage. The costs associated with the ROW in this RAMP report refer to the O&M activities required to maintain access to Company assets. These costs do not include costs regarding the acquisition of ROW space.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Unless otherwise specified, all elements of the Bow Tie concerning Potential Consequences are assumed to be addressed by the below mentioned controls. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[34] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SoCalGas' rationale for the determination of Tranches is presented below.

SoCalGas' comprehensive integrity and maintenance programs consist of policies, programs, and efforts designed to reduce the probability of a pipeline incident. The extensive activities SoCalGas performs to mitigate pipeline risks have been grouped into the controls presented herein based on the similarity of their risk profiles.

SoCalGas does differentiate some programs by asset type (e.g. steel vs plastic pipe); however, as discussed in RAMP-G, costs are not tracked at a level of detail to allow for the logical disaggregation of assets or systems at a more granular level than the controls described in the mitigation plan.

PSEP is an established, phased, program to which tranches reflecting said phases was logically discernable and maintained within this control.

---

[34] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Table 5: Summary of Tranches

ID	Mitigation/Control	Tranche	Tranche ID
SCG-5-C3	Pipeline Safety Enhancement Plan – Pipeline Replacement	Phase 1A	SCG-5-C3-T1
		Phase 2B	SCG-5-C3-T2
		Phase 2A	SCG-5-C3-T3
SCG-5-C4	Pipeline Safety Enhancement Plan – Pressure Testing	Phase 1A	SCG-5-C4-T1
		Phase 2B	SCG-5-C4-T2
		Phase 2A	SCG-5-C4-T3

A. Post-Mitigation/Control Analysis Results

As described in RAMP-D and Section IV above, SoCalGas utilized both internal data/modeling as well as PHMSA data to build RSEs for the pipeline incident risk areas. In the determination of inputs for the RSE calculations, SMEs were heavily utilized to confirm and provide data including the effectiveness of each control. The effectiveness percentages shown below are the result of discussions with SMEs whose knowledge of the control heavily dictated the values selected. The below sections detail the Risk Reduction Benefits of each control/mitigation as well as specifically outline the data used in conjunction with said SME input to develop the RSE values.

1. SCG-5-C1: Gas Infrastructure Protection Project (GIPP)

a. Description of Risk Reduction Benefits

The Gas Infrastructure Protection Project (GIPP) addresses prevention of potential third-party vehicular damage associated with above-ground pressurized natural gas facilities. An incident involving vehicular damage of a distribution facility can cause serious injuries or fatalities due to the possibility of ignition. Vehicular impacts have been one of the highest sources of significant incident risk due to the volume of incidents. The GIPP focuses on damage prevention with the following remediation measures: construction of barriers between the facility and vehicular traffic (bollards or block wall); relocation of the facility; or installation of an excess flow valve. The installation of various kinds of barriers can prevent some contacts from vehicular impacts, especially those done at low speed. The installation of excess flow valves can aid in the reduction of unrestrained gas flows.

GIPP activities increase public safety by mitigating risk associated with above-ground distribution facilities located near vehicular traffic. GIPP remediation measures are preventative in nature and are intended to reduce conditions that might lead to an incident, although they are not perfectly effective. Despite GIPP remediation measures, there is still a risk that given a large enough vehicle or high enough vehicular speed, an impact to facilities may still take place. GIPP is not mandated by state or federal regulations.

b. Elements of the Bow Tie Addressed

GIPP addresses the following elements of the bow tie:

i. **[DT.9] – Third party damage (except for underground damages)**

ii. **[PC.1] – Serious injuries and/or fatalities**

iii. **[PC.2] – Property damage**

iv. **[PC*.6] – Erosion of public confidence***

c. RSE Inputs and Basis

Scope	GIPP involves the inspection and remediation (i.e., installing bollards, relocating meters, service alterations, and abandonments) of 2,225 of 2,600 total locations on the SoCalGas high pressure system (86%).
Effectiveness	Per internal SME assessment, this tranche could reduce safety, reliability, and financial risk associated with above-ground pressurized natural gas facilities by up to 95%.
Risk Reduction	**Safety**: As there have been no significant SoCalGas or SDG&E GIPP-related incidents on the high-pressure system since 2010, a proxy based on national data was used to calculate the potential risk reduction. Based

	on an assessment of PHMSA data, 593 high pressure events can be attributed to causes other than excavation. Out of this 593-event sample, 28 were attributed to “other outside force damage - car, truck, other vehicle.” This ratio (5%) is used as a proxy for the portion of SoCalGas medium pressure safety, financial, and reliability risk associated with this tranche. Using these assumptions, this tranche could improve the SoCalGas High Pressure Gas Incident safety risk by up to 4%. **Reliability:** Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 4%. **Financial:** Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 4%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.41**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	53.25	**333.83**	801.47
	RSE	8.69	**54.46**	130.74

2. SCG-5-C2: Cathodic Protection

a. Description of Risk Reduction Benefits

A steel pipeline can corrode externally and experience a degradation process that can lead to a structural incident. Corrosion control activities like Cathodic Protection (CP) are meant to manage or arrest structural changes. CP is a method to mitigate external corrosion on steel pipelines thereby extending the life of a steel asset. The activities associated with CP include installation, monitoring, and remediation. SoCalGas has installed CP on 3432 miles of its 3433 miles of transmission and storage pipe. Given the mandated requirement to continuously monitor and evaluate the CP areas, the management of this control is cyclical in nature. Gas Transmission Operations and Gas Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

CP reduces safety risks by controlling pipeline corrosion rates thus reducing the frequency of corrosion-related incidents. Minimizing corrosion has the additional benefits of reducing reconstruction costs from pipeline incidents, reducing risk to property, and the potential benefit of improved service reliability. SoCalGas exceeds the minimum safety requirements for CP prescribed by 49 CFR 192 Subpart I, which includes monitoring of CP areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance.

b. Elements of the Bow Tie Addressed

Cathodic protection addresses the following elements of the bow tie:

i. **[DT.1] – External Corrosion**

ii. **[DT.3] – Stress corrosion cracking**

iii. **[DT.4] – Manufacturing defects**

iv. **[DT.5] – Construction and fabrication**

c. RSE Inputs and Basis

Scope	3,600 of 5,000 CP protection areas are evaluated per year (72%).
Effectiveness	Per internal SME assessment, this mitigation is 95% effective.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in year 2010. 1 out of the 7 SoCalGas and SDG&E incident samples was corrosion-related (14%).

	Using these assumptions, this control for this tranche could improve safety risk by up to 10% of the current residual risk. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 10% of the current residual risk. **Financial**: Using these assumptions, this mitigation could improve the SoCalGas High Pressure Gas Incident financial risk by up to 10% of the current residual risk.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.67**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	56.29	**352.91**	847.26
	RSE	10.51	**65.91**	158.25

3. SCG-5-C3/C4: Pipeline Safety Enhancement Plan – Pipeline Replacement/Pressure Testing

a. Description of Risk Reduction Benefits

The Pipeline Safety Enhancement Plan (PSEP) is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B. There are no standalone Phase 2B projects[35] associated with this control.

---

35 To date, portions of Phase 2B segments have been "Accelerated" and included within the scope of Phase 1 and Phase 2A projects to minimize customer and community impacts and reduce costs for customers.

SoCalGas is dividing the work to complete pressure testing on all pipelines without a record of a pressure test and complete pipeline replacements into three phases (Phase 1A, Phase 1B, and Phase 2A) The work is prioritized such that testing is completed in more populated areas first, HCAs, followed by less populated areas, non-HCAs.

Pressure testing is a pipeline integrity assessment tool. A pressure test can reveal weakened spots on a pipeline. A failed test requires immediate remediation. As part of the PSEP, SoCalGas is conducting pressure tests on segments of pipelines where no records of pressure testing exist (pressure testing has been previously completed in these areas, but it was not recorded). Once segments are tested remediations, including pipeline replacement, are completed, and records are updated. PSEP projects are coordinated to reduce capability issues and customer impacts. Once the PSEP is completed, SoCalGas will follow TIMP inspection protocols on these pipeline segments in the future.

The principal benefit of PSEP is the substantial reduction in the likelihood of a pipeline incident, which thereby increases public and employee safety. PSEP reduces risk to public and employee safety, as well as risk to property. Additionally, the PSEP improves service reliability and maximizes cost effectiveness by reducing the potential reconstruction costs from potential incidents.

b. Elements of the Bow Tie Addressed

Pipeline Safety Enhancement Plan – Pipe Replacement and Pressure Testing addresses the following elements of the bow tie:

i. **[DT.1] – External corrosion**

ii. **[DT.2] – Internal corrosion**

iii. **[DT.3] – Stress corrosion cracking**

iv. **[DT.4] – Manufacturing Defects**

v. **[DT.5] – Construction and fabrication**

vi. **[DT.6] – Outside forces**

vii. **[DT.9] – Third party damage (except for underground damages)**

viii. **[DT.10] – Incorrect /inadequate asset records**

c. RSE Inputs and Basis

i. SCG-5-C3-T2 – Pipeline Replacement: Phase 1B

Scope	SoCalGas is replacing 27 of 177 miles of high pressure pipeline in areas in scope for Phase 1B (15%).
Effectiveness	Per SME estimate, we assume 100% effectiveness. The segments being replaced are assumed to be 3.4 times more likely for an incident to occur than their replacements.
Risk Reduction	**Safety**: 2 out of 7 historical, significant incidents are due to corrosion and natural forces according to SoCalGas and SDG&E data reported to PHMSA since year 2010. 83% of the risk is assumed to be within HCAs, with 17% within non-HCAs. Phase 1B is located within non-HCAs. Using these assumptions, this tranche could improve safety risk by up to 3%. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 3%. **Financial**: The financial risk is multiplied by 3 given the one incident causing a similar proportion of total property damage. Using these

	assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 8%.

ii. SCG-5-C3-T3 – Pipeline Replacement: Phase 2A

Scope	SoCalGas is replacing 6.6 of 31 miles of high pressure pipeline in areas in scope for Phase 2A (21%).
Effectiveness	Per SME estimate, we assume 100% effectiveness. The segments being replaced are also assumed to be 3.4 times more likely for an incident to occur than their replacements.
Risk Reduction	**Safety**: 2 out of 7 historical, significant incidents are due to corrosion and natural forces according to SoCalGas and SDG&E data reported to PHMSA since year 2010. 83% of the risk is assumed to be within HCAs, with 17% of the risk within non-HCAs. Phase 2A is assumed to be located within HCAs. Using these assumptions, this tranche could improve safety risk by up to 17%. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 17%. **Financial**: The financial risk is multiplied by 3 given the one incident causing a similar proportion of total property damage. Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 52%.

iii. SCG-5-C4-T3 – Pipeline Testing: Phase 2A

Scope	SoCalGas is conducting pressure testing on 205 of 636 miles of high pressure pipeline (32%).
Effectiveness	Per SME estimate, we assume 95% effectiveness.

Risk Reduction	**Safety**: In the absence of pressure testing, incipient failures would not be detected and the rate of pipeline failure might eventually be higher reaching an SME estimated plateau where the pipe is 1.6 times more likely to have an incident occur than it would be otherwise. 2 out of 7 historical, significant incidents were due to corrosion and natural forces, according to SoCalGas and SDG&E data reported to PHMSA. 83% of the risk is assumed to be in HCAs, with 17% of the risk in non-HCAs. Phase 2A is being completed within HCAs. Using these assumptions, this control for this tranche could improve safety risk by up to 140% of the current residual risk. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 140% of the current residual risk. **Financial**: Financial risk is multiplied by 3 with one incident causing a similar proportion of property damage. Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 420% of the current residual risk.

d. Summary of Results

i. SCG-5-C3-T2 – Pipeline Replacement: Phase 1B

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.36**	
	CoRE	12.31	**75.89**	181.85
	Risk Score	53.64	**330.67**	792.39
	RSE	0.29	**1.14**	2.54

ii. SCG-5-C3-T3 – Pipeline Replacement: Phase 2A

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.98**	
	CoRE	13.52	**77.10**	183.07
	Risk Score	67.38	**384.19**	912.20
	RSE	8.00	**31.17**	69.77

iii. SCG-5-C4-T3 – Pipeline Testing: Phase 2A

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**10.20**	
	CoRE	17.84	**81.42**	187.39
	Risk Score	182.06	**830.76**	1911.94
	RSE	2.62	**10.22**	22.87

4. SCG-5-C5: Pipeline Safety Enhancement Plan – Valve Automation

a. Description of Risk Reduction Benefits

In addition to the Pipeline Safety Enhancement Plan effort on pressure tests and the replacement of pipelines, the PSEP also focuses on the enhancement of valve infrastructure via valve automation. Valve automation supports the isolation and depressurization of pipeline segments in the event of a pipeline incident. Automated valves decrease reaction time thus reducing the eventual gas release to smaller volumes than would be released and possibly combusted otherwise.

The installation of automated valves increases public and employee safety regardless of the cause of an incident by allowing the isolation and reduction in the amount of gas released. As result, valve automation facilitates quicker access to the scene of an incident by first responders because temperatures around an ignition will be reduced. Valve automation has the additional benefits of reducing risk to property in the event of an incident and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Pipeline Safety Enhancement Plan – Valve Automation addresses the following elements of the bow tie:

i. **[DT.1] – External corrosion**

ii. **[DT.2] – Internal corrosion**

iii. **[DT.5] – Construction and fabrication**

iv. **[DT.6] – Outside forces**

v. **[DT.7] – Incorrect operations**

vi. **[DT.8] – Equipment failure**

vii. **[DT.9] – Third party damage (except for underground damages)**

viii. **[DT.10] – Incorrect /inadequate asset records**

c. RSE Inputs and Basis

Scope	SoCalGas is targeting 97 valves for automation.
Effectiveness	Per SME estimate, automated valves are 100% effective in performing their intended duty.
Risk Reduction	**Safety**: Valves are useful after an incident has already taken place. Thus, it is assumed that incident risk addressed is minimal, per SME estimate set to 1%. Using these assumptions, this mitigation could improve safety risk by up to 1%.

	Reliability: The same circumstances as the safety component apply to reliability. Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 1%. **Financial**: There is a possibility of property damage reduction with faster valve closure in the event of an incident. Per SME estimate, the percent financial risk addressed is 10%. Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 8%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.28**	
	CoRE	12.43	**76.01**	181.97
	Risk Score	53.25	**325.66**	779.68
	RSE	0.49	**1.04**	1.96

5. SCG-5-C6: Transmission Integrity Management Program (TIMP)

a. Description of Risk Reduction Benefits

TIMP is a regulatory required program to assess and remediate, as necessary, transmission pipelines within HCAs every seven years using In-Line-Inspection, Direct Assessment or Pressure Test. TIMP supports the effective operation of transmission pipelines, which enhances public safety. TIMP activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident. Given TIMP mandated requirements per 49 C.F.R.192, Subpart O, the management of this control is cyclical in nature. The TIMP proactively identifies, evaluates, and reduces pipeline integrity risk thereby improving public and employee safety by reducing the likelihood of a transmission pipeline incident. A secondary activity that aids in the future risk analysis in the collection of data as part of TIMP which may reveal trends in the management of safety risks. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

TIMP addresses the following elements of the bow tie:

i. **[DT.1] – External corrosion**

ii. **[DT.2] – Internal corrosion**

iii. **[DT.3] – Stress corrosion cracking**

iv. **[DT.4] – Manufacturing defects**

v. **[DT.5] – Construction and fabrication**

vi. **[DT.6] – Outside forces**

vii. **[DT.9] – Third party damage (except for underground damages)**

viii. **[DT.10] – Incorrect /inadequate asset records**

c. RSE Inputs and Basis

Scope	Approximately 43% of the in-scope transmission system to be assessed.
Effectiveness	Per internal SME assessment, this mitigation is 95% effective. In the absence of TIMP assessments, risk levels are estimated to be 29 times higher than they would be otherwise.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 2 out of the 7 SoCalGas and SDG&E incident samples are assumed to be in-scope

	(29%). Using these assumptions, this control for this tranche could improve safety risk by up to 340% of the current residual risk. **Reliability**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident reliability risk by up to 340% of the current residual risk. **Financial**: Using these assumptions, this control for this tranche could improve the SoCalGas High Pressure Gas Incident financial risk by up to 340% of the current residual risk.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**18.59**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	224.29	**1406.04**	3375.63
	RSE	3.29	**20.64**	49.56

6. SCG-5-C7/C10 – Transmission Operations Maintenance (Valve & Pipeline Maintenance)

a. Description of Risk Reduction Benefits

Transmission Operations Maintenance supports the effective operation of gas transmission pipeline facilities and related infrastructure, which enhances public safety. Transmission Operations Maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by mitigating various risk sources, primarily corrosion and degradation. Given the mandated requirement to conduct Transmission

Operations Maintenance, the management of this control is cyclical in nature. Valve and pipeline maintenance increases public and employee safety. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Transmission Operations Maintenance addresses the following elements of the bow tie:

i. **[DT.1] – External corrosion**

ii. **[DT.2] – Internal corrosion**

iii. **[DT.3] – Stress corrosion cracking**

iv. **[DT.4] – Manufacturing defects**

v. **[DT.5] – Construction and fabrication**

vi. **[DT.6] – Outside forces**

vii. **[DT.7] – Incorrect operations**

viii. **[DT.8] – Equipment failure**

ix. **[DT.9] – Third party damage (except for underground damages)**

7. SCG-5-C8: Gas Control Supervisory Control and Data Acquisition (SCADA) Operation

a. Description of Risk Reduction Benefits

The Supervisory Control and Data Acquisition (SCADA) system is responsible for the remote monitoring, control, and real-time operation of the entire gas transmission system via instrumentation and control-enabled equipment (e.g., compressors, valves, regulators). The monitoring and control activities of the SCADA system are designed to reduce overall risk in the event of an equipment failure by detecting the unfolding events quickly. These controls reduce the reaction time in cases where pipelines need to be isolated and pressure needs to be reduced. SCADA.

The SCADA system increases public and employee safety by preventing incidents and reducing the response time to incidents that do occur. The safety benefits of SCADA include the ability to react in a more timely manner and the ability to minimize gas supply in the event of an incident, as well as the potential ability to reduce property damage in the case of an incident with ignition. SCADA also improves services reliability as SoCalGas is able to monitor the reliability of the system using SCADA. This is valuable in the event of over-pressurization, as the SCADA system can detect and reduce reaction time thereby relieving gas system stresses.

b. Elements of the Bow Tie Addressed

Gas Control SCADA Operation addresses the following elements of the bow tie:

i. **[DT.6] – Outside forces**

ii. **[DT.8] – Equipment failure**

iii. **[DT.9] – Third party damage (except for underground damages)**

iv. **[PC.3] – Operational and reliability impacts**

v. **[PC.4] – Adverse litigation**

vi. **[PC.5] – Penalties and fines**

8. SCG-5-C9: Right of Way

a. Description of Risk Reduction Benefits

Right of Way includes managing property rights that allow for the access, operation, and maintenance of SoCalGas' pipeline infrastructure on public and private properties, as well as the maintenance of access roads to allow pipelines to be accessed in a timely manner. Gas Engineering and the Land and Right-of-Way group manage the implementation of the work associated with this control. Right of Way activities are preventative in nature and are intended to increase pipeline visibility and accessibility through vegetation and land management surrounding the immediate vicinity of SoCalGas' pipelines. This allows pipelines to be accessed in a timely manner in the event of an incident which then may minimize third-party pipeline damages and reduce wildfire damage. This control increases the public and employee safety and reduces the risk of property damage when an incident does occur. The costs associated with the ROW in this RAMP report refer to the O&M activities required to maintain access to Company assets. These costs do not include costs regarding the acquisition of ROW space.

b. Elements of the Bow Tie Addressed

Right of Way addresses the following elements of the bow tie:

i. **[DT.6] – Outside forces**

ii. **[DT.9] – Third party damage (except for underground damages)**

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

As discussed, the existing controls outlined within this Chapter will continue and certain controls will increase in scope or at an accelerated pace. However, SoCalGas, as a diligent operator, will monitor the controls to determine if any adjustments are needed during the implementation period. The programs could be influenced as additional information is gathered or understanding of risk and controls relationship changes. Should controls need to change, consideration will be given to available technology, labor resources, planning and construction lead time, compliance requirements, and operational and execution considerations.

The following table provides a summary of the Risk Mitigation Plan including controls, associated costs, and RSEs by tranche. SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in the table were estimated using assumptions provided by SMEs from associated operations, maintenance, and engineering functions within SoCalGas and available accounting data.

Table 6: Risk Mitigation Plan Overview[36]

(Direct 2018 $000)[37]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[38]	2018 Baseline O&M	2020-2022 Capital[39]	2022 O&M	Total[40]	RSE[41]
SCG-5-C1	Gas Infrastructure Protection Plan (GIPP)	T1	730	250	2,700 – 3,500	620 – 800	3,300 – 4,300	8.69 - 130.74

36 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

37 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

38 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

39 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application. For PSEP capital, it is anticipated that SoCalGas will include forecasts for 2022 – 2024 in the TY2022 GRC because the TY2019 GRC Decision authorized PSEP capital projects for 2019 – 2021.

40 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

41 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[38]	2018 Baseline O&M	2020-2022 Capital[39]	2022 O&M	Total[40]	RSE[41]
SCG-5-C2	Cathodic Protection	T1	4,100	1	12,000 – 15,000	1	12,000 – 15,000	10.51 – 158.25
SCG-5-C3	PSEP – Pipeline Replacement – Phase 1A	T1	0	0	0	0	0	-
SCG-5-C3	PSEP – Pipeline Replacement – Phase 1B	T2	2,000	0	200,000 – 260,000	0	200,000 – 260,000	0.29 – 2.54
SCG-5-C3	PSEP – Pipeline Replacement – Phase 2A	T3	0	0	49,000 – 63,000	0	49,000 – 63,000	8.00 – 69.77
SCG-5-C4	PSEP – Pressure Testing - Phase 1A	T1	0	0	0	0	0	-
SCG-5-C4	PSEP – Pressure Testing - Phase 1B	T2	570	0	0	0	0	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[38]	2018 Baseline O&M	2020-2022 Capital[39]	2022 O&M	Total[40]	RSE[41]
SCG-5-C4	PSEP – Pressure Testing - Phase 2A	T3	210	1,400	66,000 – 84,000	72,000 – 92,000	140,000 – 180,000	2.62 – 22.87
SCG-5-C5	PSEP – Valve Automation	T1	10,000	0	87,000 – 110,000	0	87,000 – 110,000	0.49 – 1.96
SCG-5-C6	Transmission Integrity Management Program (TIMP)	T1	190,000	67,000	160,000 – 200,000	43,000 – 56,000	200,000 – 260,000	3.29 – 49.56
SCG-5-C7	Valve Maintenance	T1	16,000	0	70,000 – 89,000	0	70,000 – 89,000	-
SCG-5-C8	Gas Control supervisory control and data acquisition (SCADA) Operation	T1	0	3,300	0	2,600 – 3,300	2,600 – 3,300	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[38]	2018 Baseline O&M	2020-2022 Capital[39]	2022 O&M	Total[40]	RSE[41]
SCG-5-C9	Right of Way	T1	0	2,300	0	2,800 – 3,600	2,800 – 3,600	-
SCG-5-C10	Pipeline Maintenance	T1	0	9,200	0	9,400 – 12,000	9,400 – 12,000	-
TOTAL COST			**220,000**	**83,000**	**650,000 – 820,000**	**130,000– 170,000**	**780,000 – 1,000,000**	**-**

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding here. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

Control ID	Control Name	Reason for No RSE Calculation
SCG-5-C3-T1	Pipeline Replacement: Phase 1A	No costs are anticipated for the TY2022 GRC cycle for Phase 1A testing or replacement and Phase 2B testing projects.
SCG-5-C4-T1	Pipeline Testing: Phase 1A	
SCG-5-C4-T2	Pipeline Testing: Phase 1B	
SCG-5-C7	Valve Maintenance	Mandated activity per 49 CFR 192 Subpart M § 192.745
SCG-5-C8	Gas Control Supervisory Control and Data Acquisition (SCADA) Operation	Mandated activity per 49 CFR 192 Subpart L § 192.631
SCG-5-C9	Right of Way	Mandated activity per 49 CFR 192 Subpart M § 192.705
SCG-5-C10	Pipeline Maintenance	Mandated activity per 49 CFR 192 Subpart M

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the described mitigations for the High Pressure Gas Pipeline Incident risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, including but not limited to operational, compliance and resource constraints.

A. SCG-5-A1 – Proactive Soil Sampling

SoCalGas collects soil samples during TIMP-related excavations along its pipelines. These soil samples are analyzed for chemical composition and characteristics that determine the corrosivity of the soil in the vicinity of the pipeline. Expanding this soil sampling program to include collecting soil samples at regular intervals, such as every mile, along pipelines with a history of corrosive activity may allow SoCalGas to anticipate areas of their pipelines that may be susceptible to accelerated corrosion between inspection events. The cost estimate of sampling the 3,372 miles of transmission pipe is $5.25 million over the course of three years; on average, 14 samples per day will be tested at intervals of 2 samples per mile. The results of the soil sampling would be integrated into the SoCalGas pipeline GIS system and be used in a comprehensive evaluation of the SoCalGas pipeline system. Soil sample data (i.e., resistivity and pipe-to-soil reads) would be used to determine corrosion rate, which is critical information in developing a mature risk assessment of corrosion threat. SoCalGas has not initiated an expanded soil sampling program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a Relative Risk model to a Deterministic Risk model for the corrosion threat the benefit of additional information can be better understood. In the interim SoCalGas will be researching available data sets and determining the benefit of additional soil property information.

Scope	Assuming 100% of soil would be sampled, as a one-time effort: once the soil is sampled, it does not need to be resampled.
Effectiveness	Per internal SME assessment, effectiveness of having additional data for making better decisions for pipe replacements will be minimal, at 1%.[42]
Risk Reduction	Risk addressed is 14%, due to 1 out of 7 corrosion-related significant events in company history since year 2010. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.1%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	**LoRE**		**4.24**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.21	**321.03**	770.74
	RSE	0.01	**0.08**	0.19

B. SCG-5-A2 – Expanding Geotechnical Analysis

SoCalGas considered expanding its geotechnical analysis of pipelines potentially exposed to landslide, flood, and debris flow hazards. This analysis includes slope stability analysis and

42 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

flood evaluation of terrain surrounding the pipelines and evaluating the likelihood and consequence of landslides and the resulting debris flow on the pipeline. SoCalGas looks at areas susceptible to landslide, flooding, and debris flows using satellite monitoring, drones, light detection and ranging (LiDAR), strain gauges, inclinometers, and fiber optic cables. SoCalGas has performed extensive analysis and evaluation of the slope stability, landslide, and debris flow conditions of pipelines that have been impacted by severe weather events by running models based off collected field data SoCalGas has considered identifying additional pipelines with potential exposure to weather events to perform analysis regarding slope stability, landslide, and debris flow. SoCalGas has not initiated an expanded geotechnical analysis program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a Relative Risk model to a Deterministic Risk model the benefit of additional information can be better understood.

Scope	Per SME input, scope of 5.3% or about 10% of half the problematic areas where the more impactful spots can be targeted.
Effectiveness	Per internal SME assessment, the effectiveness of this mitigation is 50%.[43]
Risk Reduction	Risk addressed is assumed to be a fraction of the historical experience or 60% of 1 out of 7 significant events, for risk addressed of 9%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.2%.

[43] Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**4**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.28	**321.49**	771.84
Post-Mitigation	LoRE		**4.24**	
	CoRE	12.07	**75.65**	181.61
	Risk Score	51.17	**320.76**	770.08
	RSE	0.02	**0.12**	0.29

Table 8: Alternative Mitigation Summary

(Direct 2018 $000)[44]

ID	Mitigation	2020-2022 Capital[45]	2022 O&M	Total[46]	RSE[47]
SCG-5-A1	Proactive Soil Sampling	0	1,600 – 2,000	1,600 – 2,000	0.01 – 0.19
SCG-5-A2	Expanding Geotechnical Analysis	1,400 – 1,800	1,100 – 1,400	1,500 – 2,200	0.02 – 0.29

44 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

45 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

46 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

47 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

SoCalGas
A Sempra Energy utility®

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control Name	Elements of the Risk Bow Tie Addressed
SCG-5-C1	Gas Infrastructure Protection Plan (GIPP)	DT.9; PC.1, PC.2, PC.6
SCG-5-C2	Cathodic Protection	DT.1, DT.3, DT.4, DT.5
SCG-5-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SCG-5-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SCG-5-C3-T3	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 2A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SCG-5-C4-T1	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 1A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SCG-5-C4-T2	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 1B	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SCG-5-C4-T3	Pipeline Safety Enhancement Plan – Pressure Testing: Phase 2A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SCG-5-C5	Pipeline Safety Enhancement Plan – Valve Automation	DT.1, DT.2, DT. 5, DT.6, DT.7, DT.8, DT.9, DT.10
SCG-5-C6	Transmission Integrity Management Program (TIMP)	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SCG-5-C7	Valve Maintenance	DT.1, DT.2, DT.4, DT.5, DT.6, DT.7, DT.8, DT.9
SCG-5-C8	Gas Control supervisory control and data acquisition (SCADA) Operation	DT.6, DT.8, DT.9; PC.3, PC.4, PC.5

SCG-5-C9	Right of Way	DT.6, DT.9
SCG-5-C10	Pipeline Maintenance	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9

Risk Assessment Mitigation Phase

(Chapter SCG-6)

Third Party Dig-in on a Medium Pressure Pipeline

November 27, 2019

TABLE OF CONTENTS

Risk: Third Party Dig-in on a Medium Pressure Pipeline

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas or Company) Third Party Dig-in on a Medium Pressure Pipeline risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision). [1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC (referred to herein as the TY 2022 RAMP Report). SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the TY 2022 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This TY 2022 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and are within the scope of the analysis required in this RAMP Report. Throughout

---

[1] D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (SMAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[2] *See* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC).

this TY 2022 RAMP Report, activities are delineated between Controls and Mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Third Party Dig-in on a Medium Pressure Pipeline risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order (GO). Activities with no RSE score presented in this TY 2022 RAMP Report are identified in Section VII below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable Control/Mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

SoCalGas and San Diego Gas & Electric Company (SDG&E), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' third party dig-in related chapters.[3]

A. Risk Definition

For purposes of this TY 2022 RAMP Report, the Third Party Dig-in on a Medium Pressure Pipeline risk is defined as a dig-in on a medium pressure pipeline (Maximum Allowable Operating Pressure (MAOP), at or lower than 60 pounds per square inch gauge (psig)) caused by third party activities which results in significant consequences including serious injuries and/or fatalities.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each Control and Mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the Control or Mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation
DT.2	Locator error contributing to the incorrect marking of underground gas structures
DT.3	Hand excavation is not performed by excavator in the vicinity of located gas pipelines
DT.4	Company does not respond to 811 requests in required timeframe

3 The other third party dig-in related chapters in the 2019 RAMP Report include: SCG-7 – Third Party Dig-in on a High Pressure Pipeline; SDG&E-7 – Third Party Dig-in on a Medium Pressure Pipeline; and SDG&E-9 – Third Party Dig-in on a High-Pressure Pipeline.

4 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

ID	Description of Driver/Trigger and Potential Consequence
DT.5	Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark
DT.6	Incorrect/inadequate information in existing asset records leading to incorrect locate and mark
PC.1	Serious Injuries and/or Fatalities
PC.2	Property Damage
PC.3	Prolonged Outages
PC.4	Penalties and Fines
PC.5	Adverse Litigation
PC.6	Erosion of Public Confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SoCalGas has performed a detailed pre- and post-mitigation analysis of Controls and Mitigations for each risk selected for inclusion in RAMP, as further described below. SoCalGas' 2018 Controls for this risk consist of the following:

Table 2: Summary of Controls

ID	Control Name
SCG-6-C1	Locate and Mark Training
SCG-6-C2	Locate and Mark Activities
SCG-6-C3	Locate and Mark Annual Refresher Training and Competency Program
SCG-6-C4	Locate and Mark Operator Qualification
SCG-6-C5	Locate and Mark Quality Assurance Program
SCG-6-C6	Damage Prevention Analyst Program
SCG-6-C7	Prevention and Improvements-Refreshed Laptops
SCG-6-C8	Public Awareness Compliance
SCG-6-C9	Increase Reporting of Unsafe Excavation
SCG-6-C10	Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board
SCG-6-C11	Public Awareness-Meet with the Cities with the Highest Damage Rates
SCG-6-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance
SCG-6-C13	Continue to Participate in the Gold Shovel Standard Program
SCG-6-C14	Locating Equipment
SCG-6-C15	Remain Active Members of the California 811 One-Call Centers

5 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SoCalGas
A Sempra Energy utility

SoCalGas will continue the 2018 Controls identified above and describes additional projects and/or programs (*i.e.*, Mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SCG-6-M1	Automate Third Party Excavation Incident Reporting
SCG-6-M2	Establish a Program to Address the Area of Continual Excavation
SCG-6-M3	Recording Photographs for Each Locate & Mark Ticket Visited by Locator
SCG-6-M4	Utilize Electronic Positive Response
SCG-6-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)
SCG-6-M6	Promote Process and System Improvements in USA Ticket Routing and Monitoring
SCG-6-M7	Leverage Data Gathered by Locating Equipment
SCG-7-M8	Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)

Finally, pursuant to the SA Decision,[6] SoCalGas presents considered alternatives to the Mitigations for the Third Party Dig-in on a Medium Pressure Pipeline Risk and summarizes the reasons that the alternatives were not included into the mitigation plan in Section VIII.

II. RISK OVERVIEW

SoCalGas operates and manages a natural gas system of over 100,000 miles of Distribution pipe and 3,485 miles of Transmission pipe within its 22,000 square mile service territory. This large piping network, and large service territory exposes the Company to potential dig-in related issues. This risk is focused on the more serious results of third party dig-in damage that leads to a release of natural gas.

Excavation damage, or dig-ins, to medium pressure underground gas infrastructure have been a risk to SoCalGas for as long as pipe has been buried underground. This risk is not a risk unique to the Company. Third-party dig-ins are a common national problem for all industries and utilities with buried infrastructure. These "third-party" excavation activities can vary widely based on project scope and size. Examples can include a homeowner doing landscaping work, a

6 *Id.* at 33.

plumber repairing a sewer line, or a city upgrading its aging municipal water or sewer systems. Third-party excavation damage can range from minor scratches or dents, to ruptures with an uncontrolled release of natural gas. The release of natural gas may not just occur at the time of the damage. A leak or rupture may also occur after the infrastructure has sustained more minor damage, but then becomes weakened over time. Once damaged, the responsible party may not report non-gas release damages, bypassing the efforts of the Company to assess and make the appropriate repairs before a weakening of the pipe occurs.

Serious consequences may result if an event occurs because of this risk. For example, if a leak or rupture occurs, an ignition of the released gas could lead to an explosion, fire or both. The nearby public could be seriously injured, and property damage can be extensive. Federal and state agencies have responded to the third party dig-in risk by adopting numerous regulations and industry standards[7] and have promoted other efforts[8] to help prevent third-party dig-ins. For example, the Department of Transportation (DOT) sponsored the "Common Ground Study," completed in 1999. The "Common Ground Study" then led to the creation of the Common Ground Alliance (CGA), a member-driven association of 1,700 individuals, organizations, and sponsors in every facet of the underground utility industry. With industry-wide support, CGA created a comprehensive consensus document that details the best practices addressing every stake-holder groups' activity in promoting safe excavation and preventing dig-in damages.

While these efforts are important and commendable, and the number of dig-ins per 1,000 excavation tickets has been trending down (Figure 1), the numbers still remain high. Figure 1 represents trends for third party dig-ins on distribution lines. Similar data is not available for transmission lines since transmission incidents caused by excavations are not common enough to trend. Thus, the Pipeline and Hazardous Materials Safety Administration (PHMSA) collects

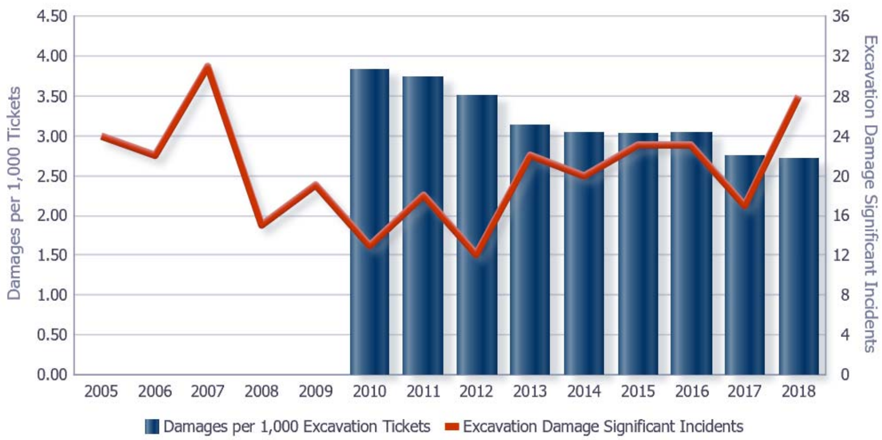
---

7 49 Code of Federal Regulations (CFR) § 192, *et al.*; *id.* at § 196; Cal. Govt. Code § 4216, General Order (GO) 112-F; American Petroleum Institute (API) Recommended Practice (RP) 1162.

8 Common Ground Alliance (CGA), Best Practices Guide (March 2019), *available at* https://commongroundalliance.com/best-practices-guide.

ticket totals in annual reports for distribution facilities but does not collect ticket information for transmission facilities.

Figure 1: Excavation Tickets & Incidents[9]



Under California State Law, [10] a third-party planning excavation work is required to contact the Regional Notification Center for their area, also known as 811 or Underground Service Alert (USA), at least two (2) full working days prior to the start of their construction excavation activities, not including the day of the notification. Eight-One-One (811) is the national phone number designated by the Federal Communications Commission (FCC), that connects homeowners or contractors who plan to dig with professionals through a local call center. California has two Regional Notification Centers, DigAlert and USA North, that split California at the Los Angeles /Kern county and Santa Barbara/San Luis Obispo county lines; USA North serves all counties north of the county lines and DigAlert serves all counties south of the county lines. DigAlert and USA North will be referenced as 811 USA for the remainder of this chapter. Once a third-party makes the contact, the Regional Notification Center will issue a USA Ticket notifying local utilities and other operators of the location and areas to be inspected for potential conflicts of underground infrastructure with the pending planned excavation work.

---

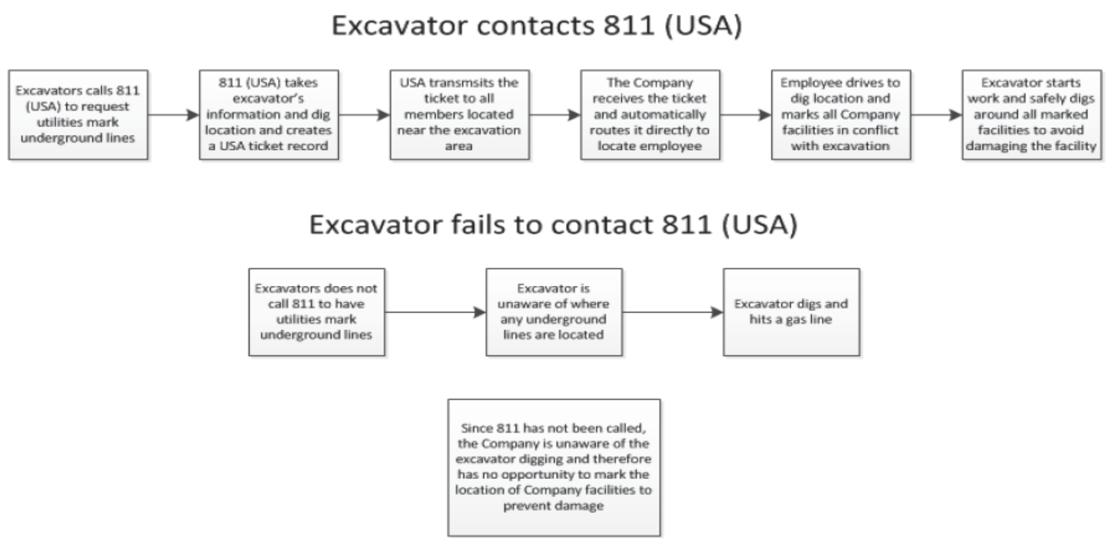
9 *See* United States Department of Transportation *National Pipeline Performance Measures*, a*vailable at* https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures/.

10 Cal. Govt. Code § 4216.2(b).

Operators are then required to provide a positive response to indicate that there are no facilities in conflict or to mark their underground facilities via aboveground identifiers (e.g. paint, chalk, flags, whiskers) to designate where underground utilities are positioned, thus enabling third parties, like contractors and homeowners, to know where these substructures are located. The law also requires third-party excavators to use careful, manual (hand digging) methods to expose substructures prior to using mechanical excavation tools.

Figure 2 below illustrates the sequence of events that may occur when a third party contacts 811 USA prior to conducting excavation work and, in contrast, the sequence that may occur when they do not.

Figure 2: Excavation Contact Process Flow



As can be seen in the figure above, while there may be more steps when a third-party calls 811 USA prior to commencing the excavation work, it is more likely to result in a positive outcome compared to when a call is not made. When third-parties call 811 USA before excavating, the risk of a dig-in is significantly reduced.

SoCalGas managed over 841,000 811 USA tickets and reported over 3,000 dig-in excavation damage incidents in 2018. Further analysis of the reported damage incidents shows that 60% were due to a lack of notification to 811 USA for a locate and mark ticket and another

28% were due to inadequate excavation practices even after the excavator called 811 USA and underground facilities were marked.[11]

In addition to direct involvement with excavators and 811 USA, SoCalGas engages in promoting safe digging practices through its Public Awareness Program[12] and corporate safety messaging through stakeholder outreach. The message is presented by way of multi-formatted educational materials through mail, email, social media, television, radio, events, and association sponsorships. This particular Control is further described in Section V.

III. RISK ASSESSMENT

In accordance with the SA Decision,[13] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Third Party Dig-in on a Medium Pressure Pipeline risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

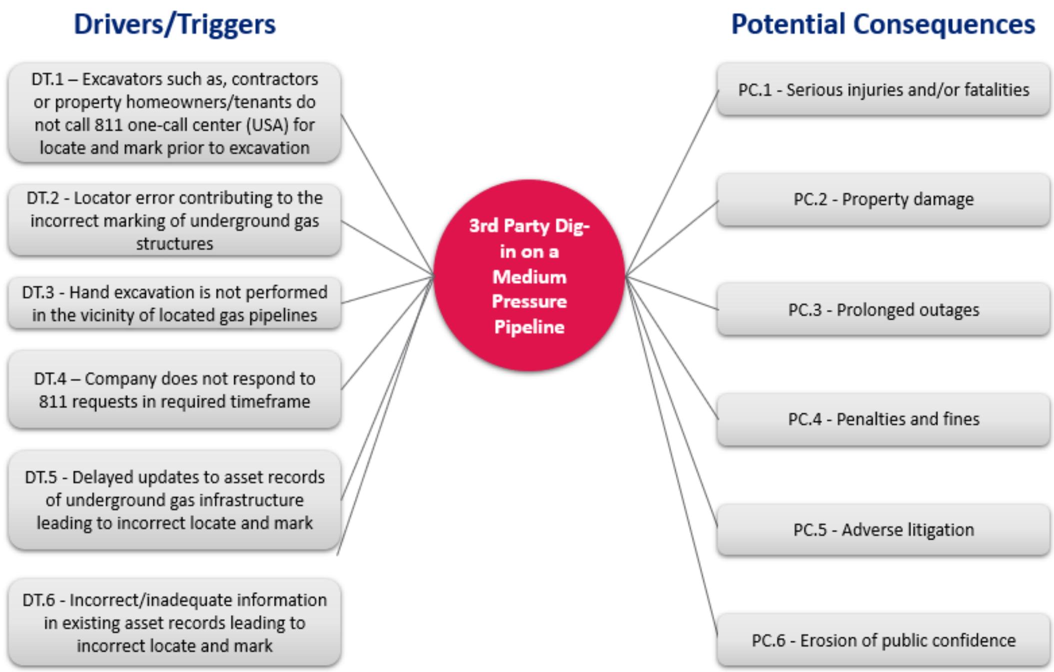
---

11 Common Ground Alliance, *CGA Released 2018 Damage Information Reporting Tool (DIRT) Report*, *available at* https://commongroundalliance.com/DIRT.

12 API RP 1162.

13 D.18-12-014 at 33 and Attachment A, A-11 (“Bow Tie”).

Figure 3: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[14] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. These assets primarily include the Natural Gas Pipeline Distribution System. SoCalGas' medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines by definition; however, these assets are operated by Distribution Operations.

---

14 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

C. Risk Event Associated with the Risk

The SA Decision[15] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the risk event (center of the bow tie) is a third party dig-in on a medium pressure pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[16] of Risk Event

The SA Decision[17] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Third Party Dig-in on a Medium Pressure Pipeline that results in significant consequences including serious injuries and/or fatalities, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT. 1 – Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation:** Despite the creation of Regional Notification Centers to inform and allow excavators to have underground infrastructure located and marked, and advertising campaigns alerting the excavator of the need to do so, incidents still occur where excavations are conducted without first calling 811 USA. In fact, third party failure to contact the Regional Notification Center prior to excavating is the leading contributor of damages to Company pipelines. Third parties can damage or rupture underground pipelines and potentially cause property damage, injuries, or even death if gas lines are not properly marked before excavation

15 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

16 An indication that a risk could occur. It does not reflect actual or threatened conditions.

17 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

activities begin. Without receiving an 811 USA ticket, the Company has no opportunity to mark its facility within the area of excavation.

- **DT. 2 – Locator error contributing to the incorrect marking of underground gas structures:** The Company, in some cases, inaccurately marks facilities due to incorrect operations, such as mapping/data inaccuracies, equipment signal interference, and human error. When this happens, third parties are not provided with accurate knowledge of underground structures in the vicinity of their excavations and the risk of damaging or rupturing gas pipelines increases.
- **DT. 3 – Hand excavation is not performed in the vicinity of located gas pipelines:** Before using any power operated excavation equipment or boring equipment, the excavator is required to hand expose, using "Hand Tools," [18] to the point of no conflict 24 inches on either side of the Medium-Pressure Gas Pipeline to determine the exact location of these structures. If excavators do not use care when digging near natural gas pipelines they put themselves and others at risk for injuries.
- **DT. 4 – Company does not respond to 811 requests in required timeframe:** The Company may fail to respond to 811 USA requests within the "legal excavation start date and time" [19] (within two working days of notification, excluding weekends and state holidays, not including the date of notification, or before the start of the excavation work, whichever is later, or at a time mutually agreeable to the operator and the excavator). This may happen because of human error, poor communication, or system failures. In these cases, the third party may not know that the locate and mark activity was not performed and may wrongly assume that not seeing any marking at their excavation site indicates there is no gas infrastructure nearby. Without the marked gas infrastructure, third parties

---

[18] Cal. Govt. Code § 4216(i).

[19] *Id.* at § 4216(l).

may damage or rupture the infrastructure if they are performing excavation activities near pipelines.

- **DT. 5 – Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark:** The Company may fail to supply the necessary information in a timely manner to update permanent mapping records necessary to meet federal, state, and local regulations, as well as corporate needs. This could result in underground infrastructure being incorrectly marked, which could lead to third party damage if the excavator does not have the correct information on infrastructure location. In addition, in the event a pipeline is damaged, obsolete maps could cause delays in performing the necessary repairs.
- **DT. 6 – Incorrect/inadequate information in existing asset records leading to incorrect locate and mark:** The use of inaccurate or incomplete information in asset records could result in the failure to meet federal, state, and local regulations, as well as corporate needs. This could result in underground infrastructure being incorrectly marked, which could lead to third party damage if the excavator does not have the correct information on infrastructure location. In addition, in the event in which a pipeline is damaged, incorrect or inadequate maps could cause delays in performing the necessary repairs.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[20] and/or fatalities;

[20] As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." *See* 8 CCR § 330(h).

- Property damage;
- Prolonged outages;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of SoCalGas' Third Party Dig-in on a Medium Pressure Pipeline Risk that occurred during the development of SoCalGas' 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP, including enhancements to the Interim Decision 16-08-018. SoCalGas has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Risk Quantification Scores[21]

Third Party Dig-in on a Medium Pressure Pipeline	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	698	**936**	1333
LoRE		**2966**	
CoRE	0.2	**0.3**	0.4

21 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score"), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

A. Risk Scope & Methodology

The SA Decision requires a pre- and post- mitigation risk calculation.[22] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification	The risk of a dig-in on a medium pressure pipeline (MAOP at or lower than 60 psig) caused by third party activities, which results in consequences such as injuries or fatalities or outages.
Out of Scope for purposes of risk quantification	The risk of pipeline event unrelated to a third-party dig-in on a medium pressure pipeline (MAOP at or lower than 60 psig) which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, as well as available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data).[23]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SoCalGas, the national average incident rate per mile per year was applied to the medium-pressure pipeline miles at SoCalGas.

The safety risk assessment primarily utilized data from PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA medium-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

---

22 *Id.* at Attachment A, A-11 ("Calculation of Risk").

23 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

B. Sources of Input

The SA Decision[24] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Link: Annual Report mileage for Gas Distribution Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: PHMSA
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SoCalGas medium-pressure pipeline miles
  - Based on 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Links: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SoCalGas end user natural gas customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)

24 *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[25] This section describes SoCalGas' Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SoCalGas' Third Party Dig-in on a Medium Pressure Pipeline Risk involves impact to gas infrastructure arising from third party dig-ins resulting in significant consequences including serious injuries and/or fatalities. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SoCalGas' Test Year 2022 GRC cycle. The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

1. SCG-6-C1 – Locate and Mark Training

This program provides employees with the training to perform activities associated with locate and mark. Adequately preparing employees by offering educational opportunities and resources gives them the knowledge to implement local, state, and federal requirements and Company policies and procedures in a safe manner. This, in turn, helps SoCalGas operate and maintain its system, as well as protect employees, contractors, and the public from the threat of an event attributable to this risk.

Locate and Mark Training consists of approximately seven days of classroom and hands-on training at a centralized training facility, as well as eLearning. SoCalGas will continue to implement a competency based training program that will encompass training on any policy or procedural changes impacting third-party dig-ins. A competency based online/video training

---

[25] D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

module system will enhance SoCalGas' ability to incorporate new policies and increase learning at a faster pace. This system will use a comprehensive, multimedia, competency-based training approach which will include self-paced, individualized, modular instruction, eLearning, just-in-time training, structured on-the-job training, and mentoring. This is a mandated activity in order to comply with Operator Qualification requirements and to provide the basic knowledge necessary to satisfactorily perform this critical task. The training schedule is dependent on annual demand, but occurs, on average, about every two months.

The training provides the participating employees several key components of locating, enabling them to locate and mark the below ground facilities accurately and in the appropriate time frame. The marked facilities provide the excavator with approximate locations of where the gas lines exist in the work area which enables the excavator to either avoid the areas or dig with hand tools so underground substructures are not accidentally damaged by the excavation work.

2. SCG-6-C2 – Locate and Mark Activities

This Control is comprised of three activities that are related to performing or supporting locate and mark work: (1) Locate and Mark, (2) Pipeline Observation (stand-by), and (3) Staff Support. Verifying that SoCalGas is executing such tasks safely can reduce the potential of an event occurring.

The first activity is Locate and Mark, which is the actual work performed by SoCalGas gas operations which is required to respond to over 800,000 811 USA notifications per year.[26] To do this activity, SoCalGas' locators travel to the job site and locate and mark any and all company operated pipelines in the delineated work area. Understanding the physical location of the pipeline allows the third-party to avoid that area or carefully perform the excavation work to avoid contact with the pipeline. This activity is mandated by both State[27] and Federal law.[28] This Control activity also includes all aspects necessary to performing the mandated locate and

26 Represents 811 USA notifications for SoCalGas' distribution and transmission system.

27 *See* Cal. Govt. Code § 4216.

28 49 CFR § 192.614.

mark activities, including locators, vehicles, tools, Mobile Data Terminals (MDTs), Geographical Information System (GIS)-related costs, ticket routing systems, locating materials, fees to Regional Notification Centers, and quality assurance.

The second Locate and Mark activity is Pipeline Observation (stand-by). In accordance with Title 49 Code of Federal Regulation, section 192.935, Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. This activity occurs daily in both Distribution and Transmission operations. The purpose of this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having another pair of qualified eyes observing the work being done. This is a best practice in the gas industry and is critical to the safety of employees, contractors, and the public.

The third activity is staff support. Support staff consists of employees who are responsible for developing and maintaining policies, processes, and procedures that guide and direct locators in properly performing their assigned tasks in compliance with Federal and State regulations. Staff is engaged daily in supporting operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, and providing refresher training as requested. This is a critical activity that allows the Company to meet or exceed State and Federal requirements and align with industry best practices when applicable.

3. SCG-6-C3 – Locate and Mark Annual Refresher Training and Competency Program

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to continue locate and mark activities. This refresher training involves all aspects of the Locate and Mark procedures to allow personnel to be able to successfully receive an 811 USA ticket and provide a proper positive response. Similar to the Locate and Mark training mentioned above, refresher training will also be an interactive eLearning course, which potentially will consist of on-the-job training and mentoring. This is a mandated activity in order to comply with regulations and code requirements and to provide employees with the basic knowledge to satisfactorily perform this critical task.[29]

4. SCG-6-C4 – Locate and Mark Operator Qualification

Locate and Mark Operator Qualification (OQ) training is an enhanced training which requires pipeline operators to document that certain employees have been adequately trained to recognize and react to abnormal operating conditions that may occur while performing specific tasks. It provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. The training demonstrates an employee's knowledge and competency to perform locate and mark activities and is mandated by PHMSA.[30] Employing resources that are formally trained to be aware and react to unusual pipeline conditions allows SoCalGas to potentially protect against an adverse event before its occurrence. Locators are qualified at the end of training and then every five years. This certification is an industry standard qualification program.

5. SCG-6-C5 – Locate and Mark Quality Assurance Program

The Locate and Mark quality assurance audit program reviews work activity to determine whether proper processes and procedures are being met. This includes, but is not limited to, employee qualification, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and mark activities, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations.

SoCalGas has developed guidelines for quality assessments of locate and mark activities. The Gas Compliance Quality Management (GCQM) team conducts the re-occurring assessments of all districts (or bases) in order to provide an independent check of processes and to verify that applicable documentation is accurate and complete. The assessments include equipment testing, documentation reviews, field checks, and operator qualification reviews. After the assessment is

---

29 See Cal. Govt. Code § 4216.

30 49 CFR §§ 192.801 - 192.809.

complete, the GCQM will review findings with base management and gas distribution operations. Base management acknowledges the final report and develops plans for corrective actions, which are provided to GCQM. Findings are tracked, recorded, and monitored by base supervision.

Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

6. SCG-6-C6 - Damage Prevention Analyst Program

SoCalGas' Damage Prevention Analysts work to reduce the number of third-party excavation incidents in cities and jurisdictions with the highest number of reported occurrences by addressing the contractors and excavators operating in these jurisdictions. The intent of the SoCalGas' Damage Prevention Analyst program is to promote safe excavation practices and reduce the number of excavation damages. An important method of achieving this goal is to build and foster positive relationships with the excavator community through visibility, communication, and safe excavation education. Through this effort the desire is also for these SoCalGas employees to be viewed as a resource for contractors, to help overcome obstacles when excavating in the vicinity of underground SoCalGas infrastructure. To achieve these objectives, the Analysts are equipped with the current 811 USA ticket information, GIS/mapping information for the local pipe network. Analysts also regularly partner with SoCalGas' operating district personnel if additional infrastructure location information is needed.

The Damage Prevention Analysts prioritize their daily job site visits with the aid of ticket prioritization software. Certain construction jobs may be more prone to excavation damage than others due to specific 811 USA ticket attributes and local environmental conditions. Eight-One-One-ticket prioritization utilizes historical damage information as well as geographic, environmental, and other publicly available information. The software weighs the pertinent attributes and performs calculations using complex algorithms to identify excavation sites that may be more susceptible to third party damage. This prioritization allows for the Company to take appropriate and timely measures to avoid damages such as making an extra phone call or email to the excavator or scheduling a pre-excavation site meeting to discuss the project in detail.

The Damage Prevention Analysts routinely visit active construction sites with known 811 USA tickets in their jurisdiction but will also look out for other active construction sites that do not appear on their 811 USA ticket listing. The purpose for visiting the latter is to make positive contact with the excavator and determine whether the supervision and workers at those projects have followed safe digging practices. If not, the Analyst explains the safety risks, law violations, and potential ramifications, and asks the excavator to stop their job and contact 811 USA to get the proper underground markings. These interactions have been very successful in getting the excavator to halt further excavation work until 811 USA contact was established. Since the program's inception in 2018, the Analysts have successfully intervened and "Stopped-The-Job" at over 470 construction sites. The most common reason for "Stopping-The-Job" was due to the excavator not having an 811 USA ticket. In addition, some were due to unsafe excavation practices.

The Damage Prevention Analysts also visit with local municipality personnel to discuss the importance of safe excavation with the Planning and Permitting departments. Gaining a safe-excavation partnership with the entities that approve, permit, and inspect excavation work is seen as an integral part of the Damage Prevention Analyst Program. During the interactions with City officials, the Analysts offer to present educational information regarding the Dig Safe laws and practices to interested parties. Since the program's inception over 330 outreach and educational sessions have been performed by the Analysts to various contractor and city workgroups.

Another key activity that falls within the Damage Prevention Analyst job responsibilities is responding to dig-in damages. Their role is to support the Operations response team through accurate documentation of the incident and collecting all relevant information to enable accurate regulatory reporting, damage-cause trending, and appropriate cost recovery where warranted. This data is used by the Damage Prevention Strategy and Distribution Integrity Management Program teams to evaluate and trend the causes of excavation damage and pursue appropriate mitigation activities.

7. SCG-6-C7 – Prevention and Improvements-Refreshed Laptops

Locate and Mark laptops and software are utilized by SoCalGas to comply with requirements of state and federal regulations.[31] SoCalGas provides locate and mark technicians rugged laptops called Mobile Data Terminals (MDTs) containing KorMobile© Ticket Management Software to respond to 811 USA tickets in real-time. Using obsolete technology increases wait times, contributes to data communication failure, and increases the likelihood of not responding to an 811 USA ticket request in the required timeframe.

SoCalGas has a vast service territory that covers 24,000 square miles in diverse terrain throughout Central and Southern California, from Visalia to the Mexican border. The service territory covers 12 counties, 220 incorporated cities in more than 500 communities. Providing durable refreshed laptops increases efficiency and the ability to work in a rugged outdoor setting. Increasing the processor speed and extending the battery life also allows for prolonged working hours. The refreshed laptops contain a detachable screen with a built in camera allowing the technician to photograph their surroundings and the excavating equipment associated with an 811 USA ticket. A 4G LTE Advanced multi carrier mobile broadband facilitates the response to 811 USA tickets in real-time.

8. SCG-6-C8 – Public Awareness Compliance

It is important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks, and private property – sometimes just inches below the surface. Hitting one of these pipelines while digging, planting, or doing demolition work can cause serious injury, property damage, and/or loss of utility service.

Under Title 49 Code of Federal Regulations, section 192.616, SoCalGas is required to educate the public, appropriate government organizations, and persons engaged in excavation related activities (1) about the use of a one-call notification system (811 USA) prior to excavation, (2) other damage prevention activities, (3) possible hazards associated with the

[31] 49 CFR § 192.614; Cal. Govt. Code § 4216.

unintended release from a gas pipeline facility, (4) physical indications of a natural gas release, (5) steps to be taken in the event of a gas pipeline release, and (6) procedures for reporting such an event. In addition to undertaking actions to meet the minimum requirements of section 192.616, SoCalGas participates, promotes, and contributes to other public awareness and excavation improvement programs. To promote public awareness of the 811 USA program SoCalGas utilizes various communication methods such as utilized bill inserts, media campaigns, damage prevention industry memberships, sponsorships, radio advertising, internet advertising, billboard advertising, and safety meetings. The four types of audiences identified in section 192.616 are the affected public, emergency officials, local public officials, and excavators. These types of audiences make up the four tranches further described below in Section VI.

9. SCG-6-C9 - Increase Reporting of Unsafe Excavation

Senate Bill (SB) 661 modified existing California Government Code, section 4126 by establishing the California Underground Facilities Safe Excavation Board (Dig Safe Board). SoCalGas has two groups involved in identifying excavators who frequently utilize unsafe practices and reporting those contactors to the appropriate state board. The Damage Prevention Strategies team informs Dig Safe Board investigators about unsafe practices SoCalGas witnesses in the field. The Claims Recovery team reports incidents to the Contractor State Licensing Board (CSLB) when it becomes aware of them through its involvement with insurance and financial considerations as a result of incidents. The Dig Safe Board is developing regulations related to reporting and SoCalGas plans to implement any new requirements.

10. SCG-6-C10 – Public Awareness-Secure Greater Enforcement through Legislation and Dig Safe Board

SoCalGas continues to actively participate in regulatory proceedings that will support the effectiveness of federal and state safe digging laws through legislation and enforcement of sanctions and penalties. Sanctions and penalties should be enforced against parties not following the well-established rules requiring third parties to call 811 USA to have pipelines marked prior to excavation. SoCalGas supported California State Senate Bill SB 661, which modified

California Government Code, section 4216, establishing the Dig Safe Board, by providing proposed language to increase protection of underground substructures.

In addition, SoCalGas participates at board meetings of the Dig Safe Board, which was created by the Dig Safe Act of 2016 and is included in California's Government Code, section 4216.12, Safe Digging law. The Dig Safe Board's charter is to coordinate education and outreach activities that encourage safe excavation practice; develop standards that support safe excavation practices; investigate possible violations of section 4216; and enforce section 4216 to the extent of granted authority.

Company involvement and participation at Dig Safe Board meetings and workshops help foster a positive working relationship with all stakeholders. These meetings and workshops provide the opportunity to raise the issues and concerns facing the Natural Gas industry and issues in regard to excavation damage prevention.

11. SCG-6-C11 – Public Awareness - Meet with Cities with Highest Damage Rates

SoCalGas Damage Prevention Analysts work to reduce the number of third party excavation incidents in cities and jurisdictions with the highest number of reported occurrences. To achieve this objective, they partner with SoCalGas' operating districts management and represented personnel to identify and meet with city officials with functions and responsibilities related to construction and excavation activities in their respective jurisdictions. This effort provides outreach and education to these officials on the proper 811 USA process and safe digging techniques. The officials can then pass those requirements on to the contractors operating in their cities as permits are granted or city inspectors visit job sites. Cities have many resources and avenues for ensuring excavation safety within their communities. All planned work requiring a permit must start at the planning and permits department. Cities thus often have the first opportunity to educate applicants about excavation safety by providing 811 USA literature. On-site City inspectors could be tasked with patrolling and enforcing California Government Code, section 4216 compliance as part of their daily work. City inspectors hold the authority to stop any job that violates code. Cities may also consider preventing excavators from working in their boundaries if the excavator is known to cause frequent excavation violations.

12. SCG-6-C12 – Public Awareness - Remain Active Members of the California Regional Common Ground Alliance

The California Regional Common Ground Alliance (CARCGA) is a group of California-based stakeholders who are impacted by excavation activities. CARCGA is the regional group within the Common Ground Alliance (CGA). The CGA works with its membership to establish best practices for the 811 USA One-Call Centers, underground facility owners, excavators, locators, project owners, and designers. Through its Damage Prevention Strategies function, SoCalGas participates with CARCGA members to inform CGA objectives from a regional perspective.

13. SCG-6-C13 – Continue to Participate in the Gold Shovel Standard Program

SoCalGas requires construction contractors doing work on its behalf to participate in the Gold Shovel program. The program certifies an excavator's policies and procedures against the Gold Shovel Standard, a set of excavator training procedures designed to protect underground facilities. The Gold Shovel standard also publishes a rating which is an ongoing measure of an excavator's digging-safety-worthiness. This requirement serves to incentivize construction contractors to follow safe excavation laws and practices. The Gold Shovel Standard (GSS) is a nonprofit organization committed to improving workforce and public safety and the integrity of buried infrastructure. GSS believes that greater transparency in all aspects of damage prevention among buried-asset operators, locators, and excavators is essential to drive continuous improvement, and vital to increasingly safe working conditions and communities. Certifying excavators who participate in the Gold Shovel Program complies with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

14. SCG-6-C14 – Locating Equipment

SoCalGas utilizes locating equipment, updated GIS maps, and/or excavating (daylighting) to verify the physical locations of underground infrastructure. Part of this process involves uploading scanned construction drawings temporarily until the job is posted officially to GIS. SoCalGas continues to remain compliant with codes and regulations and follow industry best practices and company policies and procedures as they apply to the safe and effective locating and marking of underground facilities. This Control includes written and accessible procedures, availability of proper equipment, and access to required information to enable personnel to successfully perform their duties. Locating equipment is utilized to comply with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

15. SCG-6-C15 – Remain Active Members of the California 811 One-Call Centers

Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216 require natural gas utilities to remain members and actively participate in the activities of 811 USA local one-call centers. Excavators are required to notify the 811 USA one call centers of their intent to dig. Owners of underground facilities in close proximity to the dig site are required to provide a positive response with the location of their facilities that may be in conflict with the excavation and also provide any other efforts that may be required to protect the integrity of their underground facilities. The members of the one-call centers actively meet to make the 811 USA process easier for excavators while also exploring ways to make the service more accessible on a variety of platforms. They also work to promote the safe digging message through various avenues, such as through broadcast media, mobile and electronic communications.

The Controls addressed above will continue to be performed. The Company's Mitigations, addressed below, aim to further reduce the frequency of dig-ins.

16. SCG-6-M1 – Automate Third Party Excavation Incident Reporting

Timely and accurate reporting of excavation incidents is a critical component of the continual improvement process. Enhancing the data collection of incidents helps measure the performance of adhering to compliance reporting obligations, and also assists the Company in filing various regulatory reports. The reporting system is the basis for excavation incident analysis and is used to understand the Company's opportunities for internal improvement for locate and mark activities. Through this analysis of excavation incidents, SoCalGas can further understand the internal and external leading causes of dig-ins, trend incident locations, trend frequency of damages caused by individual excavators, trend which facilities are damaged the most, and stay informed about the most common damaging excavation equipment.

Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SoCalGas is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors and is actively enhancing its ability to improve data capture, data validation, and automated escalations. New Third Party Excavation Incident Reporting systems will provide accessibility and efficiency across multiple platforms reducing reporting and notification times by automating the reporting process. The upgraded reporting system efficiently analyzes accurate incident data and provides course corrections as locate and mark trends are identified.

17. SCG-6-M2 – Establish a Program to Address Areas of Continual Excavation

Generally, a typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[32] Agricultural excavators who perform repetitive excavations prefer 811 USA Tickets that are valid for longer periods of time. Requiring 811 USA notifications every 28 days could discourage participation in the 811 USA process by agricultural excavators, who may find it too burdensome to renew a ticket. These situations are typically in flood control channels and agricultural fields where excavation and

[32] Although USA tickets are valid for 28 days from the date of issuance, if work continues beyond 28 days, the excavator may renew the ticket per Cal. Govt. Code § 4216.2(e).

digging activities can occur continually. This mitigation program fulfills the California requirement[33] to develop a process that would allow for certain agreements for continual excavation, called ACE tickets. In flood control and agricultural situations, SoCalGas will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement.

Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. The Dig Safe Board has drafted regulations[34] requiring operators to address ACE tickets by completing newly developed forms, conducting onsite meetings, potentially excavating the facility, and providing additional records. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators.

18. SCG-6-M3 – Recording Photographs for Each Locate and Mark Ticket Visited by Locator

Under this Mitigation, locators will take photographs of the areas located and marked and the areas the excavators delineated either using white paint or other approved marking methods for each ticket they complete. The pictures taken by the locators will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Pictures will also mitigate potential disputes between excavators and SoCalGas by providing visual confirmation of the location marks at the time the ticket was located and marked. The photographs will include a digital time stamp and geographical identification metadata.

19. SCG-6-M4 – Utilize Electronic Positive Response

SoCalGas will utilize an electronic positive response system (EPS) which informs an excavator once a locate and mark activity is completed for the excavator's 811 USA ticket. For example, if the locator marks the jobsite, the excavator will be notified on their USA ticket that

---

33 California Senate Bill (SB) 661 modified Cal. Govt. Code § 4216, establishing an Area of Continual Excavation (ACE) Ticket.

34 Dig Safe Board, Resolution No. 19-07-01, *available at* https://digsafe.fire.ca.gov/media/2197/resolution-19-07-01.pdf.

the company has completed markings at the ticket location. EPS gives excavators and the company a shared record of locate and mark activity completed by the locator. This will help excavators by providing them with the appropriate documented communication before they dig. Enhancing electronic positive response will be used to measure the performance of adhering to Title 49 Code of Federal Regulations, section 192.614.

20. SCG-6-M5 – Enhance Process to Leverage Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SoCalGas will work with the requesting contractor to help fulfill their request without creating an unsafe situation. More specifically, SoCalGas will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Vacuum excavation is recognized by the damage prevention industry as the safest excavation method that can be used today because the water and air used for excavation is adjustable, preventing damage to pipe and coatings. The Company proposes to enhance its excavation practices by using hydro vacuum excavation technology which is typically installed onto a truck or portable trailer and allows the excavator to perform a keyhole excavation process, when applicable. Generally, a keyhole excavation process is utilized to excavate targeted areas.

Hydro vacuum excavation uses water at a high pressure to loosen the soil, this allows for precise excavation and vacuuming of the material. The use of water at a high pressure reduces the soil’s cohesiveness thus helping to break the soil and suction easily. Dirt is stored in a debris tank, keeping the work area cleaner and avoiding the creation of dirt spoils. Hydro vacuum excavation is less invasive compared to other traditional methods of excavation. The benefits of hydro vacuum excavation include a reduced likelihood of causing third party damages, faster and precise excavations, and it also requires less manpower compared to conventional excavations.

The keyhole excavation process cost-effectively and safely exposes underground infrastructure to allow operators to perform repairs and maintenance without resorting to more costly and disruptive conventional excavation methods. The keyhole excavation process consists of performing work on the surface with smaller excavations, which can be performed on paved or non-paved areas. Pavement removal can be accomplished often by saw cutting and coring. The size of the pavement opening is determined upon the scope of the task at hand. The normal process utilizing keyhole excavation involves coring, vacuum excavation, construction and maintenance activities, and finally backfill and pavement restoration.

The Company will enhance its processes to utilize this excavation technology to facilitate hard to locate facilities.

21. SCG-6-M6 – Promote Process and System Improvements in 811 USA Ticket Routing and Monitoring

As part of continuous improvement efforts, an assessment of the current state of the 811 USA ticket routing and monitoring process is underway. The intent of this effort is to query system users and managers on potential improvements that would provide benefits to the process. The software vendor, Korterra, has been engaged to provide software solutions for identified system enhancements that will allow for more streamlined data collection, better documentation capture capability, and more detailed reports for process supervision. The primary focus of system improvements to the 811 USA ticket routing and monitoring process will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Fedearl Regulations, section 192.614.

These new tools will give the company the ability to better manage 811 USA ticket load across the company. The tools and enhancements entail workflows requiring that locators input specific data into dedicated fields detailing mutual agreements. These fields will enable reporting for all mutual agreements, giving SoCalGas additional measures for ticket compliance. Other tools include automated notifications in the form of emails and/or texts for management when tickets are approaching the mutual agreement due dates. This will trigger follow up action to address tickets on time. This Mitigation will include resources that support enhanced data collection and field management of ticket efforts and will also support 811 USA

Ticket prioritization. These resources are needed to manage data, perform analytics on the new volume of data, and to identify system enhancements.

22. SCG-6-M7 – Leverage Data Gathered by Locating Equipment

SoCalGas uses locating equipment that automatically captures GPS coordinates as the locator performs their locating activities. The GPS data may also be manually recorded when the locator pushes a designated button on the equipment console. The equipment's GPS data is downloaded through a physical connection with a terminal allowing the data to be saved then transmitted to the GIS group. Future enhancements may include the ability to wirelessly transmit the GPS data. The GPS data can then be used in GIS to compare real world locating data with GIS mapping data to evaluate discrepancies and potentially catch mapping errors or locating errors thereby increasing the accuracy of the locating activity. Correcting mapping errors or omissions using this data may potentially reduce damages caused by mapping issues. Leveraging data gathered by locating equipment improves adherence to Title 40 Code of Federal Regulations, section 192.614.

23. SCG-6-M8– Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)

Plastic underground warning mesh is a high strength polypropylene mesh and designed to alert excavators of the presence of buried utilities. It is typically installed at a minimum of 18 inches above the buried facility which provides the excavator awareness of a buried pipeline below. If an excavator was not expecting buried facilities in their excavation, the mesh serves to alert them, identifies the presence of a gas line, and directs them to contact 811 USA before proceeding so that proper precautions can be implemented before further excavation. Providing this type of warning before excavating further into an underground gas facility substantially reduces the risk of third party damage and the associated consequences. SoCalGas installs warning mesh during new pipeline installations. Warning mesh installation applies to high pressure pipelines (MAOP > 60psig) and medium pressure pipelines (MAOP ≤ 60psig).

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[35] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. Risk reduction from Controls and Mitigations and RSEs are determined at the tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SoCalGas' rationale for the determination of tranches is presented in the table below.

Table 6: Summary of Tranches

ID	Mitigation/Control	Tranche	Tranche ID
SCG-6-C8	Public Awareness Compliance	The Affected Public	SCG-6-C8-T1
		Emergency Officials	SCG-6-C8-T2
		Local Public Officials	SCG-6-C8-T3
		Excavators	SCG-6-C8-T4

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing the risk of injuries or fatalities to the public, employees, and contractors. Given the vast number of activities SoCalGas performs to mitigate the Third Party Dig-in on a Medium Pressure Pipeline risk, SoCalGas grouped like activities with like risk profiles into mitigation programs.

[35] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SoCalGas utilized historical gas dig-in results year-over-year to calculate an overall risk reduction benefit of performing these activities.[36] SoCalGas then looked at existing/continuing programs (*i.e.*, Controls), with the expectation of observing similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SoCalGas also accounted for the risk increase that would occur over time if the risk reduction activities were reduced or cancelled. For new and/or incremental Mitigations, SoCalGas expects to achieve further risk reduction. The specific risk reduction benefit percentages used for each identified Control/Mitigation is included under each of the program headings below.

1. SCG-6-C1 – Locate and Mark Training

A single tranche is appropriate for this program because SoCalGas has an obligation to provide Locate and Mark Training for all Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Training has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and mark training provides participating employees with the necessary knowledge and capabilities to locate and mark the below ground gas facilities accurately and in the appropriate time frame. At SoCalGas, the Energy Technician Distribution (ETD) and Lead Construction Technician (LCT) functions have the responsibility to locate and mark gas facilities in response to an excavation request. Gas Operations Training and Development provides each ETD and LCT with the initial in-depth locate and mark training upon being newly assigned to an ETD or LCT position. Overall training is about an 8 week course with locate and mark training comprising about one week of that time. An ETD or LCT employee are not certified to locate or mark gas facilities until they have successfully completed this training. In 2019, SoCalGas' Gas Operations Training and Development function is forecasting to provide Locate and Mark

36 *Id.* at Attachment A, A-5 ("MAVF Principle 4 – Risk Assessment").

Training to about 125 ETD and LCT employees. It is necessary to have a trained workforce to accurately locate and mark gas infrastructure to provide the necessary information for a third-party excavator to perform their work as safely as possible. Marked facilities provide the excavator with approximate locations of where the gas facilities exist, within the delineated work area. Awareness of underground gas facilities allows the excavator to either avoid the areas or carefully dig with hand tools to prevent damage caused by the excavation work. Since a vast majority of the utility's assets are buried below ground it is imperative that proper action is taken to reduce the risk of accidental damage to these facilities by accurately communicating the locations to the excavators. Without a highly skilled and trained locate and mark workforce, excavators would have little knowledge and confidence of gas line locations which could lead to third party excavation damage. By improving knowledge and competency through training, locate and mark accuracy will increase, and the number of mismarks should be reduced, leading to a decrease in the risk of third party excavation damage. Additionally, this training provides the workforce with the necessary understanding of not only the requirements for accurate locating and marking but also the importance of two-way communication with an excavator, thorough job documentation and timeliness of locate and mark completion.

SoCalGas has not performed an RSE Evaluation on SCG-6-C1 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

2. SCG-6-C2 – Locate and Mark Activities

A single tranche is appropriate for this program because SoCalGas has an obligation to perform Locate and Mark Activities across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and California Government Code, section 4216. Therefore, Locate and Mark Activities has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Activities are to prevent damage to gas infrastructure caused by third party excavators. They consist of three distinct activities:

(1) locating and marking underground gas facilities before excavation occurs;

(2) observing (stand-by) pipeline excavation activities; and

(3) providing staff support for compliance and improvement.

The first of these activities, locating and marking, refers to the physical act of locating and marking of underground facilities. In 2018, SoCalGas Distribution Field Operations fulfilled over 720,000 locate and mark requests with nearly all being classified as medium pressure. By providing a visual indication of the location of underground facilities, the excavator has the necessary information to proceed with their activities in a safe and controlled manner. The second locate and mark activity is Pipeline Observation (stand-by) which is performed in specific required situations. Pipeline Observation (stand-by) is a critical activity that requires a qualified Company representative to be present anytime excavation activities take place near a high priority pipeline segment. The purpose for this activity is to decrease the likelihood of an event occurring by having a dedicated employee representing the operator who is specifically there to maintain the integrity of the gas pipeline. The third activity involves employee staffing to provide daily support in operations by interpreting policies, tracking compliance, evaluating tools, equipment and new technologies, providing refresher training, and tracking and trending locate and mark data to proactively identify areas for improvement. This is a critical risk reduction activity that directly supports the field locator personnel in their daily activities and leads to more accurate and timely responses to locate and mark tickets and reduction in damages.

This collection of Locate and Mark Activities ultimately provides the excavator with the necessary information to avoid hitting or damaging gas facilities.

SoCalGas has not performed an RSE Evaluation on SCG-6-C2 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

3. SCG-6-C3 – Locate and Mark Annual Refresher Training and Competency Program

A single tranche is appropriate for this program because SoCalGas has an obligation to provide a Locate and Mark Annual Refresher Training and Competency program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Annual Refresher Training and Competency Program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

All employees performing locate and mark activities must complete an annual refresher training program. This program consists of local supervisors reviewing the appropriate gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to maintain their ability to perform locate and mark activities. In 2018, about 970 employees participated in the annual Refresher and Competency Training program for both high pressure and medium pressure pipelines.

The Locate and Mark Refresher Training and Competency program reinforces several key components of locate and mark. By reviewing the gas standards on an annual basis, employees performing locate and mark activities are provided an opportunity to review expected procedures, learn changes in procedures, and obtain clarification. Without an opportunity to refresh their understanding, the locate and mark workforce might not be up to date on the latest procedure, requirement, or technology. Refresher training enables trained personnel to perform their duties with greater accuracy and efficiency, and it increases trained personnel's ability to adapt to new technologies and methods. Marking facilities accurately provides the excavator and public with greater safety assurance. It enables the excavator to either avoid the delineated areas or dig with hand tools to avoid damage that could result in an immediate or future incident.

SoCalGas has not performed an RSE Evaluation on SCG-6-C3 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

4. SCG-6-C4 – Locate and Mark Operator Qualification Program

A single tranche is appropriate for this program because SoCalGas has an obligation of providing a Locate and Mark Operator Qualification program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Operator Qualification program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and Mark Operator Qualification (OQ) training provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. This would include such activities as achieving proper locating signals, interpreting the signals, and placing accurate and proper markings on the ground to indicate the location of the pipe. Locate and Mark OQ is required for employees every five years and is administered by the Gas System Integrity - Operator Qualification department at SoCalGas. There are about 480 employees at SoCalGas that participate in OQ training each year. It is mandated by PHMSA.[37]

Employing resources that are formally trained and Operator Qualified to perform Locate and Mark functions demonstrates both procedural knowledge and field implementation of the necessary tasks required to successfully perform these functions. Maintaining this level of prepared and qualified workforce allows SoCalGas to meet its regulatory requirements and the demands of the excavator community and helps provide for a safe excavation environment.

SoCalGas has not performed an RSE Evaluation on SCG-6-C4 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

37 49 CFR §§ 192.801 - 192.809.

5. SCG-6-C5 – Locate and Mark Quality Assurance Program

A single tranche is appropriate for this program because SoCalGas has an obligation to perform quality assurance activities for Locators across its entire service territory. Therefore, Locate and Mark Quality Assurance program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Quality Assurance (QA) Program is to verify that proper processes and procedures are being followed and implemented by the locate and mark workforce and to correct those instances where improvements are warranted. SoCalGas' Pipeline Safety and Compliance department administers this QA program and visits every operating district at least once per year. During these visits, they select 15 811 USA tickets for each Locator, check the employees Operator Qualification status and evaluate the documentation on the ticket. Additionally, they will perform field visits, when possible, to evaluate in-field activities such as equipment setup and use, Company Gas Standard compliance, accuracy of locate and markings, proper documentation, and proper use of the Korterra ticket management system, among other activities. Feedback on a quality assurance audit is provided to each local supervisor who is responsible to follow-up with any individuals needing further coaching or refresher training.

The Locate and Mark QA Program provides a variety of benefits to reducing the number of and potential for damage to gas infrastructure by a third party. By evaluating locate and mark activities that have been completed or are being performed, SoCalGas can address gaps in performance with additional training or updating of company documentation or recordation of assets. Locate and mark workforce errors can result in an incorrect mark and locate or one that is not done within the required timeframe. Additionally, the QA review can highlight errors in the timely and/or accurate documentation of utility assets, which, if not corrected, could result in an incorrect locate and mark. Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

b. Elements of the Bow Tie Addressed

SCG-6-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Subject Matter Experts (SMEs) estimate that 100% of activities in the program would benefit from this mitigation.
Effectiveness	Assuming 5% effectiveness as QA program has above-marginal impact on reducing mismarks.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 8% of the causes (8% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.4%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2977.4897**	
	CoRE	0.24	**0.32**	0.45

	Risk Score	701.06	**939.91**	1337.99
	RSE	9.14	**12.26**	17.45

6. SCG-6-C6– Damage Prevention Analyst Program

The Damage Prevention Analyst Program works to reduce the number of third-party damage to gas facilities by identifying at risk excavating contractors and educating them on proper one-call and safe digging techniques. Therefore, any excavating contractors at risk that are identified by the damage prevention analysts pose the same safety risk and a single tranche is appropriate for this program.

a. Description of Risk Reduction Benefits

The Damage Prevention Analyst Program works to reduce the number of third-party damages to gas facilities by identifying excavating contractors at risk of causing dig-in damages and educating them on proper 811 USA one-call and safe digging techniques. Through the Damage Prevention Strategies function, Damage Prevention Analysts focus on the four districts (out of a total 48 districts) with the greatest number of reported incidents, by driving to and physically inspecting excavation projects with 811 USA ticket requests. The Analysts will also stop at other construction projects to investigate whether proper one-call and digging techniques are being used. In cases where the Analysts find an offense, they will stop the job and provide education to the contractor on the correct safe digging practices and procedures. SoCalGas expects to expand this effort to up to ten districts. SoCalGas' Damage Prevention Analysts have stopped over 470 jobs since the program's inception in 2018 and have conducted over 4,500 contractor field contacts to develop outreach and educational opportunities.

The benefit of the Damage Prevention Analyst function is threefold. First, it enables SoCalGas to stop a job before an incident occurs if no underground markings are present or the excavator is not practicing safe digging techniques. Second, it provides an opportunity to educate contractors on the requirements before digging or when digging around gas facilities before damage is done. This education has far-reaching benefits as the contractor will perform future projects in other districts not currently part of the program, and the education could be applied to those future projects. Third, it creates a list of contractors who might be repeat offenders or of site characteristics to improve prioritization of future construction site inspections.

b. Elements of the Bow Tie Addressed

SCG-6-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call 811 USA for locate and mark prior to excavation, DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Damage Prevention Analyst program focuses on 100% of the excavation tickets through risk assessment.
Effectiveness	The effectiveness is assumed at 25% as analysts prioritize work, support training, stop unsafe jobs, support all districts, etc.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 26% of the causes (26% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 6.6%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
Pre-Mitigation	**CoRE**	0.24	**0.32**	0.45
Pre-Mitigation	**Risk Score**	698.36	**936.28**	1332.83
Post-Miti	**LoRE**		**3160.8146**	

	CoRE	0.24	**0.32**	0.45
	Risk Score	744.23	**997.78**	1420.37
	RSE	44.59	**59.78**	85.10

7. SCG-6-C7 – Prevention and Improvements – Refreshed Laptops

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and efficiently provide correct information helps with accurately locating underground infrastructure. Laptops with the applicable Software are deployed across SoCalGas's territory. SoCalGas has a vast service territory that covers 24,000 square miles in diverse terrain throughout Central and Southern California, from Visalia to the Mexican border. The service territory covers 12 counties, 220 incorporated cities in more than 500 communities. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The workforce that performs the locate and mark activities relies on laptops, 811 USA tickets, asset mapping, records data, software, and locating equipment. Using laptops in an outdoor setting, and often in construction areas, can reduce life expectancy due to the harsh environment. Therefore, SoCalGas provides its workforce with ruggedized laptops that are designed to better withstand their operating environment. Additionally, as software and data are updated and become more sophisticated with new and more powerful features, new laptops with advanced capabilities are required so that all information can be provided to the locate and mark workforce and data can be updated. Approximately 350 laptops are replaced every 5 years.

Updated and ruggedized laptops provide a longer battery life and can run the required software faster and more efficiently. Updated hardware and software increase the effectiveness of performing locate and mark. The ruggedized laptops also can take a picture of the surrounding conditions of an excavation site to update mapping information for improved asset and mapping information. All features of the refreshed laptops work to reduce the number of errors that might occur in locating gas infrastructure through improved data and could be used to support the development of improved safe-digging procedures.

b. Elements of the Bow Tie Addressed

SCG-6-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of laptops will be refreshed.
Effectiveness	Assuming negligible improvement in effectiveness (0.25%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 26% of the causes (26% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.07%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2967.9481**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.81	**936.90**	1333.71
	RSE	0.41	**0.54**	0.77

8. SCG-6-C8 – Public Awareness Compliance

For the purposes of an RSE analysis, SoCalGas separated Public Awareness into four tranches. Each of the four tranches reduces the likelihood of third party damage differently according to the RSEs.

Title 49 Code of Federal Regulation, section 192.616 requires utilities/natural gas providers to include efforts to educate the public, appropriate government organizations, and persons engaged in excavation related activities. The four types of groups identified in section 192.616[38] are the affected public, emergency officials, local public officials, and excavators. The SCG-6-C8 – Public Awareness has been tranched to match the four groups identified in section 192.616.

Periodically SoCalGas participates in Distribution Public Awareness Council (DPAC) Benchmark studies to collect and compare membership data related to the effectiveness of public awareness and community safety outreach programs managed by gas utilities. There is a clear distinction between the general level of awareness between the affected public, emergency officials, local public officials, and excavators. In order to address this gap and reduce third party damage, targeted messaging campaigns are performed for each subgroup to increase overall awareness and education. Emergency officials and local public officials are often met with in person to discuss municipal third party damage trends. The public and excavators are further informed of 811 USA and safe digging practices using bill inserts, media campaigns, SoCalGas damage prevention analysts, radio advertising, internet advertising, billboard advertising, and safety meetings. A summary of SoCalGas' 2018 public awareness activities is shown in the table below.

[38] 49 CFR § 192.616 (emphasis added):
(d) The *operator*'s program must specifically include provisions to educate the public, appropriate government organizations, and *persons* engaged in excavation related activities on:
(1) Use of a one-call notification system prior to excavation and other damage prevention activities;
(2) Possible hazards associated with unintended releases from a *gas pipeline facility*;
(3) Physical indications that such a release *may* have occurred;
(4) Steps that should be taken for public safety in the event of a *gas pipeline* release; and
(5) Procedures for reporting such an event.

Table 7: Summary of SoCalGas' 2018 Public Awareness Activities

	Mailers	**Email messages**	**Public Service Announcements**	**811 Unique Page views (2019 data)**
Excavators	162K	31.5K	1	In 2019, from 399 to 2585 unique page views per month
Public Officials	2K	600	0	
Affected Public	3.5M customers and 750K live/work near high pressure	2.2M	1	
Emergency Officials	1.9K	20	0	

A comprehensive public awareness program works to reduce the number of gas incidents by educating the general public on the indication of a gas leak and what to do if they do identify the potential for one. This allows first responders and SoCalGas to respond in a timely manner to avoid a gas incident or minimize its impact. More specifically, the Public Awareness Program works to reduce the number of potential gas incidents due to third party excavation activities. Third parties refer to a broader group than just excavators, it can also include "do it yourself" home and business owners. By providing information about the 811 USA process and safe digging practices to these audiences, SoCalGas can increase the number of locates performed by the gas utility and potentially reduce the number of incidents of damage to gas infrastructure.

9. SCG-6-C8-T1 – Public Awareness Compliance - The Affected Public

a. Description of Risk Reduction Benefits

SoCalGas continues to promote awareness of the Underground Service Alert (811, "call-before-you dig") system to the affected public by reaching out to contractors and the general public through meetings, mailers, bill inserts, hosting events, the Company website, marketing and banners at locally broadcasted events and other methods, so that gas lines are properly marked before excavation activities. Pipeline markers are to be accurate and visible. Excavation activity includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by both explosive or mechanical means, and other earth-moving operations.

Additionally, to promote National Safe Digging Month, SoCalGas brings a 30-foot-tall shovel to public gatherings to raise awareness about the importance of contacting 811 USA at least 72 hours prior to the start of any excavation project. For example, SoCalGas brings the giant shovel—popular for selfies—to inform area residents about pipeline safety, customer assistance programs, and the company's vision for California's Clean Energy Future. When residents or contractors dial 811 USA before any project that involves digging, SoCalGas marks the locations of underground lines to prevent them from being damaged, which could cause injury or service outages. This outreach is performed in compliance compliant with Title 49 Code of Fedearl Regulations, section 192.616 (d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SCG-6-C8-T1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The affected public tranche of public awareness is assumed to impact 50% of the risk.
Effectiveness	Per SME input, effectiveness is marginal (1%). More effective than targeting local public and emergency officials, but less effective than excavators.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 91% of the causes (91% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2979.4953**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	701.53	**940.54**	1338.89
	RSE	4.24	**5.69**	8.10

10. SCG-6-C8-T2 – Public Awareness Compliance - Emergency Officials

a. Description of Risk Reduction Benefits

SoCalGas has the responsibility to train its employees on the company's emergency procedures as well as establishing a liaison with first responders in accordance with Title 49 Code of Federal Regulations, section 192.615.[39] According to GO 112-F, SoCalGas, an "Operator" under GO 11-F, must comply with the requirements of sections 192, 192.615, and 192.616(e). There are significant benefits to creating strategic partnerships and promoting awareness with emergency officials. Communication and coordination are improved when it matters most. SoCalGas works to implement this requirement by establishing lines of communication between SoCalGas and first responders, by learning about the responsibility and resources available to each party in the event of a gas pipeline emergency, and by educating each other on how to best respond to a gas system emergency.

Additionally, section 192.616, which governs GO 112-F, states that SoCalGas is required to coordinate emergency exercises or drills with first responders. To commemorate "811" 8/11

[39] 49 CFR § 192.615.

Day SoCalGas, The California Regional Common Ground Alliance (CARCGA), and Orange County Fire Authority (OCFA) hold a mock utility line strike to raise awareness about the importance of contacting 811 USA at least two working days (not counting the day of notification) prior to the start of any project that involves digging. The event program includes the 811 USA process, emergency response demonstration, investigation by the Dig Safe Board, Speakers from Dig Safe Board, Orange County Fire Authority, plus exhibitor booths.

b. Elements of the Bow Tie Addressed

SCG-6-C8-T2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The emergency official's tranche of public awareness is assumed to impact 5% of the risk.
Effectiveness	Emergency officials can help with all excavation cause codes and are assumed to have the same effectiveness as the Affected Public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 28% of the causes (28% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2966.4152**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.45	**936.41**	1333.02
	RSE	1.32	**1.77**	2.51

11. SCG-6-C8-T3 – Public Awareness Compliance - Local Public Officials

a. Description of Risk Reduction Benefits

Working directly with city officials involved in construction activities within their jurisdictions helps to educate external personnel to support SoCalGas' enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. This interaction can involve several efforts. First is educating city personnel on the specific requirements of the California safe excavation laws. Second is helping officials understand their role in helping to enforce the laws by promoting the use of 811 USA for excavation tickets through their project review and permitting activities as well as the field inspections their employees perform. Third is to explain the city's potential cost savings from avoiding their emergency personnel from having to respond to a blowing gas emergency due to non-compliant excavation damage. City officials can help avoid unnecessary emergency response if they promote safe excavation practices during their routine daily planning and permitting work. The following outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616 (d) subsections 1-5.

SoCalGas
A Sempra Energy utility

b. Elements of the Bow Tie Addressed

SCG-6-C8-T3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The local public official's tranche of public awareness is assumed to impact 15% of the risk.
Effectiveness	Minimal impact since they're not the excavators; assuming 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 61% of the causes (61% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2968.7005**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.99	**937.14**	1334.04
	RSE	2.81	**3.77**	5.37

12. SCG-6-C8-T4 – Public Awareness Compliance - Excavators

a. Description of Risk Reduction Benefits

Excavator awareness of 811 USA is very important. Nationwide statistics from the Common Ground Alliance indicate that when a locate request is made prior to an underground excavation, no damage will occur 99% of the time.[40] It is especially important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks and private property – sometimes just inches below the surface. Hitting one of these pipelines while conducting routine work such as digging, planting, or doing demolition work can cause serious injury, property damage, and loss of utility service. Multiple excavator outreach events are hosted, targeted excavator communication mailings, and the Big Shovel display are used to bolster awareness and benefits of 811 USA. Excavator outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616(d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SCG-6-C8-T4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

---

[40] Common Ground Alliance, *Common Ground Alliance's 2014 DIRT Report Confirms Importance of Calling 811 Before Digging for Fifth Consecutive Year* (August 11, 2015), *available at* https://commongroundalliance.com/sites/default/files/press_release_pdfs/2014%20DIRT%20Report%20Press%20Release%20FINAL.pdf.

c. RSE Inputs and Basis

Scope	The excavator's tranche of public awareness is assumed to impact 30% of the risk.
Effectiveness	Public awareness campaigns for excavators are expected to be more effective than for other diggers, and the effectiveness is set to a higher number of 3%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 91% of the causes (91% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.8%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2990.2915**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	704.08	**943.95**	1343.75
	RSE	12.66	**16.97**	24.16

13. SCG-6-C9 – Increase Reporting of Unsafe Excavation

The purpose of Increased Reporting of Unsafe Excavation is to identify and report excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or State Licensing Board (CSLB). Reporting of unsafe excavation is applicable to the entire SoCalGas territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of Increased Reporting of Unsafe Excavation is to consolidate and formalize the Company's internal procedures for identifying and reporting excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or (CSLB). This includes consolidating the efforts of the Damage Prevention Strategies Team with the Claims Recovery Team. Both internal groups engage in various degrees of excavator education and outreach efforts on safe digging practices. The consolidation of efforts includes a consistent methodology for identifying targeted excavators. Education and outreach efforts provide the excavators understanding of the implications of unsafe excavation practices. SoCalGas has stopped over 470 jobs and conducted over 4,500 contractor field contacts to develop outreach and educational opportunities.

By combining the information from two functions within SoCalGas, this program provides a more complete effort to achieve the benefits of reducing the third-party damage. First, it provides the names of unsafe excavators to the appropriate state boards to support the state's objectives. Second, it provides an opportunity for the excavators to be educated and informed on their obligations, such as the contractor's requirement to call prior to any excavation activity and to perform hand excavation in the vicinity of gas pipelines. With a better-informed contracting community, who follow the appropriate procedures, the number of excavation activities around gas infrastructure without location marks or without following the correct excavation procedures should decrease. The number of resulting incidents from these contractors should also decrease.

b. Elements of the Bow Tie Addressed

SCG-6-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that of excavators that are causing issues less than 1% are reported.
Effectiveness	Once the process is established, an increase in excavator notifications of 30% has been observed.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 47% of the causes (47% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
Pre-Mitigation	**CoRE**	0.24	**0.32**	0.45
Pre-Mitigation	**Risk Score**	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2970.2043**	
Post-Mitigation	**CoRE**	0.24	**0.32**	0.45
Post-Mitigation	**Risk Score**	699.35	**937.61**	1334.72
Post-Mitigation	**RSE**	8.41	**11.27**	16.05

14. SCG-6-C10 – Public Awareness – Secure Greater Enforcement through Legislation and Dig Safe Board

The purpose of securing greater enforcement through Legislation and the Dig Safe Board is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the Dig Safe Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SoCalGas actively participates in the California Underground Safe Excavation Board (Dig Safe Board) to provide input and education from the natural gas utility perspective. The purpose of this participation is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority.

Through its involvement in board meetings and workshops and collaborating to achieve common objectives related to damage prevention, SoCalGas fosters a positive and stronger working relationship with all stakeholders. By playing an active role in developing and enforcing utility and contractor requirements, a more complete education and cooperative environment can be achieved among all stakeholders. The Dig Safe Board provides a way in which effective safe excavation requirements can be cooperatively developed and disseminated to reduce third party damage.

SoCalGas has not performed an RSE Evaluation on SCG-6-C10 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C10 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

15. SCG-6-C11 – Public Awareness – Meet with Cities with Highest Damage Rates

The activities associated with this program include providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. Public awareness, meeting with cities with the highest damage rates is applicable to all cities across SoCalGas' territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of meeting with cities with the highest damage rates is to reduce the number of third party excavation incidents by providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. More specifically, using its Damage Prevention Analyst function, SoCalGas meets with leaders in all the approximately 245 municipalities in its service territory. Priority is given to the cities with the highest number of excavation incidents.

The Damage Prevention Analysts will meet with the permitting, inspection, and/or other pertinent officials within the municipalities to develop a strong working relationship to reduce third party damage. Concepts are discussed, such as asking the city inspectors to also look for proper utility markings, stop the job, or incorporate 811 USA literature with the permit application.

Working directly with city officials involved in construction activities within their jurisdictions helps to develop an extended education and enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. It also creates an additional opportunity to identify poor practices and the offending excavators so that education on contacting 811 USA prior to digging and on utilizing proper excavation techniques can be provided before any digging or damage has occurred. As excavators operate in multiple jurisdictions, any education of a contractor that occurs in one city can also be applied to the contractor's future jobs in other jurisdictions. Finally, as the number of excavation incidents decreases, the demands on local first responders will also decrease.

b. Elements of the Bow Tie Addressed

SCG-6-C11 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Meeting with the top 3% of cities (7 cities out of 240 total).
Effectiveness	Minimal impact since they are not the excavators. Assuming same effectiveness as public awareness for the affected public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 89% of the causes (89% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

SoCalGas
A Sempra Energy utility®

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2966.7718**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.54	**936.53**	1333.18
	RSE	0.67	**0.90**	1.28

16. SCG-6-C12 – Public Awareness - Remain Active Members of the California Regional Common Ground Alliance

The purpose of remaining active members of the California Regional Common Ground Alliance (CARGA) is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the California State Digging Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SoCalGas is an active member in the CARGA through its Damage Prevention Strategies function. CARGA is the regional organization associated with the Common Ground Alliance (CGA). The CGA is an underground utility industry association, across North America, whose mission is to prevent damage to underground infrastructure and to protect those who live and work near these assets through the shared responsibilities of stakeholders. CGA helps to develop best practices among industry stakeholders in all aspects of the safe excavation practices of underground infrastructure.

By participating in CARGA, SoCalGas is able to play a role in developing best practices with other regional membership, to inform and help develop best practices on the national level, highlight localized issues that need to be addressed, and interact with contractors and other utilities to create safer excavation techniques and requirements. By working with all members of the underground industry, both locally and nationally, SoCalGas not only helps to develop best practices but is also be informed of other best practices in the industry which will help to improve utility and contractor implementation of safe digging techniques and procedures.

b. Elements of the Bow Tie Addressed

SCG-6-C12 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate is 50% as not all policies are affected.
Effectiveness	Maybe once every decade there is a practice that can be improved; however, improvement is marginal (0.05%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 100% of the causes (100% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2966.7718**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.53	**936.52**	1333.16
	RSE	2.14	**2.87**	4.08

17. SCG-6-C13 - Continue to Participate in the Gold Shovel Standard Program

The Gold Shovel Standard (GSS) Program utilizes an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. This program is applicable to all third party contractors working for SoCalGas. All third party damage caused by contractors working for SoCalGas poses the same safety risk. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The Gold Shovel Standard (GSS) Program is an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. The GSS provides positive reinforcement and reviews contractor's excavation performance. SoCalGas requires all of its contractors to participate in the Gold Shovel Program.

The GSS provides positive guidance to underground contractors, aligning their excavation practices against established safe digging practices and procedures. It helps to educate contractors on expected industry excavation standards and identify and address gaps in their processes. SoCalGas requires contractors who perform excavation on behalf of SoCalGas to be GSS certified. GSS serves as an additional quality check for its contractors. Actively supporting the Gold Shovel Standard Program helps to improve excavation contractors use of the 811 USA one-call requirement and to improve their safe digging techniques, such as hand-digging when near gas pipelines.

SoCalGas has not performed an RSE Evaluation on SCG-6-C13 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C13 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

18. SCG-6-C14 – Locating Equipment

SoCalGas provides the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure, as mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Locating Equipment Program is to utilize technology to standardize locating procedures and to provide the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure. The Locating Equipment program will provide the locate and mark workforce with standardized and compliant location devices and tools that are equipped with 811 USA ticket, asset records, and mapping information. Equipment will be provided to the workforce as part of the normal replacement cycle. Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Finally, providing standardized equipment allows for consistent training and field use for the equipment across all operating districts for improved locate accuracy by the workforce.

SoCalGas has not performed an RSE Evaluation on SCG-6-C14 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C14 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

19. SCG-6-C15 – Remain Active Members of the 811 California One-Call Centers

The California 811 USA One-Call Centers serve as the communication conduit between SoCalGas and excavators. SoCalGas is an active member of both Dig Alert and USA North. Dig Alert's territory includes nine Southern California Counties: Imperial, Inyo, Los Angeles, Orange, San Bernardino, San Diego, Santa Barbara, Riverside and Ventura. USA North covers fifty Northern California Counties. SoCalGas is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to remain an active member of the California One-Call Centers. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The California 811 USA One-Call Centers serve as the communication conduit between SoCalGas and excavators to support safe digging practices. Excavators contact the 811 USA one-call centers with their intent to excavate in a specific location. This information is made available to the owners and operators of underground infrastructure to provide location information before excavation occurs. SoCalGas is an active member of local one-call centers. In calendar year 2018, SoCalGas responded to over 720,000 requests for locate and mark activities of its distribution system through the local one-call centers, nearly all distribution pipe is considered as medium pressure.

As a member of the 811 USA one-call centers, SoCalGas actively works with other industry stakeholders toward simplifying the process, improving its accessibility, and educating safe digging practices. The California one-call centers play a critical role in safe excavation practices and reducing the number of third party damages. The call centers provide a single source for all excavators to contact as well as a source for utilities, simplifying the communication process between many contractors and the various utilities, many of which are not known by the contractors. The one-call process also allows this communication process to take place before digging occurs, so that utilities can correctly locate and mark their facilities within an expected timeframe. Excavating with these marks, allows the contractors to practice safe digging techniques, minimizing the potential of hitting or damaging gas piping as they complete their work.

SoCalGas has not performed an RSE Evaluation on SCG-6-C15 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-6-C15 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

20. SCG-6-M1 – Automate Third Party Excavation Incident Reporting

Automating Third Party Excavation incident reporting into one system will centralize the reporting and data analysis. This will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. SoCalGas is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to collect data on third Party Excavation Incidents. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

Automating third party excavation incident reporting will be the result of an effort to consolidate and simplify the data collection process involved in investigating a gas incident. Field supervisors complete the investigations of gas incidents. Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SoCalGas is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors.

Standardizing data collection into one system will centralize reporting and data analysis will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes.

This will facilitate improvements in SoCalGas' accuracy and timeliness in locating and marking its infrastructure.

b. Elements of the Bow Tie Addressed

SCG-6-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.6 - Incorrect/inadequate information in existing asset records leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Marginal improvement is expected (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2965.8286**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.32	**936.23**	1332.75
	RSE	0.02	**0.03**	0.04

21. SCG-6-M2 – Establish a Program to Address Areas with Continual Excavation

SB 661 modified California Government Code 4216 establishing an ACE Ticket. An ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators. Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. This ticket is applicable to areas within SoCalGas' territory. All excavations performed with the use of an ACE ticket pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

A typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[41] These situations typically are in flood control channels and agricultural fields where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement to develop a process that

[41] Although USA tickets are valid for 28 days from the date of issuance. If work continues beyond 28 days, the excavator may renew the ticket per California Government Code, section 4216.2(e).

would allow for certain agreements for continual excavation, called ACE tickets. In flood control and agricultural situations, SoCalGas will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement

Having to continuanly renew an 811 USA ticket may discourage some excavators from using the 811 USA process. This program will reduce dig-in risk as it will encourage landowners to use the 811 USA one-call process before excavating and reduce the need to continually call every time digging needs to occur in the same area over the one-year timeframe of the ticket. By informing the one-call center, and then the utility, the landowner can be made aware of gas infrastructure in the area and develop an agreed-upon process to employ safe-digging techniques within the parameters established in the ACE ticket. Additionally, this process will assist the utility in accurately and timely marking the facilities as they will not have to make multiple, repeat visits to the same excavation site. By providing a mechanism to reduce effort for both the landowner and the utility and providing the location of gas infrastructure to the landowner, the use of safe-digging practices should increase, and the amount of infrastructure damage should decrease.

b. Elements of the Bow Tie Addressed

SCG-6-M2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

SoCalGas
A Sempra Energy utility

c. RSE Inputs and Basis

Scope	For assessment purposes, SMEs consider farmers to be equivalent to excavators fielding heavy machinery. The proportion of farmers to heavy machinery excavators is assumed to be 1 to 200, hence a scope of 0.5%.
Effectiveness	Effectiveness assumed to be high (90%) as the percentage of the targeted people (farmers) are likely to follow procedure and prevent a dig-in once aware of the situation.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2961.2049**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	697.23	**934.77**	1330.68
	RSE	40.94	**54.89**	78.14

22. SCG-6-M3 – Recording Photographs for Each Locate and Mark Ticket Visited by Locator

Recording photographs for each locate and mark ticket visited by locators is planned for all SoCalGas' above and belowground facilities within its entire service territory. These pictures will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of recording photographs of each locate and mark ticket is to improve the accuracy of the locating activity and to inform process improvements based on investigations of gas incidents and quality assurance audits. By having a record of the locate marks, SoCalGas will be able to better perform root cause analyses of QA activities and investigations into gas incidents. These photographs could show incorrect markings, which would result in improved training, or they could show incorrect mapping and asset data, which could result in improved utility data. The benefits of this Mitigation is its role in improving future locate and mark accuracy to avoid damage to gas infrastructure.

b. Elements of the Bow Tie Addressed

SCG-6-M3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets will have associated photographs.
Effectiveness	The effectiveness is marginal in nature and considered to be 1% as the impact is only on lessons learned.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 8% of the causes (8% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2963.7113**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	697.82	**935.56**	1331.80
	RSE	0.26	**0.35**	0.50

23. SCG-6-M4 – Utilize Electronic Positive Response

Electronic positive response is an electronic response provided to the regional notification center (DigAlert and USA North) that informs the excavator, prior to their excavation date, if the facility has been marked or if there is no conflict with the proposed excavation. Utilizing electronic positive response is applicable to all areas within SoCalGas' territory. All excavations utilizing electronic positive response poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

SoCalGas is required to locate and mark its underground infrastructure within two days of receiving an 811 USA locate and mark ticket request. Implementing a positive response feature with the regional notification centers, such as USA North and DigAlert, improves communication between SoCalGas and excavating contractors. The system will inform the contractor that the utility has completed their task or, alternatively, will inform them if no gas infrastructure is in conflict with their excavation activities. The effort also provides a means to communicate stand-by requirements or if the locate task was not able to be completed due to weather or accessibility issues.

This program requires participation from contractors and SoCalGas. It will avoid the potential of damage to gas infrastructure due to miscommunication between the contractors and SoCalGas. This is especially important in situations where the utility was not able to provide markings within the required timeframe, but the contractor assumes no markings means no gas infrastructure. When there are no markings, the contractor may not employ safe digging procedures resulting in a hit to gas infrastructure.

b. Elements of the Bow Tie Addressed

SCG-6-M4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of tickets will have electronic positive response available.
Effectiveness	This mitigation improves communication but has a marginal impact on excavator behavior, therefore the effectiveness is assumed to be 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 2% of the causes (2% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.02%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2965.5460**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.25	**936.14**	1332.63
	RSE	0.46	**0.62**	0.89

24. SCG-6-M5 – Enhance Process to Leverage Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

Vacuum excavation technology is an example of a hydro excavation tool that can be deployed to find the location of buried company facilities when a locator is not getting an indication of where the facility is located. Technology such as this has proven itself in the damage prevention industry as a safe alternative to hand tools to prevent damage when unknown buried facilities are encountered. Vacuum excavation is utilized on an as-needed, case-by-case basis during Locate and Mark activities or in a more programmatic way by first identifying areas that are known to be hard to locate. Vacuum excavation is applicable to all areas within SoCalGas' territory. All excavations utilizing vacuum excavation technology pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SoCalGas will work with the requesting contractor to help fulfill their request without creating an unsafe situation. SoCalGas will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Using locating tools that can provide the actual location of gas infrastructure by safely exposing the pipe will provide the most accurate location of the gas infrastructure. With this knowledge, the contractor is aware of when to employ safe digging techniques and company records can be updated with the actual piping location. Both of these benefits will work toward reducing the potential for damage to underground piping for the current project and future projects.

b. Elements of the Bow Tie Addressed

SCG-6-M5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 15% of targeted locations will be assisted with emerging excavation technology.
Effectiveness	Effectiveness is high and assumed to be 95%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 9% of the causes (9% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 1.3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2928.3690**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	689.50	**924.40**	1315.92
	RSE	7.85	**10.53**	14.99

25. SCG-6-M6 – Promote Process and System Improvements in 811 USA Ticket Routing and Monitoring

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

As part of continuous improvement, an assessment of the current state of the 811 USA one-call ticket routing and monitoring is underway. The primary focus of system improvements to the USA ticket routing and monitoring will be to upgrade the ticket management system to provide increased abilities to monitor and manage locate and mark ticket requests and to evaluate and measure performance on meeting timing commitments. In calendar year 2018, SoCalGas fulfilled over 720,000 USA ticket requests from excavators for its distribution system which is nearly all medium pressure.

SoCalGas has a time requirement to fulfill locate and mark ticket requests. If these time requirements are not met, contractors might assume that no marks mean there are no underground facilities in conflict with their project, and they might start their excavation processes. If this occurs, contractors could hit and damage underground gas infrastructure due to the lack of surface markings. By providing enhanced capabilities to monitor and manage ticket request workload, SoCalGas will have the potential to be better able to prioritize ticket requests, assign crews, and balance workload among the locate and mark crews. Additionally, the data capture and reporting enhancements can improve SoCalGas' ability to monitor its own processes and identify process improvements. These enhancements work toward improving SoCalGas' performance in meeting the locate and mark timeframe, thereby reducing the potential of contractors digging without knowledge of underground gas infrastructure.

b. Elements of the Bow Tie Addressed

SCG-6-M6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Improvement of up to 15%. This mitigation is closely tied to the Damage Prevention Analysts program.

Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
Pre-Mitigation	**CoRE**	0.24	**0.32**	0.45
Pre-Mitigation	**Risk Score**	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2960.8575**	
Post-Mitigation	**CoRE**	0.24	**0.32**	0.45
Post-Mitigation	**Risk Score**	697.14	**934.66**	1330.52
Post-Mitigation	**RSE**	3.04	**4.07**	5.79

26. SCG-6-M7 – Leverage Data Gathered by Locating Equipment

The current locating equipment has the availability has the capability of recording all information from a locate. This information could be used to assess the quality of each locate and the relative accuracy of pipe location in the GIS system. By having a quality measurement for each locate the company can further determine areas that need improvement. The data gathered by leveraging locating equipment will be used to evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Leveraging Data Gathered by Locating Equipment Program is to utilize technology to improve the speed with which SoCalGas mapping and asset records are updated and improve the accuracy of the resulting locate and mark activities. It provides the locate and mark workforce with the tools and technology to facilitate the ability to update Company records by capturing location coordinates found in the field, which can then be used to evaluate against existing company records to identify any mapping, records, or locating errors.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Using equipment with the latest technology assists in locating the infrastructure more accurately by providing specific location coordinates to the company's GIS system for updated records. Accurate mapping and company records on its facilities improves the accuracy of future locate and mark activities thereby providing excavators with an improved vision of underground piping.

b. Elements of the Bow Tie Addressed

SCG-6-M7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	A 25% scope is used as a middle ground (between 13% for damages on mains and 40% for damages from backhoes).
Effectiveness	Assume marginal effectiveness of 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	LoRE		**2965.9978**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
	RSE	0.01	**0.02**	0.02

27. SCG-6-M8 – Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)

Warning mesh is a Mitigation against those excavators that do not adhere to the 811 USA excavation safety notification requirement. Approximately 60% of company damages are caused by excavators not contacting 811 USA before they dig. Warning mesh would be installed when any new open trench company facility is installed before backfilling. This program is applicable to all SoCalGas open trench buried new company facilities. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The purpose of installing warning mesh above underground gas pipelines is to provide a visual warning to excavators who have not called 811 USA of the existence of gas infrastructure. Warning mesh will be installed in all open trench applications in new construction.

The warning mesh is a visual indicator that can be exposed before the excavator damages the underlying gas infrastructure and can help to address other shortcomings in the mark and locate and safe digging process by both the utility and the excavator. It can serve as a reminder to the excavator to apply hand-digging techniques, it can act as a correction for inaccurate surface locate markings, and it could serve as a warning to an excavator who did not call to have underground facilities marked.

b. Elements of the Bow Tie Addressed

SCG-6-M8 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Used mesh procured with the proposed funding to arrive at the scope percentage (0.04%).
Effectiveness	Assuming 50% effectiveness since large machines can still cause damage.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 25% of the causes (25% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
Pre-Mitigation	**CoRE**	0.24	**0.32**	0.45
Pre-Mitigation	**Risk Score**	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2965.8383**	
Post-Mitigation	**CoRE**	0.24	**0.32**	0.45

	Risk Score	698.32	**936.23**	1332.76
	RSE	16.99	**22.78**	32.42

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SoCalGas evaluated the constraints and challenges for the Risk Mitigation Plan. Third Party Excavation Damage continues to be a difficult risk to manage due to several factors. However, according to the California Government Code, if an 811 USA ticket is requested there is an over 99% chance that there will not be damage to one of SoCalGas' pipelines.[42] One of the primary challenges faced in minimizing this risk is the actions by third party contractors and the requesting of 811 USA tickets. The requesting of a ticket allows SoCalGas to locate and mark the natural gas underground facilities within the delineated area. SoCalGas experiences a majority of the damages under this risk on small plastic lines within private property. When homeowners excavate and perform work that does not require a work permit (sprinklers, landscaping, etc.) there is no requirement by state law to request an 811 USA ticket. In addition, both licensed and unlicensed, inexperienced, or negligent contractors doing work for homeowners may not pull a work permit nor consider the activities they are performing as excavation in nature (installing a fence, electrical ground rods, pouring a driveway, etc.). Another source of damage is due to excavators who do not practice safe excavation procedures even when they have a valid 811 USA ticket. Affecting positive behavioral changes to these stakeholder groups remains a significant challenge to driving down third party excavation damages. To remain a leader in damage prevention, new technologies and strategies must continue to be evaluated to determine how they complement the existing portfolio of mitigation measures.

Below ground utility infrastructure can be challenging to locate. It requires a trained and seasoned workforce, use of sophisticated electronic equipment, and access and use of online GIS,

[42] Common Ground Alliance August 11, 2015 Press Release, *available at* https://commongroundalliance.com/sites/default/files/press_release_pdfs/2014%20DIRT%20Report%20Press%20Release%20FINAL.pdf

mapping, and historical installation information to accurately identify locations. Throughout the years, due to growth and modernization, the density of underground utilities within rights-of-way has increased significantly. This in turn can lead to increased difficulty in locating individual facilities due to locating signal interference from adjacent infrastructure. Techniques learned over the years by seasoned locators are invaluable when faced with hard to locate areas.

Additionally, implementing, operating, and maintaining a mitigation such as an 811 USA ticket risk assessment tool assumes that the algorithm will properly identify the riskiest evacuations and operators. The Company has to rely on legacy software programs and continuously perform updates to it in order to maintain the 811 USA ticket risk assessment tool. Computer hardware improvements are made to allow for the use of the software and to collect additional data and photographic documentation of the site with utility markings. Additional challenges on the locate and mark program are the occasions when tickets fail to be transmitted through the mobile data terminal (MDT) due to limited/no wireless service. This may lead the excavator to start their work prior to the utility properly delineating the under-ground substructures.

The plan was compiled using SoCalGas' current capabilities for evaluating and prioritizing mitigation measures. SoCalGas has made its best effort to identify the drivers and consequences associated with each risk with the understanding that, over time, impacting factors may change and require adjustments to the plan. If any of the Mitigations become mandated at a later date, cost and resource projects could also change.

Table 8 provides a summary of the Risk Mitigation Plan, including Controls and Mitigations activities, associated costs, and the RSEs by tranche.

SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 8 were estimated using assumptions provided by SMEs and available accounting data.

Table 8: Risk Mitigation Plan Summary[43]

(Direct 2018 $000)[44]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[45]	2018 Baseline O&M	2020-2022 Capital[46]	2022 O&M	Total[47]	RSE[48]
SCG-6-C1	Locate and Mark Training	T1	0	140	0	640 – 760	640 – 760	-
SCG-6-C2	Locate and Mark Activities	T1	0	17,000	0	21,000 – 26,000	21,000 – 26,000	-
SCG-6-C3	Locate and Mark Annual Refresher Training and Competency Program	T1	0	95	0	350 – 520	350 – 520	-

43 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

44 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

45 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

46 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

47 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

48 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[45]	2018 Baseline O&M	2020-2022 Capital[46]	2022 O&M	Total[47]	RSE[48]
SCG-6-C4	Locate and Mark Operator Qualification	T1	0	100	0	120 – 210	120 – 210	-
SCG-6-C5	Locate and Mark Quality Assurance Program	T1	0	110	0	210 – 320	210 – 320	9.14-17.45
SCG-6-C6	Damage Prevention Analyst Program	T1	0	490	0	870 – 1,100	870 – 1,100	44.59-85.10
SCG-6-C7	Prevention and Improvements - Refreshed Laptops	T1	0	25	2,800 – 3,200	380 – 850	3,200 – 4,100	0.41-0.77
SCG-6-C8-T1	Public Awareness Compliance - The Affected Public	T1	0	230	0	460 – 810	460 – 810	4.24-8.10
SCG-6-C8-T2	Public Awareness Compliance - Emergency Officials	T2	0	23	0	46 – 81	46 – 81	1.32-2.51
SCG-6-C8-T3	Public Awareness Compliance - Local Public Officials	T3	0	70	0	140 - 250	140 – 250	2.81-5.37
SCG-6-C8-T4	Public Awareness- Compliance - Excavators	T4	0	140	0	280 – 490	280 – 490	12.66-24.16
SCG-6-C9	Increase Reporting of Unsafe Excavation	T1	0	110	0	110 – 130	110 – 130	8.41-16.05
SCG-6-C10	Public Awareness- Secure Greater Enforcement through Legislation and Dig Safe Board	T1	0	1	0	1 – 27	1 – 27	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[45]	2018 Baseline O&M	2020-2022 Capital[46]	2022 O&M	Total[47]	RSE[48]
SCG-6-C11	Public Awareness- Meet with Cities with Highest Damage Rates	T1	0	3	0	150 – 290	150 – 290	0.67-1.28
SCG-6-C12	Public Awareness- Remain Active Members of the California Regional Common Ground Alliance	T1	0	22	0	22 – 88	22 – 88	2.14-4.08
SCG-6-C13	Continue to Participate in the Gold Shovel Standard Program	T1	0	2	0	2 – 3	2 – 3	-
SCG-6-C14	Locating Equipment	T1	0	40	0	44 – 470	44 – 470	-
SCG-6-C15	Remain Active Members of the California 811 One-Call Centers	T1	0	740	0	1,300 – 1,700	1,300 – 1,700	-
SCG-6-M1	Automate Third Party Excavation Reporting	T1	0	0	3,000 – 9,000	0	3,000 – 9,000	0.02-0.04
SCG-6-M2	Establish a program to address the area of continual excavation	T1	0	0	0	12 – 30	12 – 30	40.94-78.14
SCG-6-M3	Recording photographs for each locate and mark ticket visited by locator	T1	0	0	0	1,100 – 2,300	1,100 – 2,300	0.26-0.50
SCG-6-M4	Utilize electronic positive response	T1	0	0	0	100 – 250	100 – 250	0.46-0.89

ID	Mitigation/Control	Tranche	2018 Baseline Capital[45]	2018 Baseline O&M	2020-2022 Capital[46]	2022 O&M	Total[47]	RSE[48]
SCG-6-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	T1	0	0	0	2,000 – 3,000	2,000 – 3,000	7.85-14.99
SCG-6-M6	Promote process and system improvements in USA ticket routing and monitoring	T1	0	0	0	340 – 430	340 – 430	3.04-5.79
SCG-6-M7	Leverage data gathered by locating equipment	T1	0	0	0	170 – 220	170 – 220	0.01-0.02
SCG-6-M8	Install warning mesh above buried company facilities (open trench new facilities only)	T1	0	0	0	51-64	51-64	16.99-32.42
	TOTAL COST		**0**	**19,000**	**5,800 – 12,000**	**30,000 – 40,000**	**36,000 - 53,000**	

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SoCalGas also notes that there are activities related to the Third Party Dig-in on a Medium Pressure Pipeline risk that will be carried over to the GRC for which the costs are primarily internal labor (e.g., various training). The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not track labor in this manner.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 9: Summary of RSE Exclusions

Control ID	Control Name	Reason for no RSE Calculation
SCG-6-C1	Locate and Mark Training	Mandated compliance activity per CFR Part 192/GO 112-F
SCG-6-C2	Locate and Mark Activities	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SCG-6-C3	Locate and Mark Annual Refresher Training and Competency Program	Mandated compliance activity per CFR Part 192/GO 112-F
SCG-6-C4	Locate and Mark Operator Qualification	Mandated compliance activity per CFR Part 192 Subpart N
SCG-6-C10	Public Awareness-Secure Greater Enforcement through Legislation and Dig Safe Board	Dig Safe Act of 2016 and is included in California's Government Code (GC) 4216.12
SCG-6-C13	Continue to Participate in the Gold Shovel Standard Program	Mandated compliance activity per California Government Code 4216
SCG-6-C14	Locating Equipment	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SCG-6-C15	Remain Active Members of the California 811 One-Call Centers	Mandated compliance activity per CFR Part 192.614. California Government Code 4216

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the Mitigations for the Third Party Dig-in on a Medium Pressure Pipeline risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SCG-7-A1 – Virtual Reality Training / Simulation to Improve Locator Proficiency

The virtual reality Locate and Mark training simulator provides a portable and scenario-based training system. It allows for instructors to simulate a variety of real-world locate and mark scenarios. Virtual reality provides more flexibility in training curriculum and allows for more focused educational opportunities. More research is needed to identify system requirements and standardization scores and identify impacts to existing locate equipment and performance management software.

Scope	Assuming 100% of locations would receive UTTO Virtual Reality Training Tools.
Effectiveness	Per internal SME assessment, utilizing UTTO Virtual Reality Locator Training Tools will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 6%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0006%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2965.9824**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.35	**936.28**	1332.82
	RSE	0.15	**0.20**	0.29

B. SCG-7-A2 – GPS Tracking of Excavation Equipment

SoCalGas has supported the Gas Technology Institute (GTI) and other research organizations in their efforts to help the industry improve damage prevention practices. Past and ongoing efforts included real-time GPS tracking of excavation equipment operating in pipeline rights-of-way and quick-shut breakaway meter set valves.

Real-time tracking of excavation is done using a "black box" attached to the excavation equipment such as a backhoe, grader, etc. The black box monitors the location of the equipment and can sense when the equipment is getting ready to dig. There is sophisticated software that monitors the GPS data in relation to its proximity to spatial pipe locations. If the box is detected near a company asset, then an alarm is triggered on the equipment alerting the equipment operator that there is a pipeline in the area. There is also an alert that is sent to the Company, so action may be taken to investigate the location.

The technology is not being pursued at this time since it gave too many false positives. There is more work that needs to be completed and testing done before the device is ready for production.

Scope	A middle ground of 25% of available opportunities will be used as the scope for GPS tracking.
Effectiveness	Per internal SME assessment, utilizing GPS tracking of excavation equipment will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 3%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0001%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**2966.000**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
Post-Mitigation	**LoRE**		**2965.9978**	
	CoRE	0.24	**0.32**	0.45
	Risk Score	698.36	**936.28**	1332.83
	RSE	0.01	**0.01**	0.01

Table 10: Alternative Mitigation Summary

(Direct 2018 $000)[49]

ID	Mitigation	2020-2022 Capital[50]	2022 O&M	Total[51]	RSE[52]
SCG-6-A1:	Virtual reality training / simulation to improve locator proficiency	0	100-120	100 – 120	0.15-0.29
SCG-6-A2:	GPS Tracking of Excavation Equipment	0	240 – 390	240 – 390	0.01

49 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

50 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

51 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

52 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SCG-6-C1	Locate and Mark Training	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C2	Locate and Mark Activities	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C3	Locate and Mark Annual Refresher Training and Competency Program	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C4	Locate and Mark Operator Qualification	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C5	Locate and Mark Quality Assurance Program	DT.2; DT.4; DT.5; DT.6; PC.1; PC.2; PC.4; PC.5; PC.6
SCG-6-C6	Damage Prevention Analyst Program	DT.1; DT.2; DT.4 PC.1; PC.2; PC.4; PC.5; PC.6
SCG-6-C7	Prevention and Improvements-Refreshed Laptops	DT.2; DT.3; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C8	Public Awareness Compliance	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C9	Increase Reporting of Unsafe Excavation	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C10	Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board	DT.1; DT.2; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C11	Public Awareness-Meet with the Cities with the Highest Damage Rates	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance	DT.1; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C13	Continue to Participate in the Gold Shovel Standard Program	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-C14	Locating Equipment	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SCG-6-C15	Remain Active Members of the California 811 One-Call Centers	DT.1; DT.2; DT.3; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M1	Automate Third Party Excavation Incident Reporting	DT.2; DT.4; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M2	Establish a Program to Address the Area of Continual Excavation	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M3	Recording Photographs for Each Locate & Mark Ticket Visited by Locator	DT.2; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M4	Utilize Electronic Positive Response	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	DT.2; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M6	Promote Process and System Improvements in USA Ticket Routing and Monitoring	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-6-M7	Leverage Data Gathered by Locating Equipment	DT.2; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M8	Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

Risk Assessment Mitigation Phase

(Chapter SCG-7)

Third Party Dig-in on a High Pressure Pipeline

November 27, 2019

SoCalGas
A Sempra Energy utility

TABLE OF CONTENTS

Risk: Third Party Dig-in on a High Pressure Pipeline

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas or Company) Third Party Dig-in on a High Pressure Pipeline risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, (and the Settlement Agreement included therein (the SA Decision). [1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and are within the scope of the analysis required in this RAMP Report. Throughout

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (SMAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC).

this TY 2022 RAMP Report activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SoCalGas' Third Party Dig-in on a Medium Pressure Pipeline risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order (GO). Activities with no RSE score presented in this TY 2022 RAMP Report are identified in Section VII below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable Control/Mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

SoCalGas and San Diego Gas & Electric Company (SDG&E), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' third party dig-in related chapters.[3]

A. Risk Definition

For purposes of this TY 2022 RAMP Report, the Third Party Dig-in on a High Pressure Pipeline risk is defined as a dig-in on a high pressure pipeline [Maximum Allowable Operating (MAOP) greater than 60 pounds per square inch gauge (psig)] caused by third party activities which results in significant consequences including serious injuries and/or fatalities.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each Control and Mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the Control or Mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation
DT.2	Locator error contributing to the incorrect marking of underground gas structures
DT.3	Hand excavation is not performed by excavator in the vicinity of located gas pipelines
DT.4	Company does not respond to 811 requests in required timeframe
DT.5	Company does not "standby" when third party excavates near gas pipelines

3 The other third party dig-in related chapters in the 2019 RAMP Report include: SCG-6 – Third Party Dig-in on a Medium Pressure Pipeline; SDG&E-7 – Third Party Dig-in on a Medium Pressure Pipeline; and SDG&E-9 – Third Party Dig-in on a High-Pressure Pipeline.

4 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

DT.6	Contractor fails to contact company "standby" personnel
DT.7	Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark
DT.8	Incorrect/inadequate information in existing asset records leading to incorrect locate and mark
PC.1	Serious Injuries and/or Fatalities
PC.2	Property Damage
PC.3	Prolonged Outages
PC.4	Penalties and Fines
PC.5	Adverse Litigation
PC.6	Erosion of Public Confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SoCalGas has performed a detailed pre- and post-mitigation analysis of Controls and Mitigations for each risk selected for inclusion in RAMP, as further described below. SoCalGas' baseline Controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-7-C1	Locate and Mark Training
SCG-7-C2	Locate and Mark Activities
SCG-7-C3	Locate and Mark Annual Refresher Training and Competency Program
SCG-7-C4	Locate and Mark Operator Qualification
SCG-7-C5	Locate and Mark Quality Assurance Program
SCG-7-C6	Damage Prevention Analyst Program
SCG-7-C7	Prevention and Improvements-Refreshed Laptops
SCG-7-C8	Public Awareness Compliance
SCG-7-C9	Increase Reporting of Unsafe Excavation
SCG-7-C10	Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board

5 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

ID	Control Name
SCG-7-C11	Public Awareness-Meet with the Cities with the Highest Damage Rates
SCG-7-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance
SCG-7-C13	Continue to Participate in the Gold Shovel Standard Program
SCG-7-C14	Locating Equipment
SCG-7-C15	Remain Active Members of the 811 California One-Call Centers
SCG-7-C16	Install warning mesh above buried company facilities
SCG-7-C17	Prevention and Improvements-Fiber Optics

SoCalGas will continue the baseline Controls identified above and describes additional projects and/or programs (*i.e.*, Mitigations) as follows:

ID	Mitigation Name
SCG-7-M1	Automate Third Party Excavation Incident Reporting
SCG-7-M2	Establish A Program To Address The Area Of Continual Excavation
SCG-7-M3	Recording Photographs For Each Locate & Mark Ticket Visited By Locator
SCG-7-M4	Utilize Electronic Positive Response
SCG-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)
SCG-7-M6	Promote Process and System Improvements in USA Ticket Routing and Monitoring
SCG-7-M7	Leverage Data Gathered by Locating Equipment

Finally, pursuant to the SA Decision,[6] SoCalGas presents considered alternatives to the mitigation plan and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VIII.

---

6 *Id.* at 33.

II. RISK OVERVIEW

SoCalGas operates and manages a natural gas system of over 100,000 miles of Distribution pipe and 3,485 miles of Transmission pipe within its 22,000 square mile service territory. This large piping network, and large service territory exposes the Company to potential dig-in related issues. This risk is focused on the more serious results of third party damage that lead to a release of natural gas with the possibility of hazard to life and property.

Excavation damage, or dig-ins, to high pressure underground gas infrastructure have been a risk to SoCalGas for as long as pipe has been buried underground. This risk is not a risk unique to the Company. Third-party dig-ins are a common national problem for all industries and utilities with buried infrastructure. These "third-party" excavation activities can vary widely based on project scope and size. Examples can include a construction firm widening a freeway, a farmer working their land, or a city upgrading its aging municipal water or sewer systems. Third-party dig-ins, while always a concern, are especially dangerous when they involve a high pressure pipeline because the third party activity can damage or weaken the pipeline resulting in a leak, pipeline burst, or gas explosion. Thus, although this is a low occurrence event given, in part, the location of high pressure pipelines, it's a high consequence risk.

Third-party excavation damage can range from minor scratches or dents, to ruptures with an uncontrolled release of natural gas. The release of natural gas may not just occur at the time of the damage. A leak or rupture may also occur after the infrastructure has sustained more minor damage, but then becomes weakened over time. Once damaged, the responsible party may not report non-gas release damages, bypassing the effort of the Company to assess and make the appropriate repairs before a weakening of the pipe occurs.

Serious consequences may result if an event occurs because of this risk. For example, if a leak or rupture occurs, an ignition of the released gas could lead to an explosion, fire or both. The nearby public could be seriously injured, and property damage can be extensive.

Federal and state agencies have responded to this risk by adopting numerous regulations and industry standards[7] and have promoted other efforts[8] to help prevent third-party dig-ins. For example, the Department of Transportation (DOT) sponsored the "Common Ground Study," completed in 1999. The "Common Ground Study" then led to the creation of the Common Ground Alliance (CGA), a member-driven association of 1,700 individuals, organizations, and sponsors in every facet of the underground utility industry. With industry-wide support, CGA created a comprehensive consensus document that details the best practices addressing every stake-holder groups' activity in promoting safe excavation and preventing dig-in damages.

Under California State Law[9], a third-party planning excavation work is required to contact the Regional Notification Center for their area, also known as 811 or Underground Service Alert (USA), at least two (2) full working days prior to the start of their construction excavation activities, not including the day of the notification. Eight-One-One (811) is the national phone number designated by the Federal Communications Commission (FCC), that connects homeowners who plan to dig with professionals through a local call center. The call center collects information about the planned dig site and communicates with the appropriate utility companies, which then sends professional utility locating technicians to identify and mark the approximate location of lines. Once utility lines have been marked, the resident or contractor may dig safely around the marks once the legal start date and time arrives. California has two Regional Notification Centers, DigAlert and USA North, that split California at the Los Angeles/ Kern county and Santa Barbara/San Luis Obispo county lines; USA North serves all counties north of the county lines and DigAlert serves all counties south of the county lines. DigAlert and USA North will be referenced as 811 USA for the remainder of this chapter. Once a third-party

7 49 Code Fed. Reg. (CFR) § 192, *et. seq.*; *id.* at § 196; Cal. Govt. Code § 4216; CPUC General Order (GO) 112-F; American Petroleum Institute (API) Recommended Practice (RP) 1162.

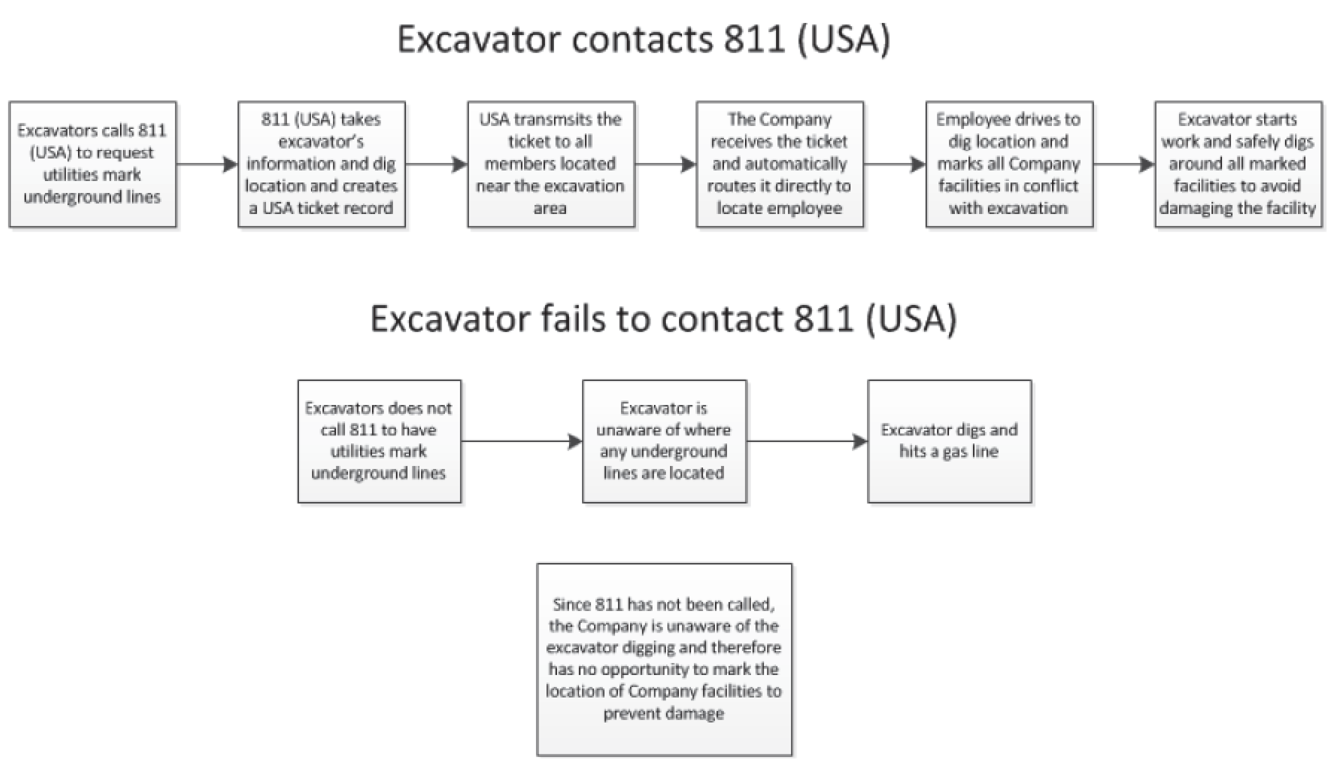
8 Common Ground Alliance (CGA), *Best Practices Guide* (March 2019), *available at* https://commongroundalliance.com/best-practices-guide.

9 Cal. Govt. Code § 4216.2(b).

makes the contact, the Regional Notification Center will issue an 811 USA Ticket notifying local utilities and other operators of the location and areas to be inspected for potential conflicts of underground infrastructure with the pending excavation work. Operators are required to provide a positive response to indicate that there are no facilities in conflict or mark their underground facilities via aboveground identifiers (e.g. paint, chalk, flags, whiskers) to designate where underground utilities are positioned, thus enabling third parties, like contractors and homeowners, to know where these substructures are located. The law also requires third-party excavators to use careful, manual (hand digging) methods to expose substructures prior to using mechanical excavation tools.

Figure 1 below illustrates the sequence of events that may occur when a third-party contacts 811 USA prior to conducting excavation work and, in contrast, the sequence that may occur when they do not.

Figure 1 : Excavation Contact Process Flow



As can be seen in the figure above, while there may be more steps when a third-party calls 811 USA prior to commencing the excavation work, it is more likely to result in a positive outcome compared to when a call is not made. When third-parties call 811 USA before excavating, the risk of a dig-in is significantly reduced.

SoCalGas managed over 841,000 811 USA tickets and reported over 3,000 dig-in excavation damage incidents in 2018, most of them associated with medium pressure pipelines. Further analysis of the reported damages shows that 60% were due to a lack of notification to an 811 USA California One-Call-Center for a locate and mark ticket and 28% were due to inadequate excavation practices even after the excavator obtained a one call ticket.[10]

In addition to the direct involvement with excavators and 811 USA, SoCalGas engages in promoting safe digging practices through its Public Awareness Program[11] and corporate safety messaging through stakeholder outreach. The message is presented by way of multi-formatted educational materials through mail, email, social media, television, radio, events, and association sponsorships. This Control is further described in Section V.

III. RISK ASSESSMENT

In accordance with the SA Decision,[12] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Third Party Dig-in on a High Pressure Pipeline risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 2 below is a commonly-used tool for risk analysis. The left side of the bow tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

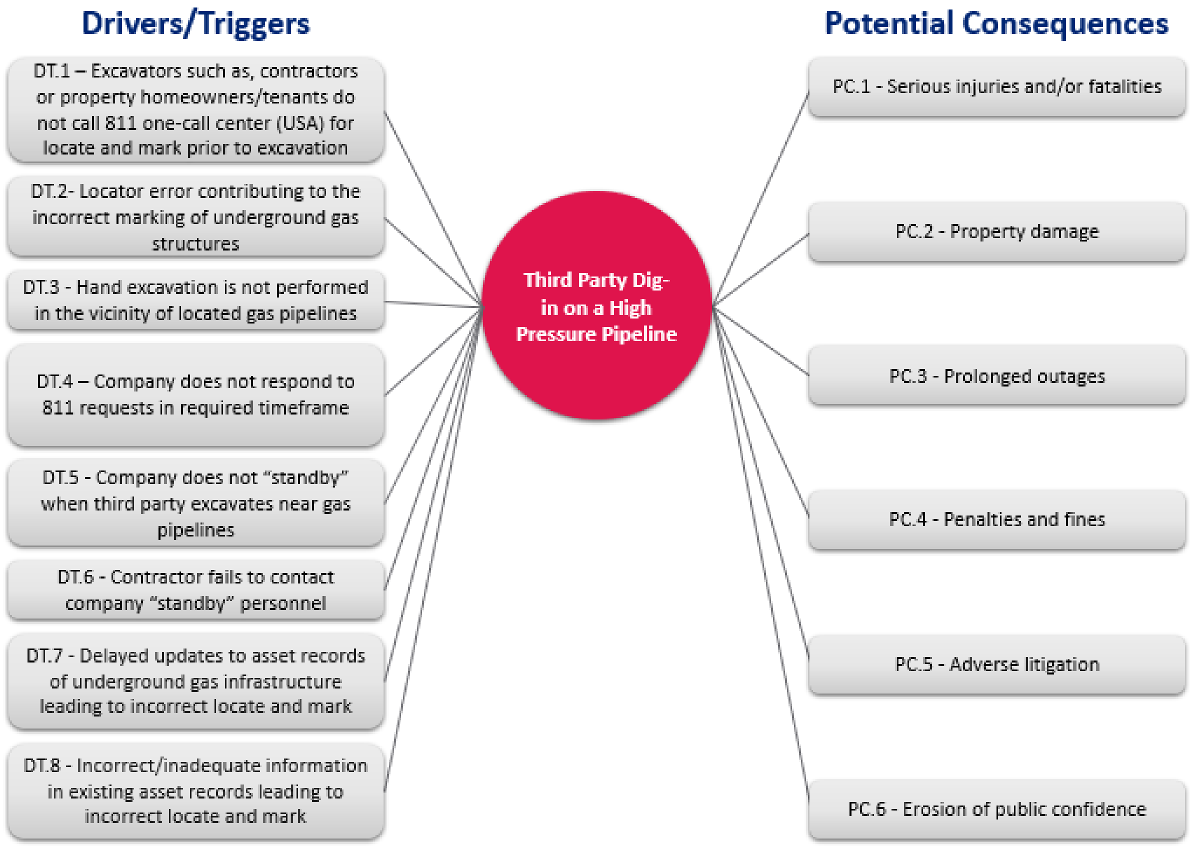
---

10 Common Ground Alliance, *CGA Released 2018 Damage Information Reporting Tool (DIRT) Report*, *available at* https://commongroundalliance.com/DIRT.

11 API RP 1162.

12 D.18-12-014 at Attachment A, A-11 (“Bow Tie”).

Figure 2: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[13] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. These assets include:

- Natural Gas Pipeline Distribution System - SoCalGas' medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and its appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of

13 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines by definition; however, these assets are operated by Distribution Operations.

- Natural Gas Pipeline Transmission System - SoCalGas' high-pressure transmission pipeline system is comprised of steel pipelines and its appurtenances (e.g., meters, regulators, risers) operating over 20% of the pipeline's SMYS.

C. Risk Event Associated with the Risk

The SA Decision[14] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a third party dig-in on a medium pressure pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[15] of Risk Event

The SA Decision[16] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Third Party Dig-in on a Medium Pressure Pipeline that results in significant consequences including serious injuries and/or fatalities, SoCalGas identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT. 1 – Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation:** Despite the creation of Regional Notification Centers to inform and allow

14 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

15 An indication that a risk could occur. It does not reflect actual or threatened conditions.

16 D.18-12-014 at Attachment A, A-11 ("Bow Tie")

excavators to have underground infrastructure located and marked, and advertising campaigns alerting the excavator of the need to do so, incidents still occur where excavations are conducted without first calling 811 USA. In fact, third party failure to contact the Regional Notification Center prior to excavating is the leading contributor of damages to Company pipelines. Third parties can damage or rupture underground pipelines and potentially cause property damage, injuries, or even death if gas lines are not properly marked before excavation activities begin. Without receiving an 811 USA ticket, the Company has no opportunity to mark its facility within the area of excavation.

- **DT. 2 – Locator error contributing to the incorrect marking of underground gas structures:** The Company, in some cases, may inaccurately mark facilities due to incorrect operations, such as mapping/data inaccuracies, equipment signal interference, and human error. When this happens, third parties are not provided with accurate knowledge of underground structures in the vicinity of their excavations and the risk of damaging or rupturing gas pipelines increases.
- **DT.3 – Hand excavation is not performed in the vicinity of located gas pipelines:** Before using any power operated excavation equipment or boring equipment, the excavator is required to hand expose, using "Hand Tools" [17], to the point of no conflict 24 inches on either side of the High Pressure Gas Pipeline to determine the exact location of these structures. If excavators do not use care when digging near natural gas pipelines they put themselves and others at risk for injuries.
- **DT.4 – Company does not respond to 811 requests in required timeframe:** The Company may not respond to 811 USA requests within the "legal excavation

[17] Cal. Govt. Code § 4216(i).

start date and time"[18] (within two working days of notification, excluding weekends and state holidays, not including the date of notification, or before the start of the excavation work, whichever is later, or at a time mutually agreeable to the operator and the excavator). This may happen because of human error, poor communication, or system failures. In these cases, the third party may not know that the locate and mark activity was not performed. They, therefore, may wrongly assume that not seeing any marking at their excavation site indicates there is no gas infrastructure nearby. Without the marked gas infrastructure, third parties may damage or rupture the infrastructure if they are performing excavation activities near pipelines.

- **DT.5 – Company does not "standby" when third party excavates near gas pipelines:** High Pressure pipelines (those that operate over 60 psig) pose a higher risk of hazard to life and property when damaged or ruptured and additional precautions are taken by the Company to observe excavation activities in the vicinity of these facilities. Qualified Company personnel are required to be present during excavation activities within 10 feet of any high pressure gas line (the presence commonly referred to as "stand-by"). The stand-by presence allows for redundancy via a Company representative should the third party not follow proper protocol during the excavation (e.g., not hand excavate near the pipeline), or should the marks be determined to be inaccurate. Stand-by presence increases the excavator's awareness of all excavation requirements near the high pressure facility.
- **DT.6 – Contractor fails to contact company "standby" personnel:** An excavator may fail to contact the Utility's "standby" personnel for the prevention of damage to high pressure gas pipelines when required, prior to excavating

[18] *Id.* at § 4216(l).

within 24 inches of a high pressure gas pipeline. This would increase the risk that the excavator damages a high pressure pipeline.

- **DT.7 – Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark:** The Company may fail to supply the necessary information in a timely manner to update permanent mapping records necessary to meet federal, state, and local and regulations, as well as corporate needs. This could result in underground infrastructure being incorrectly marked. If maps are not updated in a timely manner, new mains and services may not be marked and located if an 811 USA ticket is requested. This could lead to third party damage if the excavator does not have the correct information on infrastructure location. In the event in which a pipeline is damaged, obsolete maps could cause also delays in performing the necessary repairs.
- **DT.8 – Incorrect/inadequate information in existing asset records leading to incorrect locate and mark:** The use of inaccurate or incomplete information in asset records could result in the failure to (1) construct, operate, and maintain SoCalGas' pipeline system safely and prudently; or, (2) to satisfy regulatory compliance requirements. This could result in underground infrastructure being incorrectly marked. If maps are incorrect or inadequate, new mains and services may not be marked and located if an 811 USA ticket is requested. This could lead to third party damage if the excavator does not have the correct information on infrastructure location. In the event in which a pipeline is damaged, incorrect or inadequate maps could also cause delays in performing the necessary repairs.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[19] and/or fatalities;
- Property damage;
- Prolonged outages;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of SoCalGas' Third Party Dig-in on a High Pressure Pipeline Risk that occurred during the development of SoCalGas' 2018 ERR.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[20] including enhancements to the Interim Decision 16-08-018. SoCalGas has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

19 As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." *See* 8 CCR § 330(h).

20 D.18-12-014 at Attachment A.

Table 4: Risk Quantification Scores[21]

Third Party Dig-in on a High Pressure Pipeline	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	9	**78**	194
LoRE		**3**	
CoRE	3	**24**	60

A. Risk Scope &Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[22] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification	The risk of a dig-in on a high pressure pipeline (MAOP greater than 60 psig) caused by third party activities, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification	The risk of pipeline event unrelated to a third-party dig-in on a high pressure pipeline (MAOP greater than 60 psig) which results in consequences such as injuries or fatalities or outages.

21 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score"), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

22 *Id.* at Attachment A, A-11 ("Calculation of Risk").

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, as well as available and appropriate data (e.g., Pipeline and Hazardous Materials Safety Administration data)..[23]

Historical Pipeline and Hazardous Materials Safety Administration (PHMSA) data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SoCalGas, the national average incident rate per mile per year was applied to the high-pressure pipeline miles at SoCalGas.

The safety risk assessment primarily utilized data from PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA high-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, a Monte Carlo simulation was performed to understand the range of possible consequences.

B. Sources of Input

The SA Decision[24] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
    - Agency: PHMSA
    - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Link: Annual Report mileage for Gas Distribution Systems
    - Agency: PHMSA

[23] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

[24] *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems

- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: PHMSA
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SoCalGas high-pressure pipeline miles
  - 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Links: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SoCalGas end user natural gas customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
  - Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[25] This section describes SoCalGas' Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SoCalGas' Third Party Dig-in on a High Pressure Pipeline Risk involves impact to gas infrastructure arising from third party dig-ins resulting in significant consequences

[25] D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC).

including serious injuries and/or fatalities. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SoCalGas' Test Year 2022 General Rate Case (GRC) cycle. The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time. The Company's Mitigations, addressed below, aim to further reduce the frequency of dig-ins on high pressure pipelines.

A. SCG-7-C1 – Locate and Mark Training

This program provides employees with the training tools to perform activities associated with locate and mark. Adequately preparing employees by offering educational opportunities and resources gives them the knowledge to implement government and Company policies and procedures in a safe manner. This, in turn, helps SoCalGas operate and maintain its system, as well as protect employees, contractors, and the public from the threat of an event attributable to this risk.

Locate and Mark Training consists of approximately seven days of classroom and hands-on training at a centralized training facility, as well as eLearning. SoCalGas will continue to implement a competency-based training program that will encompass training on any policy or procedural changes impacting third-party dig-ins. A competency based online/video training module system enhances SoCalGas' ability to incorporate new policies and increases learning at a faster pace. This system uses a comprehensive, multimedia, competency-based training approach which will include self-paced, individualized, modular instruction, eLearning, just-in-time training, structured on-the-job training, and mentoring. This is a mandated activity in order to comply with Operator Qualification requirements and to provide the basic knowledge necessary to satisfactorily perform this critical task. The training schedule is dependent on annual demand, but occurs, on average, about every two months.

The training provides the participating employees several key components of locating, enabling them to locate and mark the below ground facilities accurately and in the appropriate time frame. The marked facilities provide the excavator with approximate locations of where the gas lines exist in the work area which enables the excavator to either avoid the areas or dig with hand tools so underground substructures are not accidentally damaged by the excavation work.

B. SCG-7-C2 – Locate and Mark Activities

This Control is comprised of three activities that are related to performing or supporting locate and mark work: (1) Locate and Mark, (2) Pipeline Observation (stand-by), and (3) Staff Support. Verifying that SoCalGas is executing such tasks safely can reduce the potential of an event occurring.

The first activity is Locate and Mark, which is the actual work performed by SoCalGas gas operations which is required to respond to over 800,000 811 USA notifications per year. To do this activity, SoCalGas' locators travel to the job site and locate and mark any and all company operated pipelines in the delineated work area. Understanding the physical location of the pipeline allows the third-party to avoid that area or carefully perform the excavation work to avoid contact with the pipeline. This activity is mandated by both State[26] and Federal law[27]. This Control activity also includes all aspects necessary to performing the mandated locate and mark activities, including locators, vehicles, tools, Mobile Data Terminals (MDTs), Geographical Information System (GIS)-related costs, ticket routing systems, locating materials, fees to Regional Notification Centers, and quality assurance.

The second Locate and Mark activity is Pipeline Observation (stand-by). In accordance with Title 49 Code of Federal Regulation, section 192.935, Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. This activity occurs daily in both Distribution and Transmission operations. The purpose for this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having another pair

[26] Cal. Govt. Code § 4216.

[27] 49 CFR § 192.614.

of qualified eyes observing the work being done. This is a best practice in the gas industry and is critical to the safety of employees, contractors and the public.

The third activity is staff support. Support staff consists of employees who are responsible for developing and maintaining policies, processes, and procedures that guide and direct locators in properly performing their assigned tasks in compliance with Federal and State regulations. Staff is engaged daily in supporting operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, and providing refresher training as requested. This is a critical activity that allows the Company to meet or exceed State and Federal requirements and align with industry best practices when applicable.

C. SCG-7-C3 – Locate and Mark Annual Refresher Training and Competency Program

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to continue locate and mark activities. The refresher training involves all aspects of the Locate and Mark procedures to allow personnel to be able to successfully receive a ticket and provide a proper positive response. Similar to the Locate and Mark training mentioned above, refresher training will also be an interactive eLearning course, which potentially will consist of on-the-job training and mentoring. This is a mandated activity in order to comply with regulations and code requirements and to provide employees with the basic knowledge to satisfactorily perform this critical task.[28]

D. SCG-7-C4 – Locate and Mark Operator Qualification

Locate and Mark Operator Qualification (OQ) training is an enhanced training which requires pipeline operators to document that certain employees have been adequately trained to recognize and react to abnormal operating conditions that may occur while performing specific

---

[28] *See* Cal. Govt. Code § 4216.

tasks. It provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. The training demonstrates an employee's knowledge and competency to perform locate and mark activities and it is mandated by PHMSA.[29] Employing resources that are formally trained to be aware and react to unusual pipeline conditions allows SoCalGas to potentially protect against an adverse event before its occurrence. Locators are qualified at the end of training and then every five years. This certification is an industry standard qualification program.

E. SCG-7-C5 – Locate and Mark Quality Assurance Program

The Locate and Mark quality assurance audit program reviews work activity to determine whether proper processes and procedures are being met. This includes, but is not limited to, employee qualification, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and markings, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations.

SoCalGas has developed guidelines for quality assessments of locate and mark activities. The Gas Compliance Quality Management (GCQM) team conducts the re-occurring assessments of all districts (or bases) in order to provide an independent check of processes and to verify that applicable documentation is accurate and complete. The assessments include equipment testing, documentation reviews, field checks, and operator qualification reviews. After the assessment is complete, the GCQM will review findings with base management and gas distribution operations. Base management acknowledges the final report and develops plans for corrective actions, which are provided to GCQM. Findings are tracked, recorded, and monitored by base supervision.

Adherence to proper company policy and procedures reduces the percentage of locate and mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

---

[29] 49 CFR § 192.801, *et seq.*

F. SCG-7-C6 - Damage Prevention Analyst Program

SoCalGas' Damage Prevention Analysts work to reduce the number of third-party excavation incidents in cities and jurisdictions with the highest number of reported occurrences by addressing the contractors and excavators operating in these jurisdictions. The intent of the SoCalGas' Damage Prevention Analyst program is to promote safe excavation practices and reduce the number of excavation damages. An important method of achieving this goal is to build and foster positive relationships with the excavator community through visibility, communication, and safe excavation education. Through this effort the desire is also for these SoCalGas employees to be viewed as a resource for contractors, to help overcome obstacles when excavating in the vicinity of underground SoCalGas infrastructure. To achieve these objectives, the Analysts are equipped with the current 811 USA ticket information and GIS/mapping information for the local pipe network. Analysts also regularly partner with SoCalGas' operating district personnel if additional infrastructure location information is needed.

The Damage Prevention Analysts prioritize their daily job site visits with the aid of ticket prioritization software. Certain construction jobs may be more prone to excavation damage than others due to specific 811 USA ticket attributes and local environmental conditions. Eight-One-One USA ticket prioritization utilizes historical damage information as well as geographic, environmental, and other publicly available information. The software weighs the pertinent attributes and performs calculations using complex algorithms to identify excavation sites that may be more susceptible to third party damage. This prioritization allows for the Company to take appropriate and timely measures to avoid damages such as making an extra phone call or email to the excavator or scheduling a pre-excavation site meeting to discuss the project in detail.

The Damage Prevention Analysts routinely visit active construction sites with known 811 USA tickets in their jurisdiction but will also look out for other active construction sites that do not appear on their 811 USA ticket listing. The purpose for visiting the latter is to make positive contact with the excavator and determine whether the supervision and workers at those projects have followed safe digging practices. If not, the Analyst explains the safety risks, law violations and potential ramifications, and asks the excavator to stop their job and contact 811 USA to get the proper underground markings. These interactions have been very successful in getting the excavator to halt further excavation work until 811 USA contact was established. Since the program's inception in 2018, the Analysts have successfully intervened and “Stopped-The-Job” at over 470 construction sites. The most common reason for “Stopping-The-Job” was due to the excavator not having an 811 USA ticket. In addition, some were due to unsafe excavation practices.

The Damage Prevention Analysts also visit with the local municipality personnel to discuss the importance of safe excavation with the Planning and Permitting departments. Gaining a safe-excavation partnership with the entities that approve, permit, and inspect excavation work is seen as an integral part of the Damage Prevention Analyst Program. During the interactions with City officials, the Analysts offer to present educational information regarding the Dig Safe laws and practices to interested parties. Since the program’s inception over 330 outreach and educational sessions have been performed by the Analysts to various contractor and city workgroups.

Another key activity that falls within the Damage Prevention Analyst job responsibilities is responding to dig-in damages. Their role is to support the Operations response team through accurate documentation of the incident and collecting all relevant information to enable accurate regulatory reporting, damage-cause trending, and appropriate cost recovery where warranted. This data is used by the Damage Prevention Strategy and Distribution Integrity Management Program teams to evaluate and trend the causes of excavation damage and pursue appropriate mitigation activities.

G. SCG-7-C7 – Prevention and Improvements-Refreshed Laptops

Locate and Mark laptops and software are utilized by SoCalGas to comply with the requirements of state and federal regulations.[30] SoCalGas provides locate and mark technicians with rugged laptops called Mobile Data Terminals (MDTs) containing KorMobile© Ticket

[30] 49 CFR § 192.614; Cal. Govt. Code § 4216.

Management Software to respond to 811 USA tickets real-time. Using obsolete technology increases wait times, contributes to data communication failure, and increases likelihood of not responding to an 811 USA request in the required timeframe.

SoCalGas has a vast service territory that covers 24,000 square miles in diverse terrain throughout Central and Southern California, from Visalia to the Mexican border. The service territory covers 12 counties, 220 incorporated cities in more than 500 communities. Providing durable refreshed laptops increases efficiency and the ability to work in a rugged outdoor setting. Increasing the processor speed and extending the battery life also allows for prolonged working hours. The refreshed laptops contain a detachable screen with a built-in camera allowing the technician to photograph their surroundings and the excavating equipment associated with an 811 USA ticket. A 4G LTE Advanced multi carrier mobile broadband facilitates the response to 811 USA tickets in real time.

H. SCG-7-C8 – Public Awareness Compliance

It is important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks and private property – sometimes just inches below the surface. Hitting one of these pipelines while digging, planting or doing demolition work can cause serious injury, property damage, and/or loss of utility service.

Under Title 49 Code of Federal Regulation, section 192.616, SoCalGas is required to educate the public, appropriate government organizations, and persons engaged in excavation related activities (1) about the use of a one-call notification system (811 USA) prior to excavation, (2) other damage prevention activities, (3) possible hazards associated with the unintended release from a gas pipeline facility, (4) physical indications of a natural gas release, (5) steps to be taken in the event of a gas pipeline release, and (6) procedures for reporting such an event. In addition to undertaking actions to meet the minimum requirements of section 192.616, SoCalGas participates, promotes, and contributes to other public awareness and excavation improvement programs. To promote public awareness of the 811 USA program

SoCalGas utilizes various communication methods such as utilized bill inserts, media campaigns, damage prevention industry memberships, sponsorships, radio advertising, internet advertising, billboard advertising, and safety meetings. The four types of audiences identified in section 192.616 are the affected public, emergency officials, local public officials, and excavators. These types of audiences make up the four tranches further described below in Section VI.

I. SCG-7-C9 – Increase Reporting of Unsafe Excavation

Senate Bill (SB) 661 modified existing California Government Code section 4216 by establishing the California Underground Facilities Safe Excavation Board (Dig Safe Board). SoCalGas has two groups involved in identifying excavators who frequently utilize unsafe practices and reporting those contactors to the appropriate state board. The Damage Prevention Strategies team informs Dig Safe Board investigators about unsafe practices SoCalGas witnesses in the field. The Claims Recovery team reports incidents to the Contractor State Licensing Board (CSLB) when it becomes aware of them through its involvement with insurance and financial considerations as a result of incidents. The Dig Safe Board is developing regulations related to reporting and SoCalGas plans to implement any new requirements.

J. SCG-7-C10 – Public Awareness – Secure Greater Enforcement through Legislation and Dig Safe Board

SoCalGas continues to actively participate in regulatory proceedings that will support the effectiveness of federal and state safe digging laws through legislation and enforcement of sanctions and penalties. SB 661 modified California Government Code, section 4216, establishing the Dig Safe Board. Sanctions and penalties should be enforced against parties not following the well-established rules requiring third parties to call 811 USA to have pipelines marked prior to excavation. SoCalGas supported California State Senate Bill SB 661 by providing proposed language to increase protection of underground substructures.

In addition, SoCalGas participates at board meetings of the Dig Safe Board, which was created by the Dig Safe Act of 2016 and is included in California's Government Code, section

4216.12, Safe Digging law. The Dig Safe Board's charter is to coordinate education and outreach activities that encourage safe excavation practice; develop standards that support safe excavation practices; investigate possible violations of section 4216; and enforce section 4216 to the extent of granted authority.

Company involvement and participation at Dig Safe Board meetings and workshops helps foster a positive working relationship with all stakeholders. These meetings and workshops provide the opportunity to raise the issues and concerns facing the Natural Gas industry and issues in regard to excavation damage prevention.

K. SCG-7-C11 – Public Awareness-Meet with Cities with Highest Damage Rates

SoCalGas Damage Prevention Analysts work to reduce the number of third party excavation incidents in cities and jurisdictions with the highest number of reported occurrences. To achieve this objective, Analysts partner with SoCalGas' operating districts management and represented personnel to identify and meet with city officials with functions and responsibilities related to construction and excavation activities in their respective jurisdictions. The effort provides outreach and education to these officials on the proper 811 USA one-call process and safe digging techniques. The officials can then pass those requirements on to the contractors operating in their cities as permits are granted or city inspectors visit job sites.

Cities have many resources and avenues for promoting and executing excavation safety within their communities. All planned work requiring a permit must start at the planning and permits department. Cities thus often have the first opportunity to educate applicants about excavation safety by providing 811 USA literature. On-site City inspectors could also potentially be tasked with patrolling and enforcing California Government Code, section 4216 compliance as part of their daily work. City inspectors hold the authority to stop any job that violates code. Cities may also consider preventing excavators from working in their boundaries if the excavator is known to cause frequent excavation violations.

L. SCG-7-C12 – Public Awareness-Remain Active Members of the California Regional Common Ground Alliance

The California Regional Common Ground Alliance (CARCGA) is a group of California-based stakeholders who are impacted by excavation activities. CARCGA is the regional group within the Common Ground Alliance (CGA). The CGA works with its membership to establish best practices for the 811 USA One-Call Centers, underground facility owners, excavators, locators, project owners, and designers. Through its Damage Prevention Strategies function, SoCalGas participates with CARCGA members to inform CGA objectives from a regional perspective.

M. SCG-7-C13 – Continue to Participate in the Gold Shovel Standard Program

SoCalGas requires construction contractors doing work on its behalf to participate in the Gold Shovel program. The program certifies an excavator's policies and procedures against the Gold Shovel Standard, a set of excavator training procedures designed to protect underground facilities. The Gold Shovel standard also publishes a rating which is an ongoing measure of an excavator's digging-safety-worthiness. This requirement serves to incentivize construction contractors to follow safe excavation laws and practices. The Gold Shovel Standard (GSS) is a nonprofit organization committed to improving workforce and public safety and the integrity of buried infrastructure. GSS believes that greater transparency in all aspects of damage prevention among buried-asset operators, locators, and excavators is essential to drive continuous improvement, and vital to increasingly safe working conditions and communities. Certifying excavators who participate in the Gold Shovel Program complies with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

N. SCG-7-C14 – Locating Equipment

SoCalGas utilizes locating equipment, updated GIS maps, and/or excavating (daylighting) to verify the physical locations of underground infrastructure. Part of this process involves uploading scanned construction drawings temporarily until the job is posted officially to

GIS. SoCalGas continues to remain compliant with codes and regulations and follow industry best practices and company policies and procedures as they apply to the safe and effective locating and marking of underground facilities. This Control includes written and accessible procedures, availability of proper equipment, and access to required information to enable personnel to successfully perform their duties. Locating equipment is utilized to comply with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

O. SCG-7-C15 – Remain Active Members of the 811 California One-Call Centers

Title 49 Code of Federal Regulations, section192.614 and California Government Code, section 4216 require natural gas utilities to remain members and actively participate in the activities of 811 USA local one-call centers. Excavators are required to notify the one call centers of their intent to dig. Owners of underground facilities in close proximity to the dig site are required to provide a positive response with the location of their facilities that may be in conflict with the excavation and also to provide any other efforts that may be required to protect the integrity of their underground facilities. The members of the one-call centers actively meet to make the 811 USA process easier for excavators while also exploring ways to make the service more accessible on a variety of platforms. They also work to promote the safe digging message through various avenues, such as through broadcast media, mobile and electronic communications.

P. SCG-7-C16 – Install Warning Mesh Above Buried Company Facilities

Plastic underground warning mesh is a high strength polypropylene mesh and designed to alert excavators of the presence of buried utilities. It is typically installed at a minimum of 18 inches above the buried facility which provides the excavator awareness of a buried pipeline below. If an excavator was not expecting buried facilities in their excavation area, the mesh serves to alert them, identifies the presence of a gas line, and directs them to contact "811" before proceeding so the proper precautions can be implemented before further excavation. Providing this type of warning before excavating further into an underground gas facility substantially reduces the risk of third party dig in damage and the associated consequences. SoCalGas installs warning mesh during new pipeline installations. Warning mesh installation applies to high pressure pipelines (MAOP > 60 psig) and medium pressure pipelines (MAOP ≤ 60 psig).

Q. SCG-7-C17 – Prevention and Improvements – Fiber Optics

Fiber Optic pipeline monitoring allows SoCalGas to remotely monitor the condition of high-pressure gas transmission pipelines in real-time. It serves as an early warning system to detect indications of concern in the areas around the pipeline that could suggest unauthorized construction work that could lead to pipeline damage. Fiber Optic monitoring indications can also alert to ground movement, heavy equipment mobilization, subsidence, and pipeline leakage/rupture. SoCalGas is committed to enhancing pipeline safety through modernizing its infrastructure to include new technology such as Fiber Optic monitoring. The technology uses fiber optic cables, installed about a foot above and parallel to the pipeline, that can monitor the surrounding environment and transmit data across long distances. The system operates on the principle that light signals vary when a fiber optic cable is exposed to vibration, stress, or abnormal changes in temperature – all indicators of a possible natural gas leak, an impact to a natural gas line, or localized ground disturbance which could indicate excavation. The fiber optic system can pinpoint within 20 feet where a potential problem may be developing. This access to continuous, real-time measurements and area-specific data can give SoCalGas personnel and first responders more time to plan, allocate resources, and take effective actions to mitigate potential leaks and damage to pipelines.

The Controls addressed above will continue to be performed. The Company's Mitigations, addressed below, aim to further reduce the frequency of dig-ins.

R. SCG-7-M1 – Automate Third Party Excavation Incident Reporting

Timely and accurate reporting of excavation incidents is a critical component of the continual improvement process. Enhancing the data collection of incidents helps measure the performance of adhering to compliance reporting obligations, and also assists the Company in filing various regulatory reports. The reporting system is the basis for excavation incident analysis and is used to understand the Company's opportunities for internal improvements for locate and mark activities. Through this analysis of excavation incidents, SoCalGas can further understand the internal and external leading causes of dig-ins, trend incident locations, trend frequency of damages caused by individual excavators, trench which facilities are damaged the most, and stay informed about the most common damaging excavation equipment.

Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SoCalGas is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors. SoCalGas is also actively enhancing its ability to improve data capture, data validation, and automated escalations. New Third Party Excavation Incident Reporting systems will provide accessibility and efficiency across multiple platforms reducing reporting and notification times by automating the reporting process. The upgraded reporting system efficiently analyzes accurate incident data and provides course corrections as locate and mark trends are identified.

S. SCG-7-M2 – Establish a Program to Address Areas of Continual Excavation

Generally, a typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[31] Agricultural excavators who perform repetitive excavations prefer 811 USA Tickets that are valid for longer periods of time. Requiring 811 USA notifications every 28 days could discourage participation in the 811 USA

31 Although USA tickets are valid for 28 days from the date of issuance, if work continues beyond 28 days, the excavator may renew the ticket per Cal. Govt. Code § 4216.2(e).

process by agricultural excavators, who may find it too burdensome to renew a ticket. These situations are typically in flood control channels and agricultural fields where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement[32] to develop a process that would allow for certain agreements for continual excavation, called ACE tickets. In flood control and agricultural situations, SoCalGas will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement.

Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. The Dig Safe Board has drafted regulations[33] requiring operators to address ACE tickets by completing newly developed forms, conducting onsite meetings, potentially excavating the facility, and providing additional records. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators.

T. SCG-7-M3 – Recording Photographs for Each Locat and Mark Ticket That is Visited by the Locator

Under this mitigation, locators will take photographs of the areas located and marked and the areas the excavators delineated either using white paint or other approved marking methods for each ticket they complete. The pictures taken by the locators will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Pictures will also mitigate potential disputes between excavators and SoCalGas by providing visual confirmation of the location marks at the time the ticket was located and marked. The photographs will include a digital time stamp and geographical identification metadata.

---

[32] California Senate Bill (SB) 661 modified Cal. Govt. Code § 4216, establishing an Area of Continual Excavation (ACE) Ticket.

[33] Dig Safe Board, Resolution No. 19-07-01, *available at* https://digsafe.fire.ca.gov/media/2197/resolution-19-07-01.pdf.

U. SCG-7-M4 – Utilize Electronic Positive Response

SoCalGas will utilize an electronic positive response system (EPS) which informs an excavator once a locate and mark activity is completed for the excavator's 811 USA ticket. For example, if the locator marks the jobsite, the excavator will be notified on their 811 USA ticket that the company has completed markings at the ticket location. EPS gives excavators and the company a shared record of locate and mark activity completed by the locator. This will help excavators by providing them with the appropriate documented communication before they dig. Enhancing electronic positive response will be used to measure the performance of adhering to Title 49 Code of Federal Regulations, section 192.614.

V. SCG-7-M5 – Enhance Process to Utilize and Leverage Emerging Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SoCalGas will work with the requesting contractor to help fulfill their request without creating an unsafe situation. More specifically, SoCalGas will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Vacuum excavation is recognized by the damage prevention industry as the safest excavation method that can be used today because the water and air used for excavation is adjustable, preventing damage to pipe and coatings. The Company plans to enhance its excavation practices by using hydro vacuum excavation technology which is typically installed onto a truck or portable trailer and allows the excavator to perform a keyhole excavation process, when applicable. Generally, a keyhole excavation process is utilized to excavate targeted areas.

Hydro vacuum excavation uses water at a high pressure to loosen the soil, this allows for precise excavation and vacuuming of the material. The use of water at a high pressure reduces the soil's cohesiveness thus helping to break the soil and suction easily. Dirt is stored in a debris tank, keeping the work area cleaner and avoiding the creation of dirt spoils. Hydro vacuum excavation is less invasive compared to other traditional methods of excavation. The benefits of hydro vacuum excavation include a reduced likelihood of causing third party damages, faster and precise excavations, and it also requires less manpower compared to conventional excavations.

The keyhole excavation process cost-effectively and safely exposes underground infrastructure to allow operators to perform repairs and maintenance without resorting to more costly and disruptive conventional excavation methods. The keyhole excavation process consists of performing work on the surface with smaller excavations, which can be performed on paved or non-paved areas. Pavement removal can be accomplished often by saw cutting and coring. The size of the pavement opening is determined upon the scope of the task at hand. The normal process utilizing keyhole excavation involves coring, vacuum excavation, construction and maintenance activities, and finally backfill and pavement restoration.

The Company will enhance its processes to utilize this excavation technology to facilitate hard to locate facilities.

W. SCG-7-M6 – Promote Process and System Improvements in USA Ticket Routing and Monitoring

As part of continuous improvement efforts, an assessment of the current state of the 811 USA one-call ticket routing and monitoring process is underway. The intent of this effort is to query system users and managers on potential improvements that would provide benefits to the process. The software vendor, Korterra, has been engaged to provide software solutions for identified system enhancements that will allow for more streamlined data collection, better documentation capture capability, and more detailed reports for process supervision.

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulations, section 192.614.

These new tools will give the SoCalGas the ability to better manage 811 USA ticket load across the company. The tools and enhancements entail workflows requiring that locators input specific data into dedicated fields detailing mutual agreements. These fields will enable reporting for all mutual agreements giving SoCalGas additional measures for ticket compliance. Other tools include automated notifications in the form of emails and/or texts for management when tickets are approaching the mutual agreement due dates. This will trigger follow up action to address tickets on time. This mitigation will include resources that support enhanced data collection and field management of ticket efforts and will also support 811 USA ticket prioritization. These resources are needed to manage data, perform analytics on the new volume of data, and to identify system enhancements.

X. SCG-7- M7 – Leverage Data Gathered by Locating Equipment

SoCalGas uses locating equipment that automatically captures GPS coordinates as the locator performs their locating activities. The GPS data may also be manually recorded when the locator pushes a designated button on the equipment console. The equipment's GPS data is downloaded through a physical connection with a terminal allowing the data to be saved then transmitted to the GIS group. Future enhancements may include the ability to wirelessly transmit the GPS data. The GPS data can then be used in GIS to compare real world locating data with GIS mapping data to evaluate discrepancies and potentially catching mapping errors or locating errors thereby increasing the accuracy of the locating activity. Correcting mapping errors or omissions using this data may potentially reduce damages caused by mapping issues. Leveraging data gathered by locating equipment improves adherence to Title 49 Code of Federal Regulations, section 192.614.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the Settlement Agreement. SoCalGas has not calculated an RSE for activities beyond the requirements of the Settlement Agreement but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[34] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. Risk reduction from Controls and Mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SoCalGas' rationale for the determination of tranches is presented below.

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing risk of injuries or fatalities to the public, employees, and contractors. Given the vast number of activities SoCalGas performs to mitigate the Third Party Dig-in on a High Pressure Pipeline risk, SoCalGas grouped like activities with like risk profiles into mitigation programs.

Table 6: Summary of Tranches

ID	Mitigation/Control	Tranche	Tranche ID
SCG-7-C8	Public Awareness	External Education - The Affected Public	SCG-7-C8-T1
		External Education - Emergency Officials	SCG-7-C8-T2
		External Education - Local Public Officials	SCG-7-C8-T3
		External Education – Excavators	SCG-7-C8-T4

34 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SoCalGas utilized historical gas dig-in results year-over-year to calculate an overall risk reduction benefit of performing these activities.[35] SoCalGas then looked at existing/continuing programs (*i.e.*, Controls), with the expectation of observing similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SoCalGas also accounted for the risk increase that would occur over time if the risk reduction activities were reduced or cancelled. For new and/or incremental Mitigations, we expect to achieve further risk reduction. The specific risk reduction benefit percentages used for each identified Control/Mitigation is included under each of the program headings below.

1. SCG-7-C1 – Locate and Mark Training

A single tranche is appropriate for this program because SoCalGas has an obligation to provide Locate and Mark Training for all Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Training has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and Mark Training provides participating employees with the necessary knowledge and capabilities to locate and mark the below ground gas facilities accurately and in the appropriate time frame. At SoCalGas, the Energy Technician Distribution (ETD) and Lead Construction Technician (LCT) functions have the responsibility to locate and mark gas facilities in response to an excavation request. Gas Operations Training and Development provides each ETD and LCT with the initial in-depth locate and mark training upon being newly assigned to an ETD or LCT position. Overall training is about an eight week course with locate and mark training comprising about one week of that time. An ETD or LCT employee are not certified to locate or mark gas facilities until they have successfully completed this training. In 2019,

[35] D.18-12-014 at Attachment A, A-5 ("MAVF Principle 4 – Risk Assessment").

SoCalGas' Gas Operations Training and Development function is forecasting to provide Locate and Mark Training to about 125 ETD and LCT employees.

It is necessary to have a trained workforce to accurately locate and mark gas infrastructure to provide the necessary information for a third-party excavator to perform their work as safely as possible. Marked facilities provide the excavator with approximate locations of where the gas facilities exist, within the delineated work area. Awareness of underground gas facilities allows the excavator to either avoid the areas or carefully dig with hand tools to prevent damage caused by the excavation work.

Since a vast majority of the utility's assets are buried below ground it is imperative that proper action is taken to reduce the risk of accidental damage to these facilities by accurately communicating the locations to the excavators. Without a highly skilled and trained locate and mark workforce, excavators would have little knowledge and confidence of gas line locations which could lead to third party excavation damage. By improving knowledge and competency through training, locate and mark accuracy will increase, and the number of mismarks should be reduced, leading to a decrease in the risk of third party excavation damage. Additionally, this training provides the workforce with the necessary understanding of not only the requirements for accurate locating and marking but also the importance of two-way communication with an excavator, thorough job documentation and timeliness of locate and mark completion.

SoCalGas has not performed an RSE Evaluation on SCG-7-C1 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

2. SCG-7-C2 – Locate and Mark Activities

A single tranche is appropriate for this program because SoCalGas has an obligation to perform Locate and Mark Activities across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and California Government Code, section 4216. Therefore, Locate and Mark Activities has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Activities are to prevent damage to gas infrastructure caused by third party excavators. They consist of three distinct activities:

(1) locating and marking underground gas facilities before excavation occurs;

(2) observing (stand-by) pipeline excavation activities; and

(3) providing staff support for compliance and improvement.

The first activity, locating and marking, refers to the physical act of locating and marking of underground facilities. By providing a visual indication of the location of underground facilities, the excavator has the necessary information to proceed with their activities in a safe and controlled manner. The second locate and mark activity is Pipeline Observation (stand-by) which is performed in specific required situations. Pipeline Observation (stand-by) is a critical activity that requires a qualified Company representative to be present anytime excavation activities take place near a high priority pipeline segment. The purpose of this activity is to decrease the likelihood of an event occurring by having a dedicated employee representing the operator who is specifically there to maintain the integrity of the gas pipeline. The third activity involves employee staffing to provide daily support in operations by interpreting policies, tracking compliance, evaluating tools, equipment and new technologies, providing refresher training, and tracking and trending locate and mark data to proactively identify areas for improvement. This is a critical risk reduction activity that directly supports the field locator personnel in their daily activities. The support staff have a focus on identifying program enhancement opportunities that lead to more accurate and timely responses to locate and mark tickets and reduction in damages.

This collection of Locate and Mark Activities ultimately provides the excavator with the necessary information to avoid hitting or damaging gas facilities.

SoCalGas has not performed an RSE Evaluation on SCG-7-C2 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

3. SCG-7-C3 – Locate and Mark Annual Refresher and Training Competency Program

A single tranche is appropriate for this program because SoCalGas has an obligation to provide a Locate and Mark Annual Refresher Training & Competency program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Annual Refresher Training and Competency Program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

All resources performing locate and mark activities must complete an annual re-fresher training program. This program consists of local supervisors reviewing the appropriate gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to maintain their ability to perform locate and mark activities. In 2018, about 970 employees participated in the annual Refresher and Competency Training program for both high pressure and medium pressure.

The Locate and Mark Refresher Training and Competency program reinforces several key components of locate and mark. By reviewing the gas standards on an annual basis, employees performing locate and mark activities are provided an opportunity to review expected procedures, learn changes in procedures, and obtain clarification. Without an opportunity to refresh their understanding, the locate and mark workforce might not be up to date on the latest procedure, requirement, or technology. Refresher training enables trained personnel to perform their duties with greater accuracy and efficiency, and it increases trained personnel's ability to adopt to new technologies and methods. Marking facilities accurately provides the excavator and public with a greater safety assurance. It enables the excavator to either avoid the delineated areas or dig with hand tools to avoid damage that could result in an immediate or future incident.

SoCalGas has not performed an RSE Evaluation on SCG-7-C3 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

4. SCG-7-C4 – Locate and Mark Operator Qualification Program

A single tranche is appropriate for this program because SoCalGas has an obligation of providing a Locate and Mark Operator Qualification program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Operator Qualification program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and Mark Operator Qualification (OQ) training provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. This would include such activities as achieving proper locating signals, interpreting the signals, and placing accurate and proper markings on the ground to indicate the location of the pipe. Locate and Mark OQ is required for employees every five years and is administered by the Gas System Integrity - Operator Qualification department at SoCalGas. There are about 480 employees at SoCalGas that participate in OQ training each year. It is mandated by PHMSA.

Employing resources that are formally trained and Operator Qualified to perform Locate and Mark functions demonstrates both procedural knowledge and field implementation of the necessary tasks required to successfully perform these functions. Maintaining this level of prepared and qualified workforce allows SoCalGas to meet its regulatory requirements and the demands of the excavator community and help provide for safe excavation environment.

SoCalGas has not performed an RSE Evaluation on SCG-7-C4 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

5. SCG-7-C5 – Locate and Mark Quality Assurance Program

A single tranche is appropriate for this program because SoCalGas has an obligation to perform quality assurance activities for Locators across its entire service territory. Therefore, Locate and Mark Quality Assurance program has a single risk profile and does not warrant further tranching.

a. **Description of Risk Reduction** Benefits

The purpose of the Locate and Mark Quality Assurance (QA) Program is to verify that proper processes and procedures are being followed and implemented by the locate and mark workforce and to correct those instances where improvements are warranted. SoCalGas' Pipeline Safety and Compliance department administers this QA program and visits every operating district at least once per year. During these visits, they select 15 USA tickets for each Locator, check the employees Operator Qualification status and evaluate the documentation on the ticket. Additionally, they will perform field visits, when possible, to evaluate in-field activities such as equipment setup and use, Company Gas Standard compliance, accuracy of locate and markings, proper documentation, and proper use of the Korterra ticket management system, among other activities. Feedback on a quality assurance audit is provided to each local supervisor who is responsible to follow-up with each individual needing further coaching or refresher training.

The Locate and Mark Quality Assurance Program provides a variety of benefits to reducing the number of and potential for damages to gas infrastructure by a third party. By evaluating locate and mark activities that have been completed or are being performed, SoCalGas can address gaps in performance with additional training or updating company documentation or recordation of assets. The locate and mark workforce errors can result in an incorrect locate and mark or one that is not done within the required timeframe. Additionally, the QA review can highlight errors in the timely and/or accurate documentation of its assets, which could result in an incorrect locate and mark. All issues could potentially result in damage to the gas infrastructure with serious injuries and/or fatalities and property damage. Adherence to proper company policy and procedures reduces the percentage of Locate & Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

b. Elements of the Bow Tie Addressed

SCG-7-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of activities in the program would benefit from this mitigation.
Effectiveness	Assuming 5% effectiveness as QA program has above-marginal impact on reducing mismarks.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 8% of the causes (8% risk addressed). Using these

	assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.4%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2626**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.36	**78.75**	194.40
	RSE	1.00	**8.43**	20.80

6. SCG-7-C6 – Damage Prevention Analyst Program

The Damage Prevention Analyst Program works to reduce the number of third-party damage to gas facilities by identifying at risk excavating contractors and educating them on proper one-call and safe digging techniques. Therefore, any excavating contractors at risk that are identified by the damage prevention analysts pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

The Damage Prevention Analyst Program works to reduce the number of third-party damages to gas facilities by identifying excavating contractors at risk and educating them on proper one-call and safe digging techniques. Through the Damage Prevention Strategies function, Damage Prevention Analysts focuses on the four districts (out of a total 48 districts) with the greatest number of reported incidents, by driving to and physically inspecting excavation projects with 811 USA ticket requests. The Analysts will also stop at other construction projects to investigate whether proper one-call and digging techniques are being used. In cases where the Analysts find an offense, they will stop the job and provide education to the contractor on the correct safe digging practices and procedures. SoCalGas expects to expand this effort to up to ten districts. SoCalGas Damage Prevention Analysts have stopped over 470 jobs since the program's inception in 2018 and conducted over 4,500 contractor field contacts to develop outreach and educational opportunities.

The benefit of the Damage Prevention Analyst function is threefold. First, it enables SoCalGas to stop a job before an incident occurs if no underground markings are present or the excavator is not practicing safe digging techniques. Second, it provides an opportunity to educate contractors on their requirements before digging or when digging around gas facilities before damage is done. This education has far-reaching benefits as the contractor will perform future projects in other districts not currently part of the program, and the education could be applied to those future projects. Third, it creates a list of contractors who might be repeat offenders or of site characteristics to improve prioritization of future construction site inspections.

b. Elements of the Bow Tie Addressed

SCG-7-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 – Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not “standby” when third party excavates near gas pipelines, DT.6 Contractor fails to contact company “standby” personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Damage Prevention Analyst program focuses on 100% of the excavation tickets through risk assessment.
Effectiveness	The effectiveness is assumed at 25% as analysts prioritize work, support training, stop unsafe jobs, support all districts, etc.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 26% of the causes (26% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 6.6%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.4635**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.93	**83.60**	206.37
	RSE	4.69	**39.50**	97.50

7. SCG-7-C7 – Prevention and Improvements-Refreshed Laptops

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and efficiently provide correct information helps with accurately locating underground infrastructure. Laptops with the applicable Software are deployed across SoCalGas' territory. SoCalGas has a vast service territory that covers 24,000 square miles in diverse terrain

SoCalGas
A Sempra Energy utility

throughout Central and Southern California, from Visalia to the Mexican border. The service territory covers 12 counties, 220 incorporated cities in more than 500 communities. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The workforce that performs the locate and mark activities relies on laptops, USA tickets, asset mapping, records data, software, and locating equipment. Using laptops in an outdoor setting, and often in construction areas, can reduce life expectancy due to the harsh environment. Therefore, SoCalGas provides its workforce with ruggedized laptops that are designed to better withstand their operating environment. Additionally, as software and data are updated and become more sophisticated with new and more powerful features, new laptops with advanced capabilities are required so that all information can be provided to the locate and mark workforce and data can be updated. Approximately 350 laptops are replaced every five years.

Updated and ruggedized laptops provide a longer battery life and can run the required software faster and more efficiently. Updated hardware and software increase the effectiveness of performing locate and mark. The ruggedized laptops also can take a picture of the surrounding conditions of an excavation site to update mapping information for improved asset and mapping information. All features of the refreshed laptops work to reduce the number of errors that might occur in locating gas infrastructure through improved data and could be used to support the development of improved safe-digging procedures.

b. Elements of the Bow Tie Addressed

SCG-7-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of laptops will be refreshed.
Effectiveness	Assuming negligible improvement in effectiveness (0.25%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 26% of the causes (26% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.07%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2521**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.33	**78.50**	193.77
	RSE	0.05	**0.38**	0.94

8. SCG-7-C8 – Public Awareness Compliance

For the purposes of an RSE analysis, SoCalGas separated Public Awareness into four tranches. Each of the four tranches reduces the likelihood of third party damage differently according to the RSEs.

Title 49 Code of Federal Regulation, section 192.616 requires utilities/natural gas providers to include efforts to educate the public, appropriate government organizations, and persons engaged in excavation related activities. The four types of groups identified in section192.616[36] are the affected public, emergency officials, local public officials, and excavators. Thus, SDG&E-6-C8 – Public Awareness has been tranched to match the four groups identified in section 192.616.

Periodically, SoCalGas participates in Distribution Public Awareness Council (DPAC) Benchmark studies to collect and compare membership data related to the effectiveness of public awareness and community safety outreach programs managed by gas utilities. There is a clear distinction between the general level of awareness between the affected public, emergency officials, local public officials, and excavators. In order to address this gap and reduce third party damage, targeted messaging campaigns are performed for each subgroup to increase overall awareness and education. Emergency officials and local public officials are often met with in person to discuss municipal third party damage trends. The public and excavators are informed using bill inserts, media campaigns, SoCalGas damage prevention Analysts, radio advertising, internet advertising, billboard advertising and safety meetings. A summary of SoCalGas' 2018 public awareness activities is shown in the table below.

Table 7: SoCalGas' 2018 Public Awareness Activities

	Mailers	**Email Messages**	**Public Service Announcements**	**811 Unique Page Views (2019 Data)**
Excavators	162,000	31,500	1	In 2019, from 399 to 2,585
Public Officials	2,000	600	0	

[36] 49 CFR § 192.616 (emphasis added):
(d) The **operator's** program must specifically include provisions to educate the public, appropriate government organizations, and **persons** engaged in excavation related activities on:
(1) Use of a one-call notification system prior to excavation and other damage prevention activities;
(2) Possible hazards associated with unintended releases from a **gas pipeline facility**;
(3) Physical indications that such a release **may** have occurred;
(4) Steps that should be taken for public safety in the event of a **gas pipeline** release; and
(5) Procedures for reporting such an event.

	Mailers	Email Messages	Public Service Announcements	811 Unique Page Views (2019 Data)
Affected Public	3.5 M customers and 750,000 live/work near high pressure	2.2 M	1	unique page views per month
Emergency Officials	1,900	20	0	

A comprehensive public awareness program works to reduce the number of gas incidents by educating the general public on the indication of a gas leak and what to do if they do identify the potential for one. This allows first responders and SoCalGas to respond in a timely manner to avoid a gas incident or minimize its impact. More specifically, the Public Awareness Program works to reduce the number of potential gas incidents due to third party excavation activities. Third parties refer to a broader group than just excavators, it can also include “do it yourself” home and business owners. By providing information about the 811 USA one-call process and safe digging practices to these audiences, SoCalGas can increase the number of locates performed by the gas utility and potentially reduce the number of incidents of damage to gas infrastructure.

9. SCG-7-C8-T1 – Public Awareness Compliance - The Affected Public

a. **Description of** Risk Reduction Benefits

SoCalGas continues to promote awareness of the Underground Service Alert (811, “call-before-you dig”) system to the affected public by reaching out to contractors and the general public through meetings, mailers, bill inserts, hosting events, the Company website, marketing and banners at locally broadcasted events and other methods, so that gas lines are properly marked before excavation activities. Pipeline markers are to be accurate and visible. Excavation activity includes excavation, blasting, boring, tunneling, backfilling, the removal of aboveground structures by both explosive or mechanical means, and other earth-moving operations.

Additionally, to promote National Safe Digging Month, SoCalGas brings a 30-foot-tall shovel to public gatherings to raise awareness about the importance of contacting 811 USA at least 72 hours prior to the start of any excavation project. For example, SoCalGas brings the giant shovel—popular for selfies—to inform area residents about pipeline safety, customer assistance programs, and the company's vision for California's Clean Energy Future. When residents or contractors dial 811 USA before any project that involves digging, SoCalGas marks the locations of underground lines to prevent them from being damaged, which could cause injury or service outages. This outreach is performed in compliance with Title 49 Code of Federal Regulations, sectionm192.616(d) subsections 1-5.

b. **Elements of the Bow Tie** Addressed

SCG-7-C8-T1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The affected public tranche of public awareness is assumed to impact 50% of the risk.
Effectiveness	Per SME input, effectiveness is marginal (1%). More effective than targeting local public and emergency officials, but less effective than excavators.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 91% of the causes (91% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2648**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.36	**78.80**	194.53
	RSE	0.48	**4.01**	9.89

10. SCG -7-C8-T2 – Public Awareness Compliance -Emergency Officials

a. Description of Risk Reduction Benefits

SoCalGas has the responsibility to train its employees on the company's emergency procedures as well as establishing a liaison with first responders in accordance with Title 49 Code of Federal Regulations, section 192.615.[37] According to GO 112-F, SoCalGas, an "Operator" under GO 11-F, must comply with the requirements of sections 192, 192.615, and 192.616(e). There are significant benefits to creating strategic partnerships and promoting awareness with emergency officials. Communication and coordination are improved when it matters most. SoCalGas works to implement this requirement by establishing lines of communication between SoCalGas and first responders, by learning about the responsibility and resources available to each party in the event of a gas pipeline emergency, and by educating each other on how to best respond to a gas system emergency.

---

[37] 49 CFR § 192.615.

Additionally, section 192.616, which governs GO 112-F, states that SoCalGas is required to coordinate emergency exercises or drills with first responders. To commemorate "811" 8/11 Day, SoCalGas, The California Regional Common Ground Alliance (CARCGA), and Orange County Fire Authority (OCFA) hold a mock utility line strike to raise awareness about the importance of contacting 811 USA at least two working days (not counting the day of notification) prior to the start of any project that involves digging. The event program includes the 811 USA process, emergency response demonstration, investigation by the Dig Safe Board, Speakers from Dig Safe Board, Orange County Fire Authority, plus exhibitor booths.

b. Elements of the Bow Tie Addressed

SCG-7-C8-T2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The emergency official's tranche of public awareness is assumed to impact 5% of the risk.
Effectiveness	Emergency officials can help with all excavation cause codes and are assumed to have the same effectiveness as the Affected Public.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 28% of the causes (28% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

SoCalGas
A Sempra Energy utility

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2505**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.45**	193.67
	RSE	0.14	**1.15**	2.84

11. SCG -7-C8-T3 – Public Awareness Compliance - Local Public Officials

a. Description of Risk Reduction Benefits

Working directly with city officials involved in construction activities within their jurisdictions helps to educate external personnel to support SoCalGas' enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. This interaction can involve several efforts. First is educating city personnel on the specific requirements of the California safe excavation laws. Second is helping city personnel to understand their role in helping to enforce the laws by promoting the use of 811 USA for excavation tickets through their project review and permitting activities as well as the field inspections their employees perform. Third, is to explain the city's potential cost savings from avoiding their emergency personnel having to respond to a blowing gas emergency due to a non-compliant excavation damage. They can help avoid unnecessary emergency response if they promote safe excavation practices during their routine daily planning and permitting work. The following outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616(d) subsections 1-5.

SoCalGas
A Sempra Energy utility

b. Elements of the Bow Tie Addressed

SCG-7-C8-T3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The local public official's tranche of public awareness is assumed to impact 15% of the risk.
Effectiveness	Minimal impact since they're not the excavators; assuming 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 61% of the causes (61% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2530**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.33	**78.52**	193.82
	RSE	0.32	**2.69**	6.65

12. SCG -7-C8-T4 – Public Awareness Compliance - Excavators

a. Description of Risk Reduction Benefits

Excavator awareness of 811 USA is very important. Nationwide statistics from the Common Ground Alliance indicate that when a locate request is made prior to an underground excavation, no damage will occur 99% of the time.[38] It is especially important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks and private property – sometimes just inches below the surface. Hitting one of these pipelines while conducting routine work such as digging, planting or doing demolition work can cause serious injury, property damage, and loss of utility service. Multiple excavator outreach events are hosted, targeted excavator communication mailings are sent, and the Big Shovel display are used to bolster awareness and benefits of 811 USA. Excavator outreach is performed to compliant with Title 49 Code of Federal Regulations, section 192.616(d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SCG-7-C8-T4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call 811 USA one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

---

[38] Common Ground Alliance, *Common Ground Alliance's 2014 DIRT Report Confirms Importance of Calling 811 Before Digging for Fifth Consecutive Year* (August 11, 2015), *available at* https://commongroundalliance.com/sites/default/files/press_release_pdfs/2014%20DIRT%20Report%20Press%20Release%20FINAL.pdf.

c. RSE Inputs and Basis

Scope	The excavator's tranche of public awareness is assumed to impact 30% of the risk.
Effectiveness	Public awareness campaigns for excavators are expected to be more effective than for other diggers, and the effectiveness is set to a higher number of 3%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 91% of the causes (91% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.8%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2766**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.40	**79.09**	195.23
	RSE	1.41	**11.88**	29.32

13. SCG-7-C9 – Increase Reporting of Unsafe Excavation

The purpose of Increased Reporting of Unsafe Excavation is to identify and report excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or State Licensing Board (CSLB). Reporting of unsafe excavation is applicable to the entire SoCalGas territory. Therefore, no further tranching is appropriate.

a. **Description of Risk Reduction Benefits**

The purpose of Increased Reporting of Unsafe Excavation is to consolidate and formalize the Company's internal procedures for identifying and reporting excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or State Licensing Board (CSLB). This includes consolidating the efforts of the Damage Prevention Strategies Team with the Claims Recovery Team. Both internal groups engage in various degrees of excavator education and outreach efforts on safe digging practices. The consolidation of efforts includes a consistent methodology for identifying targeted excavators. Education and outreach efforts provide the excavators understanding of the implications of unsafe excavation practices. SoCalGas has stopped over 470 jobs and conducted over 4,500 contractor field contacts to develop outreach and educational opportunities.

By combining the information from two functions within SoCalGas, this program provides a more complete effort to achieve the benefits of reducing third-party damages. First, it provides the names of unsafe excavators to the appropriate state boards to support the state's objectives. Second, it provides an opportunity for the excavators to be educated and informed on their obligations, such as the contractor's requirement to call prior to any excavation activity and to perform hand excavation in the vicinity of gas pipelines. With a better-informed contracting community, who follows the appropriate procedures, the number of excavation activities around gas infrastructure without location marks or without following the correct excavation procedures should decrease. The number of resulting incidents from these contractors should also decrease.

b. **Elements of the Bow Tie Addressed**

SCG-7-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. **RSE Inputs and Basis**

Scope	SMEs estimate that of excavators that are causing issues less than 1% are reported.
Effectiveness	Once the process is established, an increase in excavator notifications of 30% has been observed.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 47% of the causes (47% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2546**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.33	**78.55**	193.92
	RSE	0.83	**6.99**	17.25

14. SCG-7-C10 – Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board

The purpose of securing greater enforcement through Legislation and the Dig Safe Board is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the Dig Safe Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SoCalGas actively participates in the California Underground Safe Excavation Board (Dig Safe Board) to provide input and education from the natural gas utility perspective. The purpose of this participation is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority.

Through its involvement in board meetings and workshops and collaborating to achieve common objectives related to damage prevention, SoCalGas fosters a positive and stronger working relationship with all stakeholders. By playing an active role in developing and enforcing utility and contractor requirements, a more complete education and cooperative environment can be achieved among all stakeholders and new standards that get developed have had the benefit of comprehensive input. The Dig Safe Board provides a way in which effective safe excavation requirements can be cooperatively developed and disseminated to reduce third party damage.

SoCalGas has not performed an RSE Evaluation on SCG-7-C10 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C10 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

15. SCG-7-C11 – Public Awareness-Meet with Cities with Highest Damage Rates

The activities associated with this program include providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. Public awareness, meeting with cities with the highest damage rates is applicable to all cities across SoCalGas' territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of meeting with cities with highest damage rates is to reduce the number of third-party excavation incidents by providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. More specifically, using its Damage Prevention Analyst function, SoCalGas will meet with leaders in all of the approximately 245 municipalities in its service territory. Priority is given to the cities with the highest number of excavation incidents.

The Damage Prevention Analysis will meet with the permitting, inspection, and/or other pertinent officials within the municipalities to develop a strong working relationship to reduce third party damage. Concepts are discussed, such as asking the city inspectors to also look for proper utility markings, stop the job, or incorporate 811 USA literature with the permit application.

Working directly with the city officials involved in construction activities within their jurisdictions helps to develop an extended education and enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. It also creates an additional opportunity to identify poor practices and the offending excavators so that education on contacting 811 USA prior to digging and on utilizing proper excavation techniques can be provided before any digging or damage has occurred. As excavators operate in multiple jurisdictions, any education of a contractor that occurs in one city can also be applied to the contractor's future jobs in other jurisdictions. Finally, as the number of excavation incidents decreases, the demands on local first responders will also decrease.

b. Elements of the Bow Tie Addressed

SCG-7-C11 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Meeting with the top 3% of cities (7 cities out of 240 total).
Effectiveness	Minimal impact since they are not the excavators. Assuming same effectiveness as public awareness for the affected public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 89% of the causes (89% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2508**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.46**	193.70
	RSE	0.23	**1.92**	4.75

16. SCG-7-C12 – Public Awareness-Remain Active Members of the California Regional Common Ground Alliance

The purpose of remaining active members of the California is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the California State Digging Board is applicable to all third-party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SoCalGas is an active member in the California Regional Common Ground Alliance (CARGA) through its Damage Prevention Strategies function. CARGA is the regional organization associated with the Common Ground Alliance (CGA). The CGA is an underground utility industry association, across North America, whose mission is to prevent damage to underground infrastructure and to protect those who live and work near these assets through the shared responsibilities of stakeholders. CGA helps to develop best practices among industry stakeholders in all aspects of the safe excavation practices of underground infrastructure.

By participating in CARGA, SoCalGas is able to play a role in developing best practices with other regional membership, to inform and help develop best practices on the national level, highlight localized issues that need to be addressed, and interact with contractors and other utilities to create safer excavation techniques and requirements. By working with all members of the underground industry, both locally and nationally, SoCalGas not only helps to develop best practices but also be informed of other best practices in the industry which will help to improve utility and contractor implementation of safe digging techniques and procedures.

b. Elements of the Bow Tie Addressed

SCG-7-C12 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate is 50% as not all policies are affected.
Effectiveness	Maybe once every decade there is a practice that can be improved; however, improvement is marginal (0.05%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 100% of the causes (100% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2508**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.46**	193.70
	RSE	0.22	**1.85**	4.56

17. SCG-7-C13 - Continue to Participate in the Gold Shovel Standard Program

The Gold Shovel Standard (GSS) Program utilizes an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. This program is applicable to all third party contractors working for SoCalGas.

All third party damage caused by contractors working for SoCalGas poses the same safety risk. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The Gold Shovel Standard (GSS) Program is an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. The GSS provides positive reinforcement and reviews the contractor's excavation performance. SoCalGas requires all of its contractors to participate in the Gold Shovel Program.

The GSS provides positive guidance to underground contractors, aligning their excavation practices against established safe digging practices and procedures. It helps to educate contractors on expected industry excavation standards and identify and address gaps in their processes. SoCalGas requires Contractors who perform excavation on behalf of SoCalGas to be GSS certified. GSS serves as an additional quality check for its contractors. Actively supporting the Gold Shovel Standard Program helps to improve excavation contractors use of the one-call requirement and to improve their safe digging techniques, such as hand-digging when near gas pipelines.

SoCalGas has not performed an RSE Evaluation on SCG-7-C13 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C13 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.8 – Incorrect/inadequate information in existing asset records leading to incorrect locate and mark ,

PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

18. SCG-7-C14 – Locating Equipment

SoCalGas provides the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure, as mandated by Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Locating Equipment Program is to utilize technology to standardize locating procedures and to provide the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure. The Locating Equipment program will provide the locate and mark workforce with standardized and compliant location devices and tools that are equipped with USA ticket, asset records, and mapping information. Equipment will be provided to the workforce as part of the normal replacement cycle.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Finally, providing standardized equipment allows for consistent training and field use for the equipment across all operating districts for improved locate accuracy by the workforce.

SoCalGas has not performed an RSE Evaluation on SCG-7-C14 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C14 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center

(USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

19. SCG-7-C15 – Remain Active Members of the 811 California One-Call Centers

The California 811 USA One-Call Centers serve as the communication conduit between SoCalGas and excavators. SoCalGas is an active member of both Dig Alert and USA North. Dig Alert's territory includes nine Southern California Counties. They include: Imperial, Inyo, Los Angeles, Orange, San Bernardino, San Diego, Santa Barbara, Riverside and Ventura. USA North covers fifty Northern California Counties. SoCalGas is mandated by Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216 to remain an active member of the California One-Call Centers. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The California 811 USA One-Call Centers serve as the communication conduit between SoCalGas and excavators to support safe digging practices. Excavators contact the 811 USA one-call centers and inform them of their intent to excavate in a specific location. This information is made available to the owners and operators of underground infrastructure to provide location information before excavation occurs. SoCalGas is an active member of local 811 USA one-call centers. In calendar year 2018, SoCal Gas responded to over 720,000 requests for locate and mark activities of its distribution system through the local one-call centers, nearly all distribution pipe is considered as medium pressure.

As a member of the one-call centers, SoCalGas actively works with other industry stakeholders toward simplifying the process, improving its accessibility, and educating on safe digging practices. The California one-call centers play a critical role in safe excavation practices and reducing the number of third-party damages. They provide a single source for all excavators to contact as well as a source of that activity for utilities, simplifying the communication process between many contractors and the various utilities, many of which are not known by the contractors. The one-call process also allows this communication process to take place before digging occurs, so that utilities can correctly locate and mark their facilities within an expected timeframe. Excavating with these marks, allows the contractors to practice safe digging techniques, minimizing the potential of hitting or damaging gas piping as they complete their work.

SoCalGas has not performed an RSE Evaluation on SCG-7-C1 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-7-C15 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

20. SCG-7-C16 – Install Warning Mesh Above Buried Company Facilities

Warning mesh is a mitigation against those excavators that do not adhere to the 811 USA excavation safety notification requirement. Approximately 60% of company damages are caused by excavators not contacting 811 USA before they dig. Warning mesh would be installed when any new open trench company facility is installed before backfilling. This program is applicable to all SoCalGas open trench buried new company facilities. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The purpose of installing warning mesh above underground gas pipelines is to provide a visual warning to excavators of the existence of gas infrastructure. Warning mesh will be installed in all open trench applications in new construction.

The warning mesh is a visual indicator that can be exposed before the excavator damages the underlying gas infrastructure and can help to address other shortcomings in the locate and mark safe digging process by both the utility and the excavator. It can serve as a reminder to the excavator to apply hand-digging techniques, it can act as a correction for inaccurate surface locate markings, and it could serve as a warning to an excavator who did not call 811 USA to have underground facilities marked.

b. Elements of the Bow Tie Addressed

SCG-7-C16 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Used mesh procured with the proposed funding to arrive at the scope percentage (0.6%).
Effectiveness	Assuming 50% effectiveness since large machines can still cause damage.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 24% of the causes (24% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.07%.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2524**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.33	**78.50**	193.79
	RSE	3.11	**26.14**	64.53

21. SCG-7-C17 – Prevention & Improvements – Fiber Optics

The fiber optic technology installed on high pressure pipelines will serve as an early warning system to detect unauthorized construction work that could damage the pipeline and other changes in pressure in the line that could indicate a leak. This program is applicable to high pressure company facilities. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

In 2017, SoCalGas broke ground on fiber optic installation that is designed to allow real-time monitoring of the condition of its high-pressure transmission pipelines. The technology uses fiber optic cables, that are installed and run above and parallel to the pipeline, to detect stresses imposed on the pipeline that could have the potential to cause damage. The fiber optic cable sends the information to a remote monitoring station, in real time, and SoCalGas operators can interpret the data to determine potential stresses. The initial installation was along a seven-mile section of high pressure pipeline in Bakersfield, California. The company installs fiber optic cables in all high pressure new construction installations as well as replacement segments 12-inches and greater in diameter and one-mile long.

The information received from the fiber optic technology will give SoCalGas the opportunity to respond quickly to potential issues with its high-pressure transmission pipelines. It can pinpoint a potential problem within 20-feet, and with real time information, can be critical to early detection. Examples of some of the stresses that it could detect is construction and excavation activity near and around the pipeline. Receiving this information, quickly, can alert SoCalGas to inspect the area and put a stop to any excavator that does not have an 811 USA ticket or is not practicing safe-digging techniques.

b. Elements of the Bow Tie Addressed

SCG-7-C17 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company “standby” personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	87 miles of transmission pipeline out of 3,433 (3%) targeted for installation.
Effectiveness	Per internal SME assessment, fiber optics can help detect dig-ins but does not prevent the damage. Therefore, the effectiveness of this mitigation is estimated at 50%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 25% of the causes (25% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2604**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.35	**78.69**	194.26
	RSE	0.04	**0.34**	0.85

22. SCG-7-M1 – Automate Third Party Excavation Incident Reporting

Automating Third Party Excavation incident reporting into one system will centralize the reporting and data analysis. This will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. SoCalGas is mandated by Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216 to collect data on third Party Excavation Incidents. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

Automating third party excavation incident reporting will be the result of an effort to consolidate and simplify the data collection process involved in investigating a gas incident. Field supervisors complete the investigations of gas incidents. Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SoCalGas is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors.

Standardizing data collection into one system will centralize reporting and data analysis will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. This will facilitate improvements in SoCalGas' accuracy and timeliness in locating and marking its infrastructure.

b. Elements of the Bow Tie Addressed

SCG-7-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Marginal improvement is expected (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2498**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.64
	RSE	0.00	**0.02**	0.05

23. SCG-7-M2 – Establish a program to address the area of continual excavation

SB 661 modified California Government Code 4216 establishing an ACE Ticket. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators. Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. This ticket is applicable to areas within SoCalGas territory. All excavations performed with the use of an ACE ticket poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

A typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[39] These situations typically are in flood control channels and agricultural fields where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement to develop a process that

[39] Although USA tickets are valid for 28 days from the date of issuance. If work continues beyond 28 days, the excavator may renew the ticket per California Government Code, section 4216.2(e).

would allow for certain agreements for continual excavation, called ACE tickets. In flood control and agricultural situations, SoCalGas will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement

Having to continually renew an 811 USA ticket may discourage some excavators from using the 811 USA process. This program will reduce dig-in risk as it will encourage landowners to use the 811 USA one-call process before excavating and reduce the need to continually call every time digging needs to occur in the same area over the one-year timeframe of the ticket. By informing the one-call center, and then the utility, the landowner can be made aware of gas infrastructure in the area and develop an agreed-upon process to employ safe-digging techniques within the parameters established in the ACE ticket. Additionally, this process will assist the utility in accurately and timely marking the facilities as they will not have to make multiple, repeat visits to the same excavation site. By providing a mechanism to reduce effort for both the landowner and the utility and providing the location of gas infrastructure to the landowner, the use of safe-digging practices should increase, and the amount of infrastructure damage should decrease.

b. Elements of the Bow Tie Addressed

SCG-7-M2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.5 Company does not “standby” when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	For assessment purposes, SMEs consider farmers to be equivalent to excavators fielding heavy machinery. The proportion of farmers to heavy machinery excavators is assumed to be 1 to 100, hence a scope of 1%.
Effectiveness	Effectiveness assumed to be high (90%) as the percentage of the targeted people (farmers) are likely to follow procedure and prevent a dig-in once aware of the situation.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2395**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.29	**78.19**	193.02
	RSE	0.13	**1.10**	2.72

24. SCG-7-M3 – Recording photographs for each locate & mark ticket visited by locator

Recording photographs for each locate and mark ticket visited by locator is planned for all SoCalGas' above and belowground facilities within its entire service territory. These pictures will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of recording photographs of each locate and mark ticket is to improve the accuracy of the locating activity and to inform process improvements based on investigations of gas incidents and quality assurance audits. By having a record of the locate marks, SoCalGas would be able to better perform root cause analyses of QA activities and investigations into gas incidents. These photographs could show incorrect markings, which would result in improved training, or they could show incorrect mapping and asset data, which could result in improved utility data. The benefits of this mitigation is its role in improving future locate and mark accuracy to avoid damage to gas infrastructure.

b. Elements of the Bow Tie Addressed

SCG-7-M3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets will have associated photographs.
Effectiveness	The effectiveness is marginal in nature and considered to be 1% as the impact is only on lessons learned.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 8% of the causes (8% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58

	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2475**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.31	**78.38**	193.50
	RSE	0.03	**0.24**	0.60

25. SCG-7-M4 – Utilize Electronic Positive Response

Electronic positive response is an electronic response provided to the regional notification center (DigAlert and USA North) that informs the excavator, prior to their excavation date, if the facility has been marked or if there is no conflict with the proposed excavation. Utilizing electronic positive response is applicable to all areas within SoCalGas' territory. All excavations utilizing electronic positive response poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

SoCalGas is required to locate and mark its underground infrastructure within two days of receiving a locate and mark ticket request. Implementing a positive response feature with the regional notification centers, such as USA North and DigAlert, improves communication between SoCalGas and excavating contractors. The system will inform the contractor that the utility has completed their task or if no gas infrastructure is in conflict with their excavation activities. The effort also provides a means to communicate stand-by requirements or if the locate task was not able to be completed due to weather or accessibility issues.

This program requires participation from contractors and SoCalGas. It will avoid the potential of damage to gas infrastructure due to miscommunication between the contractors and SoCalGas. This is especially important in situations where the utility was not able to provide markings within the required timeframe, but the contractor assumes no markings means no gas infrastructure. When there are no markings, the contractor may not employ safe digging procedures resulting in a hit to gas infrastructure they thought was not there.

b. Elements of the Bow Tie Addressed

SCG-7-M4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of tickets will have electronic positive response available.
Effectiveness	This mitigation improves communication but has a marginal impact on excavator behavior, therefore the effectiveness is assumed to be 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 2% of the causes (2% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.02%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	LoRE		**3.2495**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.43**	193.62

	RSE	0.05	**0.44**	1.07

26. SCG-7-M5 –Enhance Process to Leverage Excavation Technology to Help With Difficult Locates (Vacuum Excavation Technology)

Vacuum excavation technology is an example of a hydro excavation tool that can be deployed to find the location of buried company facilities when a locator is not getting an indication of where the facility is located. Technology such as this has proven itself in the damage prevention industry as a safe alternative to hand tools to prevent damage when unknown buried facilities are encountered. Vacuum excavation is utilized on an as-needed, case-by-case basis during Locate and Mark activities or in a more programmatic way by first identifying areas that are known to be hard to locate. Vacuum excavation is applicable to all areas within SoCalGas' territory. All excavations utilizing vacuum excavation technology poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SoCalGas will work with the requesting contractor to help fulfill their request without creating an unsafe situation. SoCalGas will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Using locating tools that can provide the actual location of gas infrastructure by safely exposing the pipe will provide the most accurate location of the gas infrastructure. With this knowledge, the contractor is aware of when to employ safe digging techniques and company records can be updated with the actual piping location. Both of these benefits will work toward reducing the potential for damage to underground piping for the current project and future projects.

b. Elements of the Bow Tie Addressed

SCG-7-M5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.8 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 15% of targeted locations will be assisted with emerging excavation technology.
Effectiveness	Effectiveness is high and assumed to be 95%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 9% of the causes (9% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 1.3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2088**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.20	**77.45**	191.19
	RSE	0.15	**1.29**	3.18

SoCalGas
A Sempra Energy utility

27. SCG-7-M6 – Promote Process and System Improvements in USA Ticket Routing and Monitoring

The primary focus of system improvements to the USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulations, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

As part of continuous improvement, an assessment of the current state of the 811 USA one-call ticket routing and monitoring is underway. The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to provide increased abilities to monitor and manage locate and mark ticket requests and to evaluate and measure performance on meeting timing commitments. In calendar year 2018, SoCalGas fulfilled over 720,000 USA ticket requests from excavators for its distribution system which is nearly all medium pressure.

SoCalGas has a time requirement to fulfill locate and mark ticket requests. If these time requirements are not met, contractors might assume that no marks mean there are no utilities in conflict with their project, and they might start their excavation processes. If this occurs, contractors could hit and damage underground gas infrastructure due to the lack of surface markings. By providing enhanced capabilities to monitor and manage ticket request workload, SoCalGas will have the potential to be better able to prioritize ticket requests, assign crews, and balance workload among the locate and mark crews. Additionally, the data capture and reporting enhancements can improve SoCalGas' ability to monitor its own processes and identify process improvements. These enhancements work toward improving SoCalGas' performance in meeting the locate and mark timeframe, thereby reducing the potential of contractors digging without knowledge of underground gas infrastructure.

b. Elements of the Bow Tie Addressed

SCG-7-M6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Improvement of up to 15%. This mitigation is closely tied to the Damage Prevention Analysts program.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2444**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.31	**78.31**	193.31
	RSE	0.34	**2.85**	7.03

28. SCG-7-M7 – Leverage Data Gathered by Locating Equipment

The current locating equipment has the capability of recording all information from a locate. This information could be used to assess the quality of each locate and the relative accuracy of pipe location in the GIS system. By having a quality measurement for each locate the company can further determine areas that need improvement. The data gathered by leveraging locating equipment will be used to evaluate performance per Title 49 Code of Federal Regulations, section Part 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Leveraging Data Gathered by Locating Equipment Program is to utilize technology to improve the speed with which SoCalGas mapping and asset records are updated and improve the accuracy of the resulting locate and mark activities. It provides the locate and mark workforce with the tools and technology to facilitate the ability to update Company records by capturing location coordinates found in the field, which can then be used to evaluate against existing company records to identify any mapping, records, or locating errors.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Using equipment with the latest technology assists in locating the infrastructure more accurately by providing specific location coordinates to the company's GIS system for updated records. Accurate mapping and company records on its facilities improves the accuracy of future locate and mark activities thereby providing excavators with an improved vision of underground piping.

b. Elements of the Bow Tie Addressed

SCG-7-M7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.8 - Incorrect / inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or

Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	A 25% scope is used as a middle ground (between 13% for damages on mains and 40% for damages from backhoes).
Effectiveness	Assume marginal effectiveness of 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2500**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
	RSE	0.00	**0.01**	0.03

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SoCalGas evaluated the constraints and challenges for the Risk Mitigation Plan. Third Party Excavation Damage on high pressure lines are typically due to a lack of securing an 811 USA ticket and/or failure to follow safe excavation practices. These challenges are in spite of the communication and education efforts being taken by numerous utilities, associations, and other stakeholder groups who advocate for safe excavation laws and practices. Affecting positive behavioral changes to these excavators remains a significant challenge in preventing excavation damage to high pressure pipelines, a low occurrence but high consequence risk. To continue to improve damage prevention, new technologies and strategies must continue to be evaluated. It must also be determined how new technologies complement the existing portfolio of mitigation measures.

Below ground utility infrastructure can be challenging to locate. It requires a trained and seasoned workforce, use of sophisticated electronic equipment, and access and use of online GIS, mapping, and historical installation information to accurately identify locations. Throughout the years, due to growth and modernization, the density of underground utilities within rights-of-way has increased significantly. This in turn can lead to increased difficulty in locating individual facilities due to locating signal interference from adjacent infrastructure. Techniques learned over the years by seasoned locators are invaluable when faced with hard to locate areas.

Additionally, implementing, operating and maintaining a mitigation such as an 811 USA ticket risk assessment tool assumes that the algorithm will properly identify the riskiest evacuations and operators. The Company has to rely on legacy software programs and frequently perform updates to it in order to maintain the 811 USA ticket risk assessment tool. Computer hardware improvements increase the performance of the software and allow the Locate and Mark Technician to collect additional data and photographic documentation of the site with utility markings. Additional challenges on the locate and mark program are the occasions when tickets fail to be transmitted through the mobile data terminal (MDT) due to limited/no wireless service. This may lead the excavator to start their work prior to the utility properly delineating the under-ground substructures.

High pressure pipelines often traverse remote or rural areas where routine public access is infrequent. In addition, the use of non-local sub-contractor excavation companies, such as those plowing agricultural fields, who are not familiar with underground utilities can lead to devastating consequences. SoCalGas' service territory size and the driving of miles (or aerial miles) that would be required to reach remote locations, inhibits SoCalGas' ability to more closely monitor right of way activity in remote or rural locations.

The inclusion of warning mesh and fiber optics for open trench high pressure pipeline installation are both relatively new. Near term benefits of these mitigations are incremental. The wide spread benefits will only be realized as significantly more pipe installations, that include these mitigations, have been completed.

The Risk Mitigation Plan was compiled using SoCalGas' current capabilities for evaluating and prioritizing mitigation measures. SoCalGas has made its best effort to identify the Drivers/Triggers and Potential Consequences associated with each risk with the understanding that, over time, impacting factors may change and require adjustments to the Risk Mitigation Plan. If any of the mitigations become mandated at a later date, cost and resource projects could also change.

Table 8 provides a summary of the Risk Mitigation Plan, including Controls and Mitigations activities, associated costs, the RSEs by tranche.

SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 8 were estimated using assumptions provided by SMEs and available accounting data.

SoCalGas
A Sempra Energy utility

Table 8: Risk Mitigation Plan Summary[40]

(Direct 2018 $000)[41]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-C1	Locate and Mark Training	T1	0	20	0	77-92	77-92	-

40 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

41 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

42 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

43 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

44 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

45 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-C2	Located and Mark Activities	T1	0	2,300	0	3,000-3,500	3,000-3,500	-
SCG-7-C3	Locate and Mark Annual Refresher Training and Competency Program	T1	0	13	0	41-62	41-62	-
SCG-7-C4	Locate and Mark Operator Qualification	T1	0	13	0	14-16	14-16	-
SCG-7-C5	Locate and Mark Quality Assurance Program	T1	0	15	0	25-39	25-39	1.00-20.80
SCG-7-C6	Damage Prevention Analyst Program	T1	0	66	0	110-140	110-140	4.69-97.50
SCG-7-C7	Prevention and Improvements - Refreshed Laptops	T1	0	3	340-390	46-100	390-490	0.05-0.94
SCG-7-C8-T1	Public Awareness- Compliance - Tranche 1: The Affected Public	T1	0	32	0	56-97	56-97	00.48-9.89

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-C8-T2	Public Awareness- Compliance- Tranche 2: Emergency Officials	T2	0	3	0	6-10	6-10	00.14-2.84
SCG-7-C8-T3	Public Awareness- Compliance - Tranche 3: Local Public Officials	T3	0	9	0	17-29	17-29	00.32-6.65
SCG-7-C8-T4	Public Awareness- Compliance - Tranche 4: Excavators	T4	0	19	0	34-59	34-59	1.41-29.32
SCG-7-C9	Increase Reporting of Unsafe Excavation	T1	0	15	0	15-17	15-17	00.83-17.25
SCG-7-C10	Public Awareness- Secure Greater Enforcement through Legislation and California State Digging Board	T1	0	1	0	1-3	1-3	-
SCG-7-C11	Public Awareness-Meet with Cities with Highest Damage Rates	T1	0	3	0	3-12	3-12	00.23-4.75

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance	T1	0	2	0	3-12	3-12	00.22-4.56
SCG-7-C13	Continue to Participate in the Gold Shovel Standard Program	T1	0	1	0	1-2	1-2	-
SCG-7-C14	Locating Equipment	T1	0	5	0	5-56	5-56	-
SCG-7-C15	Remain Active Members of the 811 California One-Call Centers	T1	0	101	0	160-200	160-200	-
SCG-7-C16	Install warning mesh above buried company facilities	T1	*0*	51	*0*	*51-64*	*51-64*	3.11-64.53
SCG-7-C17	Prevention and Improvements – Fiber Optics	T1	6,000	0	18,000-23,000	0	18,000-23,000	00.04-0.85

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-M1	Automate Third Party Excavation Incident Reporting	T1	0	0	360-1,100	0	360-1,100	00.00-0.05
SCG-7-M2	Establish a program to address the area of continual excavation	T1	0	0	0	100-250	100-250	0.13-2.72
SCG-7-M3	Recording photographs for each locate and mark ticket visited by locator	T1	0	0	0	140-270	140-270	00.03-0.60
SCG-7-M4	Utilize electronic positive response	T1	0	0	0	12-30	12-30	00.05-1.07
SCG-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	T1	0	0	0	250-400	250-400	00.15-3.18

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-7-M6	Promote process and system improvements in USA ticket routing and monitoring	T1	0	0	0	41-52	41-52	00.34-7.03
SCG-7-M7	Leverage data gathered by locating equipment	T1	0	0	0	20-26	20-26	00.00-0.03
TOTAL COST			**6,000**	**2,700**	**19,000-25,000**	**4,200-5,500**	**23,000-30,000**	

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SoCalGas notes that there are activities related to this risk that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.*, employee time spent for internal training, performing inspections or monitoring). The costs associated with these internal labor activities are not captured in this chapter because SoCalGas does not track labor in this manner.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 9: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for no RSE Calculation
SCG-7-C1	Locate and Mark Training	Mandated compliance activity per CFR Part 192 and GO 112-F
SCG-7-C2	Locate and Mark Activities	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SCG-7-C3	Locate and Mark Annual Refresher Training and Competency Program	Mandated compliance activity per CFR Part 192 and GO 112-F
SCG-7-C4	Locate and Mark Operator Qualification	Mandated compliance activity per CFR Part 192 Subpart N
SCG-7-C10	Public Awareness – Secure Greater Enforcement through Legislation and California State Digging Board	Dig Safe Act of 2016 and is included in California's Government Code (GC) 4216.12
SCG-7-C13	Continue to Participate in the Gold Shovel Standard Program	Mandated compliance activity per California Government Code 4216
SCG-7-C14	Locating Equipment	Mandated compliance activity per CFR Part 192.614. California Government Code 4216

ID	Control/Mitigation Name	Reason for no RSE Calculation
SCG-7-C15	Remain Active Members of the 811 California One-Call Centers	Mandated compliance activity per CFR Part 192.614. California Government Code 4216

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the mitigations for the Third Party Dig-in on a High Pressure Pipeline risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SCG-7-A1 – Virtual Reality Training / Simulation to Improve Locator Proficiency

The virtual reality Locate and Mark training simulator provides a portable and scenario-based training system. It allows for instructors to simulate a variety of real-world locate and mark scenarios. Virtual reality provides more flexibility in training curriculum and allows for more focused educational opportunities. More research is needed to identify system requirements and standardization scores and identify impacts to existing locate equipment and performance management software. SoCalGas plans to explore this alternative and associated costs after more research.

Scope	Assuming 100% of locations would receive UTTO Virtual Reality Training Tools.
Effectiveness	Per internal SME assessment, utilizing UTTO Virtual Reality Locator Training Tools will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 6%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0006%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2500**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
	RSE	0.00	**0.02**	0.04

C. SCG-7-A2 – GPS Tracking of Excavation Equipment

SoCalGas has supported the Gas Technology Institute (GTI) and other research organizations in their efforts to help the industry improve damage prevention practices. Past and ongoing efforts included real time GPS tracking of excavation equipment operating in pipeline rights-of-way and quick-shut breakaway meter set valves.

Real-time tracking of excavation is done using a "black box" attached to the excavation equipment such as a backhoe, grader, etc. The black box monitors the location of the equipment and can sense when the equipment is getting ready to dig. There is sophisticated software that monitors the GPS data in relation to its proximity to spatial pipe locations. If the box is detected near a company asset, then an alarm is triggered on the equipment alerting the equipment operator that there is a pipeline in the area. There is also an alert that is sent to the Company so action may be taken to investigate the location.

The technology is not being pursued at this time since it gave too many false positives. There is more work that needs to be completed and testing done before the device is ready for production.

Scope	A middle ground of 25% of available opportunities will be used as the scope for GPS tracking.
Effectiveness	Per internal SME assessment, utilizing GPS tracking of excavation equipment will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 3%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0001%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**3.250**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
Post-Mitigation	**LoRE**		**3.2500**	
	CoRE	2.87	**24.14**	59.58
	Risk Score	9.32	**78.44**	193.65
	RSE	0.00	**0.00**	0.00

Table 10: Alternative Mitigation Summary

(Direct 2018 $000)[46]

ID	Mitigation	2020-2022 Capital[47]	2022 O&M	Total[48]	RSE[49]
SCG-7-A1	Virtual reality training / simulation to improve locator proficiency	0	100-120	100-120	**0.00 -0.04**
SCG-7-A2	GPS Tracking of Excavation Equipment	0	240 - 400	240 - 400	**0**

46 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

47 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

48 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

49 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SCG-7-C1	Locate and Mark Training	DT.2; DT.4; DT.5; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C2	Locate and Mark Activities	DT.2; DT.4; DT.5; PC.1; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C3	Locate and Mark Annual Refresher Training and Competency Program	DT.2; DT.4; DT.5; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C4	Locate and Mark Operator Qualification	DT.2; DT.4; DT.5 PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C5	Locate and Mark Quality Assurance Program	DT.2; DT.4; DT.5; DT.7; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C6	Damage Prevention Analyst Program	DT.1; DT.2; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C7	Prevention and Improvements-Refreshed Laptops	DT.2;DT.7; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C8	Public Awareness Compliance	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C9	Increase Reporting of Unsafe Excavation	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	DT.1;DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C11	Public Awareness - Meet with the Cities with the Highest Damage Rates	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	DT.1;DT.3; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C13	Continue to Participate in the Gold Shovel Standard Program	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C14	Locating Equipment	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SCG-7-C15	Remain Active Members of the 811 California One-Call Centers	DT.1; DT.2; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C16	Install warning mesh above buried company facilities	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-C17	Prevention and Improvements-Fiber Optics	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M1	Automate Third Party Excavation Incident Reporting	DT.2; DT.4; DT.5; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M2	Establish A Program To Address The Area Of Continual Excavation	DT.1; DT.3; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M3	Recording Photographs For Each Locate and Mark Ticket Visited By Locator	DT.2; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M4	Utilize Electronic Positive Response	DT.4; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	DT.2;DT.7; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M6	Promote Process and System Improvements in USA Ticket Routing and Monitoring	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SCG-7-M7	Leverage Data Gathered by Locating Equipment	DT.2; DT.7; DT.8; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

Risk Assessment Mitigation Phase

(Chapter SCG-8)

Storage Well Integrity Event

November 27, 2019

SoCalGas
A Sempra Energy utility®

TABLE OF CONTENTS

Risk: Storage Well Integrity Event

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for Southern California Gas Company's (SoCalGas) Storage Well Integrity Event (Storage) risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SoCalGas has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SoCalGas' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SoCalGas' General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SoCalGas anticipates requesting recovery in its Test Year (TY) 2022 GRC. SoCalGas' TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and are within the scope of the analysis required for this RAMP Report. Throughout this 2019

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

RAMP Report, activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC or certain internal labor costs). Additionally, SoCalGas did not perform RSE calculations on mandated activities. Mandated activities are defined in this report as control activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

SoCalGas has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SoCalGas' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

For purposes of this 2019 RAMP Report, the Storage risk is defined "as the risk of an uncontrolled release of gas that occurs over an extended period due to a storage well structural integrity issue that requires complex well control operations resulting in gas reliability issues, extensive customer impacts, injuries and/or fatalities."

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[3] for each control and mitigation presented herein, SoCalGas has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Internal/external corrosion
DT.2	Aging asset infrastructure
DT.3	Incorrect/inadequate asset records
DT.4	Outside forces (natural disasters, landslides)
DT.5	Human error
PC.1	Serious injuries[4] and/or fatalities
PC.2	Property damage
PC.3	Uncontrolled release in high consequence area
PC.4	Loss of storage injection and withdrawal capacity
PC.5	Loss of stored gas
PC.6	Adverse litigation
PC.7	Diminished public confidence
PC.8	Penalties and fines
PC.9	Environmental impacts

[3] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

[4] As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) § 330(h).

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SoCalGas has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SoCalGas' baseline controls for this risk consists of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SCG-8-C1	Well Construction Requirements and Dual Barrier System
SCG-8-C2	Well Abandonments
SCG-8-C3	Pressure Monitoring and Alarming
SCG-8-C4	Wellhead Leak Detection and Repair
SCG-8-C5	Integrity Management for Gas Storage Operations
SCG-8-C6	Integrity Demonstration, Verification, and Monitoring Practices

SoCalGas will continue the baseline controls identified above. Finally, pursuant to the SA Decision,[6] SoCalGas presents considered alternatives to the mitigation plan for the Storage risk and summarizes the reasons the alternatives were not included in the mitigation plan in Section VIII.

II. RISK OVERVIEW

Gas storage wells are a necessary and critical component of California's reliable gas delivery infrastructure because gas storage provides supply to over 21 million customers and half the electric generation in SoCalGas' territory. SoCalGas operates four underground gas storage fields: Aliso

---

[5] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[6] *Id.* at 33.

Canyon, La Goleta, Honor Rancho, and Playa del Rey with a current combined working capacity of approximately 84.4 Bcf.[7,8]

- Aliso Canyon is in Northern Los Angeles County and is the largest of the four gas storage fields that delivers gas to the Los Angeles pipeline loop. Aliso Canyon has a design working capacity of approximately 86 Bcf .[9,10] Aliso Canyon has 78 injection/withdrawal/observation wells[11] and was designed for a maximum withdrawal rate of approximately 1.8 Bcf per day.[12]
- Honor Rancho is also located in Northern Los Angeles County, approximately ten miles north of Aliso Canyon, with a working capacity of approximately 27 Bcf and delivers to the Los Angeles pipeline loop. Honor Rancho has 35 gas injection/withdrawal wells and is designed for a maximum withdrawal capability of 1.0 Bcf per day. [13]
- La Goleta is in Santa Barbara County and provides service to the northern coastal area of the SoCalGas territory. La Goleta has a working capacity of approximately 21 Bcf. La

---

7 The volumetric capacity of a natural gas storage field reservoir is measured in units of billion cubic feet (Bcf).

8 Aliso Canyon is currently restricted to a working gas capacity of 34 Bcf, per CPUC July 6, 2018 report: Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability, Summer 2018 Supplemental Report.

9 *Id.*

10 PHMSA Underground Natural Gas Storage Facility Annual Report for Calendar Year 2018 Supplemental Report.

11 PHMSA Underground Natural Gas Storage Facility Annual Report for Calendar Year 2018 – Supplemental Report, submitted May 20, 2019.

12 Withdrawal capacity is dependent on well availability and inventory.

13 PHMSA Underground Natural Gas Storage Facility Annual Report for Calendar Year 2018 – Supplemental Report, submitted May 20, 2019.

Goleta has 21 gas injection/withdrawal/observation wells and is designed for a maximum withdrawal capability of 0.4 Bcf per day.[14]

- Playa del Rey, located in central Los Angeles County, has a working capacity of approximately 2.4 Bcf. Playa del Rey has 39 gas injection/withdrawal/observation wells.[15] Playa del Rey is designed for a maximum withdrawal rate of 0.4 Bcf per day to meet residential, commercial and industrial loads throughout the western part of Los Angeles, including electric generators and oil refineries.

This chapter considers risks associated with the following storage field components: process and well servicing operations, well design, casing, tubing, and annulus or tree/wellhead for SoCalGas' four active underground gas storage facilities: Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey.

On October 23, 2015, SoCalGas' Aliso Canyon SS-25 well failed, causing a gas leak at the Aliso Canyon gas storage facility in Los Angeles, California. Ultimately, a relief well was drilled to permanently plug the leaking well on February 18, 2016. The event prompted heightened awareness of underground gas storage operations risks, and new federal and state regulations were introduced in 2016, 2017, and 2018, which include:

- U.S. Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration's (PHMSA) Underground Storage regulations, 49 Code of Federal Regulations (CFR) § 192.12 Interim Final Rule (IFR), effective January 18, 2017, adopts American Petroleum Industry (API) Recommended Practice 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as a mandatory regulation, among other things.
- Division of Oil, Gas, and Geothermal Resources (DOGGR) established 14 California Code of Regulations (CCR) §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes among other things, requirements for operators to submit project-specific Risk Management Plans, Emergency Response Plans, project

[14] *Id.*

[15] *Id.*

data requirements, a Records Management Program, well construction requirements, mechanical integrity testing requirements, and monitoring and reporting requirements.

- California Air Resources Board (CARB) established an Oil & Gas Rule regulation effective October 1, 2017, which describes monitoring requirements for natural gas underground storage facilities. SoCalGas has developed and received approval from CARB and the local air districts for an underground storage facilities monitoring plan and leak detection protocol. These include installation of continuous ambient methane monitoring at the wellheads and associated lateral piping.

SoCalGas has implemented activities and measures to comply with new federal and state regulations at an accelerated pace, and has incorporated additional industry leading safety enhancements and improvements. These activities and measures are part of the implementation of SoCalGas' Storage Integrity Management Program (SIMP). SoCalGas' SIMP was modeled after the federally mandated distribution and transmission integrity management programs, and was designed to provide a forward-looking, methodical, and structured approach, using state-of-the-art inspection technologies and risk management disciplines to address storage reservoir and well integrity issues.

SoCalGas proposed SIMP in 2014, before federal and state underground gas storage regulations were promulgated, and has an accelerated pace of completing its SIMP assessments for storage wells at all four storage fields from its original plan of six years to four years. SoCalGas has completed over 90% of its baseline assessments and abandonments for injection/withdrawal gas storage wells to date, considerably ahead of the PHMSA requirement to complete baseline assessments within three to eight years.[16]

SoCalGas has also introduced a suite of advanced leak-detection technologies and practices that allow for early detection of leaks and help quickly identify anomalies, such as changes in well pressure. These enhancements include:

---

[16] Furthermore, for well integrity casing thickness demonstration for underground storage, SoCalGas goes beyond the DOGGR regulations by performing both magnetic flux leakage ("MFL") and ultrasonic ("UT") inspection technology to detect corrosion or metal loss, even though only one method is required by regulation.

- Around-the-clock monitoring of the pressure in all wells from our 24-hour operations center;
- Continuous upwind/downwind ambient air monitoring and meteorological stations at each storage facility;
- Either daily well inspections or continuous/real-time wellhead monitoring; and
- Enhanced training for our employees and contractors.

SoCalGas also continues to support industry experts in their research efforts to advance underground storage safety.

III. RISK ASSESSMENT

In accordance with the SA Decision,[17] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Storage risk.

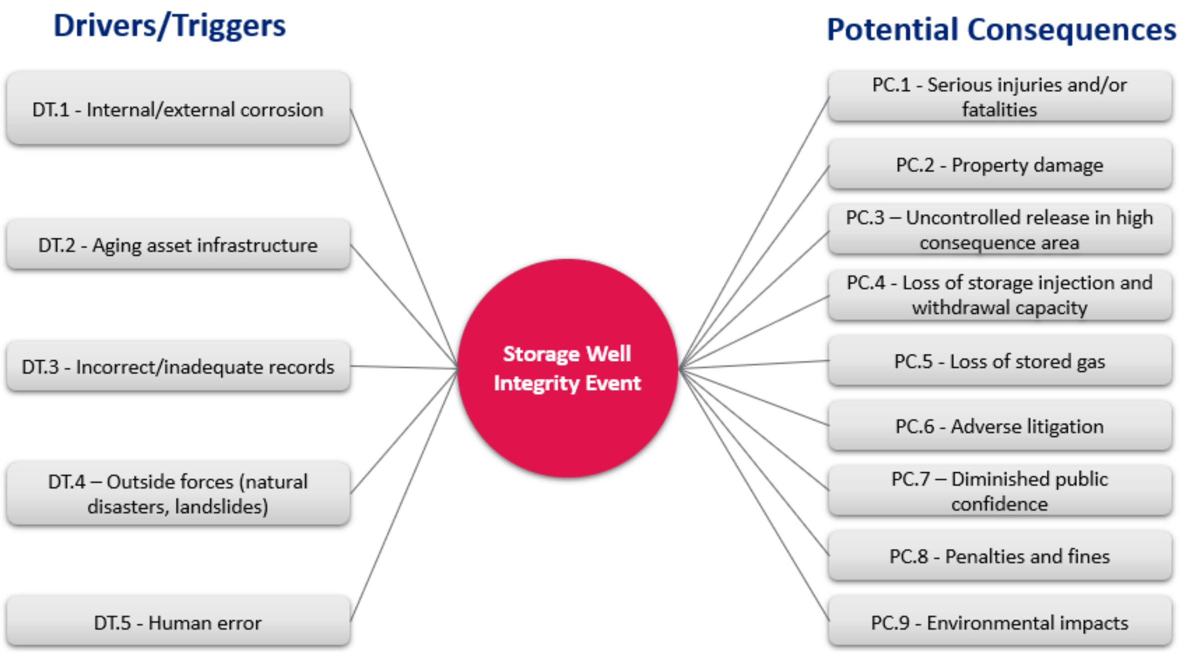
A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SoCalGas applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

---

[17] D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[18] directs the utilities to endeavor to identify all asset groups or systems subject to the Storage risk. The four underground storage fields work in conjunction with the SoCalGas transmission pipeline and distribution delivery network. This interconnected system consists of high-pressure pipelines, compressor stations, and underground storage fields, designed to receive natural gas from interstate pipelines and local production sources. The integrated system enables deliveries of natural gas to customers or into storage field reservoirs, depending on market demands.

C. Risk Event Associated with the Risk

The SA Decision[19] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a storage well integrity event, which may result in any of the Potential Consequences listed on the right.

---

[18] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[19] *Id.* at Attachment A, A-11 ("Bow Tie").

The Drivers/Triggers that may contribute to this risk event are further described in the section below. The Risk Scenario (i.e. a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency), as assessed for SoCalGas' 2018 Enterprise Risk Registry, considers a well integrity event, leading to damage and considers any direct consequences of gas deliverability reduction, gas inventory loss, environmental impacts, penalties or fines, serious injuries or fatalies, property damage, and adverse litigation associated with a single well.

D. Potential Drivers/Triggers[20]

The SA Decision[21] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Storage risk, SoCalGas identified potential leading indicators, referred to as Drivers or Triggers. These include, but are not limited to:

DT.1 – Internal/ external corrosion: The risk driver is based on the potential for corrosion on the inside or outside of tubing and buried steel casing. Internal corrosion and/or erosion may be caused by the corrosive effect of fluid, sand, and/or reactive constituents such as carbon dioxide in the gas withdrawn from the storage formations and the natural degradation of buried steel casing. External corrosion to buried steel casing may be caused by contact with certain underground soil formation conditions.

DT.2 – Aging asset infrastructure: This risk driver is based on the age of the wells at SoCalGas' storage fields. Although the four SoCalGas storage fields have been in service for various timeframes, the average age of all injection/withdrawal wells is approximately 49 years.

DT.3 – Incorrect/inadequate asset records: This risk driver is based on the potential for inaccurate or incomplete information that could result in the failure to construct, operate, and maintain SoCalGas' wells safely.

DT.4 – Outside forces (natural disasters, landslides): This risk driver includes both natural forces and those from external sources that can affect the integrity of the storage facilities.

---

20 An indication that a risk could occur. It does not reflect actual or threatened conditions.

21 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

Examples of natural forces include ground movement, landslides, and subsidence from earthquakes.

DT.5 – Human error: This risk driver is based on the potential for maintenance or inspection functions to be performed incorrectly by employees or contractors. The cause of this could be inadequate procedures, failure to follow procedures, inadequate training or inexperienced personnel.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[22] and/or fatalities;
- Property damage;
- Uncontrolled release in high consequence areas;
- Loss of storage injection and withdrawal capacity
- Loss of stored gas
- Adverse litigation
- Diminished public confidence
- Penalties and fines
- Environmental impacts

These Potential Consequences were used in the scoring of the Storage risk for the development of SoCalGas' 2018 ERR.

---

22 As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." http://services.claremont.edu/ehs/wp-content/uploads/sites/16/2017/03/cal-osha-serious-injury-definition.pdf.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[23] including enhancements to the Interim Decision 16-08-018.[24] SoCalGas has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 3: Risk Quantification Scores[25]

Storage Well Integrity Event	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	339	**348**	363
LoRE		**0.1**	
CoRE	3957	**4062**	4237

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[26] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

---

23 D.18-12-014 at Attachment A.

24 *Id.* at 2-3.

25 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, Item Nos. 17-19), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

26 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of storage incidents caused by storage well structural integrity issues, which results in significant consequences including injuries or fatalities.
Out-of-Scope for purposes of risk quantification:	The risk of storage incidents unrelated to storage well structural integrity issues.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (e.g., PHMSA data).[27] The safety risk assessment primarily considered historical occurrences of unintended releases from underground gas storage facilities of varying severity as described in the "Analysis of Occurrences at Underground Fuel Storage Facilities and Assessment of the Main Mechanisms Leading to Loss of Storage Integrity" paper as cited in the Section IV.B below, "Sources of Input." The incident rates with safety consequences were calculated as the product of national average (the frequency of an incident per field) and the number of fields SoCalGas operates currently. The safety risk was evaluated by using Monte Carlo simulation.

The reliability assessment considered internal and national data. Internal data over the past five years indicates no storage risk incidents which led to loss of service to customers. Additionally, PHMSA does not record loss of service and the US Rock Mechanics Presentation also did not provide analysis involving loss of service.

The financial assessment was estimated based on historical data from the U.S Natural Gas Storage Risk-Based Ranking Methodology and Results[28] and further supported by input from Company subject matter experts (SMEs). The data includes storage field incidents dating back approximately 70 years and their respective estimated financial impacts.

---

27 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

28 U.S. Natural Gas Storage Risk-Based Ranking Methodology and Results, Argonne National Laboratory, (October 2016), *available at* https://publications.anl.gov/anlpubs/2016/12/132436.pdf.

B. Sources of Input

The SA Decision[29] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Analysis of Occurrences at Underground Fuel Storage Facilities and Assessment of the Main Mechanisms Leading to Loss of Storage Integrity
    - Conference: 51st US Rock Mechanics/Geomechanics Symposium, at San Francisco, California
    - Authors: Evans, David J. British Geological Survey, UK; Schultz, Richard A. Petroleum and Geosystems Engineering, The University of Texas at Austin, USA
    - Link: https://www.researchgate.net/publication/317873326_Analysis_of_Occurrences_at_Underground_Fuel_Storage_Facilities_and_Assessment_of_the_Main_Mechanisms_Leading_to_Loss_of_Storage_IntegrityLink: Annual Report mileage for Gas Distribution Systems
- Number of Depleted Fields, Underground Natural Gas Storage Capacity
    - Agency: U.S. Energy Information Administration (EIA)
    - Link: https://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SA2_Count_a.htm
- U.S. Natural Gas Storage Risk-Based Ranking Methodology and Results
    - Agency: Argonne National Laboratory (U.S. Department of Energy laboratory)
    - Link: https://publications.anl.gov/anlpubs/2016/12/132436.pdf

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[30] This section describes SoCalGas' Risk Mitigation Plan by each selected control and mitigation for this risk, including the rationale supporting each selected control.

29 D.18-12-014 at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

30 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

As stated above, SoCalGas' Storage risk is defined as the risk of an uncontrolled release of gas that occurs over an extended period due to a storage well structural integrity issue that requires complex well control operations resulting in gas reliability issues, extensive customer impacts, injuries and/or fatalities. The Risk Mitigation Plan discussed below includes both controls that are expected to continue for the period of SoCalGas' TY 2022 GRC cycle.[31] The controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SCG-8-C1 – Well Construction Requirements and Dual Barrier System

SoCalGas gas storage wells are operated such that injection and withdrawal of gas into and out of the storage reservoir is accomplished only through the tubing, which is the innermost string of piping in the well configuration. The outer production casing acts as a secondary containment barrier. This is a change from historical operations at the storage fields, which previously allowed for injection and withdrawal through the tubing and casing. Retrofit activities to execute conversion of the wells to tubing only flow can include replacement of the wellhead, replacement of valves, replacement of the tubing and packer, installation of an inner casing string or liner, and installation of shallow-set subsurface safety valves.

B. SCG-8-C2 – Well Abandonments

Under certain circumstances, SoCalGas may abandon a well rather than continue to utilize it for gas storage operations. The decision to plug and abandon a well is driven by various factors including, but not limited to, well-specific information, location-specific information, deliverability, operation and maintenance history, and operational needs. To abandon a well, SoCalGas isolates the well from injection and withdrawal operations, removes casing to a certain depth and wellhead equipment, and fills the wellbore with cement.

---

31 *Id.* at p. 33. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

C. SCG-8-C3 – Pressure Monitoring and Alarming

SoCalGas is implementing continuous, real-time pressure monitoring at gas storage wells in each storage field. Monitoring devices are installed at each tubing and casing annulus, with certain setpoints established to reflect normal operating conditions. Through automated alerts, exceedance of a setpoint will notify local operations, enabling SoCalGas to investigate a potential abnormal condition or integrity issue. In alignment with DOGGR regulations,[32] the real-time pressure monitoring system will be implemented by January 1, 2020. The equipment functions continuously unless it needs to be deactivated on a temporary basis for maintenance purposes. In those instances, pressure reads are conducted manually.

D. SCG-8-C4 – Wellhead Leak Detection and Repair

Wellhead Leak Detection and repair entails performing a daily audio-visual inspection, as well as a quarterly leak survey with the use of Optical Gas Imaging. Inspections are performed on each active and idle injection/withdrawal wellhead assembly owned and operated by SoCalGas.

SoCalGas also has implemented and follows a CARB approved monitoring plan for its underground storage facilities in compliance with the CARB Oil & Gas Rule, 17 CCR § 95668(h) as of August 6, 2019. This monitoring plan addresses three CARB Oil & Gas Rule regulatory requirements: (1) continuous ambient air monitoring, (2) wellhead daily or continuous leak screening, and (3) well blowout procedures. The CARB Oil & Gas Rule requires daily or continuous leak screening at each injection/withdrawal wellhead assembly and attached pipelines according to one or both of the following methods: (1) daily leak screening with the use of US EPA Reference Method 21 instrument, or the use of Optical Gas Imaging, or (2) continuous leak screening with the use of automated instruments and a monitoring system with an alarm system.[33]

Additionally, pursuant to the CARB Oil & Gas Rule regulations, on or after January 1, 2020, any component with a leak measuring total hydrocarbon concentrations greater than or equal to 1,000 ppmv but not greater than 9,999 ppmv will be successfully repaired or removed from service within 14

---

32 14 CCR § 1726.7(d).

33 17 CCR § 95668(h).

calendar days of initial leak detection. Component leaks with measured total hydrocarbon concentrations greater than or equal to 10,000 ppmv but not greater than 49,999 ppmv will be successfully repaired or removed from service within five (5) calendar days of initial leak detection. Component leaks with measured total hydrocarbon concentrations greater than or equal to 50,000 ppmv will be successfully repaired or removed from service within two (2) calendar days of initial leak detection. Critical components or critical process units will be successfully repaired by the end of the next process shutdown or within 12 months from the date of initial leak detection, whichever is sooner.

E. SCG-8-C5 – Integrity Management for Gas Storage Operations

SoCalGas has integrated its Risk Management for Gas Storage Operations department into SoCalGas' Integrity Management organization, unifying the gas storage integrity management practices with its transmission and distribution integrity management practices. The Integrity Management organization is tasked with such responsibilities as developing and implementing processes and procedures to manage storage well integrity and compliance with new underground storage regulations, advancing the approach to data management, data governance and risk assessment, developing and tracking training of company employees on procedures pertinent to storage integrity management, and supporting execution of drills and exercises to evaluate emergency response plans.

As discussed in Chapter RAMP-G, SoCalGas has been implementing the Company's Safety Management System (SMS), which includes the principles set forth in the Petroleum Institute (API) Recommended Practice 1173 Pipeline Safety Management System. API 1173 is a systematic way to identify hazards and control risks while validating that these risk controls are effective, and has a strong emphasis on process safety and safety culture. SoCalGas also highlights several new regulations that support this implementation and which share elements of API 1173:

- PHMSA IFR Underground Storage regulations, 49 CFR § 192.12, adopts API 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs into regulation, and is an integral component of creating an SMS for Underground Storage. Specifically, "[s]torage design, construction, operation, and maintenance include activities in risk management, site security, safety, emergency preparedness, and procedural documentation and training to embed human and organizational competence in the management of storage facilities."[34]

- DOGGR Requirements for California Underground Gas Storage Projects, 14 CCR § 1726.3: which includes, among other things, incorporation of human factors into risk management plans.[35]

F. SCG-8-C6 – Integrity Demonstration, Verification, and Monitoring Practices

SoCalGas performs integrity inspections on gas storage wells to verify the pressure containing capability of the well, detect possible leaks, and identify metal loss anomalies in the tubing and casing. Inspections can include pressure testing, noise and temperature surveys, magnetic flux leakage (MFL) inspection, ultrasonic (UT) inspection. Pressure testing and wall thickness inspections (MFL or UT) are currently required to be performed on each gas storage well at a two-year recurring frequency.[36] Temperature and noise surveys are required at least annually at Aliso Canyon and Honor Rancho. Temperature surveys are required semiannually, and noise surveys are required annually, at La Goleta and Playa del Rey.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SoCalGas has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. SoCalGas has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[37] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and

---

[34] API RP 1171, Preamble, *available* at http://www.api.org/~/media/files/publications/whats%20new/1171_e1%20pa.pdf.

[35] 14 CCR § 1726.3.

[36] *Id.* at § 1726.6 (a)(3).

[37] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (i.e., the same LoRE and CoRE). SoCalGas' rationale for the determination of Tranches is presented below.

Given the vast number of activities SoCalGas performs to mitigate the Storage risk, SoCalGas grouped like activities with like risk profiles into mitigation programs. SoCalGas' Storage risk controls have the same risk profile and are not further tranched. A single tranche is appropriate for the Storage risk event as there is no logical disaggregation of assets or systems related to the controls put forth in the mitigation plan.

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SoCalGas looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[38] SoCalGas then looked at existing/continuing programs (i.e., controls), and expects to get similar results (i.e., percentage of risk reduction benefit by continuing the activity). SoCalGas also accounted for the risk increase that would occur over time if we stopped performing these activities. The specific risk reduction benefit percentages used for each identified control is included under each program heading below.

1. SCG-8-C1 – Well Construction Requirements and Dual Barrier System

a. Description of Risk Reduction Benefits

Well design and construction to achieve a dual barrier system has changed storage operations in that the injection and withdrawal of gas occurs only through the innermost tubing, with the outer casing acting as a secondary containment barrier. Equipping gas storage wells with tubing and packer and implementing a new configuration to limit operations to tubing only flow introduces a second mechanical barrier that would need to also fail, concurrent with a failure of the primary barrier, in order to result in an uncontrolled gas release at surface. Consequently, such a system has the effect of reducing the likelihood that a well integrity event will occur.

---

[38] *Id.* at Attachment A, A-12 ("Determination of Post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," and "Measurement of Post Mitigation Risk Score")

SoCalGas has not performed an RSE Evaluation on SCG-8-C1 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus, SoCalGas has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-8-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. Replacement and remediation activities as described in Section V will alleviate complications associated with several risk drivers, including internal/external corrosion (DT.1), aging asset infrastructure (DT.2), and outside forces (DT.4). Additionally, a dual barrier system aims to reduce the Potential Consequences identified in the right side of the bow tie including, but not limited to, serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), loss of stored gas (PT.5), and environmental impacts (PT.9).

2. SCG-8-C2 – Well Abandonments

a. Description of Risk Reduction Benefits

Well abandonments may occur for various reasons, including operational issues for which remediation is not a viable option. This control accounts for well plug and abandonments required by state DOGGR regulations 14 CCR §1726.3(d)(1), which requires an operator to have a work plan and schedule to either bring noncomforming wells into compliance or plugging and abandoning the wells in accordance with PRC §3208. This control allows for the well to be fully abandoned, where necessary, and it will also allow for the completion of the abandonment process on wells where partial abandonment has already occurred. Eight full abandonments and three partial abandonments are forecasted for 2020 along with three full abandonments in each of years 2021 and 2022. Abandonment of wells through isolation of the reservoir from the wellbore have the effect of reducing the likelihood that a well integrity event will occur and result in an uncontrolled gas release at surface.

SoCalGas has not performed an RSE Evaluation on SCG-8-C2 because the program elements account for well plug and abandonments required by regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-8-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. Well abandonment will address the following drivers: internal/ external corrosion (DT.1), aging asset infrastructure (DT.2), outside forces (DT.4), and human error (DT. 5). Additionally, well abandonments aim to reduce the Potential Consequences identified in the right side of the bow tie including serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), loss of storage injection and withdrawal capacity (PT.4), loss of stored gas (PT.5), adverse litigation (PT.6), diminished public confidence (PT.7), penalties and fines (PT.8), and environmental impacts (PT.9).

3. SCG-8-C3 – Pressure Monitoring and Alarming

a. Description of Risk Reduction Benefits

This control allows for real-time pressure monitoring at each tubing and casing annulus of gas storage wells. Pressure readings deviating from what is typically observed during normal operations can be an indication of equipment failure or compromised barriers. Continuous monitoring can allow for prompt notifications and issue assessments. As such, pressure monitoring and alarming reduces the likelihood that an abnormal condition or integrity issue goes unnoticed or grows to the extent that failure occurs and causes an uncontrolled release at the surface.

SoCalGas has not performed an RSE Evaluation on SCG-8-C3 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-8-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. This control addresses a number of drivers related to safety, including: internal/external corrosion (DT.1), aging asset infrastructure (DT.2), incorrect/inadequate records (DT.3), outside forces (DT.4) and human error (DT.5). Additionally, pressure monitoring and alarming will aim to reduce the Potential Consequences identified in the right side of the Bow Tie including serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), and environmental impacts (PT.9).

4. SCG-8-C4 – Wellhead Leak Detection and Repair

a. Description of Risk Reduction Benefits

SoCalGas' monitoring plan addresses continuous ambient air monitoring, wellhead daily or continuous leak screening, and well blowout procedures. The monitoring equipment is used for detection of aboveground piping for leaks and is required per DOGGR (14 CCR § 1726.7), PHMSA (49 CFR § 192.12) and CARB (17 CCR § 95668(h)). In the event of a well blowout, CARB requires Optical Gas Imaging (OGI) video footage of the well blowout to notify concerned parties. The stationary air monitors will analyze concentrations of methane in the ambient conditions. Wellhead leak detection and repair tools will be owned, installed and monitored by Aboveground Storage (AGS).

The leak detection and repair program reduces the likelihood that an abnormal condition or integrity issue goes unnoticed or grows to the extent that a failure occurs and causes an uncontrolled release at surface. OGI detects potential leaks or abnormalities efficiently so that problems can be quickly prioritized and mitigated.

SoCalGas has not performed an RSE Evaluation on SCG-8-C4 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-8-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. Wellhead leak detection and repair will address the following drivers: internal/ external corrosion (DT.1), aging asset infrastructure (DT.2), outside forces (DT.4), and human error (DT.5). Additionally, wellhead leak detection and repair aims to reduce the Potential Consequences identified in the right side of the bow tie including serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), and environmental impacts (PT.9).

5. SCG-8-C5 – Integrity Management for Gas Storage Operations

a. Description of Risk Reduction Benefits

By integrating the Risk Management department into SoCalGas' Integrity Management organization, SoCalGas reduces the likelihood and the consequences associated with a well integrity event. Unifying the gas storage integrity management practices with its transmission and distribution integrity management practices centralizes specific resources to this control to help enhance processes and procedures are in place to identify, monitor, and respond to integrity issues, supports the accuracy and accessibility of data, and enables risks to be adequately assessed and managed.

This control will allow for increased data analytics on storage activities, the standardization of processes, data integration, and a structure of work prioritization.

SoCalGas has not performed an RSE Evaluation on SCG-8-C5 because the program elements are mandated by law and/or regulation. SoCalGas is required to comply with all applicable laws/regulations, and thus has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SCG-8-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. This control addresses the following drivers, including: internal/ external corrosion (DT.1), aging asset infrastructure (DT.2), incorrect/inadequate records (DT.3), outside forces (DT.4) and human error (DT.5). Additionally, Integrity Management for Gas Storage Operations aims to reduce the Potential Consequences identified in the right side of the bow tie including, but not limited to, serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), loss of storage injection and withdrawal capacity (PT.4), loss of stored gas (PT.5), adverse litigation (PT.6), diminished public confidence (PT.7), penalties and fines (PT.8), and environmental impacts (PT.9).

6. SCG-8-C6 – Integrity Demonstration, Verification, and Monitoring Practices

a. Description of Risk Reduction Benefits

Implementation of a program to perform integrity inspections on gas storage wells on a recurring basis is designed to reduce the likelihood that an abnormal condition or integrity issue goes unnoticed or grows to the extent that a failure occurs and causes an uncontrolled release at surface. Similar to the other controls presented in this risk chapter, this control is also mandated by DOGGR regulations (14 CCR § 1726.6), with the exception where the Company exceeds minimum requirements (14 CCR § 1726.6(a)(2)) by employing casing wall thickness inspection using magnetic flux and ultrasonic technologies. As discussed in Chapter RAMP-D, the Company calculated RSEs for certain mandated controls where the Company exercised discretion in meeting the mandate, or in cases where the Company exceeded the mandate as it did with this control.

b. Elements of the Bow Tie Addressed

SCG-8-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. This control addresses the following safety drivers, including: internal/ external corrosion (DT.1), aging asset infrastructure (DT.2) and outside forces (DT.4). Additionally, this control aims to reduce the Potential Consequences identified in the right side of the Bow Tie including serious injuries and/or fatalities (PT.1), property damage (PT.2), well blow-out in high consequence area (PT.3), loss of storage injection and withdrawal capacity (PT.4), loss of stored gas (PT.5), adverse litigation (PT.6), diminished public confidence (PT.7), penalties and fines (PT.8), and environmental impacts (PT.9).

c. RSE Inputs and Basis

Scope	At least 66 wells per year would undergo a set of assessments, additional wells might undergo re-assessment.
Effectiveness	The tests are not considered infallible; thus 95% effectiveness is assumed.
Risk Reduction	Of storage risk, 11%[39] is assumed attributable to casing. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 13%. Note that in order to estimate the RSE, it was necessary to add the cost of prep work to funding earmarked for testing.

[39] *See* "Well Integrity – Basics, Prevention, Monitoring, Red Flags & Repair Options," Petroleum Safety Authority Norway (PSA), dated November 21, 2014, *available* at https://www.usea.org/sites/default/files/event-/King_DOE%20Well%20Integrity%20–%20Basics,%20Prevention,%20Monitoring,%20Red%20Flags%20and%20Repair%20Options%2021%20Nov%202014%20v3.pdf.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.086**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	339.14	**348.14**	363.14
Post-Mitigation	**LoRE**		**0.097**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	383.03	**392.16**	409.06
	RSE	0.62	**0.64**	0.66

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SoCalGas' mitigation plan takes into account compliance with regulatory requirements. SoCalGas has performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced and is contingent on other factors including, but not limited to, new compliance requirements, planning, reliability, safety, and other operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigations activities, associated costs, and the RSEs, by Tranche.

SoCalGas does not account for and track costs by activity; rather, SoCalGas accounts for and tracks costs by cost center and capital budget code. The costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[40]

(Direct 2018 $000)[41]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-8-C1	Well Construction Requirements and Dual Barrier System	T1	62,000	0	160,000 – 220,000	0	160,000 – 220,000	-
SCG-8-C2	Well Abandonments	T1	22,000	0	21,000 – 30,000	0	21,000 – 30,000	-

---

40 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

41 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

42 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

43 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

44 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

45 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[42]	2018 Baseline O&M	2020-2022 Capital[43]	2022 O&M	Total[44]	RSE[45]
SCG-8-C3	Pressure Monitoring and Alarming	T1	0	490	0	450 – 650	450 – 650	-
SCG-8-C4	Wellhead Leak Detection and Repair	T1	0	3,000	0	2,300 – 3,300	2,300 – 3,300	-
SCG-8-C5	Integrity Management for Gas Storage Operations	T1	2,800	6,300	4,100 – 5,900	5,000 – 7,200	9,100 – 13,100	-
SCG-8-C6	Integrity Demonstration, Verification, and Monitoring Practices	T1	0	3,800	0	7,100 – 10,000	7,100 - 10,000	0.62 – 0.66
		TOTAL COST	**87,000**	**14,000**	**190,000 – 260,000**	**15,000 – 21,000**	**200,000 – 280,000**	

It is important to note that SoCalGas is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SoCalGas will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for No RSE Calculation
SCG-8-C1	Well Construction Requirements and Dual Barrier System	Mandated activity per 14 CCR § 1726.5
SCG-8-C2	Well Abandonments	Mandated activity per 14 CCR § 1726.3(d)(1)
SCG-8-C3	Pressure Monitoring and Alarming	Mandated activity per 14 CCR § 1726.7
SCG-8-C4	Wellhead Leak Detection and Repair	Mandated activity per 14 CCR § 1726.7, 17 CCR § 95668, 49 CFR §192.12
SCG-8-C5	Risk Management for Gas Storage Operations	Mandated activity per 14 CCR §1726.3, 49 CFR §192.12

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SoCalGas considered alternatives to the mitigations for the Storage Risk. Typically, analysis of alternatives occurs when implementing activities. The alternatives analysis for this Risk Mitigation Plan took into account risk reduction, cost, new and existing requirements and compliance obligations, and constraints, such as budget and resources.

A. SCG-8-A1 – Casing Wall Thickness Inspection Tools

SoCalGas plans to continue to employ both magnetic flux leakage (MFL) and ultrasonic (UT) technologies each time a casing integrity inspection is performed (*see* SCG-8-C6). Current regulations do not require both technologies be employed, and as such SoCalGas considered an inspection plan that just utilizes one or the other instead of both. While potentially offering a cost savings due to elimination of contractor costs, using only one technology was deemed to be inferior to the existing practice of employing both MFL and UT technologies. It has been SoCalGas' experience that each inspection technology has specific strengths and weaknesses and utilizing both in a complimentary way reduces the chances that an anomaly is missed, thus providing a more informed assessment of the casing integrity.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.086**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	339.14	**348.14**	363.14
Post-Mitigation	LoRE		**0.0952**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	376.55	**386.54**	403.20
	RSE	0.58	**0.59**	0.62

B. SCG-8-A2 - Multi-String Metal Loss Inspections

SoCalGas Control SCG-8-C6 – Integrity Demonstration, Verification, and Monitoring Practices described in Section V of this chapter refers to the use of MFL and UT inspection tools to measure the wall thickness of the casing. In order to perform these inspections on the casing, the tubing string must first be removed from the well. Emerging pulsed-eddy current technology (through-tubing inspection) is being developed that could facilitate inspection of the casing by running an inspection tool in the tubing, thus eliminating the need to remove the tubing prior to inspection. The inspection tool, in this scenario, would need to be capable of detecting, and differentiating, metal loss in both the tubing and the casing. The result is a less intrusive inspection and the elimination of the need for a workover rig in order to perform the inspection.

SoCalGas utilized this type of through-tubing inspection on several wells and considered a wider application of its use as part of the integrity demonstration, verification, and monitoring practices. However, the preliminary through-tubing inspection logging results suggests that the pulsed-eddy technology (1) is currently limited in its ability to determine if metal loss is localized or circumferential, (2) does not provide a direct measurement ability to characterize defects for corrosion models, and (3) provides a vertical resolution that can be larger than what might be deemed through-wall defects. Through-tubing inspection technology shows potential for being used for a screening program, however its output data currently remains qualitative. SoCalGas will continue to monitor the progress of this technology and evaluate opportunities to incorporate these inspections into the integrity demonstration, verification, and monitoring practices.

		Low Alternative	**Single Point**	**High Alternative**
Pre-Mitigation	**LoRE**		**0.086**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	339.14	**348.14**	363.14
Post-Mitigation	**LoRE**		**0.0961**	
	CoRE	3956.67	**4061.67**	4236.67
	Risk Score	380.11	**390.20**	407.01
	RSE	0.60	**0.62**	0.65

Table 8: Alternative Mitigation Summary

(Direct 2018 $000)[46]

ID	Mitigation	2020-2022 Capital[47]	2022 O&M	Total[48]	RSE[49]
SCG-8-A1	Casing Wall Thickness Inspection Tools	0	5,500 – 8,000	5,500 – 8,000	0.58-0.62
SCG-8-A2	Multi-String Metal Loss Inspections	0	2,100 – 3,100	2,100 – 3,100	0.60-0.65

46 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

47 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

48 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

49 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SCG-8-C1	Well Construction Requirements and Dual Barrier System	DT.1; DT.2; DT.4 PC.1, PC.2, PC.3, PC.5, PC.9
SCG-8-C2	Well Abandonments	DT.1; DT.2; DT.4; DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7, PC.8, PC.9
SCG-8-C3	Pressure Monitoring and Alarming	DT.1; DT.2; DT.3; DT.4; DT.5 PC.1, PC.2, PC.3, PC.9
SCG-8-C4	Wellhead Leak Detection and Repair	DT.1; DT.2; DT.4; DT.5 PC.1, PC.2, PC.3, PC.9
SCG-8-C5	Integrity Management for Gas Storage Operations	DT.1; DT.2; DT.3; DT.4; DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7, PC.8, PC.9
SCG-8-C6	Integrity Demonstration, Verification, and Monitoring Practices	DT.1; DT.2; DT.4 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7, PC.8, PC.9

Risk Assessment Mitigation Phase
(Chapter SDG&E-10/SCG-9)
Cybersecurity

November 27, 2019

TABLE OF CONTENTS

Risk: Cybersecurity

I. INTRODUCTION

The purpose of this chapter is to present the risk mitigation plan San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the Companies) for the risk of Cybersecurity. This risk chapter is identical for both Companies given that the Cyber risk is currently managed centrally at the Companies. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

The Companies have identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, the Companies' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in this 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's and SoCalGas' respective General Rate Case (GRC) applications. The costs presented in this 2019 RAMP Report are those costs for which the Companies' anticipate requesting recovery in their respective Test Year (TY) 2022 GRCs. The Companies' TY 2022 GRC presentations will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address the Companies' Cybersecurity risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, the Companies did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

The Companies have also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of the Companies' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address

---

[3] *Id*. at 16.

[4] *Id.* at 17.

the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

For purposes of this 2019 RAMP Report, the Companies' Cybersecurity risk is defined as the risk of a major cybersecurity incident, which results in disruptions to electric or gas operations (*e.g.,* Industrial Control Systems, supply, transmission, distribution) and/or damage or disruption to the Companies' operations (*e.g.,* Human Resources, payroll, billing), reputation, or disclosure of sensitive customer or Company data.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[5] for each Control and Mitigation presented herein, the Companies have identified which element(s) of the Bow Tie the risk mitigation activity addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Drivers/Triggers and Potential Consequences
DT.1	Manipulated data or integrity failure
DT.2	Infrastructure or availability failure
DT.3	Access control or confidentiality failure
DT.4	Malicious software intrusions
DT.5	Cybersecurity control failures
DT.6	Operational system failures
DT.7	Equipment loss or theft
DT.8	Human error
PC.1	Disruption of energy flow systems
PC.2	Data corruption or unavailability
PC.3	Theft or destruction of systems/data
PC.4	Exposure of sensitive Company and customer data
PC.5	Adverse litigation
PC.6	Regulatory non-compliance fines and/or sanctions
PC.7	Erosion of public confidence
PC.8	Human Injury

5 *Id.* at Attachment A, A-11 ("Bow Tie").

C. Summary of Risk Mitigation Plan

The Companies' Risk Mitigation Plan for the Cybersecurity risk consists of five utility-focused operational cybersecurity categories:

1. Perimeter Defenses;
2. Internal Defenses;
3. Sensitive Data Protection;
4. Operational Technology (OT) Cybersecurity; and
5. Obsolete Information Technology (IT) Infrastructure and Application Replacement.

The Companies' Risk Mitigation Plan includes both baseline controls and new mitigation activities. Based on the foregoing assessment, the Companies' set forth future mitigations. In the previous RAMP filing, the Cybersecurity mitigation plan was structured using the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) to group like security controls. In this 2019 RAMP Report, the Companies are using operational groups to describe, and group mitigations in a more business-aligned approach. More detail can be found in Section V, below. A summary of the operational categories includes:

1. Perimeter Defenses

Enhancements to the Companies' existing Perimeter Defenses, privileged access management, firewall solutions for web applications and penetration testing consulting services to improve our solutions' ability to defend against an advanced, intelligent adversary.

2. Internal Defenses

Enhancements designed to detect and prevent malicious users (and/ or code from propagating) inside of the perimeter.

3. Sensitive Data Protection

Enhancements of security controls that will protect sensitive data throughout the technology systems.

4. **Operational Technologies (OT) Cybersecurity**

Enhancements to the management and protection of operational technology assets, improving threat intelligence and vulnerability management, and securing the communication infrastructure.

5. **Obsolete Information Technology (IT) Infrastructure and Application Replacement**

Enhancements to Information Technology (IT) components and capabilities that present cybersecurity risks to the Companies addressed via the necessary replacement and/or upgrades of obsolete and vulnerable IT operating systems, software, applications, hardware, monitoring tools, and other infrastructure components.

Pursuant to the SA Decision,[6] the Companies have performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. The Companies' 2018 Controls for this risk consist of the following:

Table 2: Summary of Controls

ID	Control Name
SDG&E-10-C1 SCG-9-C1	Perimeter Defenses
SDG&E-10-C2 SCG-9-C2	Internal Defenses
SDG&E-10-C3 SCG-9-C3	Sensitive Data Protection
SDG&E-10-C4 SCG-9-C4	Operational Technology (OT) Cybersecurity
SDG&E-10-C5 SCG-9-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement

6 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Finally, pursuant to the SA Decision,[7] the Companies considered alternatives to the Risk Mitigation Plan for the Cybersecurity risk and we summarize the reasons that the alternatives were not included in the Risk Mitigation Plan discussed in Section VIII, below.

D. Sensitive, Confidential Information to Be Protected

What is unique about the Cybersecurity risk, as compared to other risks driven by operations, asset management, or natural hazards, is that there is an intelligent adversary that is attempting to 1) understand the Companies' controls and 2) gain access to Company systems or information to achieve the adversary's objectives. It is important for our stakeholders to understand that some information about the Companies' mitigation plans or our worst-case scenarios would be useful to an adversary – and would indirectly harm our stakeholders. While some of our controls and strategies are considered standard practice, publishing some of these controls, intelligence, strategies, or tactics in the public record could aid our enemy, the criminal gang or nation state that is attempting to disrupt our systems and society. Sensitive details noted herein are available upon Commission request for discussion in person.

II. RISK OVERVIEW

Cybersecurity threats continue to rapidly evolve. As such, our strategy to counter cybersecurity threats must be flexible and allow us to adapt to these evolving threats over time.

Timely and accurate cybersecurity threat intelligence is key to staying abreast of this rapidly evolving threat landscape. We obtain cybersecurity threat intelligence from a variety of entities and sources, including Information Sharing and Analysis Centers (ISACs), the Federal Bureau of Investigations (FBI), the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the Department of Homeland Security (DHS) and a variety of United States (US) Intelligence Community agencies. Information from threat intelligence in the utility industry continues to reveal adversaries that are using advancing tradecraft to try and access our nation's utility systems.

---

7 *Id.* at 33.

A. The Companies are Faced with an Evolving Cybersecurity Threat

At the FERC 2018 Reliability Technical Conference;[8] "Addressing the Evolving Cybersecurity Threat" panel, it was noted that, "There is a widespread understanding among policymakers and industry that cyberattacks are a persistent and growing threat to the reliable or resilient operation of the Bulk-Power System."[9]

A representative sample of recent threats facing our industry are provided below:

OT Attacks on Utility Infrastructure

- ***Attack on Ukrainian Electric Operator*** (https://www.us-cert.gov/ics/alerts/IR-ALERT-H-16-056-01) This was a well-publicized and understood attack by a nation state on the electrical transmission system in Ukraine. This was an advanced attack that migrated from the IT to OT system and resulted in the loss of electric load to approximately 200,000 customers.
- ***May 2019 reporting on Western Energy Firm attack*** (https://www.dispersive.io/blog/first-of-its-kind-denial-of-service-attack-on-western-u.s.-utility*)* A distributed denial of service (DDOS) attack aimed at a Northwestern US power company, disrupted operations but did not result in a loss of electric load.

Insider Attacks

- ***Capital One former insider*** (https://www.bloomberg.com/news/articles/2019-07-29/capital-one-data-systems-breached-by-seattle-woman-u-s-says*)* An insider, formerly employed by Amazon Web Services (AWS), illicitly penetrated vulnerabilities in the AWS configurations to enable access to the Capital One customer data.

---

8 Federal Energy Regulatory Commission, Supplemental Notice of Technical Conference (July 17, 2018), *available at* https://www.ferc.gov/CalendarFiles/20180724131230-notice-AD18-11.pdf.

9 *Id.* at 5.

Supply Chain

- ***Russian attack on electric utility suppliers***
  *(*https://www.wsj.com/articles/americas-electric-grid-has-a-vulnerable-back-doorand-russia-walked-through-it-11547137112*)*
  Reports that a Russian group accessed an electric utility via one of the utility's smaller vendors. The Companies are monitoring a growing concern in cyber with respect to harmful vulnerabilities introduced in the supply chain.

IT Cybersecurity

- ***NotPetya*** *(*https://www.wired.com/story/notpetya-cyberattack-ukraine-russia-code-crashed-the-world/*)* A Russian-driven attack on IT systems, using "ransomware" malicious software that resulted in damages to the IT hardware after infection.

B. Adversaries

The adversaries the Companies face include various types of actors with varying intent to cause harm; they are not just criminal entities or hackers looking to make a political statement or achieve financial gain. They also include advanced adversaries, often aligned to nation states, that are targeting critical infrastructure for economic exploit, espionage, or covert action in preparation for some overt act (*e.g.*, disrupting energy supply). The Companies believe their investment and spend in Cybersecurity is prudent and reasonable to address the existing and growing threat.

Adversaries continue to use an evolving and more sophisticated set of tools and strategies to conduct attacks on the energy sector. Their suite of capabilities was touched on above but also includes advanced malware, more complex phishing attacks, among others. Adversaries are also conducting other campaigns to target utility employees, akin to the recently publicized targeting of US Government officials through LinkedIn.[10]

---

10 U.S. Army Cyber Command, *Army Cyber Fact Sheet: LinkedIn Scams* (September 26, 2019), *available at* https://www.arcyber.army.mil/Info/Fact-Sheets/Fact-Sheet-View-Page/Article/1972156/army-cyber-fact-sheet-linkedin-scams.

C. Cybersecurity Program

At the Companies, cybersecurity is critical to the safe and reliable delivery of electric and gas service to our customers, including critical infrastructure providers in our Southern California service territory (*e.g.,* financial services, telecommunication providers, other utilities). Our service territory includes millions of people, one of the Nation's busiest ports, largest cities, most critical military bases, countless defense contractors and small businesses.

At the Companies, everyone plays a part in cybersecurity. The cybersecurity program is led by the Cybersecurity department. The mitigations discussed in this chapter focus on those control activities performed or supported directly by the Cybersecurity department as a shared service for SDG&E, SoCalGas, and Sempra Energy. The Cybersecurity department manages cybersecurity risks across the enterprise, including information technology and operational technology.

The Cybersecurity program utilizes risk management frameworks, including but not limited to, the NIST Cybersecurity Framework, Center for Internet Security (CIS-20), and NIST 800-53. Additionally, we comply with all applicable laws and regulations both at the State and Federal level.

III. RISK ASSESSMENT

In accordance with the SA Decision,[11] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the Cybersecurity risk.

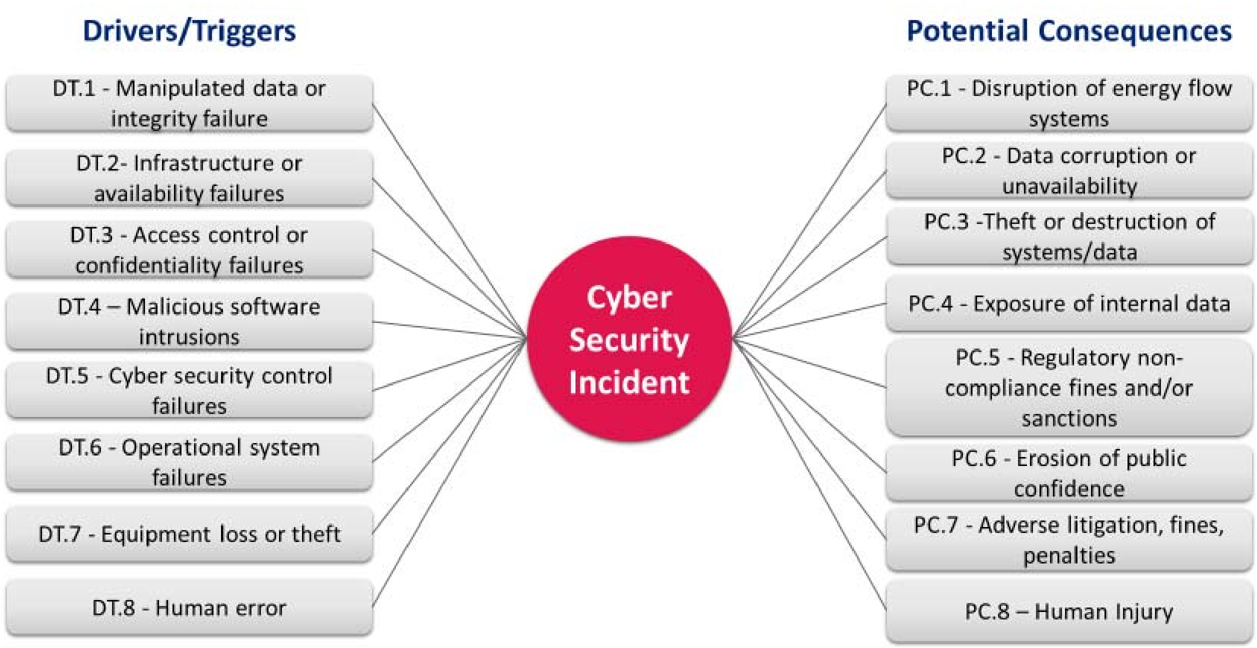
A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. The Companies applied this framework to identify and summarize the information provided above. A mapping of each Control to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

---

11 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[12] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. The Cybersecurity risk is a "cross-cutting" risk impacting all of the Companies' electric and gas operations assets, infrastructure, and systems, including: information technology (IT) perimeter, the IT internal systems, sensitive data within the IT systems, legacy technology infrastructure, and operational technology.

C. Risk Event Associated with the Risk

The SA Decision[13] instructs the utilities to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a Cybersecurity event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. There are many possible ways in which a cybersecurity event can occur. The

---

[12] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[13] *Id.* at Attachment A, A-11 ("Bow Tie").

scenario below represents a situation that could happen, within a reasonable timeframe, and lead to a relatively significant adverse outcome.

Possible scenario: A malicious cyber attacker successfully accesses Company information or technology assets, which results in disruption in energy delivery, creates an unsafe condition with safety impacts, damages financial or other operational systems, and/or exposes customer data.

D. Potential Drivers/Triggers[14]

The SA Decision[15] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Cybersecurity, the Companies identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT.1 - Manipulated data or integrity failure**: Any unintended changes to data as the result of a storage, retrieval or processing operation, including malicious intent, unexpected hardware failure, and human error.
- **DT.2- Infrastructure or availability failure**: Refers to an unplanned, severe, extensive and/or large-scale system outage caused by a cybersecurity-related event or incident.
- **DT.3 -Access control or confidentiality failure**: Inability to effectively perform identification authentication and authorization of users and entities by evaluating required login credentials that can include passwords, personal identification numbers (PINs), biometric scans, security tokens or other authentication factors.
- **DT.4 - Malicious software intrusions**: Describes any malicious program or code that is harmful to systems. Malware seeks to invade, damage, or disable computers, computer systems, networks, tablets, and mobile devices, often by taking partial control over a device’s operations.

---

14 An indication that a risk could occur. It does not reflect actual or threatened conditions.

15 D.18-12-014 at Attachment A, A-11 (“Bow Tie”).

- **DT.5 - Cybersecurity control failures**: Refers to a general failure of a Cybersecurity control(s). *E.g.,* a vulnerability scanner ceases functioning, allowing an exploitable vulnerability to go unnoticed in the environment.
- **DT.6 - Operational system failures**: A system failure occurring due a cybersecurity event/incident, causing the system to freeze, reboot, or stop functioning altogether.
- **DT.7 - Equipment loss or theft**: A type of data breach where there is a loss of a laptop, mobile device, or storage device such as backup tapes, hard drives, and flash drives whether by accidental loss or through malicious intent.
- **DT.8 - Human error (*e.g.*, clicking on a phishing email):** Refers to an accidental cybersecurity event/incident conducted by a human.

E. Potential Consequences

There are several potential worst-case scenarios that the Companies consider. However, as noted earlier, we are intentionally not sharing the details of these scenarios to avoid informing adversaries. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- **PC.1 - Disruption of energy flow systems**: Refers to a power outage, or failure of gas distribution, where there is the loss of electrical power, or natural gas supply, to an end user. Energy delivery failures are particularly critical at sites where the environment and public safety are at risk.
- **PC.2 - Data corruption or unavailability**: A situation where data is made unavailable or modified via failures in storage, transmission, processing, or a cybersecurity incident (*e.g.*, "Ransomware" attack).
- **PC.3 - Theft or destruction of systems/data**: A situation where data is accidentally or maliciously destroyed (made unavailable) or stolen causing an impact to business operations, reputation and/or financial harm.
- **PC.4 - Exposure of sensitive Company and customer data**: Exposure of sensitive Company and customer data can be a significant cybersecurity

incident to an organization with consequences that can include loss of customer confidence, public trust, financial penalties, among others.

- **PC.5 - Regulatory non-compliance fines and/or sanctions:** The risk of a regulatory compliance failure which results in potential penalties/fines or sanctions.
- **PC.6 - Erosion of public confidence:** Refers to a cybersecurity event/ incident causing a potential loss to financial capital, social capital and/or market share resulting from damages to a firm's reputation.
- **PC.7 - Adverse litigation:** Refers to Litigation risk, which is the possibility that legal action will be taken because of an individual's or corporation's actions, inaction, products, services or other events. Corporations generally employ some type of litigation risk analysis and management to identify key areas where the litigation risk is high, and thereby take appropriate measures to limit or eliminate those risks.
- **PC.8 – Human injury:** Refers to physical trauma to the body.

These Potential Consequences were used in the scoring of the Companies' Cybersecurity Risk during the development of the 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision[16] sets minimum requirements for risk and mitigation analysis in RAMP, including enhancements to the Interim Decision 16-08-018.[17] The Companies used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

16 *Id.* at Attachment A.

17 *Id.* at 2-3.

Table 3: Pre-Mitigation Analysis Risk Quantification Scores[18]

Cyber Security	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	897	**920**	958
LoRE	**0.02**		
CoRE	44873	**46018**	47925

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[19] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 4: Risk Quantification Scope

In-Scope for purposes of risk quantification:	Major cybersecurity incident on the SCADA system[20] which results in disruptions to electric or gas operations.
Out-of-Scope for purposes of risk quantification:	Disruption to Company operations (*e.g.,* HR, payroll, billing), reputation, or disclosure of sensitive customer or Company data.

Given the emerging and evolving nature of cyber risk particularly in the Operational Technology (OT) domain there is limited information to assess the risk using historical information. Therefore, the Companies used multiple indicators in predicting the likelihood and consequence of such an event.

18 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

19 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

20 SCADA is an acronym for supervisory control and data acquisition, a computer system for gathering and analyzing real time data.

Several data points and sources were used to help the Companies' subject matter experts (SME) estimate the likelihood of this event. According to the "Lloyd's Report – The Insurance Implications of a Cyber Attack on the US Power Grid," there have been 15 suspected cyber-attacks or events on the US electric grid from 2000 to 2015.[21] The estimate of the likelihood of the scenario based on that report is in the order of 2% (1 in 50 years). In addition, the Accenture, "Cost of Cyber Crime Study,"[22] indicates a rapidly evolving risk increasing at an annual rate of 27%.[23] Given this information, the Companies' SMEs provide a likelihood of 2% for the cyber risk or 1:50 years.

To determine the Potential Consequences, the Companies, including SMEs from Cybersecurity, electric operations, and gas operations, evaluated relevant industry event scenarios to determine a credible worst-case scenario of a cyberattack at the Companies. The scenarios evaluated account for the potential unavailability of a compromised SCADA system for restoration:

1. Ukraine 2015 and 2016/2018 – In 2015, remote cyber intrusions caused outages at three regional electric power distribution companies impacting approximately 225,000 customers for 6 hours in Ukraine. In 2016, hackers used a more sophisticated malware ("Crash Override") to attempt to disable protective relay devices through a denial of service (DoS) attack. Though the 2016 attack only caused a one-hour outage, recent research suggests that hackers intended to inflict lasting damage that could have led to outages for weeks or even months.
2. 2011 South West Outage – In 2011, a maintenance procedure in Yuma, Arizona caused a cascade of power failures across the Southwest resulting in widespread impact to SDG&E's service territory. As the failure spread, grid operators were

---

21 Lloyd's, *Emerging Risk Report – 2015, Business Blackout, The Insurance Implications of a Cyber Attack on the US Power Grid* (May 2015) at 53, *available at* https://www.lloyds.com/news-and-risk-insight/risk-reports/library/society-and-security/business-blackout.

22 Accenture, *2017 Cost of Cyber Crime Study, Insights on the Security Investments That Make A Difference*, *available at* https://www.accenture.com/_acnmedia/PDF-62/Accenture-2017CostCybercrime-US-FINAL.pdf#zoom=50.

23 *Id.* at 4.

unaware of many rapid-fire events outside their territories. Electrical service was restored to most SDG&E customers within 12 hours.

3. 2003 North East Outage – The biggest blackout in North America occurred in 2003. High voltage power lines came into contact with vegetation, and a combination of human error and equipment failures resulted in outages for 50 million people.

4. Lloyds Scenarios (Scenario 1) - A report produced by Lloyd's and the University of Cambridge considered the impact of a hypothetical cyber-attack. In the scenario, malware infects generation control rooms in Northeast US. The malware goes undetected until triggered and tries to take control of generators. While power is restored to some areas within 24 hours, others remain without electricity for weeks.

B. Sources of Input

The SA Decision[24] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

1. Richards, Kevin, "Accenture Report the Cost of Cyber Crime," dated 2017;
2. Maynard, Trevor, "Lloyd's Report the Insurance Implications of a Cyber Attack on the US Grid," dated May 2015; and
3. Slowick, Joe, "Dragos Inc CRASHOVERRIDE: Reassessing the 2016 Ukraine Electric Power Event as a Protection-Focused Attack," August 16, 2019.

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[25] This section describes the Companies' Risk Mitigation Plan by each selected Control for this risk, including the rationale supporting each selected Control.

---

[24] D.18-12-014 at Attachment A, A-8 – A-9 ("Identification of the Frequency of the Risk Event").

[25] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

The Cybersecurity Risk Mitigation Plan discussed below includes the five operational categories introduced in Section I above. The Risk Mitigation Plan includes Controls and Mitigations that are expected to continue for the period of the Companies' TY 2022 GRC cycle.[26] The Controls (*i.e.,* those with a "C" identifier below) are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time. In addition, the Companies have considered the evolving threat and regulatory landscape in the design of its plan. The Companies have adopted a comprehensive and enhanced control portfolio that balances risk mitigation and cost effectiveness while also establishing foundational security capabilities that will serve to mitigate risks from evolving threats. The Presented Portfolio is designed to provide adequate risk reduction to offset the projected cyber risk increase to maintain this risk at a manageable level.

A. SDG&E-10-C1/SCG-9-C1: Perimeter Defenses

The Perimeter Defenses category includes activities that the Companies take to protect the perimeter of its information technology systems. A robust set of controls at the perimeter of corporate systems contributes to the Companies' *defense-in-depth* strategy. The purpose of the defense-in-depth strategy is to manage risk with diverse defenses, so that if one layer of defense turns out to be inadequate, the additional layers of defense will prevent further impacts and/or a full breach.

Perimeter Defenses are designed to prevent attacks, protect the integrity of, and detect unauthorized access to the Companies' internal information technology systems. The information technology environment includes the entire business technology system, including email, information storage, billing and customer records, among others. The operational technology environment also uses perimeter defenses to protect operational technology assets.

Examples of the Companies' existing Perimeter Defenses include:

- Web application firewalls;

---

[26] *Id.* at 16-17 and 33. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

- Access management at the perimeter;
- Penetration testing of our perimeter to regularly challenge our defense capabilities;
- Multi-factor authentication to enhance user access controls;
- Enhanced firewalls, intrusion detection and prevention technologies;
- Email security gateway to enhance email system security; and
- Web content filter to enhance safer web site browsing/access.

B. SDG&E-10-C2/SCG-9-C2: Internal Defenses

Program activities in the Internal Defenses category are designed to detect and prevent unauthorized users, those misusing authorized credentials, and malicious software (*i.e.*, malware) from propagating inside of the perimeter. As another layer of defense-in-depth, the activities within this category include investments that will directly reduce the risk to internal assets and information. This control focuses on:

- Preventing unauthorized access to technology, systems and/or information;
- Validating that only authorized users are using a profile or credentials associated with that user (authorized employee);
- Analysis of potentially unusual and/or malicious activities;
- Automating threat detection and response activities to decrease cybersecurity risk;
- Improve ability to meet compliance requirements (*e.g.*, CCPA, NERC CIP, etc.);[27]
- Enhancing cloud security (*i.e.,* as an extension of the internal Company system); and
- Network security monitoring.

[27] California Consumer Privacy Act, North American Electric Reliability Corporation Critical Infrastructure Protection standards.

C. SDG&E-10-C3/SCG-9-C3: Sensitive Data Protection

Sensitive data protection is a core component of the Companies' defense-in-depth strategy for cybersecurity. The Sensitive Data Protection activities outlined below enhance technology to reduce the risk of unauthorized access. The Companies' current control activities target sensitive data within information technology systems, including laptops and other mobile computing devices. Sensitive data protection controls are designed to:

- Automatically scan assets to identify location of sensitive data;
- Identify the movement, copying, or dissemination of data from central and mobile technology systems;
- Monitor unauthorized patterns of data movement;
- Multi-factor authentication to enhance user access controls; and
- Data loss prevention to enhance our capabilities in securing information.

D. SDG&E-10-C4/SCG-9-C4: Operational Technology (OT) Cybersecurity

The OT Cybersecurity category focuses on securing the operational technology environments for the Companies. OT environments enable critical business functions, including safe and reliable energy delivery to customers throughout the service territory.

OT cybersecurity requires a specialized approach in order to balance operational needs with cybersecurity risk. The Companies' cybersecurity program prioritizes operational technology controls, including: the management of its existing technology assets, improving threat intelligence and vulnerability management, and securing the communication infrastructure. The Companies are focused on maintaining a secure operational environment to support safe, reliable gas and electric systems and service. The Companies' OT Cybersecurity Controls include:

- OT network anomaly detection to identify and prevent potentially malicious network traffic;
- Physical and cybersecurity operations center visibility into operational technology systems;
- Monitoring of endpoint technology devices that control electric and gas assets;

- Visibility into the status and location of all operational technology through asset management;
- Enhanced whitelisting capabilities (to validate that only approved computer programs can run);
- Secure telecommunication network capabilities; and
- Multi-factor authentication to enhance user access controls.

E. SDG&E-10-C5/SCG-9-C5: Obsolete Information Technology (IT) Infrastructure and Application Replacement

One of the fundamental practices that supports a strong cybersecurity program is the refresh of technology, both hardware and software, at regular intervals, to minimize risks posed by vulnerable, obsolete technologies. Technology lifecycles are short and require frequent upgrades to meet modern security standards and capabilities. In addition to technology obsolescence, this approach also addresses security obsolescence. Security obsolescence refers to cybersecurity tools and/or processes that are no longer effective, and/or potentially could create new vulnerabilities. The controls presented in this section include:

- Technology refreshes, including, but not limited to:
  - Infrastructure;
  - Operating systems;
  - Middleware; and
  - Applications.
- System maintenance to confirm continued secure configurations, patching, upgrading, among others.
- Use of effective architecture and other mechanisms to confirm high availability and service continuity for critical systems.

In addition, there are fundamental, baseline control activities required to support and effectively manage the cybersecurity capabilities listed in the previous sections. These baseline activities referenced in the O&M budget outlook (tables 2 and 3) support the capital investments. Some examples of these baseline controls include, but are not limited to:

- A security policy framework

- Risk management & assessments
- Cybersecurity awareness and training
- Security assessment
- Asset management
- Protective technologies (Network, User, Application)
- System authentication – public key infrastructure (PKI)
- Security Operations Center
  - Monitors security-related activities in systems and applications
  - Anomaly detection
  - Security event detection and escalation
  - Monitors detection infrastructure systems to investigate security events
  - Incident response
  - Exercises/drills

The combination of existing cybersecurity controls and enhancements will help the Companies keep pace with the rapidly evolving cybersecurity threats.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, the Companies have performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[28] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). The Companies' rationale for the determination of Tranches is presented below.

A single tranche is appropriate for a Cybersecurity risk event as there is no logical disaggregation of assets or systems related to the controls presented in the mitigation plan. The Controls for this risk are evaluated at the category level due to the availability of data, the rapidly

[28] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

changing threats and applicable counter measures. Therefore, the level of granularity for quantifying RSE is currently at the operational category level (*i.e*., perimeter defenses, internal defenses, sensitive data protection, OT cybersecurity and Obsolete IT infrastructure and asset replacement) rather than each individual risk mitigation activity for the Cybersecurity risk.

B. Post-Mitigation/Control Analysis Results

For purposes of the post-mitigation and post-control analysis, the Companies looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[29] The Companies then looked at existing/continuing programs (*i.e.*, Controls), and expect to get similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). The Companies also accounted for the risk increase that would occur over time if we stopped performing these activities. The specific risk reduction benefit percentages used for each identified control/mitigation is included under each program heading below.

C. SDG&E-10-C1/SCG-9-C1: Perimeter Defenses

1. Description of Risk Reduction Benefits

Perimeter Defenses reduce the frequency or probability of successful attacks. As a security strategy, it accomplishes this by limiting access to authorized users, reducing the likelihood that malicious code will enter the information technology environment, and delaying or frustrating potential attackers. This strategy also helps us to understand the number of pathways into or out of the perimeter while simultaneously monitoring the perimeter in real time.

Perimeter Defenses are an important component of defense-in-depth but can only reduce the probability of an adversary having unauthorized access to internal systems and data. This control includes enhancements to firewalls and other intrusion protection measures to maintain the risk at the current manageable level and keep up with the increasing potential threats to our perimeter.

---

[29] *Id.* at Attachment A, A-12 ("Determination of Post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," "Measurement of Post-Mitigation Risk Score," "Measurement of Risk Reduction Provided by a Mitigation").

2. Elements of the Bow Tie Addressed

SDG&E-10-C1/SCG-9-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Infrastructure or availability failure (DT.2), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Equipment Loss or Theft (DT.7), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0270**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1212.48	**1243.40**	1294.93
	RSE	127.50	**130.75**	136.17

D. SDG&E-10-C2/SCG-9-C2: Internal Defenses

1. Description of Risk Reduction Benefits

Internal Defense controls support the Companies' defense-in-depth strategy, which helps to detect and prevent unauthorized users, those misusing authorized credentials, and malicious software (*i.e.*, malware) from propagating once inside of the perimeter. The controls in this category are designed to detect unauthorized users from moving laterally or vertically within the IT system or into the OT system, which improves our ability to identify and respond to threats more quickly. The enhancements to our IT and OT systems' Access Management system will allow us to keep our current risk level steady/static.

2. Elements of the Bow Tie Addressed

SDG&E-10-C2/SCG-9-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated data or integrity failure (DT.1), Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Equipment Loss or Theft (DT.7), Human error (DT.8), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0256**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1149.48	**1178.79**	1227.64
	RSE	24.49	**25.12**	26.16

E. SDG&E-10-C3/SCG-9-C3: Sensitive Data Protection

1. Description of Risk Reduction Benefits

The Sensitive Data Protection control helps reduce the risk of unauthorized access to the Companies' information by understanding where sensitive data is stored, how it is transmitted, and how it is used. This helps to further protect customer and Company information. The activities for this control will help us continue the prudent management of sensitive data.

2. Elements of Bow Tie Addressed

SDG&E-10-C3/SCG-9-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated

data or integrity failure (DT.1), Access control or confidentiality failure (DT.3), Cybersecurity control failures (DT.5), Human error (DT.8), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Adverse Litigation (PC.5), Regulatory non-compliance fines and/or sanctions (PC.6), Erosion of public confidence (PC.7).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	58.13	**59.61**	62.08

F. SDG&E-10-C4/SCG-9-C4: Operational Technology (OT) Cybersecurity

1. Description of Risk Reduction Benefits

The OT environment requires a slightly different approach from IT Cybersecurity. OT activities are intended to reduce the risk of an adversary controlling or disabling the Companies' operational technology. Improving asset management helps identify unauthorized systems, which could potentially be a source of an attack. Anomaly detection, endpoint detection, and security event monitoring improves visibility into the OT environment, which allows for faster response and remediation. Enhanced secure access technologies help reduce risk of unauthorized access. These risk mitigation activities strengthen our capabilities by securing the foundation of OT security. These enhancements are necessary to maintain a secure OT system and mitigate the increasing potential threat on that critical system.

2. Elements of the Bow Tie Addressed

SDG&E-10-C4/SCG-9-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Human error (DT.8), Disruption of energy flow systems (PC.1), Data corruption or unavailability (PC.2), Adverse litigation (PC.5), Regulatory non-compliance fines and/or sanctions (PC.6), Erosion of public confidence (PC.7).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0284**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1275.48	**1308.01**	1362.21
	RSE	51.60	**52.92**	55.11

G. SDG&E-10-C5/SCG-9-C5: Obsolete Information Technology (IT) Infrastructure and Application Replacement

1. Description of Risk Reduction Benefits

Vulnerabilities inherent in legacy technology can provide a foothold for entry or movement within the Companies' environment. Failure to invest in modern technologies could degrade the value of modern investments due to compatibility restrictions. Replacing legacy technology is a necessary method of managing cybersecurity risk.

2. Elements of the Bow Tie Addressed

SDG&E-10-C5/SCG-9-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated

data or integrity failure (DT.1), Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Disruption of energy flow systems (PC.1), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0242**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1086.48	**1114.18**	1160.36
	RSE	66.06	**67.74**	70.55

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

The Companies' Risk Mitigation Plan takes into account recent data and trends related to Cybersecurity, possible labor constraints and the feasibility of mitigations. The Companies have performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors, including technology, planning, resources, compliance requirements, and operational and execution considerations.

The tables below provide a summary of the Risk Mitigation Plan, including controls, associated costs, and RSEs.

The Companies do not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Tables 5 and 6 below were estimated using assumptions provided by SMEs and available accounting data.

Table 5: SoCalGas Risk Mitigation Plan Summary[30]
(Direct 2018 $000)[31]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[32]	2018 Baseline O&M	2020-2022 Capital[33]	2022 O&M	Total[34]
SCG-9-C1	Perimeter Defenses	T1	5,400	60	6,100 - 7,800	160 - 210	6,300 – 8,000
SCG-9-C2	Internal Defenses	T1	17,000	180	36,000 - 47,000	500 - 630	37,000 – 48,000
SCG-9-C3	Sensitive Data Protection	T1	-	180	5,700 - 7,300	500 - 630	6,200 – 8,000
SCG-9-C4	Operational Technology (OT) Cybersecurity	T1	2,800	150	17,000 - 21,000	410 – 520	17,000 – 22,000
SCG-9-C5	Obsolete IT Infrastructure and Application Replacement	T1	3,300	30	7,400 - 9,500	80 - 110	7,500 – 10,000
TOTAL COST			**29,000**	**600**	**72,000 - 93,000**	**1,700 - 2,000**	**74,000 – 95,000**

30 Recorded costs and ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

31 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

32 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

33 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

34 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

Table 6: SDG&E Risk Mitigation Plan Summary[35]
(Direct 2018 $000)[36]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M	Total[39]
SDG&E-10-C1	Perimeter Defenses	T1	-	830	0	1,200 - 1,500	1,200 - 1,500
SDG&E-10-C2	Internal Defenses	T1	-	1,000	0	1,300 - 1,700	1,300 - 1,700
SDG&E-10-C3	Sensitive Data Protection	T1	-	380	0	520- 670	520- 670
SDG&E-10-C4	Operational Technology (OT) Cybersecurity	T1	280	600	8,400 – 11,000	910 - 1,200	9,310 – 12,200
SDG&E-10-C5	Obsolete IT Infrastructure and Application Replacement	T1	1,400	1,000	0	1,300 - 1,700	1,300 - 1,700
		TOTAL COST	**1,700**	**3,800**	**8,400 - 11,000**	**5,200 -6,800**	**14,000 – 18,000**

35 Recorded costs and ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

36 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

37 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

38 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

39 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

It is important to note that the Companies are identifying potential ranges of costs in this Risk Mitigation Plan and are not requesting funding herein. The Companies will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, the Companies considered alternatives to the Risk Mitigation Plan for the Cybersecurity risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost.

The alternatives analysis for this Risk Mitigation Plan also considered modifications to the Presented Portfolio and constraints, such as budget and resources. The Companies considered two Alternative Portfolios to the Presented Portfolio identified above as it developed the Risk Mitigation Plan to address the Companies' Cybersecurity risk. Alternatives were analyzed in the context of risk-spend efficiency, outlined in the tables below, and considered as portfolios rather than individual mitigations.

For the alternative analysis, the Companies analyzed the effectiveness of three portfolios:

1. Presented Portfolio,
2. Alternative 1, and
3. Alternative 2.

To create these three different portfolios, the Companies first assessed the potential impact of each capital project under consideration, identifying each as high/medium/low based on several criteria:

- Project implementation's impact on the maturity of cybersecurity at the Companies;

- Extent to which each project addresses recommendations from CSC 20,[40] ICS-CERT,[41] and other frameworks;
- Extent to which each project addresses threats to cybersecurity of high impact and likelihood; and
- Effectiveness in mitigating a credible attack impacting safety.

After each project was tagged as High/Medium/Low, the following three portfolios were developed: Presented Portfolio, Alternative Portfolio 1 and Alternative Portfolio 2.

A. Presented Portfolio

The Companies' Presented Portfolio (*i.e.*, the Risk Mitigation Plan as described in Sections V and VI, above) includes a mix of "high" impact and "medium" impact projects. The identified high-impact and medium-impact projects were grouped into the five categories described above: 1) Perimeter Defenses, 2) Internal Defenses, 3) Sensitive Data Protection, 4) Operational Technology Cybersecurity, and 5) Obsolete IT Infrastructure and Application Replacement. The post-mitigation analysis demonstrates that the Companies' Presented Portfolio of high- and medium-impact projects is the most cost-effective portfolio for managing the increase in cybersecurity risk, as is demonstrated by the high RSE compared to other alternative portfolios. Company SMEs estimated that the Presented Portfolio will have an effectiveness proportional to the growth rate of the risk of cybersecurity threats, hence funding at this level will maintain the risk at a manageable level.

---

40 CSC-20: The Twenty (20) Critical Security Controls (CSC) for Cyber Defense are a culmination of exhaustive research and development of information security initiatives that advocate a "offense must inform defense approach," as noted by the SANS institute.

41 ICS-CERT: The Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) provides a control system security focus in collaboration with US-CERT to:

- Conduct vulnerability and malware analysis
- Provide onsite support for incident response and forensic analysis
- Provide situational awareness in the form of actionable intelligence
- Coordinate the responsible disclosure of vulnerabilities/mitigations
- Share and coordinate vulnerability information and threat analysis through information products and alerts.

B. Alternative Portfolio 1

The Companies' Alternative Portfolio 1 consists of "high" impact projects only. The identified high-impact projects were grouped into the same five categories described above. The post-mitigation analysis demonstrates that the Companies' Alternative Portfolio 1, comprising only high-impact projects, is estimated to have a lower RSE than the Presented Portfolio when considering the RSE of the individual categories, as shown below. In addition, this portfolio does not provide enough risk reduction to address the increasing rate of cybersecurity risk. The effectiveness of the projects in this alternative portfolio is lower than the growth rate of the risk, as estimated by the Companies; hence, if we fund at this level, the cyber risk will increase.

The post-mitigation analyses for each of the five utility-focused operational cybersecurity categories are presented below. As stated above, these projects, when combined into an alternative portfolio, is lower than the Companies' Presented Portfolio provided in Sections V and VI.

1. Alternative Portfolio 1 – C1 (High-impact Perimeter Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0256**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1149.48	**1178.79**	1227.64
	RSE	122.26	**125.37**	130.57

2. Alternative Portfolio 1 – C2 (High-impact Internal Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	15.53	**15.93**	16.59

3. Alternative Portfolio 1 – C3 (High-impact Sensitive Data Protection)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0214**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	960.47	**984.96**	1025.78
	RSE	35.83	**36.74**	38.26

4. Alternative Portfolio 1 – C4 (High-impact OT Cybersecurity)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0276**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1237.68	**1269.24**	1321.84
	RSE	52.69	**54.03**	56.27

5. Alternative Portfolio 1 – C5 (High-impact Obsolete IT Infrastructure and Application Replacement)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0238**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1067.57	**1094.80**	1140.17
	RSE	65.03	**66.69**	69.46

C. Alternative Portfolio 2

Alternative Portfolio 2 consists of all cybersecurity projects under consideration (*i.e.,* high-impact, medium-impact and low-impact). Whereas the Companies' Presented Portfolio includes high- and medium-impact projects, and Alternative Portfolio 1 includes only high-impact projects, this Alternative Portfolio 2 presents all projects that the Companies have currently identified. Alternative Portfolio 2 has the highest cost, and the most risk reduction. Alternative Portfolio 2 has an RSE lower than the Presented Portfolio since the additional projects in the portfolio (the low-impact projects beyond those included in the Presented Portfolio) provide an incremental benefit; however, that incremental benefit is less effective relative to its incremental cost.

1. Alternative Portfolio 2 – C1 (High-, Medium-, and Low-impact Perimeter Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0277**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1243.98	**1275.70**	1328.57
	RSE	123.40	**126.55**	131.80

2. Alternative Portfolio 2 – C2 (High-, Medium-, and Low-impact Internal Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0262**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1174.68	**1204.63**	1254.56
	RSE	24.32	**24.94**	25.97

3. Alternative Portfolio 2 – C3 (High-, Medium-, and Low-impact Sensitive Data Protection)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	58.13	**59.61**	62.08

4. Alternative Portfolio 2 – C4 (High-, Medium-, and Low-impact OT Cybersecurity)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0284**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1275.48	**1308.01**	1362.21
	RSE	51.60	**52.92**	55.11

5. **Alternative Portfolio 2 – C5 (High-, Medium-, and Low-impact Obsolete IT Infrastructure and Application Replacement)**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0242**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1086.48	**1114.18**	1160.36
	RSE	66.06	**67.74**	70.55

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

Control ID	Control Name	Driver(s), Trigger(s) & Potential Consequences Addressed
SDG&E-10-C1 SCG-9-C1	Perimeter Defenses	DT.2, DT.4, DT.5, DT.6, DT.7 PC.4, PC.6
SDG&E-10-C2 SCG-9-C2	Internal Defenses	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8 PC.2, PC.3, PC.4, PC.6
SDG&E-10-C3 SCG-9-C3	Sensitive Data Protection	DT.1, DT.3, DT.5, DT.8, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7
SDG&E-10-C4 SCG-9-C4	Operational Technology (OT) Cybersecurity	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8 PC.1, PC.2, PC.5, PC.6, PC.7
SDG&E-10-C5 SCG-9-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, PC.1, PC.2, PC.3, PC.4, PC.6

Risk Assessment Mitigation Phase
(RAMP-A)
Overview & Approach

November 27, 2019

TABLE OF CONTENTS

I. RAMP OVERVIEW

A. Introduction

San Diego Gas & Electric Company (SDG&E or Company) presents its 2019 Risk Assessment Mitigation Phase (RAMP) Report to the California Public Utilities Commission (Commission or CPUC) in the RAMP Order Instituting Investigation (OII) proceedings, I.19-11-011 (approved on November 7, 2019). This 2019 RAMP Report marks a significant milestone in the Company's risk-informed decision-making framework process and in the journey of the California investor-owned utilities' (IOUs) efforts over the past several years to incorporate in this Report the "quantitative approach to risk assessment and risk prioritization"[1] approved by the Commission in Decision (D.) 18-12-014, the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement Decision (SA Decision). This Chapter provides an overview of the Company's 2019 RAMP Report and outlines the approach and guiding principles applied to this RAMP Report.

The RAMP is considered the first phase of the Company's next General Rate Case (GRC), Test Year (TY) 2022. The purpose of the RAMP is 'to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks."[2] Consistent with this purpose, the 2019 RAMP Report focuses on the Company's key safety risks and the current and proposed activities to help mitigate those risks. Specifically, the RAMP Reports of Southern California Gas Company (SoCalGas) and SDG&E present 18 risk specific chapters; eight for SoCalGas, nine for SDG&E, and one joint SoCalGas/SDG&E chapter. These chapters are categorized into risks related to 1) gas assets, 2) electric assets, and 3) human systems (or cross-cutting) risks. Each identified RAMP risk is discussed in detail in the individual risk chapters associated to a particular Risk Event[3] and complies with the directives in the SA Decision.

---

1 D.18-12-014 at 28.

2 D.14-12-025 at 31 (citation omitted).

3 Attachment A-1 provides a glossary of the terms used in this 2019 RAMP Report.

Although this is not the Company's first RAMP Report, it is the first RAMP Report that implements the methodology and processes adopted in the SA Decision;[4] including developing a new Multi-Attribute Value Function (MAVF).[5] This RAMP Report also reflects lessons learned from the Company's 2016 RAMP Report as well as from the RAMP filings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE).

B. Requirements for RAMP

This 2019 RAMP Report was developed in accordance with Commission guidance and the directives adopted in D.14-12-025, D.16-08-018, and the SA Decision. The SA Decision adopted the following minimum required elements:[6]

- Building a MAVF (Step 1A);
- Identifying Risks for Investor-Owned Utilities' Enterprise Risk Register (Step 1B);
- Risk Assessment and Risk Ranking in Preparation for RAMP (Step 2A);
- Selecting Enterprise Risks for RAMP (Step 2B); and
- Mitigation Analysis for Risks in RAMP (Step 3).

In addition to the above, the SA Decision also adopted modifications or enhancements of D.16-08-018 as follows:

- In the MAVF, establish a minimum 40% safety weight unless utilities can justify a lower weight based on their respective analyses;
- Enhance the current RAMP 10-major components;
- Update the risk lexicon; and
- Identify future matters for an Order Instituting Rulemaking that will explore lessons learned from the first S-MAP, adopt a Long-Term Road Map, and develop a scope and timeline for successive S-MAP applications.

---

4 *See* D.18-12-014, which adopted the S-MAP Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

5 The MAVF is discussed further in Chapter RAMP-C.

6 D.18-12-014 at Attachment A, A-4.

A roadmap demonstrating compliance with the RAMP requirements, in particular the 10 components of RAMP filings, is provided further below.

In addition to the RAMP requirements set forth in various risk-related proceeding directives, the Company's TY 2019 GRC decision (D.19-09-051) included items to be addressed in this RAMP Report. One such directive requires inclusion of a re-testing implementation plan related to pipelines under Pipeline Safety Enhancement Plan (PSEP) Phase 2B as part of this 2019 RAMP filing, and provides specific items to be included in this plan.[7] The Company intends to present information, as required in D.19-09-051, in RAMP and GRC filings when the anticipated PSEP Phase 2B projects are within the applicable GRC period. At this time, the Company forecasts that its PSEP Phase 2B projects will begin after 2025, which is approximately two GRC cycles from now; clearly not in scope of the Company's 2019 RAMP Report or the TY 2022 GRC. Consistent with the foregoing, a letter to Executive Director, Alice Stebbins, was sent on October 31, 2019, requesting an extension of time to comply with this directive related to the PSEP Phase 2B implementation plan in D.19-09-051.[8] The extension was granted on November 18, 2019, and therefore the PSEP Phase 2B implementation plan ordered in D.19-09-051 is not included in this RAMP Report.

In addition, D.19-09-051 suggested that many of the recommendations put forth by the Office of the Safety Advocate (OSA) regarding enhancements to the Company's safety culture and safety management systems, in particular American Pipeline Institute (API) Recommended Practice (RP) 1173, are "better addressed in SoCalGas' next RAMP filing."[9] The Company includes supplemental information on safety culture and its safety management systems in Chapter RAMP-F of this RAMP Report and looks forward to continuing to work with stakeholders on these matters.

---

7 D.19-09-051 at Ordering Paragraph 15.

8 SDG&E did not include PSEP forecasts in the TY 2019 GRC. While D.19-09-051 only ordered SoCalGas to complete the re-testing implementation plan, SDG&E also anticipates classifying pipeline segments as Phase 2B for inclusion in future GRC requests. Accordingly, both SoCalGas and SDG&E requested an extension to comply with what was ordered in D.19-09-051.

9 D.19-09-051 at 97.

II. RAMP APPROACH

A. General Approach

The Company's intent is to present a transparent and collaborative RAMP Report that advances utility risk-informed decision-making within the Commission's regulatory process. To accomplish this, the Company developed this RAMP Report in accordance with the SA Decision, with due consideration of feedback received from various stakeholder groups,[10] and incorporated lessons learned. Each are further discussed in this Section.

1. Roadmap of Compliance with RAMP Requirements

The approach adopted by the Company herein satisfies the following "Ten Major Components of RAMP Filings" as enhanced by the SA Decision.[11] Further, this approach, together with the enterprise risk management framework presented in Chapter RAMP-B, satisfies the Cycla ten-step evaluation process.

1. **Identify its top risks.** The Company identified its respective top risks as part of the 2018 Enterprise Risk Registry (ERR). The 2018 ERR was used as the starting point for RAMP. Consistent with the SA Decision, the risks presented within this 2019 RAMP Report include, at minimum, those risks that were the top 40% of risks identified in the Company's 2018 ERR with a safety score greater than zero.
2. **Describe the controls or mitigations currently in place.** Section V of each individual risk chapter describes the Company's current baseline controls and proposed mitigations as part of the Company's Proposed Risk Mitigation Plan. A Control, as defined by the Lexicon adopted in D.18-12-014, is a "[c]urrently established measure that is modifying risk."[12] Therefore, the Company generally considered Controls to be activities in place as of the end of 2018 and baseline

---

10 On January 9, 2019, the Company had a meeting with the Safety Enforcement Division (SED) regarding RAMP. On February 5, 2019, the Company provided SED with a preview of its showing for the March 5, 2019 workshop. On March 27, 2019, the Company had a follow-up discussion with The Utility Reform Network (TURN), SED, and OSA. SED and OSA met with the Company again on July 10, 2019.

11 D.18-12-014 at 33-35.

12 *Id.* at 16. A Mitigation is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event." *Id*. at 17.

costs represent costs incurred for said Controls in 2018. The Controls currently in place are identified in each risk chapter in Section I.B and are further described in Section V of each risk chapter. Baseline and forecasted costs are identified within Section VII of each risk chapter.

3. **Present its plan for improving the mitigation of each risk.** The Company's proposed Risk Mitigation Plans, presented within each of the individual risk chapters, are plans that the Company believes are feasible to be executed and which it plans to put forth in the next GRC application, currently anticipated to be filed in September 2020. The proposed Risk Mitigation Plans are contingent on resource availability, permitting, operational compliance, and other factors, and therefore the Company's identified activities may be subject to constraints and/or delays.

4. **Present two alternative mitigation plans that it considered.** Section VIII within each of the individual risk chapters present at least two considered alternative mitigations with associated costs and Risk Spend Efficiencies (RSEs). The Company's alternative mitigation plans presented herein are defined as specific individual activities that were considered in the process of determining the Company's risk management efforts but are not currently proposed at this time. Although an increase/decrease in scope of activities may be a feasible approach to alternatives, the individual risk chapters (with the exception of the Cybersecurity risk chapter) do not take this approach, based on feedback from the Commission's Safety and Enforcement Division (SED).

5. **Present an early stage "risk mitigated to cost ratio" or related optimization.** For each Control or Mitigation activity where an RSE analysis is performed, the Company includes a post-mitigation analysis, which includes a Likelihood of Risk Event (LoRE) and Consequence of Risk Event (CoRE), within Section VI of each individual risk chapter. In addition, Appendix D-1 provides a ranking of the Company's Controls and Mitigations by RSE, where an RSE analysis is

performed, consistent with the SA Decision.[13] Controls and mitigations with RSEs are listed in descending order.

6. **Identify lessons learned in the current round to apply in future rounds.** As the first utilities to prepare a RAMP Report under the current S-MAP framework, "lessons learned" are discussed in Chapter RAMP-G.

7. **Move toward probabilistic calculations, to the maximum extent possible.** This 2019 RAMP Report applies the probabilistic analysis required by the SA Decision. The Company will continue working toward a more probabilistic analysis in future RAMP reports, as further discussed in Chapter RAMP-C.

8. **For those business areas with less data, improve the collection of data and provide a timeframe for improvement**. The Company will position itself to continually improve data collection efforts and therefore improve the risk assessment process. Further discussion on data collection can be found in Chapter RAMP-G.

9. **Describe the company's safety culture, executive engagement, and compensation policies.** Chapter RAMP-F is dedicated to describing the Company's safety culture, executive engagement, and compensation policies.

10. **Respond to immediate or short-term crises outside of the RAMP and GRC process.** Although this 2019 RAMP Report identifies the Company's key safety risks, the Company responds to immediate or short-term needs outside of this RAMP effort and continually manages risk.

B. RAMP Workshop Requirement

The SA Decision requires the Company to host a publicly noticed workshop in preparation for the RAMP filing (Pre-RAMP Workshop). The Company's Pre-RAMP Workshop was properly noticed and held on March 5, 2019.[14] The intent of the Pre-RAMP Workshop was to gather input from stakeholders to inform the determination of the final list of

---

[13] *Id.* at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

[14] The presentation provided for the Pre-RAMP workshop may be accessed on the California Public Utilities Commission, Utility Risk Assessment and Safety Advisory website (Major Proceedings), *available at* https://www.cpuc.ca.gov/riskassessment/.

risks to be included in the 2019 RAMP Report. Accordingly, the Company provided the following information to the interested parties on February 19, 2019, in advance of the workshop:

- their preliminary list of RAMP risks;
- the Safety Risk Score for each risk in the ERR; and
- the Multi-Attribute Risk Score for the top ERR risks.

Representatives from the SED and Energy Division, The Utility Reform Network (TURN), OSA, and Indicated Shippers attended the Company's Pre-RAMP Workshop. The Company appreciates the input received during the Pre-RAMP Workshop,[15] had subsequent discussions with the above-noted stakeholders and has incorporated or otherwise addressed such feedback, as described below, in this 2019 RAMP Report.

1. Use of National Data for Determining the Risk Quantification Score

During the Pre-RAMP Workshop, TURN raised concerns that the use of national data could potentially overestimate the safety implications of a given risk and may undermine strides and investments that have been made in California to improve safety. The Company appreciates TURN's feedback on the use of national level data. As noted above, the methods implemented in this RAMP Report, which were adopted in the SA Decision, are more quantitative than before, making the use of data, as well as subject matter expertise, necessary. That said, many of the risks included in the Company's ERRs are low frequency, high consequence events (e.g., high pressure pipeline incidents) for which there is minimal available data related to the Company's systems. Because relying solely on the Company's own data would limit the available data set, national data was appropriately applied to inform the risk assessments in this RAMP Report. When national or external data was used, the Company supplemented its analysis with subject matter expertise, consistent with the SA Decision,[16] to confirm certain portions of the risk assessment, including the applicability of the data to the Company. Additionally, the Company

---

15 The Company made its determination of the final list of risks to be addressed in the RAMP Report based on the input received from SED and other interested parties. *See* D.18-12-014 at Attachment A, A-10.

16 *Id.* at Attachment A, A-8 – A-9 (Identification of Potential Consequences of Risk Event, Identification of the Frequency of the Risk Event).

primarily used national data to estimate an incident rate in the pre-mitigation risk score. The incident rate was then scaled to the characteristics of the Company's system or service territory.

Moreover, the use of external data is not new. External data is often used to determine potential outcomes of a risk event and the magnitude of the impacts. References to industry incidents has been informative in helping the Company determine the potential severity of the risks. Chapter RAMP-C further discusses the Risk Quantification Framework and expands on the use of national data. Further discussion on the Company's data collection efforts are included in Chapter RAMP-G.

2. Consideration of Mitigation Effectiveness

During the Pre-RAMP Workshop, SED asked how the Company planned to address mitigation effectiveness in the 2019 RAMP Report. The Company replied by explaining that estimated risk reduction benefits would be addressed in the individual risk chapters. Subject Matter Experts (SME) for each respective risk developed risk reduction benefit percentages for each Control and Mitigation where an RSE analysis was performed. Estimated risk reduction benefits are an input to each RSE. The overall methodology for determining risk reduction benefits is addressed in Chapter RAMP-D and within Section VI of each risk chapter.

As for reporting of mitigation effectiveness, *the Phase Two Decision Adopting Risk Spending Accountability Report Requirements and Safety Performance Metrics for Investor-Owned Utilities and Adopting a Safety Model Approach for Small and Multi-Jurisdictional Utilities*[17] defers approval of specific reporting requirements for the Risk Mitigation Accountability Report, contemplated in D.14-12-025, and the identification and benchmarking of industry risk-based decision-making practices to a subsequent S-MAP. The Company looks forward to collaborating with the Commission and other stakeholders on developing operative methodologies for further determining mitigation effectiveness.

3. Scoping of Risks

During the Pre-RAMP Workshop, the scope of risks and the potential overlap between risks were addressed. Based on this feedback, the Company reviewed its risks to clarify the scope of each in this RAMP Report and refined it as necessary to align with the data that was

[17] D.19-04-020.

used to determine the pre-mitigation risk score. For details regarding the calculation of pre-mitigation risk scores, please refer to Chapter RAMP-C. Additional information is also included in Chapter RAMP-G.

4. Changes Compared to the Pre-RAMP Workshop

The pre-mitigation risk scores presented at the Pre-RAMP Workshop were the result of a preliminarily MAVF.[18] The Company notes that the SA Decision permits adjustments to a MAVF over time. The Company communicated the preliminary state of its Risk Quantification Framework at the Pre-RAMP Workshop and stated that its Risk Quantification Framework may evolve prior to filing the RAMP Report.

Following the Pre-RAMP Workshop, the Company revised certain aspects of its Risk Quantification Framework. The attributes themselves (Safety, Reliability, and Financial) have not changed. The scaled units for the Safety attribute have been refined and are in accordance with MAVF Principle 5 of the SA Decision. These revisions to the Risk Quantification Framework result in modifications to the pre-mitigation risk scores as compared to the information served in preparation for the Pre-RAMP Workshop. In addition, after the Pre-RAMP Workshop, the Company added a 100,000 multiplier to the Risk Quantification Framework risk score for purposes of readability. While the multiplier changed the Risk Quantification Framework numbers, the presence of the multiplier did not in itself change the underlying math. Rather, it simply changed the position of the decimal (*e.g.*, 17.2 instead of 0.000172). Appendix A-2 provides a summary of changes to the materials presented for the Pre-RAMP Workshop using this revised Risk Quantification Framework. The rationale for the Company's Risk Quantification Framework is discussed in Chapter RAMP-C.

5. Incorporation of Lessons Learned

As mentioned above, this RAMP Report is the first instance in which the new S-MAP methodology will be applied to and presented in RAMP and GRC filings. While the Company has experienced one full RAMP/GRC process (*i.e.*, filing the first-ever RAMP Report in November 2016, incorporating the RAMP results into its TY 2019 GRC, and getting a final decision in the TY 2019 GRC that reflected RAMP), this RAMP Report differs from the

---

18 The Company refers to its MAVF herein as the Risk Quantification Framework.

Company's prior RAMP Report by implementing both the requirements set forth in the SA Decision and also by implementing lessons learned. Not only does the Company have its own experience to draw from, it has also learned from PG&E's 2017 RAMP filing, SCE's 2018 RAMP filing, and the resulting feedback from SED and other parties.

For instance, a "lessons learned" from its prior RAMP filing is that the Company attempts to show activities and corresponding cost forecasts in this 2019 RAMP Report either within a single risk chapter and/or allocated between risks. In the 2016 RAMP filing, the Company did not attempt to split or apportion the costs of mitigation to each risk. Rather, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters. Additionally, in this 2019 RAMP Report, the Third Party Dig-in risk has been addressed in two separate risk chapters, Third Party Dig-in on a High Pressure Pipeline and Third Party Dig-in on a Medium Pressure, for additional granularity and alignment of Controls and Mitigations (compared with one chapter addressing all Third Party Dig-ins in the Company's 2016 RAMP Report).

Further, there were risk chapters that were included in the 2016 RAMP Report that are now identified as Drivers/Triggers instead of Risk Events that warrant distinct risk chapters. These items (*e.g.*, climate change) are discussed within the individual risk chapters and assessed as Drivers/Triggers that may contribute to an identified Risk Event (*e.g.,* asset failure). Additional lessons learned are discussed in Chapter RAMP-G.

C. Guiding Principles

The Company strives to provide transparency and uniformity of its risk presentation. This is demonstrated by also providing detailed workpapers submitted concurrently with this RAMP Report. In addition, there are several assumptions and decisions that the Company applied broadly in developing the 2019 RAMP Report. This section outlines these main assumptions and guiding principles that were globally applied throughout the 2019 RAMP Report.[19] Many of these global assumptions resulted from lessons learned and are therefore also discussed in Chapter RAMP-G.

[19] Unless otherwise noted throughout the 2019 RAMP Report, these global assumptions and parameters apply to all risk areas.

1. The 2018 Enterprise Risk Registry Served as a Starting Point

The Company used its 2018 ERR as a starting point for selecting the risks to be addressed in the 2019 RAMP Report consistent with the requirements called forth in the SA Decision.[20] Although the 2018 ERR was based on the Company's 7x7 matrix, all the risks in the 2018 ERR were re-assessed within the new quantitative assessment for RAMP and the assessments in this Report reflect the implementation of the new methodology.[21] These risks were then evaluated using the process and methods approved in the SA Decision. SoCalGas' and SDG&E's 2018 ERR each identified 24 risks. Of those risks, 11 risks for SoCalGas and 12 risks for SDG&E had a safety score greater than zero. Therefore, using the processes adopted in the SA Decision, there were five risks in the top 40% for the Company that required further analysis. The result, after consulting with stakeholders, is that SoCalGas selected eight risks, SDG&E selected nine risks, and there is one risk shared between SoCalGas and SDG&E that are included in this 2019 RAMP Report.[22] Further discussion regarding the ERR-related processes are provided in Chapter RAMP-B.

The 2018 ERR was the basis for the selection of RAMP risks, based on the data used for purposes of performing the quantitative analysis, including the pre-mitigation risk score. However, the risk definitions and scope for a given risk may slightly differ from the 2018 ERR.

2. The Risk Quantification Framework Generally Excluded Secondary Impacts from the Assessment

As discussed in Chapter RAMP-C, secondary impacts were generally excluded from the risk quantification assessments; only direct impacts of a risk event were evaluated for purposes of determining the pre-mitigation risk score. Accounting for secondary impacts is particularly challenging as the impacts would span across multiple risk areas and an improved methodology and data collection is needed to determine how to best account for risk reduction benefits that may indirectly mitigate other risks.

---

20 D.18-12-014 at Attachment A, A-7 (Risk Identification and Definition).

21 The SA Decision was issued in December 2018 after the Company's 2018 ERRs were finalized.

22 D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP) (Based on input received from SED, other interested CPUC staff, and interested parties, the utility will make its determination of the final list of risks to be addressed in its RAMP.).

The Company recognizes that not capturing indirect impacts may underestimate the magnitude of certain risks. Although secondary impacts are managed daily, and these impacts certainly present additional risks, there are a number of hypothetical events, considerable assumptions, and limited data that may be relied upon for quantifying such impacts with a reasonable degree of confidence. An example of an event with a secondary impact is a prolonged power outage which leads to inoperable traffic lights that could result in an automobile accident, the consequences of which may include a serious injury and/or fatality. The Company will continue collaborating with the other California IOUs and stakeholders to continue to refine the process and develop improved methodologies for capturing data to support quantifying secondary impacts.

3. Cost Information Presented in RAMP

The purpose of RAMP is not to request funding. Any funding requests will be made in the Company's TY 2022 GRC application, currently anticipated to be filed in September 2020. The range of costs presented in this 2019 RAMP Report are those costs which the company anticipates requesting recovery for in the TY 2022 GRC. For this 2019 RAMP Report, the baseline costs of Controls and Mitigations are the costs incurred in 2018. This is because at the time of this RAMP Report, the last available recorded annual financial data is 2018. The cost forecasts presented herein include forecasts for anticipated capital expenditures over the forecast years of the next GRC cycle (2020-2022) and estimated operations and maintenance (O&M) cost forecasts for TY 2022. The 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas O&M costs are presented for TY 2022. All dollars are presented in direct, constant 2018 thousands of dollars. This approach is anticipated to be consistent with the Company's GRC presentation. Section VII of each risk Chapter presents a summary of the baseline and forecasted costs for each Control and Mitigation by tranche.

a. RAMP Cost Forecasts are Presented in Ranges

The Company has developed cost estimates for the 2020-2022 GRC period for each Control and Mitigation, unless otherwise noted. The Company presents these cost forecasts, for both O&M and capital, in 2018 direct dollars. Using reasonable efforts, the Company has developed estimated forecast costs in ranges. It is important to note that these costs are estimates at this point in time. The Company's TY 2022 GRC will further refine the cost estimates shown in this RAMP Report with supporting testimony.

b. Cost Forecast Methodologies

The Company generally applied a forecast methodology (*e.g.*, base year, historical average, zero-based) to identify forecast cost estimates, consistent with how costs are presented in the GRC. The Company's accounting systems are not configured to capture all costs by the level or type of risk-management activities as anticipated by the RAMP process – costs are tracked by cost center (O&M) and budget code (capital). Therefore, estimates, assumptions, and available accounting data were provided by SMEs where feasible. For Controls and Mitigations funded through capital expenditures, the Company generally does not include associated O&M expense, which typically amounts to less than 2-3% of the capital spend. As the exclusion does not materially change the risk analysis, the Company will address such expenses in its TY 2022 GRC.

c. TY 2019 Authorized Funding

The Company's test year for its prior GRC application was 2019, for which the CPUC recently issued a final decision on September 26, 2019.[23] The Company is thus expeditiously moving forward with many of the programs authorized in that decision. Because this RAMP has a base year of or identifies baseline costs for 2018, if no historical spend was recorded in 2018 or prior, an activity was denoted as a Mitigation, rather than a Control. Many of the activities authorized in the TY 2019 GRC are underway and have recorded costs in 2019. This will be shown in the TY 2022 GRC. Therefore, if funding was authorized in the TY 2019 GRC, it may still be labeled as a Mitigation, even though the Company is actively performing such activities in 2019.

d. Exclusions

For the 2019 RAMP Report, internal labor for certain baseline controls (*e.g.*, internal labor to attend training, adhering to internal protocols or standards, internal time spent at meetings, etc.) is generally excluded from the O&M baseline and forecasted cost estimates. Forecasting internal labor requires the use of cost assumptions (*e.g.*, x number of employees, x

---

[23] *See* D.19-09-051.

length of training, x average hourly wage). As the Company moves towards a more probabilistic approach, it was determined that cost estimates for internal labor that are not specifically accounted for in that manner should not be explicitly identified in RAMP. Further, internal labor costs are not currently tracked in such a manner which would impede accountability reporting requirements. In the spirit of the SA Decision, the Company aims to demonstrate progress toward "probabilistic calculations" for RSEs and thus attempted to eliminate assumptions, such as internal labor cost estimates, as an input to those calculations where possible. The Company points out that the exclusion of internal labor costs in this RAMP Report resulted in decreased O&M cost forecasts in some instances, particularly those related to employee, contractor, and customer and public safety.

Further, the Company expects to include the costs presented herein in its TY 2022 GRC applications. While non-GRC costs are not included herein, the Company provides in this RAMP Report a complete narrative description of the activities being proposed in the respective risk chapters' Risk Mitigation Plans, even though costs for such activities may not be specifically identified or included. This approach is necessary because, in computing RSEs, the Company found that in one instance the risk reduction was estimated for the program in its entirety, not limited to those presented in GRCs. Therefore, on a piloted basis, in the Electric Infrastructure Integrity risk chapter (Chapter SDG&E-4), SDG&E included the costs applicable to the program (GRC and non-GRC costs) to match the estimated total program benefits.

The determination of treatment of costs in this 2019 RAMP Report was highly influenced through lessons learned from the Company's 2016 RAMP Report, the TY 2019 GRC, new spending accountability reporting requirements, and overall configuration of internal accounting and tracking systems. The Company will continue to implement lessons learned and refine the process.

4. Treatment of Risk Mitigating Activities Presented in Risk Chapters

In a few cases within this RAMP Report, a Control or Mitigation may help mitigate multiple risks. For example, a safe driving training program helps mitigate employee safety risk but also helps mitigate customer and public safety. A Control or Mitigation may address multiple risks, but the full cost for those Controls and/or Mitigations that address multiple risks are presented in a single risk chapter, unless otherwise noted. While the costs may reside within the risk chapter of primary benefit, other risk chapters may qualitatively discuss how the mitigation affects the risk in the chapter receiving the benefit. As an additional "lessons learned" from its prior RAMP filing, the Company attempts to show cost forecasts either within a single risk Chapter and/or allocated between risks. In the 2016 RAMP filing, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters. As the Company continues to move towards probabilistic RSE calculations, the Company aims to present costs in a single instance, even though these activities may provide risk mitigation benefits to multiple risks. Chapter RAMP-D contains further discussion on this topic.

Given that risks are dynamic and cross-cutting in nature, there are activities in this 2019 RAMP Report that contribute to mitigating other risks. This is outlined in Appendix A-3. The Company notes that for purposes of funding, these activities will only be requested once in the GRC.

This RAMP Report provides analysis of activities in scope of the risk description (as required by the SA Decision) and provides a qualitative discussion of certain risk mitigation activities that are otherwise out-of-scope due to the risk definition, to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of the Company's mitigation activities. For example, emissions reduction activities in compliance with Senate Bill (SB) 1371 that could result in collateral safety benefits are discussed in the Medium Pressure Pipeline Incident risk chapter. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions. These distinctions are discussed in the applicable narratives within the individual risk chapters, in Section VI. Similarly, a narrative discussion of certain activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis.

5. RSE Analysis

The SA Decision directs the Company to provide a Step 3 analysis of mitigations.[24] As further discussed in Chapter RAMP-D, RSE Methodology, where costs are not identified or not

24 D.18-12-014 at Attachment A, A-11 – A-13.

available for a given Control/Mitigation, such as with non-GRC jurisdictional or certain internal labor costs, no RSE calculation is provided. Additionally, the Company did not perform RSE calculations on certain mandated activities. Mandated activities are defined in this RAMP Report as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order.[25] Activities with no RSE score are identified within Section VI of the individual risk chapters. Lastly, the RSEs are generally expressed in ranges.[26]

III. RAMP REPORT OVERVIEW

A. Selection of RAMP Risks

As discussed above, SoCalGas and SDG&E held a Pre-RAMP Workshop on March 5, 2019. Per the SA Decision,[27] the Company will make its determination of the final list of risks to be addressed in the RAMP based on the input received from SED and other interested parties. After considering feedback from the Pre-RAMP Workshop and subsequent discussions with interested parties, 18 separate risk chapters are being presented in this RAMP Report: eight for SoCalGas, nine for SDG&E, and one joint SoCalGas/SDG&E chapter.

The Company actively manages several other risks that are not part of the 2019 RAMP Report but are integral to daily operations and are reflected in the ERR. For example, the Company continuously monitors risks related to reliability and resiliency of the system as well as risks related to technology applications and business resumption. Consistent with the SA Decision, a supplemental analysis will be conducted in the GRC for programs not included in this RAMP Report that meet certain criteria, including those associated with ERR risks that were not included in RAMP.

---

25 For purposes of this report, the Company uses the term "mandated" in place of compliance. However, the term mandated is defined consistently with how compliance is described in Row 28 of the SA Decision. *Id.* at Attachment A, A-14 – A-17 (Step 3 Supplemental Analysis in the GRC).

26 Risk mitigation activities with no direct safety impact will not have a range in scoring since only the safety attribute weighting contributes to the ranges.

27 D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP).

B. Report Overview

This 2019 RAMP Report focuses on the Company's key safety risks and the current and proposed activities to help mitigate those risks. Each risk is discussed in detail in the individual chapters associated with a particular Risk Event. The Company also presents the following chapters, which set the foundation of this filing:[28]

- RAMP-A: Overview & Approach
- RAMP-B: Enterprise Risk Management (ERM) Framework
- RAMP-C: Risk Quantification Framework
- RAMP-D: Risk Spend Efficiency (RSE) Methodology
- RAMP-E: A Discussion on the Use of Risk Spend Efficiencies
- SCG RAMP-F: Safety Culture, Executive Engagement, and Compensation Policies
- SDG&E RAMP-F: Safety Culture, Executive Engagement, and Compensation Policies
- RAMP-G: Lessons Learned

SoCalGas' 2019 RAMP Report comprises the following risk chapters:

Chapter	Risk
SCG-1	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
SCG-2	Employee Safety
SCG-3	Contractor Safety
SCG-4	Customer and Public Safety
SCG-5	High Pressure Gas Pipeline Incident (Excluding Dig-in)
SCG-6	Third Party Dig-in on a Medium Pressure Pipeline
SCG-7	Third Party Dig-in on a High Pressure Pipeline
SCG-8	Storage Well Integrity Event
SCG-9/ SDG&E-10	Cybersecurity

SDG&E's 2019 RAMP Report comprises the following risk chapters:

[28] Chapters RAMP-A through RAMP-E and RAMP-G contain largely the same content; however, Chapter RAMP-F is Company-specific as denoted by SCG RAMP-F and SDG&E RAMP-F.

Chapter	Risk
SDG&E-1	Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)
SDG&E-2	Contractor Safety
SDG&E-3	Employee Safety
SDG&E-4	Electric Infrastructure Integrity
SDG&E-5	Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline
SCG-9/ SDG&E-10	Cybersecurity

The chapter number associated with the RAMP risk chapters identified above (*e.g.,* SDG&E-1) were assigned based on each Company's ERR risks sorted in descending order by the Safety risk score as presented at the Pre-RAMP Workshop.[29]

C. Risk Chapter Overview

In each individual risk chapter, the Company presents each risk's baseline Controls, identifies new and/or incremental proposed Mitigations to address these risks, and presents at least two alternative mitigation plans for each risk.[30] The process for selecting the risks presented in the 2019 RAMP Report is further detailed in Chapter RAMP-B.

The Company presents the following sections in each chapter:

1. Introduction
2. Risk Overview – This section provides context to the given risk including background and why this is a risk in the Company's ERR.
3. Risk Assessment – In accordance with the SA Decision,[31] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of each identified risk.

---

29 *See* D.18-12-014 at Attachment A, A-8 (Risk Assessment).

30 Compliance requirements are further addressed in Section II herein.

31 D.18-12-014 at 33 and Attachment A, A-11 (Bow Tie).

4. Risk Quantification – This section provides an overview of the scope and methodologies applied for the purpose of risk quantification.
5. Risk Mitigation Plan – This section includes Controls that are expected to continue and proposed Mitigations for the period of the Company's TY 2022 GRC cycle.
6. Post-Mitigation Analysis of Risk Mitigation Plan – This section describes the Step 3 analysis performed for the identified Controls and Mitigations presented as part of the Risk Mitigation Plan pursuant to the terms of the SA Decision.
7. Summary of Risk Mitigation Plan Results – This section provides a summary table of the Risk Mitigation Plan, including Controls and proposed Mitigation activities, associated costs, and RSEs, by tranche.
8. Alternative Mitigation Plan Analysis – This section presents at least two alternative mitigation plans considered as part of the risk assessment process included forecasted costs and post-mitigation analysis.

In sum, this RAMP Report represents a significant step forward in how the Company thinks about, plans for, and mitigates its key safety risks. This RAMP Report will inform the safety-related funding requests that the Company will include in its TY 2022 GRC application, currently anticipated to be filed in September 2020.

Appendix A-1

Glossary of Terms

APPENDIX A-1

Glossary of Risk Terms

The following are terms used by the Company for purposes of the 2019 RAMP Report:

Term	Definition
Baseline Costs	Costs incurred for Controls in 2018.
Base Year	The last available year of recorded financial data. In the 2019 RAMP Report the Base Year is 2018.
High Alternative	Risk Quantification Framework that provides a narrower range of the Safety attribute compared to the Single Point method (*see* Chapter RAMP-C)
Low Alternative	Risk Quantification Framework that provides a wider range of the Safety attribute compared to the Single Point method (see Chapter RAMP-C).
Mandated	Activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. For purposes of the 2019 RAMP Report, SoCalGas and SDG&E use the term "mandated" synonymously with compliance. "Mandated" in this RAMP Report is defined consistently with "compliance" as described in Row 28 of the SA Decision.
Measurement Unit	The measured attribute, also analogous to "Natural Unit" per the SA Decision Lexicon.
Monte Carlo analysis (simulation or modeling)	A technique used to understand the impact of uncertainty related to a particular risk.
Non-GRC costs	Costs with forecasts and recovery sought in a separate CPUC proceeding (outside of the GRC) and/or outside the CPUC's jurisdiction.
Pre-Mitigation Risk Score	Risk score measuring the current state of the risks with the current controls in place.
Post-Mitigation Risk Score	Risk score after implementing the mitigation activity.
Risk Quantification Framework	The Company's Multi Attribute Value Function (MAVF) presented in this 2019 RAMP Report.
SA Decision	Commission Decision (D.) 18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement With Modifications
Secondary Impacts	Impacts that are "downstream" of the initial risk event; this includes indirect impacts from a risk event.
Serious Injury	Defined as an event that requires overnight hospitalization.
Single Point	Risk Quantification Framework presented in the RAMP as mandated by the Settlement Agreement that includes one range for each Attribute.

Term	Definition
Sub-Attribute	An observable and measurable attribute that, in an attribute hierarchy, relates to a higher-level attribute. Also referred to as a lower-level attribute.
Subject Matter Expert(s)	Individual(s) with special skills or knowledge on a topic.
Tail Risks	Risk events that have a small probability of occurring, typically measured by three standard deviations from the mean of a normal distribution. Sometimes referred to as low frequency, high consequence risk events.
Test Year	First year of a General Rate Case (GRC) cycle. The 2019 RAMP Report is prepared in anticipation of the Company's subsequent GRC – the Test Year (TY) 2022 GRC.

The risk lexicon adopted by the SA Decision was used in the 2019 RAMP Report and is included below for reference:[1]

Term	Definition
Alternative Analysis	Evaluation of different alternatives available to mitigate risk.
Attribute	An observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability. Changes in the levels of attributes are used to determine the consequences of a Risk Event. The attributes in an MAVF should cover the reasons that a utility would undertake risk mitigation activities.
Bow Tie	A tool that consists of the Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of Consequences on the right side that show the potential outcomes if the Risk Event occurs.
Consequence (or Impact)	The effect of the occurrence of a Risk Event. Consequences affect Attributes of a Multi Attribute Value Function (MAVF).
Control	Currently established measure that is modifying risk.
CoRE	Consequences of a Risk Event.
CPUC	California Public Utilities Commission
Driver	A factor that could influence the likelihood of occurrence of a Risk Event. A driver may include external events or characteristics inherent to the asset or system.
Enterprise Risk Register (also referred to as "risk registry" or "ERR")	An inventory of enterprise risks at a snapshot in time that summarizes (for a utility's management and/or stakeholders such as the CPUC) risks that a utility may face. The ERR must be refreshed on a regular basis and can reflect the changing nature of a risk; for example, risks that were consolidated together may be separated, new risks may be added, and the level of risks may change over time.

[1] D.18-12-014 at 16.

Term	Definition
Exposure	The measure that indicates the scope of the risk, e.g., miles of transmission pipeline, number or employees, miles of overhead distribution lines, etc. Exposure defines the context of the risk, i.e., specifies whether the risk is associated with the entire system, or focused on a part of it.
Frequency	The number of events generally defined per unit of time. (Frequency is not synonymous with probability or likelihood.)
General Rate Case (GRC)	A CPUC proceeding that is denominated a general rate case, as well as PG&E’s Gas Transmission and Storage (GT&S) rate proceeding.
Inherent Risk	The level of risk that exists without risk controls or mitigations.
Likelihood or Probability	The relative possibility that an event will occur, quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certain we are that the event will occur.
LoRE	Likelihood of a Risk Event.
Mitigation	Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.
Multi-Attribute Value Function (MAVF)	A tool for combining all potential consequences of the occurrence of a risk event, and creates a single measurement of value.
Natural Unit of an Attribute	The way the level of an attribute is measured or expressed. For example, the natural unit of a financial attribute may be dollars. Natural units are chosen for convenience and ease of communication and are distinct from scaled units.
Outcome	The final resolution or end result.
Planned or Forecasted Residual Risk	Risk remaining after implementation of proposed mitigations.
Range of the Natural Unit	Part of the specification of an Attribute. For an Attribute with a numerical natural unit, such as dollars, the smallest observable value of the Attribute is the low end of the range and the largest observable value is the high end of the range. Therefore, any Attribute level that results as a consequence of an event, or a risk mitigation action, or of doing nothing should be found within the range. For weighting purposes, the range of the natural units of an Attribute should be able to describe any mitigation action. For an Attribute with a categorical natural unit, such as corporate image, the range of the Attribute is from the least desirable level to the most desirable level.
Residual Risk	Risk remaining after current controls.
Risk	The potential for the occurrence of an event that would be desirable to avoid, often expressed in terms of a combination of various outcomes of an adverse event and their associated

Term	Definition
	probabilities. Different stakeholders may have varied perspectives on risk.
Risk Driver	Same as definition for Driver.
Risk Event	An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address. In particular, the occurrence of a Risk Event changes the levels of some or all of the Attributes of a risky situation.
Risk Score	Numerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time.
Risk Tolerance	Maximum amount of residual risk that an entity or its stakeholders are willing to accept after application of risk control or mitigation. Risk tolerance can be influenced by legal or regulatory requirements.
Scaled Unit of an Attribute: a value that varies from 0 to 100	The scaled unit is set to 0 for the most desirable level of natural unit in the range of natural units. The scaled unit is set to 100 for the least desirable level of natural unit in the range of natural units. For any level of attribute between the most desirable and the least desirable levels, the scale unit is between 0 and 100. The benefit achieved by changing the level of an Attribute in natural units is measured by the corresponding difference in scaled units. In the special case of moving from the least desirable level to the most desirable level, the benefit is equal to 100 scaled units.
Tranche	A logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment.
Settlement Agreement	The entirety of the agreement between Pacific Gas & Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company, The Utility Reform Network, Energy Producers and Users Coalition, Indicated Shippers, and the Public Advocate's Office of the Public Utilities Commission.

Appendix A-2

SoCalGas and SDG&E

Risk Quantification Framework Comparison

APPENDIX A-2
SoCalGas' 2019 RAMP Report Risk Quantification Framework
Compared to the Pre-RAMP Workshop Presentation

Risk	Risk Scores Presented at the Pre-RAMP Workshop[1]				Risk Scores Presented in the 2019 RAMP Report					
	Safety	Reliability	Financial	MAVF	Safety	Reliability	Financial	Single Point Risk Score	Low Alternative	High Alternative
SCG-1 Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	0.71	0.005	3.9	0.073	0.70	0.005	3.8	1581	315	3692
SCG-2 Employee Safety	0.55	0	0.3	0.055	0.55	0	0.3	1112	117	2771
SCG-3 Contractor Safety	0.52	0	0.3	0.052	0.52	0	0.3	1037	109	2582
SCG-4 Customer and Public Safety	0.37	0	1.2	0.037	0.37	0	1.2	765	98	1875
SCG-5 High Pressure Gas Pipeline Incident (Excluding Dig-in)	0.15	0.00001	1.1	0.015	0.15	0.00001	1.1	321	51	772
SCG-6 Third Party Dig-in on a Medium Pressure Pipeline	0.148	Not Presented During the Pre-RAMP Workshop			0.13	0.02	15.1	936	698	1333
SCG-7 Third Party Dig-in on a High Pressure Pipeline	0.04				0.04	0.00001	0.1	78	9	194
SCG-8 Storage Well Integrity Event	0.005				0.005	0	16.9	348	339	363
SCG-9/SDG&E-10 Cyber Security	0				0.013	0.04	3.7	920	897	958

[1] This is consistent with what the Company presented during the Pre-RAMP Workshop on March 5, 2019 and reflects changes as discussed in Chapter RAMP-C.

APPENDIX A-2
SDG&E's 2019 RAMP Report Risk Quantification Framework
Compared to the Pre-RAMP Workshop Presentation

Risk	Risk Scores Presented at the Pre-RAMP Workshop[1]				Risk Scores Presented in the 2019 RAMP Report					
	Safety	**Reliability**	**Financial**	**MAVF**	**Safety**	**Reliability**	**Financial**	**Single Point Risk Score**	**Low Alternative**	**High Alternative**
SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)	0.98	0.04	280	0.162	0.96	0.04	225	7215	5493	10085
SDG&E-2 Contractor Safety	0.65	0	5	0.66	0.65	0	5	1408	231	3371
SDG&E-3 Employee Safety	0.53	0	1	0.054	0.53	0	1	1086	127	2684
SDG&E-4 Electric Infrastructure Integrity	0.3	0.15	6	0.061	0.3	0.15	6	3720	3180	4620
SDG&E-5 Customer and Public Safety	0.16	0	0.2	0.016	0.16	0	0.4	323	39	796
SDG&E-6 Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	0.11	Not Presented During the Pre-RAMP Workshop			0.11	0.001	0.7	252	47	594
SDG&E-6 Third Party Dig-in on a Medium Pressure Pipeline	0.03				0.03	0.004	1.7	172	125	250
SDG&E-7 High Pressure Gas Pipeline Incident (Excluding Dig-in)	0.01				0.02	0.000001	0.04	31	4	77
SDG&E-8 Third Party Dig-in on a High Pressure Pipeline	0.002				0.002	0.0000004	0.01	4	1	11
SCG-9/SDG&E-10 Cyber Security	0				0.013	0.04	3.7	920	897	958

[1] This is consistent with what the Company presented during the Pre-RAMP Workshop on March 5, 2019 and reflects changes as discussed in Chapter RAMP-C.

Appendix A-3

Cross-Cutting Overlap

Risks are dynamic and cross-cutting in nature and the controls and mitigations presented in the 2019 RAMP Report may contribute to mitigating other risk areas as shown below.[1]

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C1	Operating Conditions	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C2	Recloser Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C3	Other Special Work Procedures	SDG&E-3 Employee Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C4	Distribution System Inspections – Corrective Maintenance Program	SDG&E-4 Electric Infrastructure Integrity
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C5	Distribution System Inspections – Quality Assurance/Quality Control	SDG&E-4 Electric Infrastructure Integrity
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C6	Substation System Inspections	
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C7	Transmission System Inspections	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C9	Cleveland National Forest Fire-Hardening	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C10 / M5	Fire Risk Mitigation	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C11 / M6	Pole Risk Mitigation and Engineering	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C12 / M9	Wire Safety Enhancement	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C13 / M11	Fire Threat Zone Advanced Protection	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C14 / M14	Replacement and Reinforcement	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C15	Tree Trimming	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C16	Pole Brushing	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C17	Fire Science & Climate Adaptation Department	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C18 / M21	Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C19 / M22	Camera Networks and Advanced Weather Station Integration	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C20 / M23	High-Performance Computing Infrastructure	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C21/M25	Asset Management	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C23 / M30	Communication Practices	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C25 / M31	Emergency Management Operations	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C26	Disaster and Emergency Preparedness Plan	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C27	Customer Support in Emergencies	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C28 / M32	Wildfire Infrastructure Protection Teams (Contract Fire Resources)	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C29 / M33	Aviation Firefighting Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C30	Industrial Fire Brigade	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-C31 / M34	Wireless Fault Indicators	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M1	Distribution System Inspections – Infrared/Corona	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M2	Distribution System Inspections – Drone Inspections	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M3	Distribution System Inspections – Circuit Ownership	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M4	Strategic Undergrounding	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M7	Expulsion Fuse Replacement	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M8	Hotline Clamps	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M10	Covered Conductor	SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M12	LTE Communication Network	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M15	Backup Power for Resilience – Generator Grant, Critical Infrastructure, and HPWREN	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M16	Backup Power for Resilience – Microgrids	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M17	Lightning Arrester Removal/Replacement Program	SDG&E-5 Customer and Public Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M18	SCADA Capacitors	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M19	Enhanced Vegetation Management	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M20	Fuel Management Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M24	Ignition Management Program	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M26	Monitoring and Correcting Deficiencies	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M27	Wildfire Mitigation Personnel	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M28	NMS Situational Awareness Upgrades	SDG&E-5 Customer and Public Safety
SDG&E-1	Wildfires Involving SDG&E Equipment	SDG&E-1-M29	Situational Awareness Dashboard	SDG&E-5 Customer and Public Safety
SDG&E-2	Contractor Safety	SDG&E-2-C1	Contractor Safety Oversight Program	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C2	Contractual Requirements	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C3	Third-Party Administration and Tools	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C4	Stop the Job	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Pipeline Gas Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C5	Near Miss/Close Call Reporting Program	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M1	Expanded Contractor Oversight Program (Additional FTEs, enhance reporting software)	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M2	Updated Class 1 Contractor Safety Manual, Development of Class 2 Contractor Safety Manual	SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-2	Contractor Safety	SDG&E-2-M3	Near Miss/Close Call reporting portal/app All contractor safety data from ISN and predictive solutions rolled up into real-time dashboard	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C1	Mandatory employee health and safety training programs and standardized policies	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C10	Personal protection equipment	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C11	Near Miss, Stop the Job and jobsite safety programs	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C2	Drug and alcohol testing program	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C3	Safety culture	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-3	Employee Safety	SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Pipeline Gas Incident
SDG&E-3	Employee Safety	SDG&E-3-C5	A comprehensive Environmental & Safety Compliance Management Program (ESCMP)	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C6	Employee safety training and awareness programs	SDG&E-5 Customer and Public Safety SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-3	Employee Safety	SDG&E-3-C7	Employee wellness programs	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	SDG&E-2 Contractor Safety
SDG&E-3	Employee Safety	SDG&E-3-C9	Safe driving programs	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M2	Safety in Action Program Enhancement	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)	SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M4	Implementing findings from VPP program assessments	SDG&E-2 Contractor Safety
SDG&E-3	Employee Safety	SDG&E-3-M5	Energized Skills Training and Testing Yard	SDG&E-2 Contractor Safety SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety
SDG&E-3	Employee Safety	SDG&E-3-M6	Employee Wildfire Smoke Protections – Cal/OSHA emergency regulation	SDG&E-2 Contractor Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C1	GO165: Distribution Inspect and Repair program – Overhead	SDG&E-1 Wildfires SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C2	4 kV Modernization and System Hardening – Distribution	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C3	Distribution Overhead Switch Replacement Program	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C5	Restoration of Service	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C6	Underground Cable Replacement Program - Reactive	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C7	Tee Modernization Program - Underground	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C9	DOE Switch Replacement – Underground	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C10	Vegetation Management (Non-HFTD)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair	SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C14	Field SCADA RTU Replacement	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C15	Distribution Circuit Reliability	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C16	Emergency Substation Equipment	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C19	Underground Cable Replacement Program – Proactive	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-C20	Enterprise Asset Management – Substation	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M1	Overhead Public Safety (OPS) Program	SDG&E-5 Customer and Public Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive	SDG&E-3 Employee Safety
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M3	Proactive Substation Reliability for Distribution Components	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M4	Substation Breaker Replacements – FLISR (Fault Locations, Isolation, and Restoration)	
SDG&E-4	Electric Infrastructure Integrity	SDG&E-4-M5	Enterprise Asset Management – Distribution	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-5	Customer and Public Safety	SDG&E-5-C1	Public Safety Communications	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-5	Customer and Public Safety	SDG&E-5-C2	Field & Public Safety	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-5	Customer and Public Safety	SDG&E-5-C3	First Responder Outreach & Training	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-5	Customer and Public Safety	SDG&E-5-M1	Expansion of Utility Incident Command	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-5	Customer and Public Safety	SDG&E-5-M2	Expanded Public Safety Communications	SDG&E-1 Wildfires involving SDG&E Equipment (including Third Party Pole Attachments) SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-9 Third Party Dig-in on a High-Pressure Pipeline
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C1	Cathodic Protection	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C2	Assessment of Buried Piping in Vaults	SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C3	Regulator & Valve Inspections and Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C4	Plastic Pipe Replacement	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C5	Leak Repair	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C7	Utility Conflict Review (Right of Way)	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-7 Third Party Dig-in on a Medium Pressure Pipeline SDG&E-9 Third Party Dig-in on a High Pressure Pipeline
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C8	Meter Inspection and Maintenance	SDG&E-5 Customer and Public Safety SDG&E-8 High Pressure Gas Pipeline Incident
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1	Early Vintage Program (Pipeline)	SDG&E-5 Customer and Public Safety
SDG&E-6	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2	Early Vintage Program (Fittings)	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C1	Locate and Mark Training	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C2	Locate and Mark Activities	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C3	Locate and Mark Annual Refresher Training and Competency Program	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C4	Locate and Mark Operator Qualification	SDG&E-3 Employee Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C5	Locate & Mark Quality Assurance Program	SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C6	Damage Prevention Analyst Program	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C7	Prevention and Improvements-Refreshed Laptops	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8	Public Awareness Compliance	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C9	Increase Reporting of Unsafe Excavation	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C14	Locating Equipment	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C15	Remain Active Members of the 811 California One-Call Centers	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M2	Establish a program to address the area of continual excavation	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M4	Utilize electronic positive response	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M5	Enhance process to utilize and leverage emerging excavation technology to help with difficult locates	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M7	Leverage data gathered by locating equipment	SDG&E-5 Customer and Public Safety
SDG&E-7	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M8	Install warning mesh above buried company facilities	SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C1	Cathodic Protection	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C2	Valve Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C3	Pipeline Safety Enhancement Plan – Pipeline Replacement	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C5	Pipeline Maintenance	SDG&E-5 Customer and Public Safety
SDG&E-8	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C6	Pipeline Safety Enhancement Plan – Pressure Testing	SDG&E-5 Customer and Public Safety

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C1	Locate & Mark Training	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C2	Locate & Mark Activities	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C3	Locate & Mark Annual Refresher Training & Competency Program	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C4	Locate & Mark Operator Qualification	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C5	Locate & Mark Quality Assurance Program	SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C6	Damage Prevention Analyst Program	SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C7	Prevention & Improvements-Refreshed Laptops	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8	Public Awareness Compliance	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C9	Increase Reporting of Unsafe Excavation	SDG&E-8 High Pressure Gas Pipeline Incident SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C11	Public Awareness - Meet with the Cities with the Highest Damage Rates	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C14	Locating Equipment	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C16	Install warning mesh above buried company facilities	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M2	Establish A Program To Address The Area Of Continual Excavation	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M3	Recording Photographs For Each Locate & Mark Ticket Visited By Locator	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M4	Utilize Electronic Positive Response	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M5	Enhance Process To Utilize And Leverage Emerging Excavation Technology To Help With Difficult Locates	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M6	Promote Process And System Improvements In USA Ticket Routing And M onitoring	SDG&E-5 Customer and Public Safety
SDG&E-9	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M7	Leverage Data Gathered By Locating Equipment	SDG&E-2 Contractor Safety SDG&E-3 Employee Safety SDG&E-5 Customer and Public Safety
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C1	Perimeter Defenses	SDG&E-4 Electric Infrastructure Integrity SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C2	Internal Defenses	SDG&E-4 Electric Infrastructure Integrity SDG&E -6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C3	Sensitive Data Protection	
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C4	Operational Technology (OT) Cybersecurity	SDG&E-3 Employee Safety SDG&E-4 Electric Infrastructure Integrity SDG&E-5 Customer and Public Safety SDG&E-6 Medium Pressure Gas Pipeline Incident SDG&E-8 High Pressure Gas Pipeline Incident
SCG-9/SDG&E-10	Cybersecurity	SCG-10-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement	

Chapter	RAMP Risk	Control/Mitigation ID	Control/Mitigation Name	Other Risk(s) Addressed by the Control/Mitigation

1 This table does not present an exhaustive list of risks that may be addressed by the controls and mitigations presented in this 2019 RAMP Report

Risk Assessment Mitigation Phase
(RAMP-B)
Enterprise Risk Management Framework

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This chapter discusses the risk management framework for San Diego Gas & Electric Company (SDG&E or Company). For purpose of RAMP, the Company has integrated the directives established in Decision (D.) 18-12-014 and the Settlement Agreement adopted therein (SA Decision) into the Company's existing enterprise risk management (ERM) framework. This chapter describes in detail the current ERM framework utilized by the Company.

II. ENTERPRISE RISK MANAGEMENT FRAMEWORK

As described in the direct testimony of Risk Management and Policy witness Diana Day in the Test Year 2019 General Rate Case,[1] the Company's risk framework:

> is modeled after ISO [International Organization for Standardization] 31000, an internationally recognized risk management standard. This framework consists of an enterprise risk management governance structure, which addresses the roles of employees at various levels ranging up to the Companies' Board of Directors, as well as risk processes and tools. One such process is the six-step enterprise risk management process.

Figure 1 below describes the Company's enterprise risk management process, by which the Company identifies, manages, and mitigates enterprise risks, and aims to provide consistent, transparent, and repeatable results.

1 A.17-10-007/-008 (cons.), Exhibit (Ex.) 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-8.

Figure 1: Enterprise Risk Management Process

The process illustrated in Figure 1 aligns with Cycla Corporation's 10-step evaluation method, which was adopted by the Commission in 2016 "as a common yardstick for evaluating maturity, robustness, and thoroughness of utility Risk Assessment and Mitigation Models and risk management frameworks."[2] While the lexicon used by Cycla differs slightly from that of the Company, the content is largely aligned. Table 1 below provides a side-by-side comparison of the steps in the Company's ERM process to the Cycla method sections.

Table 1: ERM Process Alignment with the Cycla Method

Steps in Cycla[3]	**Corresponding Risk Step in Enterprise Risk Management Process**
Step 1: Identify Threats	1. Risk Identification

2 D.16-08-018 at Ordering Paragraph (OP) 4.

3 *Id.* at 17, referencing Evaluation of PG&E's 2014 Gas Distribution General Rate Case (GRC) Filing, by Cycla Corporation, Attachment 3, page 2, Figure 3-1.

Step 2: Characterize Sources of Risk; Step 3: Identify Candidate Risk Control Measures (RCMs)	2. Risk Analysis
Step 4: Evaluate the Anticipated Risk Reduction for Identified RCM	3. Risk Evaluation & Prioritization
Step 5: Determine Resource Requirements for Identified RCMs; Step 6: Select RCMs Considering Resource Requirements and Anticipated Risk Reduction	4. Risk Mitigation Plan Development & Documentation
Step 7: Determine Total Resource Requirement for Selected RCMs; Step 8: Adjust the Set of RCMs to be Presented in Rate Case Considering Resource Constraints; Step 9: Adjust RCMs for Implementation following CPUC Decision on Allowed Resources	5. Risk Informed Investment Decisions and Risk Mitigation Implementation
Step 10: Monitor the Effectiveness of RCMs	6. Monitoring and Review

The Company performs its ERM process annually, resulting in an enterprise risk registry (ERR). The ERR contains each of the Company's identified enterprise-level risks. Each risk is assigned to one or more risk owner(s), a member of the senior management team who is ultimately responsible and accountable for the risk, and one or more risk manager(s) responsible for ongoing risk assessments and overseeing the implementation of risk plans. The ERM organization facilitates sessions amongst the Company's risk owners to identify, evaluate, and prioritize risks, and to review mitigation plans and consider how investments align with risk priorities.

As Ms. Day explained: "The enterprise risk management process is both a 'bottom-up' and 'top-down' approach, by taking input from the risk managers and the risk owners to ultimately finalize the risk registry. As with any useful risk assessment, the enterprise risk registry is not intended to be static; it must be refreshed on an annual basis. Risks are dynamic; risks that were consolidated together may be separated out, new risks may appear, and the level of the risk may change over time."[4]

Each of the steps in the ERM process are discussed further below.

A. Risk Identification

Risk identification is the process of finding, recognizing, and describing risks. As the first step in the risk management process, the ERM organization works with various business units to update existing risk information and identify enterprise-level risks that have emerged or accelerated since the prior assessment. This part of the process also includes the identification of risk events, their causes, and potential consequences. Figure 2 below provides a depiction of the Risk Bow Tie, which is a commonly-used tool for risk analysis. The risk Bow Tie is a way to systematically and consistently evaluate the Drivers/Triggers, possible outcomes, and Potential Consequences of a Risk Event. The left side of the Risk Bow Tie illustrates potential Drivers and/or Triggers that may lead to a Risk Event (center of the Risk Bow Tie) and the right side shows the Potential Consequences of a Risk Event.[5]

---

4 Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-9.

5 This 2019 RAMP Report uses the SA Decision lexicon. Please refer to Appendix A-1 in Chapter RAMP-A for a glossary of terms.

Figure 2: Example of Risk Bow Tie

The Company breaks down risks into two groupings – operational risks and cross-cutting risks. Operational risks are those events that have operational implications and may result in damage to or loss of company or public assets, serious injury and/or fatality, and/or interruption of service to customers. An example of an operational risk is Third Party Dig-in on a Medium or High Pressure Pipeline Incident. Cross-cutting risks, while not specific to one asset or group of assets, may also have similar potential consequences to those of operational risks. An example of a cross-cutting risk is Employee Safety, since it focuses on human systems and cuts across all asset types.

The categorization of the 2019 RAMP Report's risks is outlined in Table 2 below. As discussed in RAMP-A, there are 18 separate risk chapters presented: eight for Southern California Gas Company (SoCalGas), nine for SDG&E, and one joint SoCalGas/SDG&E chapter.

Table 2: Categorization of Risks

<table>
<tr><th>Category</th><th>SoCalGas</th><th>SDG&E</th></tr>
<tr><td rowspan="5">Gas</td><td colspan="2">Medium Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td colspan="2">High Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td colspan="2">Third Party Dig-in on a Medium Pressure Pipeline</td></tr>
<tr><td colspan="2">Third Party Dig-in on a High Pressure Pipeline</td></tr>
<tr><td>Storage Well Integrity Event</td><td>N/A</td></tr>
<tr><td rowspan="2">Electric</td><td>N/A</td><td>Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)</td></tr>
<tr><td>N/A</td><td>Electric Infrastructure Integrity</td></tr>
<tr><td rowspan="4">Cross-Cutting</td><td colspan="2">Employee Safety</td></tr>
<tr><td colspan="2">Contractor Safety</td></tr>
<tr><td colspan="2">Customer and Public Safety</td></tr>
<tr><td colspan="2">Cybersecurity</td></tr>
</table>

B. Risk Analysis

Risk analysis is the process of understanding the risk and the degree of risk. Risk analysis provides a basis for risk evaluation and decisions about risk mitigation. Risk analysis is undertaken using varying methodologies, depending on the risk and the availability of data and resources. The Company utilizes a combination of qualitative (*e.g.*, calibrated subject matter expertise) and quantitative analyses (including external data) to analyze its risks.

C. Risk Evaluation and Prioritization

Using the information from the prior steps, an evaluation and prioritization is performed. The result of this step is pre-mitigation risk scores for each risk in the ERR and a relative ranking reflecting consensus around risk priorities. This step involves a discussion of each ERR risk, including changes in the risk frequency or impact, challenges, and elements of the previous assessment's implementation of mitigants. Arriving at a risk prioritization can be an iterative process; risks that may be very different are compared to one another to determine a relative ranking (for example, evaluating an IT risk in comparison with a customer service risk).

In 2018, the Company completed its ERR before year-end and in advance of the issuance of the SA Decision. The evaluation and prioritization process for the 2018 ERRs used the Company's 7x7 matrix, a risk tool that aids in developing the pre-mitigation risk score for ERR risks. Subsequently, the SA Decision was adopted in December 2018 and provided, among other things, a new methodology to be used as the basis of this RAMP Report, rather than the 7x7 matrix.

In particular, the SA Decision established a multi-attribute value function (MAVF).[6] For purposes of this RAMP Report, the Company developed a new MAVF consistent with the SA Decision. Using this MAVF, the Company conducted a secondary analysis on each risk that was identified in its 2018 ERR, which resulted in new pre-mitigation risk scores. This process, methodology, and calculations for the pre-mitigation risk scores are further discussed in Chapter RAMP-C.

D. Risk Mitigation Plan Development & Documentation

Based on the analysis and evaluation of risks in the prior steps, risk owners and managers develop, and document risk mitigation plans to capture the state of the risk given current control activities and any additional mitigations. On an annual basis, the ERM organization facilitates the risk mitigation planning session where risk owners present their key risk mitigation plans and alternatives considered to the senior management team and discuss the feasibility and prudence of those plans. This risk mitigation planning session helps shape the Company's priorities going into the annual investment planning process and helps identify gaps and/or areas of overlap in risk mitigation plans.

E. Risk-Informed Investment Decisions and Risk Mitigation Implementation

The capital planning process is the Company's current annual process for prioritizing funding based on risk informed priorities and input from operations. The capital allocation planning sessions begin with input from functional capital committees that comprise subject matter experts who perform high level assessments of the capital requirements based on achieving the highest risk mitigation at the lowest attainable costs. These requirements are

[6] D.18-12-014 at Attachment A, A-8 (Risk Assessment).

presented to a cross-functional team representing each functional area with capital requests. This committee reviews the resource requirement submissions from all functional areas, and projects are evaluated against priority by assessing a variety of metrics including safety, cost effectiveness, reliability, security, environmental, strategic, and customer experience. Recommendations for capital spending are then presented to an executive committee for approval. Once the capital allocations are approved, each individual operating organization is chartered to manage their respective capital needs within the capital allotted by the plan. This includes re-prioritizations as necessary to address imminent safety concerns as they arise. Similar to the Company's risk evaluation processes, the capital planning process is continuing to evolve as the Company endeavors to achieve the goal of determining more quantitatively the risk reduction per dollar invested.

F. Monitoring and Review

Monitoring and reviewing the aspects of risk management supports the Company's efforts to continuously improve their risk management practices. Periodic reviews of the ERR are performed to keep the register current and facilitate discussions on any emerging new risks that the Company could face. In addition to using risk scores to monitor changes in risks, the Company leverages risk metrics similar to those identified in the S-MAP to hold parties accountable and improve risk oversight.

III. CONTINUOUS IMPROVEMENT OF RISK MANAGEMENT PRACTICES

The Company's risk management practices continue to mature. This is evidenced through the implementation of the processes and methodologies in the SA Decision, as well as other steps the Company is taking for advancement. The TY 2019 GRC presented a vision related to integrating risk, asset, and investment management to be accomplished over future GRC cycles.[7] The Company is moving on that trajectory, further integrating risk, asset, and investment management into the Company's culture.

While the Company's risk practices to date have largely focused on expressing risks in terms of risk events, there is a growing interest in aligning risks with asset management

---

7 Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at Figure DD-4.

practices. Accordingly, there are considerable efforts underway to provide additional granularity of risks and asset health.

One effort demonstrating additional granularity is the development of operating unit risk registries. As explained by Ms. Day, "[t]he operating unit risk registries are intended to provide each operating unit with a tool to capture its specific risks and enable a more structured management of lower consequence risks that occur more frequently and are dealt with at the operating unit levels. As the operating unit risk registries evolve and mature, they will inform the assessment of risks at the enterprise level and provide improved risk quantification and granularity across the Company."[8] The Company continues to work on developing operating unit risk registries in different operating areas of the Company and refining the process. The Company is leveraging the operating unit risk registries to inform internal asset management strategies to continue the integration of risk and asset management.

Additionally, the Company is committed to developing a Safety Management System (SMS),[9] which, according to the Office of Safety Advocate (OSA), is "a key tool for achieving safety goals, managing risks and opportunities, and meeting requirements and expectations."[10] A prudent SMS will further integrate risk, safety, and asset management under one framework. SMS is further discussed in Chapter RAMP-F.[11]

The Company continually seeks to implement metrics into its risk-based decision-making processes. Risk metrics span risk, asset, and investment management, in that they help evaluate and monitor asset health and potentially inform and demonstrate progress related to investments. D.19-04-020 approved safety performance metrics, which are reportable on an annual basis beginning in March 2020. The Company's data collection efforts and the metrics themselves will continue to support risk-based decision-making. Further, metrics are tied to investments in that the Company will provide an explanation in its annual Risk Spending Accountability

---

[8] *Id.* at DD-23.

[9] A.17-10-007/008 (cons.), Ex. 90 (SCG/SDG&E Buczkowski/Geier Rebuttal) at DLB/DLG-5.

[10] A.17-10-007/008 (cons.), Ex. 442 (OSA Contreras Prepared Testimony) at 2-20.

[11] Chapter RAMP-F is Company-specific as denoted by SCG RAMP-F and SDG&E RAMP-F.

Reports of how the reported safety metric data reflects progress against the safety goals in the Company's RAMP and GRC. In addition to CPUC-reportable metrics, the Company is in the process of identifying ways in which to quantify and track effectiveness related to its mitigations from this 2019 RAMP Report.

IV. EVOLUTION OF RISKS IN THE ERR COMPARED TO 2016 RAMP AND TY 2019 GRC

The SA Decision requires that the RAMP Report highlight changes to the ERR from previous RAMP or GRC filings.[12] Pursuant to this requirement, Appendix B-1 puts forth a comparison of the risks in this 2019 RAMP Report compared to those that were presented in the Company's 2016 RAMP Report, which was integrated into the TY 2019 GRC, and the 2018 ERR.

The primary driver for changes in the risks selected for the 2019 RAMP Report is related to the assessment methodology as established by the SA Decision. Essentially, in using the more quantitative method for risk assessment from the SA Decision[13] compared to the Company's prior risk analysis tools (*i.e.*, the 7x7 matrix), certain risks' scores in the Safety attribute changed (*e.g.*, Workplace Violence). The Company notes that the risks are dynamic; accordingly, risks in the ERR may change annually based on the ERM process identified above. Some risks that the Company manages, while important, did not rise to the enterprise-level to be included in the 2018 ERR. In addition, as discussed in Chapter RAMP-A, the Company generally excluded secondary impacts from its quantitative analysis when identifying risks for this 2019 RAMP Report. Additionally, as explained in Chapter RAMP-A, for this 2019 RAMP Report, some risks from the Company's 2016 RAMP Report are no longer presented as distinct risk chapters, but rather are identified as Drivers/Triggers to other risks. Examples of these include records management and climate change. Because the Company's ERRs are risk-event based, meaning generally risks in the ERR are identified as risk events, capturing risks such as records management and climate change as Drivers/Triggers to other risks is aligned with the

---

12 D.18-12-014 at Attachment A, A-7 (Risk Identification and Definition).

13 *See id.* at Attachment A, A-8 – A-9 (Step 2A).

Company's enterprise risk management framework. Records management and climate change adaptation are further discussed below.

A. Records Management

Records management-related risks were captured in the Company's 2018 ERRs as mitigations related to risks supporting the Company's efforts to construct, operate, and maintain the system safely and prudently as well as satisfy regulatory compliance requirements and data retention policies. A number of risks presented in the 2019 RAMP Report have records management related Drivers/Triggers associated with them. For example, the Medium Pressure Pipeline Incident risks (SCG-1 and SDG&E-6) have an "Incorrect/inadequate asset records" Driver/Trigger incorporated into their respective Bow Ties. Although there are some Controls and Mitigations that directly mitigate this risk, there may be additional efforts by the Company to target this risk that are not presented in the 2019 RAMP Report. Maintaining asset records, having adequate systems and processes in place for capturing changes in asset information, and executing projects that improve data automation and validation are critical to the Company's operations.

B. Climate Change Adaptation

Climate Change Adaptation was included in the Company's 2018 ERRs. The risk of Climate Change Adaptation remains a significant issue globally and here in California. The Company has several programs in place and takes the risk of climate change very seriously. The Company views climate change as a driver and/or trigger to some of the top-identified safety risks included herein. To address the risk of climate change, the Company's RAMP Report focuses on the drivers of climate change and the potential resulting impacts, which in turn yielded the adaptation assessment and mitigation efforts presented in the risk chapters of this 2019 RAMP Report. Therefore, Climate Change Adaptation is not included as an individual risk chapter within this 2019 RAMP Report but is addressed within the risk chapters, including Wildfire (Chapter SDG&E-1), Electric Infrastructure Integrity (SDG&E-4), Medium Pressure

Pipeline Incident (SCG-1 and SDG&E-6) and High Pressure Pipeline Incident (SCG-5 and SDG&E-8),[14] as a driver/trigger.

[14] In certain risk chapters, such as the High Pressure Pipeline Incident, the Driver/Trigger "Natural forces (natural disasters, fires, earthquakes)," includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, wildfires and high winds.

Appendix B-1
SoCalGas and SDG&E
Risk Comparison

Appendix B-1 – Comparison of 2016 RAMP Risks to 2018 ERR and 2019 RAMP Risks

SoCalGas		
2016 RAMP Risks Integrated into TY 2019 GRC	**2018 ERR**	**2019 RAMP Risk[1]**
Catastrophic Damage involving Medium-Pressure Pipeline Failure	Medium Pressure Gas Pipeline Incident (Excluding Dig-in) that Leads to Catastrophic Damage	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)
Employee, Contractor, Customer and Public Safety	Employee Safety	Employee Safety
	Contractor Safety	Contractor Safety
	Customer and Public Safety	Customer and Public Safety
Catastrophic Damage involving High-Pressure Pipeline Failure	High Pressure Gas Pipeline Incident (Excluding Dig-in) that Leads to Catastrophic Damage	High Pressure Gas Pipeline Incident (Excluding Dig-in)
Catastrophic Damage Involving Third Party Dig-Ins	Third Party Dig-in on a Medium Pressure Pipeline that Leads to Catastrophic Damage	Third Party Dig-in on a Medium Pressure Pipeline
	Third Party Dig-in on a High Pressure Pipeline that Leads to Catastrophic Damage	Third Party Dig-in on a High Pressure Pipeline
Catastrophic Event related to Storage Well Integrity	Storage Well Integrity Event that Leads to Catastrophic Damage	Storage Well Integrity Event
Cyber Security	Cyber Security	Cybersecurity
Workplace Violence	Workplace Violence	n/a
Physical Security of Critical Gas Infrastructure	Physical Security of Critical Gas Infrastructure	n/a
Workforce Planning	Workforce Planning	n/a
Records Management	Inadequate Asset Records for High Pressure Gas that Lead to Catastrophic Damage	n/a
	Inadequate Asset Records for Medium Pressure Gas that Lead to Catastrophic Damage	n/a
Climate Change Adaptation	Climate Change Adaptation	n/a
Other Risks in the SoCalGas 2018 ERR[2]		
System Reliability Impacts Due to Loss of a Storage Field		
Insufficient Supply to the Natural Gas Transmission System		
Southern System Reliability		
Inability to Recover Technology and Applications		
Gas Pipeline Safety Regulatory Compliance		

1 Each risk presented in the 2019 RAMP Report was part of the 2018 ERR; however, risk names as presented in the 2019 RAMP Report may be modified slightly in comparison to the 2018 ERR to align with the risk definition applied for purposes of the 2019 RAMP Report. Per the SA Decision, "[t]he [ERR] is the starting point for identifying the risks that will be included in the RAMP." (D.18-12-014, Attachment A, at Item No. 8.)

2 These risks were part of the 2018 ERR but were not included in the 2016 RAMP Report or the 2019 RAMP Report.

Ability to Continue to Procure Insurance
Environmental Compliance
Failure of Disaster Recovery / Business Resumption
Capacity Restrictions or Disruptions to the Natural Gas Transmission System

<table>
<tr><th colspan="3">SDG&E</th></tr>
<tr><th>2016 RAMP Risks Integrated into TY 2019 GRC</th><th>2018 ERR</th><th>2019 RAMP Risk[1]</th></tr>
<tr><td>Wildfires Caused by SDG&E Equipment</td><td>Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)</td><td>Wildfires involving SDG&E Equipment (including Third Party Pole Attachments)</td></tr>
<tr><td rowspan="3">Employee, Contractor and Public Safety</td><td>Contractor Safety</td><td>Contractor Safety</td></tr>
<tr><td>Employee Safety</td><td>Employee Safety</td></tr>
<tr><td>Customer and Public Safety</td><td>Customer and Public Safety</td></tr>
<tr><td>Electric Infrastructure Integrity</td><td>Electric Infrastructure Integrity</td><td>Electric Infrastructure Integrity</td></tr>
<tr><td>Catastrophic Damage Involving Medium-Pressure Pipeline Failure</td><td>Medium Pressure Gas Pipeline Incident (Excluding Dig-ins) that Leads to Catastrophic Damage</td><td>Medium Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td rowspan="2">Catastrophic Damage involving Third Party Dig-Ins</td><td>Third Party Dig-in on a Medium Pressure Pipeline that Leads to Catastrophic Damage</td><td>Third Party Dig-in on a Medium Pressure Pipeline</td></tr>
<tr><td>Third Party Dig-in on a High Pressure Pipeline that Leads to Catastrophic Damage</td><td>Third Party Dig-in on a High Pressure Pipeline</td></tr>
<tr><td>Catastrophic Damage involving High-Pressure Gas Pipeline Failure</td><td>High Pressure Gas Pipeline Incident (Excluding Dig-ins) that Leads to Catastrophic Damage</td><td>High Pressure Gas Pipeline Incident (Excluding Dig-in)</td></tr>
<tr><td>Cyber Security</td><td>Cyber Security</td><td>Cybersecurity</td></tr>
<tr><td>Major Disturbance to Electrical Service (Blackout)</td><td rowspan="2">Electric Grid Failure and Restoration (Blackout/ Failure to Black Start)</td><td rowspan="2">n/a</td></tr>
<tr><td>Fail to Black Start</td></tr>
<tr><td>Aviation Incident</td><td rowspan="2">Aviation Incident</td><td rowspan="2">n/a</td></tr>
<tr><td>Unmanned Aircraft System (UAS) Incident</td></tr>
<tr><td>Workplace Violence</td><td>Workplace Violence</td><td>n/a</td></tr>
<tr><td>Records Management</td><td>Inadequate Asset Records for High Pressure Gas that Lead to Catastrophic Damage</td><td>n/a</td></tr>
</table>

[1] Each risk presented in the 2019 RAMP Report was part of the 2018 ERR; however, risk names as presented in the 2019 RAMP Report may be modified slightly in comparison to the 2018 ERR to align with the risk definition applied for purposes of the 2019 RAMP Report. Per the SA Decision, "[t]he [ERR] is the starting point for identifying the risks that will be included in the RAMP." (D.18-12-014, Attachment A, at Item No. 8.)

	Inadequate Asset Records for Electric	n/a
Climate Change Adaptation	Climate Change Adaptation	n/a
Distributed Energy Resources (DER)	n/a	n/a
Public Safety Event – Electric[2]	n/a	n/a
Workforce Planning	n/a	n/a
Other Risks in the SDG&E 2018 ERR[3]		
Capacity Restrictions or Disruptions to the Natural Gas Transmission System		
Ability to Continue to Procure Insurance		
Negative Customer Impacts Caused by Outdated Customer Information Systems		
Insufficient Supply to the Natural Gas Transmission System		
Inability to Recover Technology and Applications		
Physical Security of Critical Electric Infrastructure		
Environmental Compliance		
Massive Smart Meter Outage		

2 Elements of this risk (*e.g.*, controls) are now included in other risks in the 2018 ERR.
3 These risks were part of the 2018 ERR but were not included in the 2016 RAMP Report or the 2019 RAMP Report.

Risk Assessment Mitigation Phase
(RAMP-C)
Risk Quantification Framework

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This chapter provides a detailed overview of the multi-attribute value function (MAVF) applied to quantitatively assess risks throughout this report (referred to herein as the Risk Quantification Framework), including illustrating hypothetical examples of risk scores (using the ranges displayed in the examples). The Risk Quantification Framework is used to analyze risk by estimating current risk scores (the Pre-Mitigation Risk Scores) and forecasting future risk scores if new activities are started or current ones are ceased (the Post-Mitigation Risk Scores).

- Section II provides an overview of the quantitative analysis used to analyze each risk, according to the S-MAP settlement agreement (the SA Decision).[1]
- Section III describes the requirements of the MAVF per the SA Decision, and how the Company's Risk Quantification Framework was accordingly constructed.
- Section IV describes the steps to apply the Risk Quantification Framework in accordance with the SA Decision.
- Section V shows a hypothetical example of a risk score calculation using the Risk Quantification Framework.
- Section VI describes the decisions made in constructing the Risk Quantification Framework, including the scaling and weighing of attributes, demonstrating compliance with the SA Decision.
- Finally, Section VII demonstrates the Company's efforts towards development of probabilistic calculations and analysis, and discusses quantitative methodologies including statistical information and the use of computer software in development of this RAMP Report.

As the first to apply the quantitative analysis required by the SA Decision, the Company possesses a number of observations about the process that may aid the California Public Utilities Commission (Commission or CPUC) and other investor-owned utilities (IOU) in future applications of the framework. The Company offers these "lessons learned" in Chapter RAMP-G.

---

1 The SA Decision is Decision (D.) 18-12-014, including the settlement agreement adopted therein.

II. OVERVIEW AND APPROACH

The quantitative analysis applied in this RAMP Report is derived from the SA Decision, and can be outlined as follows:

- Develop a MAVF, which the Company refers to as the Risk Quantification Framework;[2]
- Consider risks as defined and scoped in the Company's Enterprise Risk Register (ERR);[3]
- Compute a Safety Risk Score using the Safety Attribute of the MAVF for each risk included in the ERR;[4]
- For each identified risk that meets the SA Decision thresholds:[5]
    - Estimate the frequency of a risk event occurring in a given year and use that value for the Likelihood of Risk Event (LoRE);
    - Estimate the average (mean) consequences if the Risk Event were to occur;
    - Apply the average consequences to the Risk Quantification Framework to create a value known as the Consequence of Risk Event (CoRE); and
    - Multiply the values of LoRE and CoRE to determine a Risk Score for that risk. The result of this calculation constitutes a Pre-Mitigation Risk Score.

As required by the SA Decision, a resulting Pre-Mitigation Risk Score will be used: (1) to demonstrate a risk score for each risk along with a ranking, and (2) as an input into the calculations to determine the change in risk scores when a risk-reducing activity is started or ceased.

---

2 *Id.* at Attachment A, A-5 – A-6 (Step 1A).

3 *Id.* at Attachment A, A-7 (Step 1B).

4 *Id.* at Attachment A, A-8 – A-9 (Step 2A).

5 *Id.* at Attachment A, A-11 – A-13 (Step 3).

III. RISK QUANTIFICATION FRAMEWORK (OVERVIEW)

A. Introduction

The Risk Quantification Framework (or MAVF) is a tool for combining all potential consequences of the occurrence of a risk event to create a measurement of value. This section presents the Risk Quantification Framework that will be used throughout this RAMP Report. Section IV of this chapter provides a thorough walkthrough of how this Risk Quantification Framework is applied, and Section V provides an example of its application. Section VI of this chapter describes the rationales for how the Company set the assumptions used in this Risk Quantification Framework.

This RAMP Report is the first filing that implements the SA Decision, and therefore there is still much to be learned and improved in the future.[6] The quantitative aspects shown in this chapter are not meant to reflect precision or a comprehensive view of risk, but rather serve as a starting point on which to build. Further, as explained below, the Risk Quantification Framework is the result of many discretionary assumptions. Should those assumptions change, different results would be expected.

B. Risk Quantification Framework

According to the SA Decision, the Risk Quantification Framework requires a company to select certain "attributes," defined as "an observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability."[7] The attributes "should cover the reasons that a utility would undertake risk mitigation activities" and must be reflected in "the way the level of an attribute is measured or expressed."[8] The determination of attributes is left to each utility's discretion. These attributes are a subset of the many criteria used to assess and manage risk. The selection of attributes for RAMP Report purposes is predicated on, among

---

[6] The Company offers "lessons learned" to aid the Commission and other IOUs in future applications of the framework in Chapter RAMP-G.

[7] D.18-12-014 at Attachment A, A-2.

[8] *Id.* at Attachment A, A-2 – A-3.

other factors, the level of data available, the strength of the data available, and the commonality of the attribute across risks.

The SA Decision also requires construction of a scale "that converts the range of natural units … to scaled units to specify the relative value of changes within the range, including capturing aversion to extreme outcomes or indifference over a range of outcomes."[9] Attributes also must be assigned weights reflecting each attribute's relative importance to other identified attributes:

> Weights are assigned based on the relative value of moving each Attribute from its least desirable to its most desirable level, considering the entire range of the Attribute.… Weights are assigned based on actual Attribute measurement ranges, not a fixed weight arbitrarily assigned to an Attribute. For example, the Attribute weights will reflect the relative importance of moving the safety outcomes from the least to the most desirable levels as compared with moving financial outcomes from the least to the most desirable levels in a risky situation.[10]

The following three tables show a Risk Quantification Framework utilized in this RAMP Report. Each table shows chosen attributes and assigned weights and scales. A narrative summary of the choices examined and made in assigning values to the variables shown below (*e.g.*, attributes, scales, weights) is described in Section VI below.

The Risk Quantification Framework is a prescribed methodology that is performed in accordance with the SA Decision, which may provide a data point to help inform risk-based decision making (amongst many other available data points). There are numerous ways to select attributes, scaling and weights. However, the SA Decision contains a prescribed methodology for selecting attributes, scaling and weights, which limits a utility's choices in certain ways. The choices elected in accordance with the SA Decision's prescribed methodology should not be viewed as a precise reflection of real-world circumstances and are made for RAMP purposes only.

---

[9] *Id.* at Attachment A, A-5.

[10] *Id.* at Attachment A, A-6.

The SA Decision requires the Company to follow six principles to construct its MAVF.[11] The Company applied these six principles to arrive at the Risk Quantification Framework summarized in Table 1 below. The top-level attributes of Safety, Reliability, and Financial are consistent with the minimum attributes required by the SA Decision.[12] Given that "[a]ttributes are combined in a hierarchy,"[13] the top-level attributes are further broken down into sub-attributes.[14] Measurement of each sub-attribute is also required and is assigned based on the unique characteristics.[15] These sub-attributes are then rolled up to the top-level attribute. The combined measurement of each top-level attribute is represented in Table 1 below as the Measurement Unit. The scales contained in Table 1 also reflect the SA Decision's MAVF principles and were constructed to represent the relative value of changes in a range of the measured units.[16] Similarly, the Company completed a weighting process in accordance with the SA Decision[17] to develop the weights in Table 1 below (as further described in Section VI.C, *infra*).

---

11 *Id.* at Attachment A, A-5 ("MAVF").

12 *Id.* at Attachment A, A-8 ("Risk Assessment").

13 *Id.* at Attachment A, A-5 ("MAVF Principle 1 – Attribute Hierarchy").

14 *Id.* at Attachment A, A-5, ("MAVF Principle 1 – Attribute Hierarchy") and ("MAVF Principle 2 – Measured Observations") refer to lower-level attributes in the context of building a MAVF. The term "lower-level attribute" is referred to herein as "sub-attribute."

15 *Id.* at Attachment A, A-5 ("MAVF Principle 2 – Measured Observations") and ("MAVF Principle 3 – Comparison").

16 *Id.* at Attachment A, A-5 ("MAVF Principle 5 – Scaled Units").

17 *Id.* at Ordering Paragraph 2 and at Attachment A, A-6 ("MAVF Principle 6 – Relative Importance").

Table 1: Risk Quantification Framework Top-Level Attributes

Top-Level Attribute	Measurement Unit[18]	Scale	Weight
Safety	Safety Index	0 – 30	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 2 below shows the sub-attributes contained in the Safety top-level attribute from Table 1 above. The measured unit for each of Safety's sub-attributes, when used together, create a single Safety Index value that is used in Table 1 above.[19] The components of the Safety Index are provided in Table 2 below.

Table 2: Risk Quantification Framework Safety Index

Safety Sub-Attributes	Value
Fatality	1
Serious Injury	0.25

Similar to Table 2 above, the following Table 3 shows the sub-attributes that are included in the Reliability top-level attribute from Table 1. Each sub-attribute is measured by its own unit. The Company's determination of Attributes, Scales and Weights are explained in Section VI, *infra*. When all of the four sub-attributes for reliability are summed together, it creates a single Reliability Index value that is used in Table 1 above.[20] These are shown in Table 3 below.

---

18 "Measurement Unit" used herein is the measured attribute, also analogous to "Natural Unit" per the SA Decision Lexicon included in D.18-12-014 at Attachment A, A-3.

19 MAVF Principle 1 - Attributes are combined in a hierarchy. *See* D.18-12-014 at Attachment A, A-5.

20 *Id.*

Table 3: Risk Quantification Framework Reliability Index

Reliability Sub-Attribute	Measurement Unit	Scale	Weight
Gas Core Meters	Number of Gas Core Meters Experiencing Outage	0 – 75,000 meters	25%
Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day	0 – 500 MMcf	25%
Electric SAIDI	System Average Interruption Duration Index (SAIDI) minutes	0 – 100 minutes	25%
Electric SAIFI	System Average Interruption Frequency Index (SAIFI) outages	0 – 1 outages	25%

Despite some of the prescriptive elements in the SA Decision, there remain a wide range of possible choices available to each utility in assigning attributes, weights, scales, and other variables. Because of this, the Company has chosen to provide a range of scoring, based upon two additional alternative Risk Quantification Framework methods. These alternative methods, and the rationales behind their presence, are described in greater detail in Section VI of this chapter. The two alternatives demonstrate a range of risk scores for each risk and consequently demonstrate a range of RSEs for each activity. The Risk Quantification Framework provides a direction on how to improve risk, but it is not a precise tool and should not be construed as such.

The structure of the alternatives is exactly the same as described above, with the only change being in the scale factor for the Safety Attribute. The "High Alternative" has a safety scale of 0 – 12, rather than 0 – 30; and the "Low Alternative" has a safety scale of 0 – 300, rather than 0 – 30. The SA Decision requires the Company to produce a single risk score and RSE using the adopted methodology. The Company refers herein to the result from its chosen Risk Quantification Framework methodology as the "Single Point" result. The Single Point represents a single score out of a range of possibilities, resulting from applying the SA Decision, using the Company's chosen set of assumptions. However, because of the uncertainty and subjective nature of the methodology with respect to the relative importance of each attribute, as further described in Section VI, *infra*, the Company is presenting a range of potential scales (and the resulting RSEs) in this RAMP Report. A Safety Index Scale that has a tighter range will tend to emphasize safety more than a Safety Index Scale that has a wider range. For example, a Safety Score of 2 will be 1/6 of the score when the Scales range from 0 – 12, but that score will only be 1/150 of the score when the Scales range from 0 – 300.

Summary tables for both alternatives are shown below in Tables 4 and 5.

Table 4: High Alternative

Top-Level Attribute	Measurement Unit	Scale	Weighting
Safety	Safety Index	0 – 12	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 5: Low Alternative

Top-Level Attribute	Measurement Unit	Scale	Weighting
Safety	Safety Index	0 – 300	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

As a hypothetical example, suppose there was a risk that had a likelihood of exactly one event per year, and that the consequence of the event occurring lead to exactly one fatality every time. The LoRE for this risk would be 1, and the CoRE would be calculated using the Risk Quantification Framework.

The Single Point method would yield a CoRE of:

$$(1/30) * 60\% + (0/1) * 20\% + (0/\$1B) * 20\% = \mathbf{0.02}$$

The High Alternative shown above would yield a CoRE of:

(1/12) * 60% + (0/1) * 20% + (0/$1B) * 20% = **0.05**

The Low Alternative shown above would yield a CoRE of:

(1/300) * 60% + (0/1) * 20% + (0/$1B) * 20% = **0.002**

The three different methods, each based on a LoRE of 1, can be summarized in the following table:

Table 6: Example of Illustrative Risk Showing Single Point and Alternative Scorings

	LoRE	CoRE	Risk Score
Single Point	1	0.024	2,400
High Alternative	1	0.05	5,000
Low Alternative	1	0.002	200

IV. APPLICATION OF RISK QUANTIFICATION FRAMEWORK

Per the SA Decision, the Risk Quantification Framework must use specific methods of applying statistical information. The following statistical concepts are key to understanding the Risk Quantification Framework: (a) risks are evaluated at the "risk-level" as defined by the Company's ERR, (b) each risk is evaluated for annual frequency using the risk quantification method (as required by the SA Decision), (c) each risk is evaluated by considering all possible consequences attributed to a risk event (rather than specific scenarios), and (d) averages, or expected values, are used for LoRE and CoRE.

In more detail, the Risk Quantification Framework methodology uses the following steps:

Step 1: Estimate LoRE. Estimate the frequency of a risk event occurring in a given year and set the LoRE to this value. If the frequency is estimated to be less than one per year, the frequency is put into decimal form. For example, if the estimate was a frequency of a risk event occurring 5 times a year, the LoRE would be set to 5. If the frequency of a risk events was estimated to be one event in 10 years, the LoRE would be set to 0.1. Depending on the risk, the frequency of Risk Events in the RAMP Report range from approximately 0.06 to 2000.

Step 2: Estimate consequences of event for each attribute. As discussed above, the Risk Quantification Framework has three attributes with several sub-attributes. This step uses the average consequence for each attribute and sub-attribute based on the wide variety of possible consequences. For example, suppose a Risk Event had a 10% chance of having a $2 million consequence and a 90% chance of having a $100,000 consequence. The value used for the financial consequence would be the weighted average of those chances, or (10% x $2 million) + (90% x $100,000) = $290,000. A similar exercise is done for all of the attributes in the Risk Quantification Framework.

Step 3: Estimate CoRE. Once the averages of consequences for each attribute are determined, use the Risk Quantification Framework to obtain a single consequence value known as the Consequence of Risk Event (CoRE). CoRE is a value that incorporates all attributes.

Step 4: Calculate Risk Score. Lastly, multiply the LoRE and the CoRE to calculate the Risk Score. To ease readability, the Risk Score is multiplied by 100,000, then rounded to the nearest whole number, or decimal if less than 1.

These steps are also undertaken for the two alternative methods mentioned above in Section III of this chapter. The alternatives differ in Step 3 (because of a slight variation in how CoRE is calculated). Then Step 4 for each alternative uses the alternative CoRE values to multiple with LoRE.

The application of these process results in the Company's Single Point method and the two alternatives – low alternative, and high alternative.

V. HYPOTHETICAL EXAMPLE OF RISK SCORE CALCULATION USING THE RISK QUANTIFICATION FRAMEWORK WITH ALTERNATIVES

The following example will follow steps 1 - 4 shown above. All values in this example are illustrative and not representative of a specific risk.

A. Example: Risk XYZ Single Point Method

Step 1: Estimate LoRE. Internal and external data suggest that Risk XYZ will have an average of 12 Risk Events per year.

Step 2: Estimate consequences of attributes. Internal and external data suggest that if a Risk Event were to occur for Risk XYZ, the consequences would average as follows:

a. Fatalities: 0.02 (*i.e.* 1 fatality for every 50 risk events)
b. Serious Injuries: 0.1 (*i.e.* 1 serious injury for every 10 risk events)
c. Electric SAIDI: 0 minutes of SAIDI
d. Electric SAIFI: 0 outages of SAIFI
e. Gas Core Meters: 0 meters
f. Gas Curtailment: 0 curtailment
g. Financial: $1.5 million from damage to property

Step 3: Estimate CoRE. Using the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% = 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{30}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\% = \frac{0.045}{30}\ x\ 60\% + \frac{0}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x = 0.0012$

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.0012. Risk Score = 12 x 0.0012 x 100,000 = 1,440. The Risk Score of Risk XYZ is 1,440.

As mentioned in Section III of this Chapter, the Company is providing ranges for each risk score. The risk scores will be calculated using the High Alternative and Low Alternative methods. The values for High Alternative and Low Alternative only differ in how CoRE is calculated.

B. Example XYZ using Low Alternative

Step 1: Same as above.

Step 2: Same as above.

Step 3: Estimate CoRE. Using the Low Alternative version of the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% = 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{300}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\% = \frac{0.045}{300}\ x\ 60\% + \frac{0.0125}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x = 0.0039$

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.00039. Risk Score = 12 x 0.00039 x 100,000 = 468. The Low Alternative Risk Score of Risk XYZ is 468.

C. Example XYZ using High Alternative

Step 1: Same as above

Step 2: Same as above

Step 3: Estimate CoRE. Using the High Alternative version of the Risk Quantification Framework, apply each of the estimates for each attribute/sub-attribute to generate top-level attribute information, then apply those values to the Risk Quantification Framework top-level attributes. The values from Step 2 are used below and shown in bold face type.

a. Safety Index: (Fatalities x 1) + (Serious Injuries x 0.25) = (**0.02** x 1) + (**0.1** x 0.25) = 0.045

b. Reliability Index: $\frac{Gas\ Core\ Meters\ Experiencing\ Outage}{75{,}000}\ x\ 25\% + \frac{Gas\ Curtailed\ exceeding\ 250MMcfd}{500MM}\ x\ 25\% + \frac{SAIDI}{100}\ x\ 25\% + \frac{SAIFI}{1}\ x\ 25\% = \frac{\mathbf{0}}{75{,}000}\ x\ 25\% + \frac{\mathbf{0}}{500MM}\ x\ 25\% + \frac{\mathbf{0}}{100}\ x\ 25\% + \frac{\mathbf{0}}{1}\ x\ 25\% =\ 0$

c. Financial: **$1.5 million**

d. CoRE = $\frac{Safety\ Index}{12}\ x\ 60\% + \frac{Reliability\ Index}{1}\ x\ 20\% + \frac{Financial}{\$1B}\ x\ 20\%\ = \frac{0.045}{12}\ x\ 60\% + \frac{0}{1}\ x\ 20\% + \frac{1.5M}{\$1B}\ x\ 20\%\ x\ = 0.00255$

Step 4: Calculate Risk Score. Multiply LoRE x CoRE x 100,000 and round to nearest whole number. From step 1, LoRE = 12, from step 3, CoRE = 0.00255. Risk Score = 12 x 0.00255 x 100,000 = 3,060. The High Alternative Risk Score of Risk XYZ is 3,060.

Table 7: Summary of Risk XYZ Risk Scores

	Low Alternative	**Single Point**	**High Alternative**
Risk XYZ	468	1,440	3,060

VI. MAVF CONSTRUCTION

Per the SA Decision, each utility is required to create a multi-attribute value function that will be used in the RAMP Report for risk scoring.[21] As stated above, the MAVF is a tool for combining all potential consequences of the occurrence of a risk event to create a measurement of value. The Company's MAVF construction followed the steps outlined in the SA Decision.[22] The process of creating the MAVF is complex and should be considered a non-perfect method to

21 *Id.* at Attachment A, A-5 – A-6 (Step 1A).

22 *Id.*

interpret the utility risk. Because the Company is in the process of determining effective quantitative risk methods, the value functions presented in this RAMP Report are the beginning steps into a complex and multi-layered methodology.

It is important to note that the construction of the MAVF discussed herein was a single effort undertaken for both SoCalGas and SDG&E. The attributes, scales, and weighting of attributes in the MAVF were determined collectively for both Companies given the Companies' shared assets (*e.g*., natural gas distribution system, IT infrastructure), and shared risk management framework.

There were several considerations when developing the Companies' first Risk Quantification Framework, as described below.

A. Determination of Attributes

An attribute, as defined by the SA Decision, is "an observable aspect of a risky situation that has value or reflects a utility objective, such as safety or reliability. Changes in the levels of attributes are used to determine the consequences of a Risk Event."[23] Following MAVF Principle 1, the Company considered a large number of attributes for the Risk Quantification Framework. The method of attribute inclusion was: (a) create a list of potential attributes - where the list was generated by combining efforts with the CPUC workshops, consulting internal subject matter experts (SMEs), and researching external entities, and (b) determine the ability to include such attributes by considering availability of data, consistency of data, commonality of the attribute across risks, and complications arising from their inclusion, among others. The attributes included in this RAMP Report are not meant to represent all dimensions of risk management that occur at the Company but are useful for the purposes of this filing, namely to create estimated risk quantification that can assist in decision-making.

An example of a potential attribute that was not selected due to the unavailability of consistent data is company trust. It is possible to measure company trust through public surveys or polling, but the purpose of the attribute for the RAMP Report is to determine pre- and post-activity measurements and it will require consistency of individuals for each survey or polling,

---

[23] *Id.* at Attachment A, A-2.

and a measurement after each activity, which can be in the hundreds. The Company has, for now, concluded that measuring company trust for each change in risk-reducing activities would be an exercise that requires large amounts of guesswork and subjectivity. Perhaps in the future, the concept of company trust will be more easily measurable, or some appropriate proxy will be devised so that this attribute could be included.

Environmental attributes were also not selected. While the Company is very focused on environmental impacts and thoughtfully consider how to reduce those impacts, for the purposes of quantification, the Company was unable to determine how to express an environmental attribute that would meet the standards of the SA Decision. There are several dimensions of impacts related to the environment, including impacts to water, soil, air, species, and cultural. Within those dimensions there are numerous sub-dimensions. For example, pollution of air can take many forms that include greenhouse gas (GHG) emissions, but also near-ground pollution such as exhaust from vehicles and generators that have more of a local impact to air quality.

In addition to the various challenges described earlier as to the scope and impacts of the environmental attributes, it was also difficult to define relative weights between each of these environmental impacts. One option was to focus on a narrower view of environmental impacts, such as only considering GHG for use in the attribute. But it was understood that this narrow approach would lead to undesirable outcomes by overestimating certain projects and giving an incorrect impression that the Company was not interested in reducing the other non-represented impacts.

Future versions of the Risk Quantification Framework may be designed with the goal of expanding and refining the number of attributes and sub-attributes in line with other key parameters used in day-to-day decision making.

B. Scales of Attributes

The SA Decision directs the utility to construct a scale that converts the range of natural units to scaled units.[24] While the notion of applying scales for attributes appears to be straightforward, there are many aspects to consider, especially when applying the next step of

[24] *Id.* at Attachment A, A-5 – A-6 (Step 1A).

assigning weights to each scale. The SA Decision states that the top of the scale approximates the maximum expected results for a risk. However, the SA Decision method also requires expected values to be used and expected values have very different "maximum expected results" depending on each scenario used. For example, a plane crash might lead to a few hundred deaths, but the annual expected value of fatalities for a particular airline in a given year is something far less. The Company exercised its discretion[25] to make a reasoned decision in choosing the top end of the scales for the attributes because not all risk scenarios involving a particular risk yield the same maximum expected results. As discussed in the Weights of Attributes section below, scales and weights are strongly connected.

C. Weights of Attributes

1. Quantitative Notes on Weights

The weight applied to each attribute is an important step in determining risk scores. Different weights applied to several risks can lead to different rankings of those risks. Below is a simplified, illustrative example of sample risks that show how weights can alter results:

Table 8: Illustrative Example of Weighting

	Safety Score	Financial Score	Risk Score Method 1: Safety: 90% Weight Financial: 10% Weight	Risk Score Method 2: Safety: 50% Weight Financial: 50% Weight
Risk A	0.5	0.2	4700	3500
Risk B	0.2	0.6	2400	4000

In Table 8, above, Risk A has a Risk Score near twice as large as Risk B (4700 vs 2400) using Method 1 (90% Safety and 10% Financial) but has a lower risk score using Method 2. This is because Risk A has more Safety risk relative to Risk B, and a weighting that favors Safety would therefore favor Risk A. This example illustrates that choosing weights can have significant impact on the scoring that follows. The Company is aware that its choice of weights is not perfect for all situations, and therefore scores should be thought of as estimates, rather than precise values.

25 The discretion built into the MAVF may be a good topic of consideration for future S-MAP proceedings.

There is a very strong relationship between scales and weights. The two characteristics work hand-in-hand to create the value framework. The following example highlights this point.

Suppose there are two Multi-attribute Value Functions that only have attributes for Safety and Financial. Their illustrative characteristics are shown below:

Table 9: Illustrative Example of Scale & Weight

	MAVF #1	MAVF #2
Safety Scale	0 – 100 (measured in fatalities)	0 - 10 (measured in fatalities)
Safety Weight	80%	50%
Financial Scale	0 - $1 billion (measured in $)	0 - $1 billion (measured in $)
Financial Weight	20%	50%

Now suppose there is a risk that has been assessed as having an expected value of impacts as $100M financial loss for property damage, and 2 fatalities. The Consequence of Risk Event for each MAVF would be:

MAVF #1: CoRE = (2 / 100) * 80% + ($100 million / $1000 million) * 20% = 0.036

MAVF #2: CoRE = (2 / 10) * 50% + ($100 million / $1000 million) * 50% = 0.15

Note that the portion of the CoRE that comes from the Safety is:

MAVF #1: CoRE = (2 / 100) * 80% = 0.016

MAVF #2: CoRE = (2 / 10) * 50% = 0.1

Although MAVF #1 has a higher weighting for Safety (80% versus 50%), it gives a lower score for safety, due to the scale being different. Therefore, it is not enough to solely focus on the weight of each attribute to determine the importance of the attribute in the risk score.

2. Methodology for Determining Weights

The SA Decision requires that the Safety Attribute of the MAVF have a minimum weight of 40%.[26] Other than that safety minimum weight requirement, the SA Decision provides discretion for the Company to select the applicable weights through its own internal processes.

The main method to determine weights for the Company's Risk Quantification Framework was to consider alignment with the Company's ERM ERR process. During the creation of the ERR, a qualitative scoring method that contained several risk dimensions was used.

Using the ERR as a starting point, initial weights were identified and considered for use in the RAMP Report. Although the ERR is more of a qualitative than quantitative view of risk, it can lend itself to numerical comparisons. For example, in the ERR, an attribute of Health, Safety, and Environmental (HSE) are weighted 40%, and Reliability is weighted as 20%. Therefore, an HSE score of 4 would give twice the value to the Risk Score as a Reliability score of 4. Below is sample from the qualitative scoring method that is currently part of the Company's ERR:

Table 10: Qualitative Scoring

	Impact Score 4	**Impact Score 3**	**Weight**
Health, Safety and Environmental	Permanent/Serious Injuries or Illnesses: Few serious injuries or illnesses to the public or employees. Significant and short-term impacts to environment	Minor Injuries or Illnesses: Minor injuries or illnesses to many public members or employees. Moderate and short-term impacts to environment	40%
Operations and Reliability	> 10,000 customers affected; impacts single critical location or customer; disruption of service greater than 1 day	> 1,000 customers affected; impacts single critical location or customer; disruption of service for 1 day	20%

[26] D.18-12-014 at Ordering Paragraph 2.

By observing the relationship between the types of impacts that would create an HSE score of 4 versus a Reliability score of 4, for example, it is possible to adjust the Risk Quantification Framework to find similar relationships.

Additional information considered in the creation of Risk Quantification Framework weights was to utilize an industry-leading reliability study that comments on financial equivalences with reliability.[27] The study considers the amount of financial loss to customers due to loss of electric power. As mentioned in more detail below, because every electric outage is unique, the study is used as a guide rather than as a source of precise equivalences. While there is not an equivalent reliability study available specific to financial loss to customers due to loss of natural gas, the findings in the study can be extrapolated to generally apply to all utility customers.

The use of the ERR and the reliability study led to a rough approximation of how weights might look across all three attributes. Draft versions of the scales and weights were created and run through a series of real-world events to check the results for reasonableness. Adjustments were made after the reasonableness test runs and results were internally discussed.

During the internal testing and discussions, it became clear that no set of scales and weights would lead to expected results for all situations for all individuals. Different subject matter experts had their own experience of how to value different scenarios. More refinements were made, and a set of scales and weights that may reflect a compromise on how different subject matter experts and external sources view this relationship is being utilized in this RAMP Report.

To summarize how weights used in the Risk Quantification Framework were attained, the solution was a reconciliation of different values and data points and considers the following items: a) current ERR framework, b) electric reliability study, c) historical comparison of gas and electric reliability impacts to society, d) scenario testing, e) input from ERM staff and leadership, f) research into other utilities and industries, g) input from personnel of varying levels

[27] Ernest Orlando Lawrence Berkeley National Laboratory, *Estimated Value of Service Reliability for Electric Utility Customers in the United States* (June 2009), *available at* https://emp.lbl.gov/sites/default/files/lbnl-2132e.pdf.

at the Company through the senior vice president level, and h) using rounded numbers for readability.

3. Observations when Determining Weights

This section discusses several issues the Company encountered when determining the final scales and weights to utilize for the Risk Quantification Framework.

The Risk Quantification Framework utilizes three attributes – safety, reliability and financial. In an ideal world, the relationship between each of the three pairwise combinations (*i.e.,* reliability vs. safety, safety vs. financial, and financial vs. reliability) would be consistent. In mathematics, the transitive property is commonly stated as "If a=b and b=c, then a=c." But for multi-attribute value functions the transitive property is less clear. As noted above, for electric reliability, the Lawrence Berkeley study was used as a starting point to compare reliability to financial. Using that data, a blackout occurring across SDG&E's service territory for eight hours would have a financial impact to SDG&E's customers of over $1 billion. As stated previously, while there is not a gas customer-specific equivalent study, the results generally can be extrapolated to SoCalGas customers. This hypothetical created one pairwise combination of the attributes (reliability vs. financial). Separately, a hypothetical question was posed to determine another pairwise combination (reliability vs. safety): "Which risk event would you least like to happen, a systemwide blackout for eight hours that harms no one or a safety incident at a substation that results in an employee fatality?" The Company prioritized the elimination of the safety incident. With the two pair-wise comparisons developed, the transitive property was applied to derive the third pair-wise comparison. When doing so, the third pair-wise comparison (safety vs. financial) did not follow the first two pair-wise comparisons and thus led to unhelpful values for the third pair-wise comparison.

Another issue is that the Company is not accustomed to quantifying the value (financially or otherwise) of preventing safety incidents. Safety is not simply a priority at the Company; it is our culture and is the Company's core value.

Another concept observed during the creation of the Risk Quantification Framework relates to comparing the value of preventing an incident versus the value of remediating the impact if the incident were to happen. For example, if an employee becomes injured on the job, it might take some amount of financial effort and Human Resource involvement to make sure the employee is taken care of and that the employee's group has a trained person to temporarily fill the role. The value of trying to prevent the event is not equal to the value of the expected remediation costs

To address uncertainty and discretion, the Company constructed a Risk Quantification Framework that demonstrates the variability in outcomes based upon the reasoned inputs used by the Company. The Company uses in this RAMP Report three versions of the Risk Quantification Framework, which together will create a "Single Point" number as well as a range around that number. The information at the beginning of this chapter discussed the Single Point version, which satisfies the SA Decision. The additional range of outputs will be reflected in the Risk Score of each risk and in the RSE values that are created for each risk-reducing activity. The range created by presenting options of the Safety Scale provides different views on how interested parties might view a risk based on differing views of safety. The ranges are illustrated in Tables 11, 12, and 13 below:

Table 11: Single Point

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 30	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 12: High Alternative

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 12	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

Table 13: Low Alternative

Top-Level Attribute	Natural Unit	Scale	Weighting
Safety	Safety Index	0 – 300	60%
Reliability	Reliability Index	0 – 1	20%
Financial	$	$0 - $1B	20%

D. Implementation of Attributes

The SA Decision contemplates expression of attributes in "natural units."[28] The natural unit of an attribute is defined as follows:

> [T]he way the level of an attribute is measured or expressed. For example, the natural unit of a financial attribute may be dollars. Natural units are chosen for convenience and ease of communication and are distinct from scaled units.[29]

The top-level attributes of Safety and Reliability comprise sub-attributes that are used to create Safety and Reliability indices, respectively. The Safety Index has two sub-attributes, while the Reliability Index has four sub-attributes. The measurement units chosen to represent the natural units for the sub-attributes are shown in Table 14 below. The sub-attributes within safety and reliability are used to create an index for the top-level attribute.

Table 14: Attributes

Attribute	Sub-Attribute	Measurement Unit
Safety	Fatality	Number of Fatalities
Safety	Serious Injury	Number of Serious Injuries
Reliability	Gas Core Meters	Number of Gas Core Meters Experiencing Outage
Reliability	Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day

28 D.18-12-014 at Attachment A, A-3.

29 *Id.*

Reliability	Electric SAIDI	System Average Interruption Duration Index (SAIDI)
Reliability	Electric SAIFI	System Average Interruption Frequency Index (SAIFI)

E. Safety Attribute

The Safety Attribute consists of a Safety Index, which is calculated by assessing its two sub-attributes. The sub-attributes are included because the data is readily available. The relative value between Fatalities and Serious Injuries is derived from information provided through the Occupational Health & Safety Administration (OSHA) and the Federal Aviation Administration (FAA).[30] Fatalities each receive a score of 1, and Serious Injuries receive a score of 0.25 each. A Serious Injury is usually defined as an event that requires overnight hospitalization or a permanent disfigurement of an individual.[31] The sum of these two sub-attributes create the Safety Index, which is then used as a top-level attribute in the Risk Quantification Framework.

Table 15: Safety Attributes

Safety Sub-Attribute	Value
Fatality	1
Serious Injury	0.25

In the RAMP Report, safety impacts are agnostic to (a) cause or reason for the event that results in safety impact, (b) characteristics of those affected, (c) level of fault for the utilities or others, (d) mitigating or aggravating circumstances related to the person's situation, and (e) other such concerns.

30 *See* United States Department of Labor, *Severe Injury Reports*, *available at* https://www.osha.gov/severeinjury/; *see also* United States Department of Labor, *Reports of Fatalities and Catastrophes – Archive*, *available at* https://www.osha.gov/fatalities/reports/archive; *see also* Federal Aviation Administration, *Data & Research*, *available at* https://www.faa.gov/data_research.

31 8 CCR § 330(h).

F. Reliability Attribute

The Reliability Attribute comprises a Reliability Index that consists of four equally weighted sub-attributes. The sub-attributes with their Natural Units (Measurement Units) are shown in Table 16 below. The Reliability Index shown below is structured similarly to the overall Risk Quantification Framework and also contains attributes, scales, and weights.

Table 16: Reliability Attributes

Reliability Sub-Attribute	Measurement Unit	Scale	Weight
Gas Core Meters	Number of Gas Core Meters Experiencing Outage	0 – 75,000 meters	25%
Gas Curtailment	Volume of Curtailments of Natural Gas exceeding 250 million cubic feet/day	0 – 500 MMcf	25%
Electric SAIDI	System Average Interruption Duration Index (SAIDI) minutes	0 – 100 minutes	25%
Electric SAIFI	System Average Interruption Frequency Index (SAIFI) outages	0 – 1 outages	25%

The SA Decision requires a utility to identify relative weights between sub-attributes like gas and electric reliability, but relating the gas to electric reliability is difficult, with little industry consensus on how to do so. The rationale for the scales/weights used for the Reliability attributes was therefore based on a combination of external information and internal subject matter expert judgment. "Worst case" scenarios that have occurred involving gas and electric outages were used to consider the impact from gas and electric reliability. In 1994, the Northridge earthquake affected tens of thousands of core gas customers, and the Pacific Southwest blackout of 2011 affected all of SDG&E's customers for several hours. It was reasoned that the respective impacts of these events could be used as a baseline to create the sub-attribute scales with the Northridge gas event approximately equaling 200 minutes of a system wide SDG&E blackout.

In addition, with respect to gas Reliability sub-attributes, residential and select commercial gas customers are designated as "core" customers and have top priority to receive gas service during outages.[32] The prioritization means that core customers will not normally get curtailed during gas supply shortages. Core customers can also be affected by local pipeline events such as dig-ins or equipment issues. The gas reliability sub-attribute Gas Core Meters is used to value the importance of maintaining natural gas service to core customers.

The gas Reliability sub-attribute of Gas Curtailment is a new measurement, one that the Company believes can be useful in describing the impact to customers and society. For various reasons – such as when there is a disturbance with a major gas transmission pipeline and a coincident high demand for natural gas – there are situations when natural gas service needs to be curtailed to non-core customers. The order in which curtailments are undertaken is systematic, with a goal to prevent severe disruptions to the community. However, when large curtailments are necessary, the impact to the greater community can eventually be felt. The Company strives to prevent all curtailments, especially those that require curtailing over 250MMcfd. Curtailments at that higher level can impact critical infrastructure such as electric generation, major industries, and hospitals. The use of this sub-attribute helps to value the importance of keeping curtailments limited in size and duration.

Valuing electric reliability is a complex endeavor but requires a simplified view for the purposes of the RAMP Report. To the customer, electric reliability is a composite of at least the following items: a) having electricity when the customer wants it, b) having a high quality of electricity without flicker or dimming, c) having power restored quickly if an outage occurs, and d) having access to information about when power will be restored.

The Institute of Electrical and Electronics Engineers (IEEE) has been viewed as a leader on topics related to Electric Reliability. IEEE publishes a document, known as IEEE 366-2012, that is considered the industry "best practice" for how to measure electric reliability. The IEEE 1366-2012 has 12 distinct measurements that utilities can use to express reliability, and some of those measurements have sub-measurements providing essentially infinite combinations of

---

32 *See* SoCalGas Rule 1 at Sheet 3 ("Core Service: Service to end-use Priority 1 or Priority 2A as set forth in Rule No. 23").

measurements. For example, one measurement indicates the number of customers who experience a certain number of outages in a year. That measurement can be used to evaluate customers who experience one outage, or three outages, or seven outages, and so on. The large number of possibilities of measurements is indicative of how complex the subject can be.

SDG&E has used eight different measurements in the past few years to internally measure its reliability (SAIDI, SAIFI, Worst Circuit SAIDI, Worst Circuit SAIFI, MAIFI, CAIDI, SAIDET, and ERT). For the Risk Quantification Framework, SAIDI and SAIFI were the sole indices used due to their widespread industry usage and their relative ease to use from a forecasting perspective. Future versions of the Risk Quantification Framework may include additional methods of valuing electric and gas reliability.

The electric reliability sub-attribute of Electric SAIDI measures the average duration of service loss for each utility's electric meters over the span of a year. SAIDI is a widely used index in the electric utility industry and is frequently used to compare utilities' performance. This index does not distinguish between the type of customer or the time of day of an electric outage.

The electric reliability sub-attribute of Electric SAIFI measures the average number of outages that each utility's electric meters experiences over the span of a year. This index does not distinguish between the type of customer or the time of day of an electric outage. A SAIFI value of 0.8, for example, means that on average 80% of customers served by the utility experienced an outage during a calendar year. But because SAIFI measures averages, using SAIFI alone is not enough to ascertain how many different customers experienced outages. If a utility had 100,000 meters, a SAIFI value of 0.8 could mean that 80,000 meters experienced one outage during one calendar year or it could mean that 40,000 meters experienced two outages during one calendar year.

There is significant complexity when trying to determine appropriate scales and weights to SAIDI and SAIFI in the Risk Quantification Framework. Different outages have different impacts depending on who is affected and when the outage occurred. For example, given a choice between three short outages or one long outage, a small retail store may prefer the shorter outages. Shorter outages may only temporarily affect their sales and not significantly affect their infrastructure. A large factory however may prefer one long outage, because some machinery may be negatively affected by outages and subjecting the equipment to multiple outages can be detrimental to the business' operations. Similarly, a three-hour electric outage at a residence will be dramatically different while cooking a Thanksgiving feast versus one while everyone at the residence is at school or work.

Although gas and electric sub-attributes give information to help understand levels of reliability risk, in the end, they are merely numbers that tell a story. Particularly with reliability, limited data exists to determine the equivalency of gas reliability relative to other attributes resulting in the need to leverage electric reliability data at this time. Accordingly, there is no single combination of reliability attributes that will give the perfect answer on how to measure risk. The values shown throughout the RAMP Report should be thought of as an approximation of risk rather than a precise value.

G. Financial Attribute

The Financial attribute has no sub-attributes or index and is measured in dollars. Like the other attributes, the Financial attribute is used to estimate aspects of the impact from risk events. However, different types of costs are measured in the attribute. The types of costs measured include: societal damage (including physical damages, lost wages, relocation costs, etc.) and utility repair costs (labor, materials). As required by D.16-08-018, the Financial attribute does not include any direct impacts related to shareholder financial interests, such as fines to shareholders, stock price changes, changes in credit ratings, or unrecoverable legal fees.

The quantitative approach used by the Company considered historical events as a guide for possible future impacts. But precision for the financial attribute is difficult to achieve. Risk events are rarely reported with a single summation of all financial impacts. Depending on the risk event, differing approaches were used to estimate the financial impacts. For pipeline risks, Pipeline and Hazardous Materials Safety Administration (PHMSA) data was used in combination with internal data, but the financial values provided by PHMSA do not necessarily include all financial impacts to society. For electrical outages, estimates were made for the amount of labor and cost of repair.

Financial estimates are gathered from various sources including internal estimates based on claims data or work orders, third party sources, news reporting, among others. Because these data sources rarely include all financial impacts from a risk event, estimates are used.

VII. PROBABILISTIC INFORMATION

This section will discuss quantitative methodologies, including statistical information as well as how computer software was used for this RAMP Report.

The SA Decision requires utilization of specific quantification methods for the RAMP Report. Among those methods are the creation of LoRE and CoRE values for each current risk. These two values are then multiplied together to obtain a risk score. Additionally, LoRE and CoRE are used to calculate Risk Spend Efficiencies (RSEs) by estimating new LoRE and CoRE when risk-reducing activities are introduced or ceased.

A. Expected Values

As mentioned above, LoRE and CoRE utilize expected values. The term "Expected Value" is a statistical term meaning the weighted average. For example, suppose there was a casino game that paid $10 to the player 25% of the time and paid $1 to the player the other 75% of the time. The expected value of this game would $3.25 because $10 * 25% + $1 * 75% = $3.25. The term "Expected Value" is not meant to imply that the Company expects a certain outcome. Note that in the example above, the expected value of $3.25 can never occur, because only the values of $10 and $1 can be paid out.

B. Likelihood of Risk Event (LoRE)

In the context of the SA Decision, the "Likelihood" is not a true likelihood in the usual statistical or probabilistic sense. In standard mathematics, a likelihood is the probability of an event occurring given a set of conditions (*e.g.*, the chance that a red jellybean is drawn from a jar of jellybeans). These standard probabilities can take a value between 0 and 1, where 0 indicates the event will never occur and 1 indicates the event will always occur. In traditional terms, the probability of flipping a coin and obtaining "tails" is 0.5. For purposes of the RAMP Report, however, likelihood is used in the sense of frequency, and that frequency is always in the context of the annual frequency of an event.

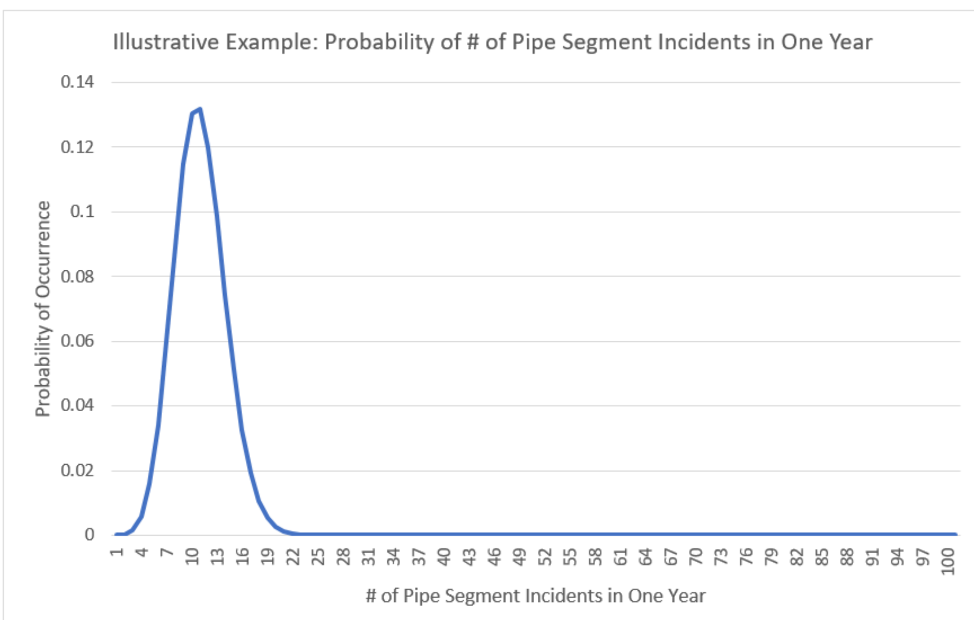
The following is an illustrative example to highlight how likelihoods are used in the RAMP Report:

i. Example: Illustrative Gas Risk

The RAMP Report views risks at the "risk-level" over the span of a year. Suppose that the Company has an item in its ERR known as Illustrative Gas Risk. For the RAMP Report, it is necessary to determine the likelihood of that risk occurring each year. In this illustrative example, assume the following:

- The utility uses data to estimate the incident rate.
- The illustrative gas system is composed of 100 pipe segments.
- Each pipe segment has a likelihood of an event of 1/10 over a given year.
- If the pipe segment had an event, the event would cause some amount of safety, reliability, and financial impact to society and to the utility.

From a purely probabilistic point of view, the likelihood that at least one pipe segment will have an incident in a given year is quite high (>0.999 or over 99.9%). The graph below shows the probability of the number of incidents, given the assumptions above:



For the RAMP Report, the important concept is not the *likelihood that a pipe segment will have an incident*, but rather, the number of pipe segments that are estimated to have an incident in a year. The likelihood value that is provided is the "Expected Value" of the frequency. In the example above, the expected value of pipe segments that will have an incident in a given year is determined by multiplying the number of pipe segments in the system by the likelihood of a single pipe segment incident occurring: 100 x 1/10 = 10.

In this example, the LoRE for this system would be 10, which behaves like an estimated frequency of the number of incidents predicted in a year.

Depending on the risk, LoREs were compiled using a combination of internal data, external data, and/or SME input. In the individual risk chapters throughout the RAMP Report, the methods used to estimate LoRE are indicated in Sections IV and VI.

C. Consequence of Risk Event (CoRE)

The CoRE is determined by estimating each of the data points required by the Risk Quantification Framework as discussed below. Like LoRE, the data points that inform CoRE are also expected values. For example, the number of serious injuries used in the calculations are the expected values of serious injuries if the risk event were to occur. Applying this to one of the RAMP risks, an illustrative example can be found in the SoCalGas Customer and Public Safety Risk Chapter (Chapter SCG-4) where actual safety consequences range from one serious injury to several fatalities. The calculations used in the Risk Quantification Framework for that risk use the expected value of that range. In the case of Customer and Public Safety, the expected value of the safety impact when a risk event occurs is 0.37.

The expected values of each of the seven attributes and sub-attributes are used as inputs into the Risk Quantification Framework to produce a CoRE for each risk. This process was undertaken many times for each risk; once to establish the current Risk Score, and once for each activity where the estimations of CoRE are performed as if the risk-reducing activity has been put in place in order to calculate RSEs.

Depending on the risk, the data used to compute CoREs was a combination of internal data, external data, and/or SME input. In the individual risk chapters throughout the RAMP Report, the methods used to estimate CoRE are indicated in Sections IV and VI.

D. Modeling

Computer software was used for many quantitative aspects of the RAMP Report. The primary software applications used by the Company was Microsoft Excel, Visual Basic, and @Risk. Additional work was also done with Microsoft Access, R, and Python. Various business units at the Company have unique ways of storing and accessing data that involve other software.

Monte Carlo simulations were performed on each risk. Monte Carlo analysis is a technique used to understand the impact of uncertainty related to a particular risk. Although the Settlement Agreement does not specify that Monte Carlo simulations are necessary, the modeling assisted in several ways that bolstered the analysis and occasionally informed critical elements. Throughout the individual risk chapters, analytical methods are discussed including the extent of modeling.

One of the benefits of modeling is that it can be used to demonstrate a range of outcomes that might be observed, given a set of inputs. When trying to identify ranges of outcomes, or the certainty thereof, performing Monte Carlo modeling can be easier to implement than precise statistical equations.

Devising ranges is an important part of risk analysis. Consider two risks, both with an expected value of a $10 million loss, but with very different ranges. Suppose Risk A rarely occurs, but when it does, it can require $1 billion of reparations; but, assuming it is a 1/100-year event, its expected value is $10 million ($1 billion x 1/100). Risk B has risk events that occur several times a year and the annual financial impact varies only slightly from $8 million to $12 million, with an expected value of $10 million. Certain stakeholders may be interested in knowing that the risks are not similar in their range of outcomes. Creating ranges of outcomes, whether through Monte Carlo modeling or via pure statistical approaches, can illuminate differences in risks.

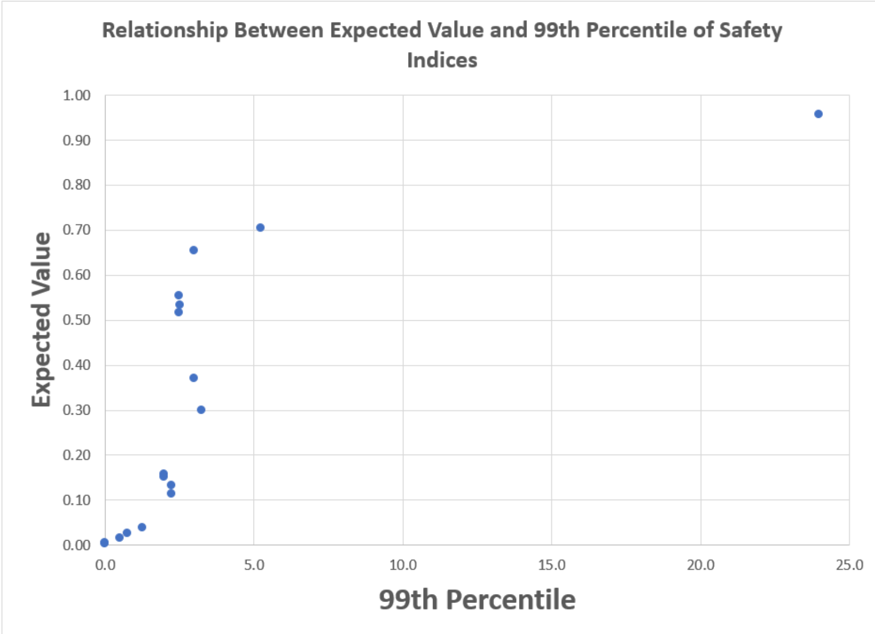
The Company found that using a Monte Carlo analysis to show where differences arise between these various types of risks (*i.e.*, one with a more consistent loss compared to a rarer but more significant loss) can be informative. To obtain a 99th Percentile, each risk was modeled 10,000 times, then ranked in order of consequence from lowest to highest. The 99th Percentile is the 100th worst consequence out of the 10,000 runs. This analysis was conducted by ERM to determine how large of an impact risks might have, even though less frequent. The result of this analysis is shown in Table 17 below.

Table 17: Risks Sorted by Expected Value of Safety Index

Utility	Risk Name	Expected Value Safety Index	99th Percentile of Safety Index
SDG&E	Wildfire	0.96	24.0
SDG&E	Contractor Safety	0.65	3.0
SDG&E	Electric Infrastructure Integrity	0.53	2.5
SDG&E	Employee Safety	0.30	3.3
SDG&E	Customer and Public Safety	0.16	2.0
SDG&E	Medium Pressure Gas Pipeline Incident	0.11	2.3
SDG&E	Third Party Dig-in on a Medium Pressure Pipeline	0.03	0.8
SDG&E	High Pressure Gas Pipeline Incident	0.02	0.5
SDG&E	Third Party Dig-in on a High Pressure Pipeline	0.00	0.0

Utility	Risk Name	Expected Value Safety Index	99th Percentile of Safety Index
SCG	Medium Pressure Gas Pipeline Incident	0.70	5.3
SCG	Employee Safety	0.55	2.5
SCG	Contractor Safety	0.52	2.5
SCG	Customer and Public Safety	0.37	3.0
SCG	High Pressure Gas Pipeline Incident	0.15	2.0
SCG	Third Party Dig-in on a Medium Pressure Pipeline	0.13	2.3
SCG	Third Party Dig-in on a High Pressure Pipeline	0.04	1.3
SCG	Storage Well Integrity	0.01	0.0

In some cases, in the RAMP analysis, the 99th percentile gives a different risk ranking than the Expected Value. The following is a graph showing the relationship between the Expected Value and the 99th Percentile for each risk's Safety Index. Note that the relationship between the two variables is not very strong, which supports the case that Expected Values are sufficient in themselves to understand the consequences from infrequent risks.



Because this alternative analysis provides useful information on rarer but more significant risk events, the individual risk chapters in this RAMP Report include this alternative analysis in addition to the standard modeling.

E. Key Considerations

1. Secondary Impacts

The Company uses the term "Secondary Impacts" to distinguish between the impacts that are directly caused by a Risk Event, and those impacts that are "downstream" of the initial Risk Event. Because each risk has its own definition of a Risk Event, it is difficult to generalize the difference between the direct impacts and secondary impacts. Table 18 below provides examples, using the Companies' different RAMP risks:

Table 18: Illustrative Examples of Secondary Impacts

	Direct Impact	**Secondary Impact**
Electric Infrastructure Integrity	Person hurt due to touching fallen electrical wire	Driver of vehicle not stopping at traffic light that is not operating properly during electrical outage
Medium Pressure Gas Incident	Person hurt due to gas explosion	Customer experiencing gas outage decides to cook using a charcoal barbecue, and is accidentally injured

Cyber Security	Intruder uses remote attack to overload transformer which subsequently explodes and harms individuals	Intruder uses remote attack to steal financial information from utility customer, which leads to financial harm to customer

Secondary Impacts are generally not used in risk scoring in this RAMP Report because they are difficult to estimate and track and are not always controllable by the Company. Data sources used for risk assessments do not consistently track secondary impacts, if tracked at all. Secondary impacts will rarely be a large driver of risk scores, even if the data was well collected. One illustrative example mentioned earlier-- large electrical outages that span entire cities--could have secondary impacts, but the history of such events fail to provide sufficient data to measure that risk. SDG&E experienced a systemwide blackout in 2011 due to electrical problems outside of its service territory. The blackout caused outages in all of San Diego and Imperial counties, as well as parts of Orange County and western Arizona. The outage in SDG&E's service territory lasted nearly 12 hours, with the average customer without power for over eight hours. During that time, safety-related incidents were reported. It is clear that undesirable outcomes can occur in large electric or gas outages, but the available data is not conducive to determining expected values of impact. Perhaps in future years, there will be more opportunities to refine how to use secondary impact information as part of risk assessments.

VIII. CONCLUSION

The purpose of this chapter was to describe the quantitative approaches used throughout this RAMP Report and to provide a detailed overview of the Company's Risk Quantification Framework. The framework is intended to be "customizable."[33] The SA Decision recognizes that there are both advantages and disadvantages to the currently adopted approach.[34] The Company offers further discussion on this topic in Chapter RAMP-E. The Company also offers "lessons learned" to aid the Commission and other IOUs in future application of the framework in Chapter RAMP-G, from the perspective of one of the first utilities to apply the new Risk Quantification Framework adopted by the SA Decision.

33 D.18-12-014 at 27.

34 *See* D.18-12-014 at 28-30.

Risk Assessment Mitigation Phase

(RAMP-D)

Risk Spend Efficiency – Methodology

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This chapter addresses how Risk Spend Efficiencies (RSEs) are calculated in this 2019 Risk Assessment Mitigtion Phase (RAMP) Report. RSEs are numerical values that attempt to portray changes in risk scores per dollar spent. The change in a risk score is one data point that can help to inform decision-making and can be due to: (a) the amount of risk reduction when a new activity is completed, or (b) the amount of risk increase if a currently on-going activity is ceased.[1] The overall guiding principle of an RSE is that it presents the difference between the risk score over a certain span of time if the activity is undertaken versus if the activity is not undertaken. However, as discussed further in Chapters RAMP-C and RAMP-E, these data points should be viewed critically. This chapter: (1) illustrates how RSEs are created, with examples of RSEs for both Controls and Mitigations, (2) explains how benefits over time are treated, and (3) explains how the Company determined which activities to perform an RSE on in this RAMP Report (and which activities would not have RSEs).

II. DETERMINING RISK SPEND EFFICIENCIES

As discussed in Chapter RAMP-C, each risk has a Risk Score, calculated using the Risk Quantification Framework. The Risk Score that is developed is meant to represent the current risk situation. The current situation for each risk attempts to consider existing activities (known as Controls), current work standards, and all other current characteristics, such as asset conditions, environmental conditions, etc. As described in Decision (D.) 18-12-014, a Control is a "[c]urrently established activity that is modifying risk."[2] A Mitigation is an "activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[3]

---

1 It should be noted that in reality risk reductions could be the result of other activities that have a positive effect, the improvement of industry wide data, or other factors not necessarily tied to the mitigation itself. *See* Chapter RAMP-E for additional discussion of this point.

2 D.18-12-014 at 16.

3 *Id.* at 17.

Risk Scores are calculated by multiplying the Likelihood of Risk Event (LoRE) and the Consequence of Risk Event (CoRE), where LoRE is the annual frequency of the Risk Event and CoRE is the output of the Risk Quantification Framework assuming a Risk Event occurred. Please see Chapter RAMP-C for more information on how LoRE and CoRE are created and used.

The risk score that results from using the Risk Quantification Framework is the baseline used when calculating RSEs. Next, a second estimate for LoRE and CoRE that considers a change in a risk-reducing activity is estimated. For Mitigations, the second LoRE and CoRE are estimated assuming the new activity is in place. For Controls, the second LoRE and CoRE reflect the estimated risk if the activity is ceased.

For purposes of this RAMP Report, the terms "pre-mitigation[4] LoRE" and "pre-mitigation CoRE" refer to the estimated risk values given current situations. The terms "post-mitigation LoRE" and "post-mitigation CoRE" refer to the estimated risk values if an activity is ceased or a new activity is undertaken. The same terminology applies to the Risk Scores, which are the product of LoRE multiplied by CoRE. In short:

$$pre - mitigation\ Risk\ Score = (pre - mitigation\ LoRE)\ x\ (pre - mitigation\ CoRE)$$

and

$$post - mitigation\ Risk\ Score = (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)$$

The RSE is the ratio between the pre-mitigation and post-mitigation Risk Scores divided by the cost. In its most simplistic form, the equation is:

$$simplified\ RSE = \frac{(pre - mitigation\ Risk\ Score) - (post - mitigation\ Risk\ Score)}{\$\ cost\ of\ activity}$$

4 The terms "pre-mitigation" and "post-mitigation" used herein (and referenced in the SA Decision) are not intended to suggest that all activities are Mitigations (*i.e.,* this terminology also applies to Controls).

Later in this chapter, there is an in-depth discussion on the more detailed points of the RSE calculation, including concepts such as the duration of benefits and the present value of benefits pursuant to the SA Decision.[5]

A. Illustrative Example (One Year Mitigation)

The following is a more thorough example of a one-year mitigation that builds upon the brief example above. Suppose there is a risk in the Company's Enterprise Risk Register (ERR), known as Risk X, which has been assessed using the Risk Quantification Framework. Suppose the assessment generated an assumption that a Risk Event related to Risk X would occur four times a year. Further, the assessment considered the Potential Consequences when the Risk Events occur. Suppose, for this example, that when a Risk Event occurs, the assessment, consistent with methods described in Chapter RAMP-C, estimates a 1/10 chance that there will be four serious injuries, no reliability consequence, and an average financial consequence of $15 million to repair damage to equipment.

Step 1: The first step is to formulate the pre-mitigation LoRE and CoRE. In this example, LoRE is simply four, because the LoRE is the average annual frequency. To determine CoRE, the Risk Quantification Framework is applied. Key parameters from the Risk Quantification Framework discussed in Chapter RAMP-C are in the following table:

Table 1: Single Point [6]

Attribute	Scale	Weight
Safety	0-30	60%
Reliability	0-1	20%
Financial	0-$1B	20%

5 D.18-12-014 at Attachment A, A-13 (Risk Spend Efficiency (RSE) Calculation).

6 As discussed in Chapter RAMP-C, because of the wide range of possible choices available to each utility in assigning attributes, weights, scales, and other variables chosen through implementing the SA Decision, the Company has also chosen to provide a range of scoring, based upon two additional alternative Risk Quantification Framework methods. To simplfy this example, the Company is presenting only the Single Point methodology.

Step 2: Applying the formula explained in Chapter RAMP-C, CoRE would be calculated as:

$$CoRE = \left[\frac{0.1}{30}\right] x\ 60\% + \left[\frac{0}{1}\right] x\ 20\% + \left[\frac{\$5}{\$1000}\right] x\ 20\% = \ .003$$

Step 3: The final step is to multiply by 100,000, as discussed in Chapter RAMP-C, for readability purposes. Therefore, the pre-mitigation Risk Score is:

$$Risk\ Score = LoRE\ x\ CoRE\ x\ 100{,}000 = 4\ x\ .003\ x\ 100{,}000 = 1{,}200$$

Suppose now that there is a proposed activity that will help reduce risk associated to Risk X. Perhaps the activity is replacing older equipment with newer equipment. Assume that, based upon data, it is estimated that undertaking the proposed activity will reduce the likelihood of Risk X occurring by 25%. In this example, the LoRE would therefore change from four to three. This activity, however, is not believed to affect the consequence if the Risk Event were to occur, so the CoRE stays the same.

Therefore, the post-mitigation Risk Score would be:

$$\begin{aligned} &post - mitigation\ Risk\ Score \\ &\qquad = (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)\ x\ 100{,}000 \\ &\qquad = 3\ x\ .003\ x\ 100{,}000 = 900 \end{aligned}$$

Suppose the useful life of this activity is for one year, and that it costs $10 million to perform. The RSE calculation would therefore be:

$$RSE = \frac{(post - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{\$10M} = \frac{1200 - 900}{\$10M}$$

$$= \frac{300}{\$10M} = 3$$

B. Illustrative Example (One Year Control)

A similar process is used when Control activities are considered. One important distinction for such situations is that in the RAMP Report, when considering the change in Risk Score if a control were no longer in place, the difference between the pre-mitigation Risk Score and the post-mitigation Risk Score will still be shown as a positive number because the cost of the activity in the denominator would be savings. For consistency, in the RAMP Report both the numerator and the denominator will be shown as positive numbers.

Suppose there is a risk in the Company's ERR known as Risk ABC and this risk has been assessed using the Risk Quantification Framework. Suppose the assessment led to the estimate that a Risk Event related to Risk ABC would occur once every five years. Further, the assessment estimated the consequences to be two fatalities, no reliability consequence, and an average financial consequence of \$50 million to repair and replace equipment damaged by the event.

The first step is to formulate the pre-mitigation LoRE and CoRE. In this example, LoRE is 1/5 or 0.2. To determine CoRE, the Risk Quantification Framework is applied as follows:

$$CoRE = \left[\frac{2}{30}\right] x\ 60\% + \left[\frac{0}{1}\right] x\ 20\% + \left[\frac{\$50}{\$1000}\right] x\ 20\% = .05$$

For readability purposes, the utilities multiply these small decimal numbers by 100,000. Therefore, the pre-mitigation Risk Score is:

$$Risk\ Score = LoRE\ x\ CoRE\ x\ 100{,}000 = 0.2\ \ x\ \ .05\ x\ \ 100{,}000 = 1000$$

Suppose there is a current activity that contributes to the Risk Score as it stands currently. Further, suppose there is a proposal to alter the activity in some way, such as changing the frequency of inspection. An example might be to stop a Quality Assurance program. Lastly, assume that based upon available data and subject matter expertise, it is believed that the likelihood of the risk event will be increased by 10% and save \$25 million. In this example, the LoRE would therefore change from 0.2 to 0.22 (i.e. 10% more than 0.2 is 0.22). Ceasing this activity is not believed to affect the consequence if the Risk Event were to occur, so the CoRE stays the same.

Therefore, the post-mitigation Risk Score would be:

$$post - mitigation\ Risk\ Score = (post - mitigation\ LoRE)\ x\ (post - mitigation\ CoRE)$$
$$= 0.22\ x\ .05\ x\ 100{,}000 = 1{,}100$$

Suppose the useful life of this activity is for one year. The RSE calculation would therefore be:

$$RSE = \frac{(pre - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{-\$25M} = \frac{1000 - 1100}{-\$25M}$$

$$= \frac{100}{\$25M} = 0.4$$

The Control therefore has an RSE of 0.4.

III. DURATION OF BENEFITS

One of the more nuanced aspects of RSEs is how to address risk-reducing activities that have long-term benefits. The RSE is a comparison between performing an activity versus not performing that activity. In some cases, the implications of an activity have long term affects: pipelines last many years, computer software can be used for several years, etc. To utilize RSEs properly, some consideration needs to be given for the length of time, or duration, of predicted benefits.

A working assumption is that activities involving assets receive benefits for the life of the asset. Other activities, such as training or inspection programs, might have shorter durations of benefits. An illustrative example is a tree trimming program, which will only have a duration of benefits that match the time it takes for a tree to grow back to its former size.

Any activity that has a duration of benefits exceeding one year requires additional data points for the RSE calculation. In "Example (One Year Control)" above, the assumption was that the activity has a one year duration of benefits. However, if the assumption was raised to three years of benefits, the activity can be considered to affect three years of risk results. The two tables below illustrate the differnces in assuming the duration of benefits last for one versus three years.

Table 2: "Example (One Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	1078	1078	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	0	0	0	0

Table 3: "Example (Three Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	980	980	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	98	98	0	0

As shown in these tables above, the three-year benefit stream provides more value than the one-year benefit stream. The RSE calculation needs to address these differences.

C. Discounting of Benefits

The SA Decision allows accounting of long term benefits of activities but requires an extra step before inclusion into the RSE.[7] The SA Decision mandates that future benefits have less value than present benefits. The Company meets this requirement by applying a "discount" rate to the difference in the Risk Score. In this RAMP filing, the Company uses a 3% discount rate for purposes of determining the present value of the risk reduction benefits or numerator of the RSE calcualtion. As shown in the example below, this discount rate lowers the benefits of years after the first by 3%, compounded each year. The Company applied a 3% discount rate based on federal recommendations.[8]

---

[7] D.18-12-014 at Attachment A, A-13 (Risk Spend Efficiency (RSE) Calculation).

[8] *See* Centers for Disease Control and Prevention, Dataset Number SD-1002-2017-0, *Economic Burden of Occupational Fatal Injuries in the United States Based on the Census of Fatal Occupational Unjuries, 2003-2010* (August 2017) (citing 1996 recommendation from U.S. Department of Health and Human Services Panel on Cost-Effectiveness in Health and Medicine).

Table 4: "Example (Three Year Control)"

	Year				
	2020	**2021**	**2022**	**2023**	**2024**
Risk Score with Activity	980	980	980	1078	1078
Risk Score without Activity	1078	1078	1078	1078	1078
Difference	98	98	98	0	0
Discounted Difference	98 / (1) = 98	98 / (1.03) = 95.1	98 / $(1.03)^2$ = 92.4	0	0

As shown in the table above, the benefit decreases from 98 in the first year to 92.4 in the third year. The term "Present Value" can be used when discussing the future benefits of a long-term activity. For the example above, the present value of the benefit in 2022 is 92.4.

For activities that have multiple years of benefits, the simplified RSE calculation changes from:

$$RSE = \frac{(pre - mitigation\ Risk\ Score) - (pre - mitigation\ Risk\ Score)}{\$\ of\ activity}$$

to:

$$RSE = \frac{\sum_i^L Present\ Value\ ((pre - mitigation\ Risk\ Score_i) - (post - mitigation\ Risk\ Score_i))}{\$\ of\ activity}$$

where *i* is the year of the project, and *L* is the duration of benefits measured in years.

D. Discounting of Costs

Similar to the discounting of benefits mentioned in the section above, the SA Decision requires that the cost of activities also be discounted if they span more than one year. However, in a General Rate Case (GRC), the Company presents its forecasts in base year,[9] direct constant dollars. The base year for the Company's Test Year 2022 GRC is 2019.[10] While the Company will be seeking approval for Test Year 2022 forecasts for operations and maintenance (O&M) and 2020-2022 for capital expenditures, all these forecasts will be presented in 2019 constant dollars. Please note that these direct dollar forecasts will be converted into an overall revenue requirement through the Results of Operations (RO) model. In this RAMP Report, the Company is presenting costs in direct constant 2018 dollars. Therefore, for the purposes of the RSE calculation the costs are effectively already discounted prior to being used in the RSE calculation. Meaning, the cost for activities with multi-year expenditures does not take into account inflation prior to their usage for RSEs. For example, suppose there was a capital project that sought $10 million a year for all three years of the next GRC forecast period (2020 through 2022). In the RAMP and in GRC, the Company would present these costs as $10 million for each year, 2020, 2021, and 2022. No inflation is shown for those years; therefore, there is no need to further discount costs shown for years 2021 and 2022.

IV. APPLICATION OF RISK SPEND EFFICIENCIES

The RAMP Report includes 151 activities for SoCalGas and 224 activities for SDG&E. Of these, 100 and 146 activities for SoCalGas and SDG&E, respectively, had RSEs calculated.[11] RSEs were calculated for a wide variety of activities, including all in-scope non-mandated activities, certain mandated Controls, and all Mitigations whether they were mandated or not. RSEs were calculated for all non-mandated activities and all new activities. This was a

---

9 The term "base year" refers to the last recorded year available prior to a GRC filing.

10 The Company notes that as of the filing date of this RAMP Report, a Proposed Decision is pending before the Commission which could possibly change the anticipated filing date of the Company's next GRC application. *See* R.13-11-006, Proposed Decision Modifying the Commission's Rate Case Plan for Energy Utilities (October 4, 2019).

11 The references here account for activities at the tranche level and also include the activities presented as alternatives.

substantial undertaking for the Company, especially when taking into account that this is the first implementation of these more quantitative analyses pursuant to the SA Decision.

Despite the Company's best efforts, in the development of particular RSEs for the many Mitigations and Controls in this RAMP Report, it was discovered that in certain situations RSEs could not be reasonably calculated in certain circumstances or were of minimal value. These situations include:

1) Where there is mandated work that is difficult to separate from other work. For example, when a particular regulation, and therefore Control, has been in place for decades, it is difficult to separate how it impacts likelihoods and consequences of Risk Events. It is difficult to unravel the value of that Control to determine quantitatively the benefits it currently gives, especially in any meaningful way.
2) Where non-risk-reducing activities enable risk-reducing activities. For example, line inspections do not, by themselves, reduce risk directly but they do provide information to operators and field personnel which is then used to find appropriate remediations where necessary. In the case of inspections, they are bundled together with their remediations when calculating RSEs.
3) Where activities fall outside of the scope of the risk, but nevertheless are related to the risk and were included in the Risk chapter. From an analytic perspective, it is not appropriate to calculate an RSE for an activity that is not included in the scope of how the risk scores were calculated. An example of this is the Company's Customer and Public Safety risk. The scope of that risk is confined to events that are under the Company's control (see RAMP SCG-4 and SDG&E-5 for more details on risk scope). In other words, the risk scope for Customer and Public Safety risk does not include issues that are outside the control of the utility, and therefore the Risk Score does not assess those types of Risk Events. However, the Company performs activities that aim to mitigate public safety risk. Those activities that assist customers in being safe are presented in the Company's Customer and Public Safety risk chapter, but an RSE has not been

performed since those activities are outside of the scope of risk. For example, Company employees respond to all emergency calls from customers regarding gas leaks, and therefore the Company should be funded for that activity - but because essentially all emergency calls from customers are related to events that are outside the control of the Company, they are not considered within the scope of the risk score. Therefore, since responding to emergency calls is outside of the Customer and Public Safety risk scope, there is no change in the risk score due to the activity, which would result in an RSE score of 0.

V. CONCLUSION

The calculation of RSEs in this RAMP Report represents the Company's best efforts and is in compliance with the SA Decision. The methodologies and processes herein have advanced the RSEs. As further discussed in Chapter RAMP-E, RSEs should be considered as a single data point, rather that the sole source for risk-based decision-making.

Appendix D-1

SoCalGas and SDG&E

RSE Ranking

SoCalGas
A Sempra Energy utility

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1] Low Alternative	RSE[1] Single Point	RSE[1] High Alternative
1	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C6	GIPP - Tranche 1 Medium Pressure	63.58	**319.61**	746.34
2	Contractor Safety	SCG-3-C5	Contractor Engagement	25.47	**242.07**	603.08
3	Contractor Safety	SCG-3-C4	Third-Party Administration Tools	21.78	**207.00**	515.70
4	Cybersecurity	SCG-9-C1	Perimeter Defense	127.50	**130.75**	136.17
5	Cybersecurity	SCG-9-C5	Obsolete IT Infrastructure Modernization	66.06	**67.74**	70.55
6	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C2	Cathodic Protection	10.51	**65.91**	158.25
7	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C6	Damage Prevention Analyst Program	44.59	**59.78**	85.10
8	Cybersecurity	SCG-9-C3	Sensitive Data Protection	58.13	**59.61**	62.08
9	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M2	Establish a program to address the area of continual excavation	40.94	**54.89**	78.14
10	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C1	GIPP - Tranche 2 High Pressure	8.69	**54.46**	130.74
11	Cybersecurity	SCG-9-C4	Operational Technology (OT) Cybersecurity	51.60	**52.92**	55.11
12	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C6	Damage Prevention Analysts Program	4.69	**39.50**	97.50
13	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C3-T3	PSEP - Pipeline Replacement - Tranche 3 Phase 2A	8.00	**31.17**	69.77
14	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C16	Install warning mesh above buried company facilities	3.11	**26.14**	64.53
15	Cybersecurity	SCG-9-C2	Internal Defense	24.49	**25.12**	26.16
16	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M8	Install warning mesh above buried company facilities (open trench new facilities only)	16.99	**22.78**	32.42
17	Contractor Safety	SCG-3-M1	Expanded Contractor Safety Oversight	2.26	**21.52**	53.63
18	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C6	Transmission Integrity Management Program (TIMP)	3.29	**20.64**	49.56
19	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T4	Public Awareness Compliance - Excavators	12.66	**16.97**	24.16
20	Employee Safety	SCG-2-M5	Expanded Safety Congress and expanded Executive Safety Council	1.74	**16.64**	41.46
21	Customer and Public Safety	SCG-4-C6	Quality Assurance and Controls Program	2.74	**15.06**	35.60
22	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C7-T1	DREAMS Vintage Integrity Plastic Plan (VIPP)	2.68	**13.45**	31.40
23	Employee Safety	SCG-2-C7	Near Miss, Stop the Job and jobsite safety programs	1.31	**12.48**	31.10
24	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C5	Locate and Mark Quality Assurance Program	9.14	**12.26**	17.45
25	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T4	Public Awareness Compliance - Excavators	1.41	**11.88**	29.32
26	Employee Safety	SCG-2-M4	Safety video library	1.22	**11.65**	29.03
27	Employee Safety	SCG-2-M6	Expanded Safety Culture Assessments	1.22	**11.65**	29.03
28	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C9	Increase Reporting of Unsafe Excavation	8.41	**11.27**	16.05
29	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	7.85	**10.53**	14.99
30	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C4-T3	PSEP - Pressure Testing - Tranche 3 Phase 2A	2.62	**10.22**	22.87
31	Contractor Safety	SCG-3-C1	Contractor Safety Oversight	1.06	**10.12**	25.22
32	Employee Safety	SCG-2-M3	Establish proactive monitoring for indoor air quality (IAQ) and chemicals of concern	1.02	**9.71**	24.19
33	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C5	Locate and Mark Quality Assurance Program	1.00	**8.43**	20.80
34	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C9	Increase Reporting of Unsafe Excavation	0.83	**6.99**	17.25
35	Employee Safety	SCG-2-C8	Safety Culture	0.70	**6.69**	16.66
36	Employee Safety	SCG-2-M1	OSHA 30-hour construction certification training	0.68	**6.47**	16.13
37	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C9	Distribution Riser Inspection Project	1.23	**6.21**	14.49
38	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T1	Public Awareness Compliance - The Affected Public	4.24	**5.69**	8.10
39	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C1	Cathodic Protection (CP)	1.01	**5.06**	11.81
40	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C8	Sewer Lateral Inspection Project (SLIP)	0.89	**4.46**	10.43
41	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M6	Promote process and system improvements in USA ticket routing and monitoring.	3.04	**4.07**	5.79
42	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T1	Public Awareness Compliance - The Affected Public	0.48	**4.01**	9.89
43	Employee Safety	SCG-2-C5	Safe Driving Programs	0.41	**3.90**	9.72
44	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T3	Public Awareness Compliance - Local Public Officials	2.81	**3.77**	5.37
45	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C7-T2	DREAMS Bare Steel Replacement Program (BSRP)	0.64	**3.20**	7.48
46	Employee Safety	SCG-2-C9	Utilizing Occupational Safety and Health Administration (OSHA) and industry best practices and industry benchmarking	0.33	**3.15**	7.85
47	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	2.14	**2.87**	4.08
48	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M6	Promote process and system improvements in USA ticket routing and monitoring	0.34	**2.85**	7.03
49	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T3	Public Awareness Compliance - Local Public Officials	0.32	**2.69**	6.65
50	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-1-C3	Meter and Regulator (M&R) Maintenance	0.47	**2.35**	5.50
51	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.23	**1.92**	4.75

SoCalGas
A Sempra Energy utility

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
52	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.22	**1.85**	4.56
53	Employee Safety	SCG-2-M2	Industrial hygiene program refresh	0.19	**1.80**	4.48
54	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C8-T2	Public Awareness Compliance - Emergency Officials	1.32	**1.77**	2.51
55	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.15	**1.29**	3.18
56	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C8-T2	Public Awareness Compliance - Emergency Officials	0.14	**1.15**	2.84
57	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C3-T2	PSEP - Pipeline Replacement - Tranche 2 Phase 1B	0.29	**1.14**	2.54
58	Employee Safety	SCG-2-C3	Wellness Programs	0.12	**1.10**	2.75
59	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M2	Establish a program to address the area of continual excavation	0.13	**1.10**	2.72
60	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SCG-5-C5	PSEP - Valve Automation	0.49	**1.04**	1.96
61	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.67	**0.90**	1.28
62	Storage Well Integrity Event	SCG-8-C6	Integrity Demonstration, Verification, and Monitoring Practices	0.62	**0.64**	0.66
63	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M4	Utilize electronic positive response	0.46	**0.62**	0.89
64	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-C7	Prevention and Improvements - Refreshed Laptops	0.41	**0.54**	0.77
65	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M4	Utilize electronic positive response	0.05	**0.44**	1.07
66	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C7	Prevention and Improvements - Refreshed Laptops	0.05	**0.38**	0.94
67	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M3	Recording photographs for each locating mark ticket that is visited by the locator	0.26	**0.35**	0.50
68	Third Party Dig-in on a High Pressure Pipeline	SCG-7-C17	Prevention and Improvements - Fiber Optics	0.04	**0.34**	0.85
69	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M3	Recording photographs for each locate and mark ticket visited by locator	0.03	**0.24**	0.60
70	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M1	Automate Third Party Excavation Reporting	0.02	**0.03**	0.04
71	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.02**	0.05
72	Third Party Dig-in on a Medium Pressure Pipeline	SCG-6-M7	Leverage data gathered by locating equipment	0.01	**0.02**	0.02
73	Third Party Dig-in on a High Pressure Pipeline	SCG-7-M7	Leverage data gathered by locating equipment	0.00	**0.01**	0.03

[1]The RSE ranges are further discussed in Chapter RAMP-C.

SDGE
A Sempra Energy utility®

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
1	Contractor Safety	SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings	58.51	**356.94**	854.34
2	Electric Infrastructure Integrity	SDG&E-4-M3-T1	Proactive Substation Reliability for Distribution Components Streamview Bank 30 Re-build	225.33	**225.33**	225.33
3	Wildfires	SDG&E-1-C15	Tree Trimming	151.32	**198.75**	277.80
4	Contractor Safety	SDG&E-2-C3	Third-Party Administration and Tools	32.24	**196.72**	470.84
5	Wildfires	SDG&E-1-M8	Hotline Clamps	137.89	**181.11**	253.15
6	Wildfires	SDG&E-1-Group3	PSPS Group	100.08	**131.45**	183.73
7	Cybersecurity	SDG&E-10-C1	Perimeter Defense	127.50	**130.75**	136.17
8	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C6	Damage Prevention Analysts Program	92.03	**126.35**	183.55
9	Wildfires	SDG&E-1-M7	Expulsion Fuse Replacement	92.16	**121.05**	169.19
10	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M2	Establish a program to address the area of continual excavation	71.84	**98.63**	143.27
11	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C1	Cathodic Protection	11.40	**91.00**	223.66
12	Electric Infrastructure Integrity	SDG&E-4-M3-T2	Proactive Substation Reliability for Distribution Components Pacific Beach 12kV Replacement Re-build	82.20	**82.20**	82.20
13	Employee Safety	SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	8.52	**73.12**	180.77
14	Cybersecurity	SDG&E-10-C5	Obsolete IT Infrastructure Modernization	66.06	**67.74**	70.55
15	Wildfires	SDG&E-1-M19	Enhanced Inspections, Patrols, and Trimming	51.39	**67.50**	94.35
16	Electric Infrastructure Integrity	SDG&E-4-C10	Vegetation Management (Non-HFTD)	39.34	**65.50**	109.10
17	Cybersecurity	SDG&E-10-C3	Sensitive Data Protection	58.13	**59.61**	62.08
18	Contractor Safety	SDG&E-2-C1	Contractor Safety Oversight Program	9.20	**56.13**	134.34
19	Cybersecurity	SDG&E-10-C4	Operational Technology (OT) Cybersecurity	51.60	**52.92**	55.11
20	Wildfires	SDG&E-1-M18	SCADA Capacitors	39.02	**51.26**	71.64
21	Electric Infrastructure Integrity	SDG&E-4-M1	Overhead Public Safety (OPS) Program	9.09	**47.54**	111.63
22	Wildfires	SDG&E-1-C28 / M32	Wildfire Infrastructure Protection Teams	34.46	**45.27**	63.27
23	Contractor Safety	SDG&E-2-M3	Near Miss/Close Call Reporting Portal/App	7.25	**44.26**	105.94
24	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M8	Install warning mesh above buried company facilities (above open trench new facilities only)	30.42	**41.77**	60.67
25	Electric Infrastructure Integrity	SDG&E-4-C15	Distribution Circuit Reliability	40.25	**40.25**	40.25
26	Employee Safety	SDG&E-3-C3	Safety Culture	4.58	**39.24**	97.03
27	Employee Safety	SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA)	4.42	**37.91**	93.73
28	Wildfires	SDG&E-1-C29 / M33	Aviation Firefighting Program	27.33	**35.89**	50.17
29	Employee Safety	SDG&E-3-M4	Implementing findings from VPP program assessments	3.98	**34.12**	84.36
30	Wildfires	SDG&E-1-FiRM	FiRM Group	25.69	**33.74**	47.16
31	Employee Safety	SDG&E-3-M2	Safety In Action Enhancement Program	3.77	**32.33**	79.92
32	Wildfires	SDG&E-1-M10	Covered Conductor	24.30	**31.91**	44.61
33	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C16	Install warning mesh above buried company facilities	4.01	**31.85**	78.24
34	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C6-T1	PSEP - Pressure Testing - Tranche 1 Phase 1B	5.27	**30.84**	73.45
35	Customer and Public Safety	SDG&E-5-C2	Field & Public Safety (CSF/AMO Quality Assurance Program)	4.83	**28.24**	67.24
36	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T2	Early Vintage Program (Pipeline) - Tranche 2 Early Vintage Steel Replacement	5.09	**27.53**	64.92
37	Electric Infrastructure Integrity	SDG&E-4-C14	Field SCADA RTU Replacement	26.65	**26.65**	26.65
38	Wildfires	SDG&E-1-Group2	FTZAP & LTE Communications Network	20.15	**26.47**	37.00
39	Wildfires	SDG&E-1-M17	Lightning Arrester Removal / Replacement Program	19.31	**25.36**	35.44
40	Electric Infrastructure Integrity	SDG&E-4-C19-T2	Underground Cable Replacement Program – Proactive - Tranche 2 Unjacketed Cable - Branch	25.32	**25.32**	25.32
41	Cybersecurity	SDG&E-10-C2	Internal Defense	24.49	**25.12**	26.16
42	Wildfires	SDG&E-1-C30	Industrial Fire Brigade	18.35	**24.11**	33.70
43	Wildfires	SDG&E-1-M4	Strategic Undergrounding Underground Circuit Line Segments	17.52	**23.01**	32.16
44	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	2.81	**22.47**	55.22
45	Electric Infrastructure Integrity	SDG&E-4-M3-T4	Proactive Substation Reliability for Distribution Components New Substation	21.36	**21.36**	21.36
46	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C6	Damage Prevention Analysts Program	2.68	**21.27**	52.26
47	Employee Safety	SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	2.47	**21.18**	52.36
48	Wildfires	SDG&E-1-Group1	Non-Mandated Inspections Group	15.60	**20.49**	28.64
49	Electric Infrastructure Integrity	SDG&E-4-C3-T3	Distribution Switch Replacement Program - Tranche 3 Switches in Contamination District One with large customer count that could benefit from SCADA	20.46	**20.46**	20.46
50	Contractor Safety	SDG&E-2-M1	Expanded Contractor Oversight Program	3.02	**18.44**	44.12
51	Wildfires	SDG&E-1-M20	Fuel Management Program	13.93	**18.29**	25.57
52	Wildfires	SDG&E-1-PRiME	PRiME Group	13.70	**18.00**	25.15
53	Employee Safety	SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)	2.00	**17.14**	42.38
54	Employee Safety	SDG&E-3-C9	Safe Driving Programs	1.98	**16.95**	41.90
55	Electric Infrastructure Integrity	SDG&E-4-C3-T1	Distribution Switch Replacement Program - Tranche 1 Hook Stick Switches and Solid Blades in Contamination District One	16.80	**16.80**	16.80
56	Electric Infrastructure Integrity	SDG&E-4-M4-T2	Substation Breaker Replacements – Tranche 2 Murray Breaker Replacement	16.53	**16.53**	16.53
57	Electric Infrastructure Integrity	SDG&E-4-C7	Tee Modernization Program - Underground	16.06	**16.06**	16.06
58	Wildfires	SDG&E-1-C9	Cleveland National Forest Fire Hardening	11.14	**14.63**	20.44
59	Employee Safety	SDG&E-3-M5	Energized Skills Training and Testing Yard	1.49	**12.79**	31.63
60	Electric Infrastructure Integrity	SDG&E-4-C2	Overhead 4kV Modernization and System Hardening - Distribution	4.11	**12.56**	26.65
61	Electric Infrastructure Integrity	SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive	4.15	**12.29**	25.85
62	Electric Infrastructure Integrity	SDG&E-4-M3-T3	Proactive Substation Reliability for Distribution Components Ash 12kV Cap Replacement Re-build	12.20	**12.20**	12.20
63	Electric Infrastructure Integrity	SDG&E-4-C3-T2	Distribution Switch Replacement Program - Tranche 2 Tie Switches (Gang or Hook Stick) in Contamination District One	11.81	**11.81**	11.81
64	Employee Safety	SDG&E-3-C7	Employee Wellness Programs	1.31	**11.22**	27.73
65	Electric Infrastructure Integrity	SDG&E-4-C19-T1	Underground Cable Replacement Program – Proactive - Tranche 1 Unjacketed Cable - Feeder	10.39	**10.39**	10.39
66	Electric Infrastructure Integrity	SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive	2.63	**8.44**	18.13

A Sempra Energy utility

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
67	Employee Safety	SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	0.88	**7.53**	18.61
68	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C5	Locate and Mark Quality Assurance Program	5.22	**7.16**	10.41
69	Electric Infrastructure Integrity	SDG&E-4-C9	DOE Switch Replacement - Underground	7.00	**7.00**	7.00
70	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T1	Early Vintage Program (Pipeline) - Tranche 1 Early Vintage Threaded Main Replacement	1.20	**6.51**	15.35
71	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T4	Public Awareness Compliance - Excavators	3.96	**5.43**	7.89
72	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M1-T3	Early Vintage Program (Pipeline) - Tranche 3 Oil Drip Removal	0.98	**5.28**	12.46
73	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C1	Cathodic Protection	0.77	**4.16**	9.81
74	Electric Infrastructure Integrity	SDG&E-4-M4-T1	Substation Breaker Replacements – Tranche 1 San Ysidro Breaker Replacement	3.55	**3.55**	3.55
75	Employee Safety	SDG&E-3-C11	Near Miss, Stop the Job and jobsite safety programs	0.39	**3.30**	8.17
76	Wildfires	SDG&E-1-C12 / M9	Wire Safety Enhancement	1.96	**2.57**	3.59
77	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2-T2	Early Vintage Program (Fittings) - Tranche 2 High/Medium Valve Separation Removal	0.45	**2.45**	5.77
78	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C9	Increase Reporting of Unsafe Excavation	1.68	**2.31**	3.35
79	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T1	Public Awareness Compliance - The Affected Public	1.32	**1.81**	2.63
80	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C5	Locate and Mark Quality Assurance Program	0.20	**1.58**	3.87
81	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	1.03	**1.41**	2.05
82	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C4	Plastic Pipe Replacement	0.24	**1.28**	3.03
83	High Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-8-C3-T2	Pipe Replacement - Tranche 2 Phase 1B (PSEP)	0.20	**1.19**	2.83
84	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T4	Public Awareness Compliance - Excavators	0.15	**1.18**	2.91
85	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M2	Establish a program to address the area of continual excavation	0.14	**1.09**	2.69
86	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T3	Public Awareness Compliance - Local Public Officials	0.76	**1.05**	1.52
87	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.71	**0.98**	1.42
88	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-C2	Assessment Buried Piping in Vaults	0.15	**0.81**	1.91
89	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C8-T2	Public Awareness Compliance - Emergency Officials	0.39	**0.53**	0.77
90	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.38	**0.53**	0.77
91	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.36	**0.49**	0.71
92	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C9	Increase Reporting of Unsafe Excavation	0.06	**0.49**	1.20
93	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-C7	Prevention and Improvements - Refreshed Laptops	0.31	**0.43**	0.63
94	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T1	Public Awareness Compliance - The Affected Public	0.05	**0.39**	0.96
95	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	0.04	**0.36**	0.87
96	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M6	Promote process and system improvements in USA ticket routing and monitoring	0.04	**0.30**	0.75
97	Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	SDG&E-6-M2-T1	Early Vintage Program (Fittings) - Tranche 1 Dresser Mechanical Coupling Removal	0.05	**0.28**	0.65
98	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T3	Public Awareness Compliance - Local Public Officials	0.03	**0.22**	0.54
99	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C11	Public Awareness - Meet with Cities with Highest Damage Rates	0.03	**0.22**	0.54
100	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	0.14	**0.19**	0.28
101	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C8-T2	Public Awareness Compliance - Emergency Officials	0.01	**0.12**	0.29
102	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	0.01	**0.11**	0.26
103	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M4	Utilize electronic positive response	0.07	**0.10**	0.14
104	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-C7	Prevention and Improvements - Refreshed Laptops	0.01	**0.09**	0.22
105	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M3	Recording photographs for each locate & mark ticket visited by locator	0.01	**0.04**	0.10
106	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M4	Utilize electronic positive response	0.00	**0.02**	0.05

Appendix D-1

Line No.	RAMP Chapter	ID	Control/Mitigation Name	RSE[1]		
				Low Alternative	Single Point	High Alternative
107	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.00**	0.01
108	Third Party Dig-in on a Medium Pressure Pipeline	SDG&E-7-M7	Leverage data gathered by locating equipment	0.00	**0.00**	0.00
109	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	0.00	**0.00**	0.00
110	Third Party Dig-in on a High Pressure Pipeline	SDG&E-9-M7	Leverage data gathered by locating equipment	0.00	**0.00**	0.00
111	Wildfires	SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	0.00	**0.00**	0.00
112	Wildfires	SDG&E-1-M16	Backup Power for Resilience - Microgrid	0.00	**0.00**	0.00
113	Wildfires	SDG&E-1-C31 / M34	Wireless Fault Indicators	0.00	**0.00**	0.00
114	Wildfires	SDG&E-1-M28	NMS Situational Awareness Upgrades	0.00	**0.00**	0.00

[1]The RSE ranges are further discussed in Chapter RAMP-C.

Risk Assessment Mitigation Phase

(RAMP-E)

A Discussion of the Use of Risk Spend Efficiency

November 27, 2019

SDGE
A Sempra Energy utility

TABLE OF CONTENTS

I. INTRODUCTION

Over the last five years the California Public Utilities Commission (the CPUC or Commission), its Safety and Enforcement Division (SED), the Investor Owned Utilities (IOUs), and intervenors have been collaborating on developing and implementing into the regulatory process a reliable and more quantitative process to better understand how utilities mitigate risks. One of the concepts adopted to provide more information is the Risk Spend Efficiency (RSE).

In theory, RSEs are a mechanism that can help IOUs and the Commission understand risks and mitigations better and compare mitigations in addressing risks. Conceptually, RSEs could be a useful tool to assist in decision-making, but even when they were first suggested to the Commission, RSEs had critical shortcomings – shortcomings that continue with their most recent iteration. Because of these continuing deficiencies (and newer ones that have been discovered as RSEs have evolved and expanded), RSEs remain a data point for utilities to consider, but not the deciding factor for mitigation selection – a fact that is recognized by SED, the IOUs, and even the Commission in Decision (D.) 18-12-014, the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement Decision (SA Decision).

San Diego Gas & Electric Company (SDG&E or Company) supports tools to prioritize and optimize their activities that mitigate risks. As such, the Company agrees with the concept of an RSE. In implementing RSEs, however, the Company has found that they are not as effective at prioritizing work as some have expected. As demonstrated in this Chapter, there are challenges with RSEs, including considerable subjectivity, that limit their extensive use at this stage.

The purpose of this 2019 RAMP Report Chapter is to:

- Discuss the background of RSEs and their evolution since 2015;
- Explain why RSEs, as currently constructed, should not be used to prioritize or select investments; and
- Suggest actions that could be taken to strengthen the RSE concept.

This Chapter is structured as follows:

- RSE History

- Shortcomings of RSEs
- Conclusion and Potential Next Steps

II. RSE HISTORY

A. First Presentation of RSEs

The concept of RSE was first publicly discussed in a Commission proceeding in an August 3, 2015 workshop. The basic formula proposed for determining an RSE was:

$$\textbf{\textit{Risk Spend Efficiency for a Mitigation}} = \frac{\textbf{\textit{Risk Score Pre-Mitigation} - \textit{Risk Score Post Mitigation}}}{\textbf{\textit{Cost to Implement the Mitigation}}}$$

Southern California Edison Company (SCE) proposed the use of RSEs with purportedly two long-term goals:

- Develop a multi-year spending plan based on the most effective mitigation.[1]
- Use RSEs to measure the effectiveness of mitigations.[2]

But, even in this initial foray into the development of RSEs, SCE recognized a number of shortcomings and challenges, including:

- Data on incidents and assets is not always available, or not compiled in a manner that facilitates analysis;
- Industry data and informed judgment will be needed as utility data is developed;
- Further analysis is needed to isolate risk drivers;
- Models for forecasting asset condition and asset failures are necessary;
- Risk evaluation, mitigation evaluation, and prioritization methodologies need to evolve; and

---

1 Southern California Edison Company, *SMAP Workshop* (August 3, 2015) at 2, *available at* https://www.cpuc.ca.gov/General.aspx?id=9099.

2 *Id.*

- RSEs were an input into the decision-making process, but any prioritization approach had to consider non-risk related inputs (including funding, compliance requirements, ongoing projects, resources, and operational constraints).[3]

As discussed below, these challenges and others persist.

B. Treatment of RSEs Since Creation

The Commission has required each utility to include RSEs in their RAMP filings since 2016.[4] All four IOUs have completed their first RAMP filings incorporating RSEs. In each of these filings, and in the feedback of SED and others, the persistent challenges with RSEs have been noted.

<u>SoCalGas and SDG&E</u>

In their 2016 RAMP filing, Southern California Gas Company (SoCalGas) and SDG&E developed estimates and ranges for RSEs.[5] In that first presentation of RSEs, they were calculated by dividing Annual Risk Reduction (as the number developed through SoCalGas' and SDG&E's risk scoring processes) by Total Mitigation Cost (the forecasted 3-year capital expenditure plus the annual Operating and Maintenance (O&M) expenses), multiplied by the number of years for which benefits from the risk reduction are expected.[6]

SED reviewed SoCalGas' and SDG&E's filing and concluded that "[t]he concept of [RSE] has not been completely developed in the S-MAP proceeding, and the Sempra Utilities' RAMP represents the first attempt to quantify and RSE for identified risks as a way of measuring the impacts of mitigations. Because of the novelty of the approach, staff feels it is something

---

3 *Id*. at 5.

4 California Public Utilities Commission, *Safety and Enforcement Division Evaluation Report on the Risk Evaluation Models and Risk-based Decision Frameworks in A.15-05-002, et al.* (March 21, 2016) at 78-79.

5 Investigation (I.) 16-10-015/-016 (cons.), Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company (November 30, 2016) at A-9.

6 *Id.*

that needs to be further reviewed and refined. Or, given the attempts in S-MAP to provide a more quantifiable methodology, perhaps it will be supplanted by some other process."[7] SED also recognized that, "This is admittedly an evolving area."[8]

Pacific Gas & Electric Company (PG&E)

In its 2017 RAMP filing, for RSE calculations, PG&E used a different formula to calculate RSEs for mitigations. PG&E essentially calculated RSEs for broader mitigation *plans*, incorporating a number of mitigations under one umbrella RSE. PG&E noted in their filing that the concept of RSEs was one of many factors that should be taken into consideration in determining where to make investments.[9]

In their review of PG&E's RSE methodology, SED agreed that RSEs were not the only factor for consideration in selecting mitigations.[10] For example, SED acknowledged that "resource constraints, compliance constraints, or operational constraints" could lead to selection of mitigations with lower RSEs.[11] In addition, SED referenced PG&E's self-assessment regarding the use of RSEs: "[I]mprovements 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."[12] SED pointed out how mitigation isolation could be a "pitfall" and "suboptimal from an aggregate risk portfolio standpoint."[13]

---

7 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016* (March 8, 2017) at 6.

8 *Id*.

9 I.17-11-003, 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (November 30, 2017) at A-14.

10 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003* (March 30, 2018) at 35.

11 *Id*. at 17.

12 *Id.* at 25.

13 *Id*. at 18.

SCE

In its 2018 RAMP filing, SCE used an approach similar to PG&E, but instead calculated the difference between the Multi-Attribute Risk Scores (MARS) before and after a mitigation.[14] SED included in their review several comments regarding SCE's filing. An important comment was that SCE's "[R]isk reduction analysis including RSEs would be most appropriate for decision-makers to be able to assess programs based on SCE's internal standards based on safety risks and costs."[15] SED continued to recognize that RSEs remain one element of the risk/mitigation analysis – not the entire analysis.

S-MAP

In the SA Decision, the Commission reconfirmed that the utilities will provide RSE calculations in the RAMP for all mitigations and alternatives.[16] The Settlement Agreement adopted in the SA Decision increases the quantitative aspects of RSEs and standardizes to some extent the process for developing RSEs between the utilities. However, many shortcomings of RSEs are not alleviated by the Settlement Agreement, and the process included therein has created new challenges with RSEs. Thus, while the process underlying the creation of RSEs became more quantitative, the value of RSEs still should not be overstated.

II. SHORTCOMINGS OF RSEs

In their current iteration, RSEs have a significant number of limitations keeping them from being entirely reliable or valuable as a decision-making tool. Below (in no particular order) several of these shortcomings are described.

Lack of data: The foundation of the RSE process is the availability of broad, accurate data for every risk and mitigation. Without such data, RSEs become drastically devalued by

---

14 I.18-11-006, Southern California Edison Company's 2018 Risk Assessment and Mitigation Phase Report (November 15, 2018) at 2-13.

15 California Public Utilities Commission, *A Regulatory Review of the Southern California Edison's Risk Assessment Mitigation Phase Report for the Test Case 2021 General Rate Case Investigation 18-11-006* (May 15, 2019) at 48.

16 D.18-12-014 at 22-23.

uncertainty. To properly calculate an RSE, as required by the Settlement Agreement, there must be an accurate measure of the frequency and consequences of a risk, the effects of a mitigation on both the frequency and consequence of a risk, and the cost required to implement the mitigation.

The problem is that for the majority of risks and mitigations, such data is scant or incomplete. For example, the Commission requires the Company to inspect the system annually, but there has been little data as to how many incidents were avoided through such annual inspections. Nevertheless, if an anomaly is observed during an inspection the Company would respond as needed. While the Company may capture additional information during an inspection, the data may not always be useful for risk reduction analysis. Therefore, the risk reduction benefit associated with annual inspections cannot be accurately determined at this time. All of the IOUs and SED have acknowledged the challenge with this dearth of data.[17] As SED noted, as recently as last year, "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."[18] Without current and accurate data the value of RSEs is limited.[19]

Another challenge commonly experienced with data is determining which data is most appropriate. Although utility specific data is best, it is not always available. The Company explains within specific RAMP chapters when data came from other sources. But when data is pulled from other sources, it can invite a host of questions. Most notably, how comparable a situation was to the one that the data was pulled from. For example, for an asset-based risk, the nationally-relied upon data could be based on a utility which had not invested as much in the safety of its infrastructure. But, at the same time, the utility's infrastructure may be less likely to experience risk events for other reasons, such as population densities, environment, or other

[17] *See* I.16-10-015/-016 (cons.), I.17-11-003 and I.18-11-006.

[18] California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003* (March 30, 2018) at 25.

[19] Another issue, not addressed here, is the associated cost of collecting data, which presents its own difficulties and constraints.

factors. It is difficult to balance all of these factors properly. For example, in evaluating the risk reduction benefits of certain mitigations, such as mitigating service damages within a sewer lateral, the Company relied on national PHMSA data to determine the incident rate since there was limited Company data available for such incidents. A mitigation focused on relocating services from within sewer laterals to remove the likelihood of damage addresses identified threats of low frequency, but potentially high consequence events. Although there is limited internal data to support that incidents related to this threat have occurred, the Company relied on nationally available data to determine the potential consequence of this threat.

Frequency of Incidents: Related to the previous point, the lack of the availability of data is difficult to overcome in some instances because of the infrequency of incidents for many risks. This is particularly the case with "tail" risks. Tail risks are those risks which occur very infrequently, finding themselves on the very extreme end of a probability curve (*i.e.*, the "tail"). Understanding the reduction in risk associated with infrequent catastrophic incidents is difficult to determine because of the frequency of events. For example, Florida Power & Light (FP&L) invested billions of dollars in "hardening" their electric system against hurricane risk starting in 2004. A significant hurricane did not impact their system until 2016. Accurately determining the benefit of FP&L's investments (*i.e.*, the risk reduction) took over 12 years.

Reliance on Subject Matter Experts (SMEs): The lack of available data and frequency of tail risks leads to a reliance on SMEs to assess how much a risk will be reduced by the implementation of a mitigation and requires SMEs to calibrate that the available data is appropriate and applicable to our operations. As SED has acknowledged, the RSE is a product of SME input.[20] As a result, it is subject to the potential issues that can occur with uncalibrated SME input.

Changes Occur: Conditions change over time. Consequences and frequencies of events, priorities for the Commission and utilities, and other important factors in decision-making can change, even within a rate case cycle. As a result, predictive RSEs can be of limited value and

---

[20] California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016* (March 8, 2017) at 16.

fairly speculative. One of the clearest examples of this is when calculating RSEs for vegetation management mitigations. In such calculations, one cannot reasonably take into account changes in growth rates, costs or even fluctuations in weather. Vegetation can change in an area; unpredicted weather patterns can change the biological and geographical landscape. RSEs can therefore vary widely from forecast to reality. The Commission appears to recognize this, as evidenced by its acknowledgement that utilities require flexibly to adapt to changing conditions and in addressing risk.

Changing Methodologies and Tools: Comparing past and future RSEs, even from one cycle to the next, is generally of limited value. Changes will occur in methodologies and tools over time. This is recognized in D.18-12-014, which notes that utilities' multi-attribute value functions (MAVFs) will evolve over time.[21,22] This evolution can take many forms. It can result from simply refining data, but also wholesale changes to the structure of the Company's Risk Quantification Framework. The Company is already aware that intervenors encourage the IOUs to incorporate additional attributes into the MAVF, such as an environmental attribute and a customer satisfaction attribute. Although such attributes may be, to some extent, built into the current three attributes, adding new attributes will undoubtedly affect RSEs for many if not all mitigations. RSEs are thus of limited value in that they cannot effectively be compared between cycles.

Non-RSE Factors: Perhaps one of the most critical shortcomings of RSEs is that there is much they do not capture. The methodologies for determining RSEs do not take into consideration all the factors that go into the decision to select a mitigation. For example, if a utility intends to replace a bare wire conductor with insulated conductor, the RSE calculation will consider the risk reduction achieved by installing the new conductor and the cost of the new conductor. While factors such as resource availability, permitting requirements, and changing climate conditions are not considered within the RSE calculation, these factors are certainly taken into consideration for decision-making purposes. Similarly, certain human factor benefits,

---

[21] D.18-12-014 at 54.

[22] The Company at times refers to its MAVF herein as the Risk Quantification Framework.

such as those related to training and communicating with the public, are not easily captured as part of the RSE calculation. For example, the human benefits related to improved training and tools to allow the use of a newer laptop technology to enhance data collection was not captured in the RSE, which contributed to a low score resulting for this mitigation. This deficiency in RSEs has been recognized in essentially every RAMP filing and the SED report discussion therein.[23]

<u>RSEs Cannot Be Compared Across Utilities</u>: RSEs cannot be compared in any meaningful way across utilities. Although the Commission and Intervenors have in the past expressed a desire to be able to compare RSEs across utilities for similar risks/mitigations, that is not possible at this time.[24] Each of the utilities will use different formulas and methodologies in calculating RSEs. Each utility might use different attributes, different weights and scaling, and even different frequency and consequence valuations. SED acknowledged this in reference to PG&E's RAMP where it noted that the calculations and methodologies in calculating RSEs are complex and require significant effort to interpret.[25] Although the Settlement Agreement standardized certain processes and aspects of the creation of RSEs, the differences still confound any meaningful comparison.

<u>Lack of Common View of Risk Tolerance</u>: As noted by PG&E in their 2017 RAMP filing, a deeper understanding of the implications of differing risk tolerances is required before comparability can truly be achieved.[26] For example, SED, an intervenor, and a utility might have different views regarding the number of fire incidents that should be able to occur on a particular system. Some might say they want zero incidents while others may say there should be no incidents that burn beyond three-square feet. These varying tolerances lead to different

---

23 *See* I.16-10-015/-016 (cons.), I.17-11-003 and I.18-11-006.

24 D.16-08-018 at 164.

25 California Public Utilities Commission, *Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric* Company *Investigation 17-11-003* (March 30, 2018) at 23 and 139-140.

26 I.17-11-003, 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (November 30, 2017) at A-6.

mitigations and RSEs. In addition, certain outcomes can be a higher priority because of their cause, even if the RSE cannot reflect that type of preference. The Company attempted to capture some of this in the alternative methodology discussed in Chapter RAMP-D, which can emphasize a need to reduce more significant events compared to more frequent risk events.

Mitigation Synergy not Recognized: As the MAVF for creation of RSEs currently stands, it is incapable of correctly showing the value of RSEs when mitigations are combined or broken up. Some mitigations work best when combined with one or more mitigations. Because RSEs have to be presented as standalone scores, the value of combining RSEs cannot be captured. Similarly, some mitigations apply across multiple risks. The RSE calculation methodology as it currently stands does not allow for a recognition of such benefits. Although combining the benefits across all risks impacted improves accuracy, this would significantly add to the complexity of the analysis and presentation of the mitigation benefits. For example, the replacement of live front equipment mitigation impacts both the Electric Infrastructure Integrity (EII) risk and the Employee Safety risk. However, the Company elected to assess the mitigation benefit as part of the EII risk to minimize double counting of benefits throughout this 2019 RAMP Report.[27] Thus, the risk reduction within the Employee Safety risk is underestimated, since the mitigation was assessed against the EII risk. This is another instance of RSEs not being able to capture the entire picture when it comes to the costs and benefits of mitigations or controls.

Non-Asset Mitigations/Controls: Non-Asset mitigations also do not lend themselves well to evaluation by RSEs. Because such mitigations do not clearly lend themselves well to being broken down into discrete data points, trying to force them into a quantitative analysis is challenging. For example, the benefit of training or public awareness efforts for third party dig-ins is challenging to quantify because these non-asset mitigations rely on a variety of sources and indirect measurements related to the risk. There are a substantial number of mitigations that

[27] Additional discussion on the Treatment of Risk Mitigating Activities Presented in Risk Chapters is in Section III.B.4 of Chapter RAMP-A.

utilities pursue and implement which are not asset based. Determining how to assess them within an RSE-driven framework continues to be problematic.

RSEs Do Not Reflect Reality of Utility or Commission Priorities: Although there are several shortcomings in the RSEs that are primarily data driven, perhaps one of the most challenging to quantify is related to valuing mitigations that are strongly supported by the Commission and IOUs' strategic efforts and priorities. Certain mitigations are recognized by essentially all interested parties to be important – yet their RSEs would suggest they should be treated as lower priority work. For example, in the high-pressure pipeline incident risk, the valve automation mitigation had a relatively low RSE, yet valve automation was required by the Commission in D.14-06-007. The rankings of RSEs shown in Appendix D-1 contain other examples of these types of mitigations. Because there are so many mitigations like this, it becomes difficult to accept the results of other less unanimously supported mitigations (or any of the RSEs, for that matter).

Cannot be Used to Prioritize: Another shortcoming of RSEs is that they are not particularly effective at their presumed purpose: to rank mitigations. When SCE first proposed the use of RSEs in August 2015, they recognized it would take time to develop them and they were, at best, only one of many factors to be taken into consideration in measuring mitigation effectiveness.[28] PG&E and SED went further in concluding that RSEs cannot be used to compare RSEs across risks or across utilities.[29] Based on all the shortcomings noted above, the conclusions reached by SED, SCE, and PG&E regarding whether RSEs can be used to simply rank mitigations are correct. There are too many shortcomings and variables to be able to use RSEs in their current format to determine whether an investment should or should not be made relative to another risk.

---

[28] Southern California Edison Company, *SMAP Workshop* (August 3, 2015), *available at* https://www.cpuc.ca.gov/General.aspx?id=9099.

[29] D.16-08-018 at 164.

III. CONCLUSION AND POTENTIAL NEXT STEPS

SoCalGas and SDG&E, PG&E and SCE have all included RSE calculations in their respective RAMP Reports; however, as noted in numerous S-MAP Workshop documents and SED briefings, RSEs are flawed and provide imperfect results. While there is a belief that RSEs can be used as an input into investment decision making, neither SED nor the utilities believe RSEs can be used to prioritize investments or that they should be the determining input into decision making.

In conclusion, for RSEs to be of increased value in investment decision making, then RSEs specifically:

1. Must provide insights into mitigation selection but cannot be the only criteria used to prioritize mitigation investments.
2. Need further study and methodological development to address the complexity of deciding which mitigations are best implemented to address a risk.
3. Cannot address all the factors that go into determining which mitigations can be implemented (*e.g.,* resource availability and scheduling/permitting issues cannot be taken into consideration in developing RSEs).
4. Require historic data in addition to SME insights to be of most value.
5. May not provide an optimized portfolio of mitigations.
6. Need a better understanding of each stakeholders' risk tolerance for RSEs to be valuable.
7. Are of limited value when evaluating the effectiveness of non-asset mitigations.
8. Should be the subject of additional investigation in future S-MAPs.

The Company is hopeful that an exploration of how to strengthen RSEs can be included in future S-MAP proceedings. This exploration could include, but not be limited to, a determination of a risk tolerance methodology, RSEs and risk mitigation effectiveness and the access to historic data that goes well beyond subject matter expertise. This will likely mean that RSEs will have limited use for future GRC cycles while the methodology is refined, and data is improved and collected.

Risk Assessment Mitigation Phase

(RAMP-F)

Safety Culture, Organizational Structure, Executive and Utility Board Engagement, and Compensation Policies Related to Safety

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

This Chapter provides supplemental information regarding SDG&E's organizational structure, programs, culture and compensation as they relate to safety, as required by Decision (D.) 16-08-018.[1] The California Public Utilities Commission (Commission or CPUC) has stated that "[a]n effective safety culture is a prerequisite to a utility's positive safety performance record,"[2] and defines "safety culture" as follows:

> An organization's culture is the collective set of that organization's values, principles, beliefs, and norms, which are manifested in the planning, behaviors, and actions of all individuals leading and associated with the organization, and where the effectiveness of the culture is judged and measured by the organization's performance and results in the world (reality). Various governmental studies and federal agencies rely on this definition of organizational culture to define "safety culture."[3]

The Commission has further stated that, under the above definition, a positive safety culture includes "[a] clearly articulated set of principles and values with a clear expectation of full compliance," and "[e]ffective communication and continuous education and testing."[4] SDG&E fully agrees and has developed values, goals, and practices for a safety culture throughout its history, advancing its programs, policies, procedures, guidelines, and best practices to improve the safety of its operations.[5]

In addition to addressing safety as an integral component of all the risk assessments and mitigation activities outlined in each of the individual risk chapters of this RAMP Report, the

---

1 D.16-08-018 at 140-142. Additionally, the Commission stated "[t]he company's compensation policies related to safety also should be included in the RAMP filing." *Id*. at 141 (citation omitted). *See*, *also*, Investigation (I.) 19-06-014, Order Instituting Investigation (June 27, 2019) at 3.

2 I.15-08-019, Order Instituting Investigation on the Commission's Own Motion Into Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety (August 27, 2015) at 4 (citation omitted).

3 I.19-06-014 at 3.

4 *Id.*

5 *See, e.g.,* Application (A.) 17-10-007/-008 (cons.), Exhibit (Ex.) 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-28.

Commission has instructed the utilities to include specific discussion in this filing regarding the following: [6]

- Safety organizational structure;
- Safety culture;
- Compensation policies related to safety;
- Executive and senior management engagement in the risk assessment, prioritization, mitigation, and budgeting process; and
- Utility board engagement and oversight over safety performance and expenditures.

This chapter addresses each of these topics in the following sections below.

II. BACKGROUND

Following issuance of D.16-08-018, SDG&E has described the elements of its safety culture in various proceedings. For example, various SDG&E witnesses in the test year (TY) 2019 general rate case (GRC) testified regarding safety culture, as it related to their respective subject matter area.[7] Testimony that was sponsored by approximately 50 witnesses, including by SDG&E's President and Chief Operating Officer,[8] demonstrated SDG&E's safety culture and safety management practices and based its GRC funding request on key safety and risk-informed RAMP risks and mitigations. SDG&E also provided TY 2019 GRC testimony and information regarding its governance, safety record, and safety culture,[9] pursuant to Commission direction in D.16-06-054.[10]

SDG&E's testimony chapters in the TY 2019 GRC proceeding outlined various safety programs and new and evolving initiatives to build safety management systems. Furthermore,

---

6 *See* D.16-08-018 at 140-142.

7 *See* A.17-10-007.

8 SDG&E's Chief Operating Officer, Caroline Winn, also currently serves as the Company's Chief Safety Officer.

9 A.17-10-007/-008 (cons.), Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) and Ex. 208 (SCG/SDG&E Robinson Direct).

10 D.16-06-054 at 154.

following the formal release in July 2015 of American National Standards Institute (ANSI)/American Petroleum Institute Recommended Practice 1173 (API 1173), SDG&E voluntarily adopted and began to implement its foundational principles of safety management systems for its gas operations and is encouraging its pipeline construction contractors to also do the same.[11] As of fall 2019, SDG&E is also embarking to apply API 1173 principles to its electric operations. Details on this effort will be presented in SDG&E's next GRC application. Additionally, in 2017, SDG&E began the implementation of asset management practices pursuant to the internationally recognized standard ISO 55000, of which safety is a core element of decision-making.

III. SAFETY ORGANIZATIONAL STRUCTURE

This section provides an overview of how safety is incorporated into SDG&E's organizational structure.[12] Detailed descriptions of SDG&E's safety organization can be found within SDG&E's Employee, Contractor, and Customer and Public Safety chapters included in this RAMP Report.

SDG&E has dedicated teams embedded in the organization whose roles revolve around management of safety and other risks. Currently, SDG&E has four departments/organizations that work together to identify and monitor safety risks. These departments include SDG&E's:

- Safety Department,
- Asset Management Organization,
- Enterprise Risk Management (ERM) Organization, and
- Emergency Management Department.

These departments/organizations collaborate to address the Company's safety risks. For instance, SDG&E's ERM organization identifies safety risks through its on-going risk management processes. These risks are shared with the operating units and Company leadership,

11 Southern California Gas Company (SoCalGas) and SDG&E (collectively, the Utilities) own and operate an integrated natural gas system. The Utilities collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency.

12 "RAMP filings should also cover the company's organizational structure as it relates to safety." D.16-08-018 at 141.

including leaders of each organization referenced above, through the ERR process. SDG&E's Asset Management department looks specifically at the health of assets and assets safety. Again, these findings are shared with the other three departments. Emergency Management, building upon and leveraging the work of the other three departments, develops policies, practices and processes to manage Potential Consequences, should a Risk Event occur. SDG&E's Safety department uses information gathered from these departments to develop policies and practices that are implemented throughout the entire Company. All four departments participate in meetings coordinated through ERM to ensure alignment of their efforts.

While these four departments/organizations currently collaborate and participate in joint meetings to align their efforts, SDG&E's endeavor to implement an enterprise-wide Safety Management System will further consolidate these groups and develop SDG&E's safety culture throughout all operations, gas, electric and support services, at all levels. In addition to these centralized functions that promote safety across the Company, SDG&E embeds safety practices into its operating groups. This is done in the form of safety procedures and policies that are driven across the Company.

A. Safety Department

SDG&E's safety department is organized under SDG&E's Chief Safety Officer. SDG&E has a dedicated safety department comprising a director and managers who oversee the implementation of the company's various safety policies, trainings, and programs, including the Environmental & Safety Compliance Management Program (ESCMP), the Behavior Based Safety Programs, Stop the Job, Close Call/Near-Miss program, Incident Investigations, Safety Culture Assessments and Contractor Safety Programs. These programs are described within the Employee Safety Chapter of this RAMP Report (SDG&E-3).

SDG&E's Executive Safety Council is the governing body for all safety committees. Led by SDG&E's Chief Safety Officer and the Director of Safety, and consisting of various Company officers, the Executive Safety Council advances the Company's safety culture and addresses enterprise-wide safety strategy. These monthly meetings are held at various Company locations to allow top Company leadership to engage directly with SDG&E's front-line employees representing its labor and represented workforce. Executive Safety Council meetings integrate front-line employee and supervisor dialogue sessions so that employees have an opportunity to share safety experiences with Company leadership. Additionally, SDG&E has numerous field and office site safety committees. These site-specific committees are actively engaged in safety awareness through education, promoting a healthy lifestyle, encouraging work-life balance, and always maintaining a safe work environment. To keep the committees connected, quarterly meetings are held with committee chairpersons and co-chairpersons. During these meetings safety updates are shared, training is provided, and action planning steps identified. The Executive Safety Council is the governing body for all of SDG&E's safety committees.

B. Asset Management Organization

SDG&E's Asset Management organization was created in 2017 to develop a strategic asset management capability for the company that aligns with the international standard of ISO 55000. The group comprises a dedicated team of director, managers and staff, who focuses on implementing the tenets of ISO 55000 across the organization to more optimally balance asset cost, asset risk (including safety), and asset performance. This program enables SDG&E to place the safe and effective management of the Company's physical assets at the heart of the Company's operations. This program and others are further described below and in the Electric Infrastructure Integrity chapter of this RAMP Report (SDG&E-4).

C. Enterprise Risk Management Organization

The Enterprise Risk Management Organization comprises a Chief Risk Officer, vice presidents, directors, and risk managers, whose roles are dedicated to implementing the risk management process and the integration of risk-informed decision-making across the Company. This includes the development of transparent, repeatable and consistent processes that are quantitative and data-driven, facilitating an annual identification and evaluation of risk, as well as supporting operational areas across the Company in the assessment of their risks and development of associated risk mitigations. SDG&E's Enterprise Risk Management Organization oversees the development of the annual risk registry process, as described in Chapter RAMP-B. Additionally, other efforts include the responsiveness to regulatory requirements such as accountability and S-MAP metric reporting.

D. Emergency Management Department

SDG&E's Emergency Management Department coordinates safe, effective and risk-based emergency preparedness to safely and efficiently prepare for, respond to, and recover from all threats and hazards. The Emergency Management Department sustains quality assurance and improvement processes through strategic planning, training, simulation exercises, and a comprehensive After-Action Review and Improvement program. The Emergency Management Department includes: 1) aviation services, 2) business resumption, 3) emergency preparedness and response operations, 4) information and technical services, and 5) operational field emergency readiness.

SDG&E responds to gas and electric emergencies as an important part of its normal business practices and has implemented and adapted a Utility Incident Command System (UICS) into those practices based on the National Incident Management System. Elements of SDG&E's UICS program include:

- Certification of 460 Emergency Operations Center responders in ICS 100 and 200;
- Training Operational Leadership in UICS roles and responsibilities;
- Annual Unified Command, gas and electric safety and response training with all First Responders in the SDG&E service territory;
- Development and deployment of Tactical Command Vehicles, and Command/Communications Trailers to support the UICS and Unified Command System on incidents and emergencies;
- Providing UICS Liaisons to Fire and Law Enforcement Unified Command Posts; and
- The effectiveness of all programs listed is measured through our AAR program (Quality Assurance and Improvement).

Each SDG&E operational area has emergency procedures that are specifically written for these types of incidents. These emergency response procedures are thoroughly practiced, and the personnel is well-trained to respond to and resolve routine gas and electric emergencies. When an emergency escalates, there is a need for an organized response with specific procedures and designated personnel. This organized response, through the UICS, provides the required specialized decision-making, the communication capabilities and the additional resources needed to efficiently respond to and recover from an event.

IV. SAFETY CULTURE

Safety culture requires action and organizational focus by all employees. SDG&E takes both a "top-down" and "bottom-up" approach with respect to safety. SDG&E's safety efforts start at the top with appropriate safety governance. Governed by the Executive Safety Council and led by SDG&E's Chief Safety Officer, SDG&E has various safety committees to help inform and educate employees about safety issues throughout all levels of the Company and set meaningful and attainable safety goals throughout the organization. The safety committees also provide an opportunity to receive employee feedback on key safety issues. In addition to employee feedback gathered from safety committees, SDG&E also deploys Behavior Based Safety programs and grassroots safety culture change initiatives, for example, to identify and address at-risk behaviors. Company employees attend safety meetings, tailgates, and safety congresses, and are surveyed every two years to solicit their candid feedback.

SDG&E is continuing its efforts to implement an enterprise-wide Safety Management System (SMS) and plans to put forth its SMS proposal in the TY 2022 GRC. SDG&E's Gas Operations' SMS is guided by the API 1173 guidelines. While there is not currently an electric operations SMS similar to the well-vetted API 1173, SDG&E Electric Operations' culture largely aligns with the ten essential elements of API 1173 and is in the process of creating, a first in the electric industry, equivalent of API 1173 for electric utilities. Therefore, SDG&E is moving the enterprise (both gas and electric) towards the ten essential elements of API 1173. These include:

1. Leadership and Management Commitment;
2. Stakeholder Engagement;
3. Risk Management;
4. Operational Controls;
5. Incident Investigation, Evaluation, and Lessons Learned;
6. Safety Assurance;

7. Management Review and Continuous Improvement;
8. Emergency Preparedness and Response;
9. Competence, Awareness, and Training; and
10. Documentation and Record Keeping.

SDG&E's efforts as they relate to each of the above ten elements is discussed below. SDG&E's Gas Operations' SMS is guided by the API 1173 guidelines. Beginning fall 2019, SDG&E is embarking on an effort to adapt API 1173 principles and approaches to create an SMS to drive continuous improvement in electric operations. This is an innovative effort by SDG&E electric operations to adapt a broad-based API 1173 safety standard for use in an electric operations environment, as suggested by The Office of the Safety Advocate in SDG&E's TY 2019 GRC proceeding.[13] Using API 1173 as a general standard for operational safety for both gas and electric operations requires alignment of risk management (based on ISO 31000) asset management (based on ISO 55000, and emergency management (based on the Incident Command System) with traditional views of safety management (based on OSHA) to support development of a comprehensive and proactive safety program that produces ever-improving levels of work forces and public safety.

A. Leadership and Management Commitment

In SDG&E's TY 2019 GRC proceeding, several executive witnesses testified to SDG&E's longstanding commitments to operating a safe utility and to aggressively enhancing the focus placed on the implementation of effective safety risk mitigations, including asset health and safety.[14] For example, SDG&E's Chief Safety Officer, Caroline Winn, testified: "At SDG&E, safety isn't a goal – it is part of the Company's DNA. Nothing is more important than keeping our employees, contractors and the public safe. We are making strategic investments in

---

13 "The Utilities should develop a SMS framework to address electric and underground gas storage assets/operations, and present its proposal in the next GRC. The framework/s should leverage the API 1173 framework's emphasis on safety culture." A.17-10-007/-008 (cons.), Opening Brief of The Office of the Safety Advocate (September 21, 2018) at 15.

14 A.17-10-007/-008 (cons.), Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-26.

culture, technology, system upgrades and community partnerships to enhance the safety of our customers and the communities we serve."[15]

SDG&E has processes, programs, and committees in place that solicit feedback on safety from employees on the management of risks and unsafe practices or incidents. To promote these principles throughout, and to foster a culture of continuous safety improvement, SDG&E continuously strives for a work environment where employees at all levels can raise pipeline and electric infrastructure, customer safety, and employee safety concerns and offer suggestions for improvement. SDG&E urges two-way formal and informal communication between the company and the public, employees and management, and contractors and the company, in order to identify and manage safety risks before incidents occur. The vision and emphasis on risk management begins at the top, with strong support for the risk management process. SDG&E has an open-door policy that promotes open communication between employees and their direct supervisors. In addition to these culture-based items, there are formal programs designed to compel employees to speak up if they see unsafe behaviors, such as "Stop the Job." SDG&E conducts a Safety Congress as well as safety meetings for field employees that provide safety training, share best practices and promote leadership and employee engagement. If an employee does not feel comfortable reporting unsafe behaviors and incidents through the above-mentioned avenues, there are anonymous means to do so including the Ethics & Compliance Hotline, employee engagement surveys, and National Safety Council Culture Survey.

B. Stakeholder Engagement

SDG&E compels two-way formal and informal communication between the company and the public, employees and management, and contractors and the company. SDG&E's safety department regularly issues employee safety communications to provide employees with safety-related information in a timely manner regarding standards and safe work practices. These safety communications are a tool used to inform employees about safety hazards and exposures, hazard mitigation, rules, regulations, warnings, goals, and progress reports through an array of media. SDG&E communicates information through safety bulletins, emails, newsletters,

[15] A.17-10-007/-008 (cons.), Ex. 02 (SDG&E Winn Revised Direct) at CAW-1.

electronic bulletin boards (*e.g.,* digiboards), posted signage throughout the workplace, tailgate meetings and reports.

To continuously monitor, measure and improve the Companies' workplace safety culture, SDG&E regularly assesses itself through the National Safety Council (NSC) Foundation's Barometer Safety Culture Survey and the Employee Engagement Survey. As described by TY 2019 GRC witnesses Diana Day and Tashonda Taylor, the Safety Barometer Survey assesses overall safety climate health and identifies areas of opportunity to eliminate injuries and improve focus and commitment to safety.[16] SDG&E TY 2019 GRC witnesses David Buczkowski and David Geier sponsored joint safety policy testimony that provided the following reasons supporting SDG&E's position that the NSC Safety Barometer Survey is a leading practice approach to evaluating safety culture:

1. NSC's mission is safety – eliminating preventable deaths, through leadership, education and advocacy;
2. The NSC Safety Barometer Survey is led by third-party experts;
3. The practices included in the survey are the leading practices drawn from survey participants, allowing SDG&E to compare itself to almost 1,000 other Companies; and
4. The survey goes well beyond the utility industry and includes other industries.[17]

Through regular participation in the survey, SDG&E shares results, develops targets, implements plans, and measures progress, with the goal of increasing employee participation in, and contribution to, improvements in safety performance.

SDG&E began conducting safety culture assessments in 2013, using NSC's Safety Barometer Survey. The NSC Safety Barometer survey is an employee perception survey that engages employees and asks for their anonymous feedback on safety by measuring elements of safety excellence in the following areas:

---

[16] A.17-10-007/-008 (cons.), Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) and Ex. 362 (SDG&E Taylor Direct).

[17] A.17-10-007/-008 (cons.), Ex. 90 (SCG/SDG&E Buczkowski/Geier Rebuttal) at DLB/DLG-12.

- Organizational Climate – Items probe general conditions that interact with the safety program to affect its ultimate success, such as teamwork, morale, and employee turnover;
- Management Participation – Items describe ways in which top and middle management demonstrates their leadership and commitment to safety in the form of words, actions, organizational strategy, and personal engagement with safety;
- Supervisory Participation – Items consider six primary roles through which supervisors communicate their personal support for safety: leader, manager, controller, trainer, organizational representative, and advocate for workers;
- Safety Support Climate – Items ask employees across an organization for general beliefs, impressions, and observations about management's commitment and underlying values about safety;
- Employee Participation – Items specify selected actions and reactions that are critical to making a safety program work. Emphasis is given on personal engagement, responsibility, and compliance; and
- Safety Support Activities – Items probe the presence or quality of various safety program practices. This focuses on communications, training, inspection, maintenance, and emergency response.

NSC Barometer Survey gives the information and insight in the six critical areas of safety culture described above. Furthermore, NSC's rich database provides the ability to benchmark the results with hundreds of other companies who have conducted similar surveys with NSC and gives a comparative analysis of relative strengths and potential opportunities for organizational improvements and for individual work locations and departments.

SDG&E has now completed three cycles of the NSC Safety Barometer Survey (in 2013, 2016, and 2018) and, when compared to 580 other companies who have gone through similar surveys, the companies have ranked consistently high. In 2013 and 2018, SDG&E ranked above the 90th percentile. In addition to ranking, the NSC survey tool has helped to identify safety areas of alignment and strength as well as opportunities for potential improvement.

SDG&E has found the NSC survey tool to be very valuable in identifying improvement opportunities in its safety programs and system of safety controls. SDG&E's Safety Department takes the lead in identifying and implementing improvement opportunities that have company-wide relevance and benefit. Management at each work location and business function use the survey results to identify potential improvement opportunities and work with their local management, safety committees, and employee base to create action plans and make needed improvements.

C. Risk Management

Effective risk management practices help to reinforce a strong and positive safety culture. SDG&E has undertaken a thoughtful and measured approach to the adoption of risk management structures and processes at all levels, to further the development of a risk-aware culture. As described in (then-Vice President, Enterprise Risk Management for SDG&E) Diana Day's testimony in the TY 2019 GRC, SDG&E's enterprise risk management organization facilitates the identification, analysis, evaluation and prioritization of risks, with an emphasis on safety, to ultimately inform the investment decision-making process, and works to integrate risk management with asset and investment management through the creation of governance structures, competencies, and tools.[18] The Enterprise Risk Management practices and processes are continuing to be used by SDG&E Electric and Gas Operations to identify safety risks, thus providing a critical element of SDG&E's SMS implementation efforts.

SDG&E's risk management framework is consistent with the Cycla Corporation 10-step Evaluation Method adopted in D.16-08-018. Risk identification, as defined by ISO 31000, is the process of finding, recognizing and describing risks. It includes the identification of risk sources, events, their causes and potential consequences. On an annual basis, SDG&E's Enterprise Risk Management Organization facilitates the enterprise risk identification process through interviews and meetings with risk owners and managers to review and discuss potential

18 A.17-10-007/-008 (cons.), Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-2.

changes to the utilities' respective Enterprise Risk Registry. SDG&E continues to work on developing operating unit risk registries in different operating areas of the Utilities and refining the process. SDG&E is leveraging the operating unit risk registries to inform internal asset management strategies to continue the integration of risk and asset management. SDG&E's risk management framework is further discussed in Chapter RAMP-B.

D. Operational Controls

SDG&E describes its operational controls for human safety, pipeline infrastructure and electric infrastructure below. SDG&E's wildfire management efforts are an example of robust operational controls. SDG&E's implementation of Public Safety Power Shutoff (PSPS) events and resiliency efforts are critical operational controls with strong ties to both asset management and risk management.

1. Employee and Contractor Safety

Employee safety is a core value at SDG&E. SDG&E's safety-first culture focuses on its employees, customers, and the public, and is embedded in every aspect of the Company's work. SDG&E's Employee Safety risk mitigation programs are founded on proven employee-based programs, safety training, workforce education, and SDG&E's Illness & Injury Prevention Program (IIPP).

SDG&E's relies heavily on the use of contractors. As further detailed in the Contractor Safety Chapter of this RAMP Report (SDG&E-2), SDG&E standardizes its approach to contractor safety through its contractor oversight program. SDG&E uses both the Contractor Safety Program Standard G8308 for SDG&E and the Class 1 Contractor Safety Manual for contractors to hold all business units and Class 1 Contractors to the same requirements and/or standards. Business units such as Major Projects, Construction Services, and Vegetation Management also have field safety oversight of all construction work performed by Class 1 Contractors working for those respective groups. This oversight includes instituting safeguards to perform all contracted work in accordance with SDG&E standards, OSHA regulations, applicable laws, and Commission Orders such as G.O. 95 (Rules for Overhead Electric Line Construction), and G.O. 128 (Rules for Construction of Underground Electric Supply and Communications Systems). Further, SDG&E currently utilizes third-party administration tools to ensure contractors comply with SDG&E's established safety and contractual requirements (*see* SDG&E-2-C3).

2. Pipeline Safety Management System (PSMS) – API RP 1173 Implementation

In 2017, SDG&E began its Pipeline Safety Management (PSMS) initiative to align the company's practices with American Petroleum Institute's Recommended Practice 1173 (API RP 1173) and reinforce the company's safety culture through the integration of business needs and gas operational risks in a systematic manner.

Safety Policy witnesses David Buczkowski and David Geier testified in SDG&E's TY 2019 GRC proceeding regarding the elements and varying maturity levels of the Safety Management System that had been implemented to date.[19] More specifically, SDG&E, in its implementation of API 1173 for its gas pipeline operations, has adopted a three-pronged approach based on the following:

a. Employee and Contractor Safety;
b. Customer and Public Safety; and
c. Safety of SDG&E's gas delivery systems.

Each of these categories is addressed in SDG&E's risk management policies, processes, and practices, as well as through day-to-day operations. Moreover, these areas are all reflected in the various risk chapters of this RAMP Report.

As discussed in Omar Rivera's testimony in SDG&E's TY 2019 GRC, API RP 1173 is a structured way to identify hazards and control risks while validating that the risk controls are effective.[20] This includes increased interdepartmental integration of all pipeline safety-related programs and risk management, development and monitoring of leading and lagging indicators, implementation of reporting and oversight processes, continuous program monitoring and improvement, enhanced incident investigation and lessons learned, safety culture evaluation, improved management of change and recordkeeping, enhanced emergency preparedness, and application of competence training.

---

[19] A.17-10-007/-008 (cons.), Ex. 90 (SCG/SDG&E Buczkowski/Geier Rebuttal).

[20] A.17-10-007/-008 (cons.), Ex. 89 (SDG&E Rivera Rebuttal).

3. Asset Integrity Management (AIM) – ISO 55000 Implementation

In 2017, SDG&E began the implementation of its Asset Integrity Management (AIM) program, aligning asset management functions and strategies across SDG&E's electric system operations and implementing an integrated and comprehensive (across entire life cycles) asset management program in accordance with ISO 55000. As discussed in Will Speer's testimony in SDG&E's TY 2019 GRC, the benefits of applying ISO 55000 are three-fold:

1. Establishing an internal structure supports SDG&E's optimal balancing of asset cost, asset risk, and asset performance, by making safe and effective management of its physical assets a core business function;

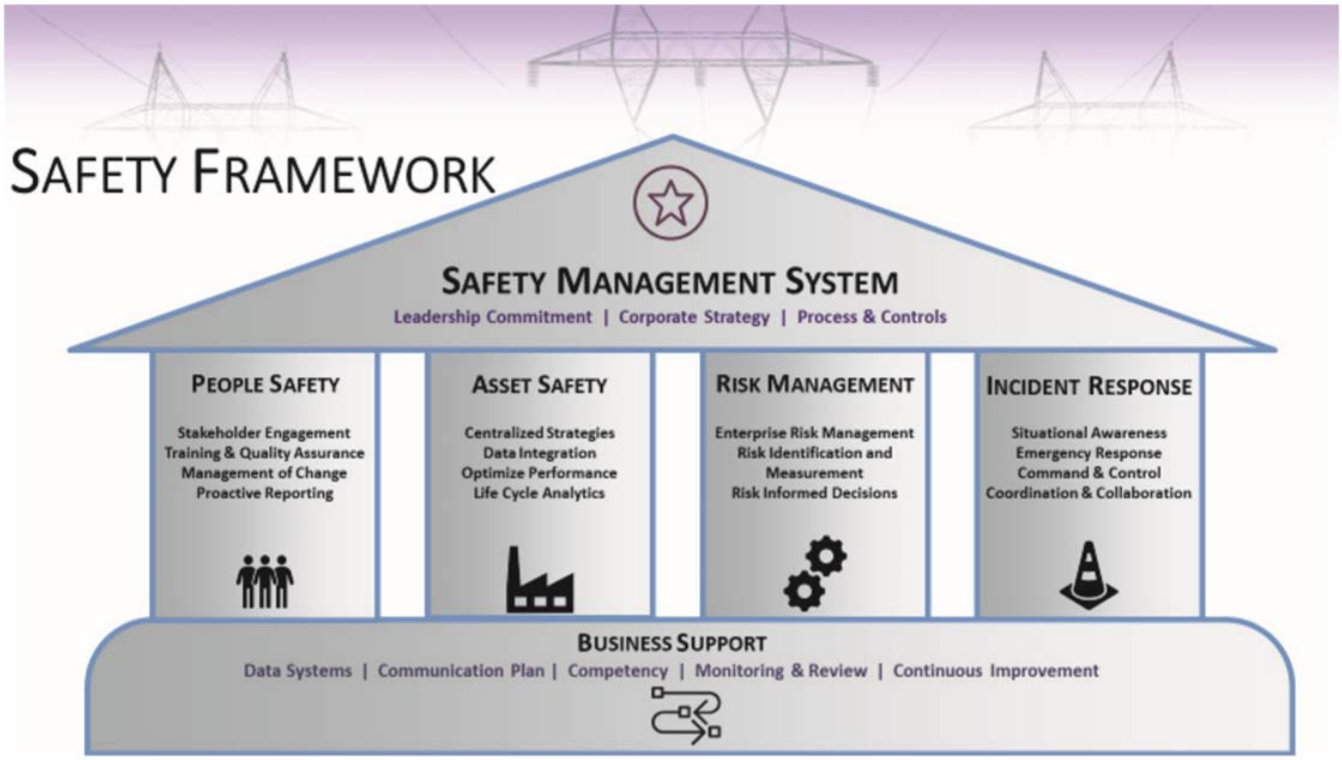
2. Following ISO 55000 (a proven benchmark) will lead to greater internal consistency across asset groups and repeatable and transparent business and asset management processes; and

3. Implementing the ISO 55000 framework will promote significant alignment across the organization and build "line of sight" to ensure employees at all levels fully understand their role in supporting the goals of the organization, at the top of which is safety.[21]

This asset management initiative is directly aligned with and is a critical extension of SDG&E's enterprise risk management program and is a key component of managing asset safety across the company. In fact, the ISO 55000 standard is structured in a very similar manner to API 1173, regarding the required tenets to achieve conformance, with both standards anchored on the "Plan-Do-Check-Act" process cycle. As outlined in Kenneth Deremer's rebuttal testimony in SDG&E's TY 2019 GRC, managing asset safety is a key pillar of SDG&E's overall enterprise safety system, demonstrated the chart below.

[21] A.17-10-007/-008 (cons.), Ex. 68 (SDG&E Speer Second Revised Direct) at WHS-63.

Figure 1: Safety Framework



Since 2017, the Asset Management organization has developed the Asset Integrity Management (AIM) Program to implement an asset management system, which is a systematic and coordinated activities and practices, for electric assets that includes ***integrative approach*** for governance, strategy, analytics and continuous improvement. Utilizing ISO 55000 asset management framework and requirements, the AIM Program has developed a policy, an integrated electric strategy and individual asset management plans, which serve as key foundational documents for reinforcing asset safety practices and implementing reliable management and operations of electric system assets. Because safety is the company's highest priority, the organization is incorporating a multi-attribute value framework for evaluating investments through a data-driven, quantitative risk- and safety-based lens. This value framework utilizes the company's strategic values and determines standardized value-based metrics to quantitatively compare projects, and thereby enhancing the company's ability to cross-prioritize across portfolio and optimize investment decisions. The initial development of this value framework will be applied to electric distribution assets and employ a phased approach to implement to transmission other assets supporting the electric system infrastructure. Furthermore, SDG&E is developing an information system platform to enable data integration and perform asset risk analytics to manage risk-informed asset life-cycle planning, strategy development and prioritization. This system platform includes three components – an asset data integration platform, an asset performance management analytics tool, and an asset investment prioritization tool including the value framework. Consistent with the value framework, the initial development of this platform will be applied to electric distribution assets and then phased to other electric system assets.

To date, the Asset Management organization has achieved several milestones, all of which are ISO 55000 requirements:

- Development of organizational structure including executive steering committee, asset management governance, program leadership, asset class owners and managers, implementation and support leaders, and subject matter experts;
- Determination of asset classes and identification of critical asset types within each class based on risk assessments;
- Development of asset management policy, integrated electric strategy, and asset operational plans for electric distribution, transmission and substation operations;
- Initial compilation of asset-related operational and performance metrics for consistent and comprehensive reporting;
- Initial development of alternative replacement strategy analyses and asset health indices for certain critical assets;
- Assessment and design of information systems needed to support electric asset management;
- Launch of development of information system solutions for data integration, asset performance analytics and portfolio optimization;

- Development of value framework utilizing company strategic values and determining value-based metrics for initial application to electric distribution assets;
- Development of high-level asset management processes and identification of sub-processes for integrated governance, strategy, analytics and performance evaluation; and
- Assessment and assignment of roles and responsibilities required for organizational development and implementation of the AIM program.

As stated above, as of fall 2019, SDG&E is in the process of applying the elements of API 1173 to its electric operations. It should be noted that any SMS development under API 1173 has only begun but the intent is to align fully with the above-described AIM program.

E. Incident Investigation, Evaluation, and Lessons Learned

The SDG&E Injury and Illness Prevention Programs (IIPP) describe procedures and responsibilities for incident and injury reporting and the steps involved to conduct an incident evaluation. Employees are required to report all work-related incidents and injuries promptly to their supervisor. The incident evaluation process includes proper notification, visiting the incident scene, interviewing employee(s) and witnesses involved, examining the factors associated with the incident, determining the contributing factors of the incident, developing and implementing corrective actions to prevent reoccurrence and documenting findings and corrective actions using the incident evaluation form (or safety information management system*)*. Through the incident evaluation process, SDG&E develops and communicates lessons learned from both internal and external incidents and investigations and makes recommendations for safety performance improvement, including changes to training, processes and procedures.

Every employee at SDG&E has the authority and is expected to "Stop the Job" or stop a task that they believe is unsafe or requires a pause for clarification regardless of level. This action is supported by management, the union, and employees throughout the company. SDG&E's "Near Miss" reporting program is a means to help raise awareness and provides the opportunity to help prevent future incidents by communicating the facts around events that had the potential to result in injury, illness or damage, but did not. This program allows potential hazards to be investigated, mitigated, and communicated. Reporting near misses also reduces risk by promoting a safety culture that establishes opportunities to review safety systems and hazard control and to share lessons learned. SDG&E has a Close Call (or Near Miss) Reporting portal where employees can report an incident on-line. Additionally, this portal allows for employees to print the form and anonymously submit to their supervisor or the Safety Department. Further discussion on these programs can be found in the Employee Safety Chapter of this RAMP Report (SDG&E-3).

SDG&E has established a team to create a more comprehensive and robust investigation standard and reporting process. Applying this process uniformly across the Company will result in more consistent investigations and will allow lessons learned to be shared broadly. In addition, regular training is provided for those conducting incident investigations to confirm consistency and thorough investigations.

F. Safety Assurance

<u>Audits & Evaluations –</u> Regularly scheduled internal audits are performed by Sempra Energy Audit Services who work directly with Company management to assist in assessing risks and evaluating business controls needed to enable SDG&E to achieve its objectives. Audit Services has full access to all levels of management, and to all organizational activities, records, property and personnel relevant to activities under review. Audit Services is authorized to select activities for audit, allocate resources, determine audit scope and apply techniques required to accomplish audit objectives. Audit Services is authorized to obtain the necessary direct access of personnel in units of the organization where they perform audits, as well as other specialized services from within or outside the organization. The scope of work conducted by Audit Services is to ascertain that Sempra Energy's processes and business controls, as designed and maintained by management, are adequate and functioning in a manner to help ensure compliance with policies, plans, procedures, laws, regulations and contracts; safeguarding of assets; effectiveness and efficiency of operations; and reliability and integrity of operating and financial information. Business controls are actions that increase the likelihood of achieving the above objectives. Management is responsible for taking ownership of, and being accountable for,

understanding, establishing, and maintaining effective business controls. Through this effort, Audit Services can effectively work with management to ensure the business controls are designed and functioning properly. These collective efforts provide a basis for Audit Services to provide an independent evaluation to management and the Board of Directors as to the adequacy of the Company's overall system of business control. Management will address any identified deficiencies by Audit Services and develop management corrective actions to resolve the findings. Management corrective actions are assigned a completion date and Audit Services reviews to ensure identified findings are resolved prior to closing out the audit.

Executive Safety Council Team Meeting Dialogs – The Executive Safety Council is the governing body for all safety committees. Led by SDG&E's Chief Safety Officer and Director - Safety, this is a roundtable with company officers to advance the company safety culture, address enterprise-wide safety strategy, and give employees an opportunity to share their safety experiences with company leadership. The Executive Safety Council represents SDG&E's labor and represented workforce.

Electric Safety Subcommittee – This committee brings management and electric front-line personnel together as a forum to discuss safety concerns from the perspective of those closest to the risks. The objectives are to make a lasting difference in reducing unnecessary risk, resolve division-wide safety issues/concerns and have front line employees bring information back to their respective workgroups.

Gas Safety Subcommittee – This committee brings represented employee representatives from each district and management together monthly to discuss concerns and address potential gas operations safety hazards. The objective is to reduce unnecessary risk, resolve gas safety issues/concerns, and communicate information back to frontline employees.

Field and Office Safety Committees (site-specific) – These committees (approx. 50) are actively engaged in safety awareness through education, promoting a healthy lifestyle, encouraging work-life balance and always maintaining a work environment. To keep the committees connected, quarterly meetings are held with committee chairpersons and co-chairpersons. During these meetings safety updates are shared, training is provided, and action planning steps are identified. Like SDG&E's other safety committees, site committees roll up to the Executive Safety Council as the governing body.

Behavior Based Safety Program – SDG&E's Behavior Based Safety Program is a leading proactive approach to safety and health management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. Behavior Based Safety is the "application of science of behavior change to real world safety problems." This process is a safety partnership between management and employees that continually focuses attention and actions on their, and others', daily safety behavior, to identify safe and at-risk behaviors (*i.e.*, leading indicators). Through a peer observation program, employees observe employees working using a critical behavior inventory checklist to track safety behaviors and have a dialog on safe and at-risk behaviors, then recommended behavioral safety changes. The purpose is to reduce recurrences of at-risk behaviors by modifying an individual's actions and/or behaviors through observation, feedback, and positive interventions aimed at developing safe work habits.

Management Field Observations – Field supervisors conduct documented observations with their employees to address at-risk behaviors and to attempt to modify an individual's actions and/or behaviors through these interactions. Supervisors provide quality feedback during these positive interventions aimed at developing safe work habits and improving safety culture.

Grassroots Safety Culture Change Teams - SDG&E's grassroots safety culture change initiative involves a safety culture journey that goes beyond the "3 E's" of engineering, enforcement and education. The emphasis is on building relationships, partnerships and trusts which impact strategic focus areas of the company including safety. This approach uses an "iceberg analysis" to identify cultural norms and assumptions that cannot be seen (below the waterline) that may undermine established policies and procedures, uses Behavior Based Safety observations and develops a culture action team to address at-risk behaviors.

Safety Congress and Leadership Awards – Held annually, the Safety Congress provides a forum for safety committee members, safety leaders and others to share and exchange information and ideas through networking and workshops. At this event, safety leaders are recognized for living by the company's safety vision, turning that vision into action, embracing the SDG&E safety culture and demonstrating safety leadership.

The National Safety Council (NSC) Barometer Survey – As noted above, the NSC Barometer Survey is used to assess the overall health of the safety climate and helps to identify areas of opportunity to eliminate injuries and improve focus and commitment to safety. The survey is administered to employees every other year. All organizations interpret their results using a three-step process to investigate, discuss, and understand where the improvement opportunities are. Organizational leaders work with their employees and decide where the attention is needed. After analysis, they identify and implement specific action-oriented strategies within their organization and carry out action plans to completion.

Environmental & Safety Compliance Management Program (ESCMP) – SDG&E's comprehensive health and safety risk management organization and framework establishes and carries out SDG&E's health and safety risk management policies, including SDG&E's ESCMP. ESCMP is an environmental, health and safety management program to plan, set priorities, inspect, educate, train, and monitor the effectiveness of environmental, health and safety activities in accordance with the internationally accepted standard, ISO 14001. ESCMP addresses compliance requirements, awareness, goals, monitoring and verification related to all applicable environmental, health and safety laws, rules and regulations, and company standards. SDG&E also has an annual ESCMP Certification process, which involves submittal of information into the database used to collect and record employee and facility compliance. In January of each year, ESCMP information is submitted into an online system for year-end approval and certification for the prior calendar year. ESCMP has been refined, improved and matured over the years and is still in place at SDG&E.

G. Management Review and Continuous Improvement

As noted above, SDG&E's management review and continuous improvement efforts begin with the continuous assessment of risks identified through the ERM and Asset Management processes. The observations and information captured through the ERM and Asset Management work are used to develop the strategic risk mitigations. The mitigations are implemented though operating and functional units. The implementation status, results and lessons learned are captured though on-going managerial oversight throughout all layers of management. The results of these oversight efforts are reviewed with the Executive Safety Council and SDG&E's leadership on a regular basis.

Management Review of Performance – Safety metrics provide a baseline for how well our organization is performing. Tracking both leading and lagging indicators and comparing historical results provides a baseline for continuous improvement and offers the ability to identify improvement opportunities. Common metrics (*e.g.,* OSHA, LTI, DART, CMVI and Near Miss incidents) are tracked and analyzed and recommendations for safety performance improvement are made, including training, tools, equipment, processes and procedures. SDG&E is also in the process of developing an electric operations SMS based on the principles and tenets of API 1173. This effort will codify the expectations and drive development and monitoring of proactive objectives. Robust review processes will be developed to maintain and continuously improve a strong SMS.

Continuous Improvement – As described above, management reviews results from a variety of safety metrics, including injuries, motor vehicle accidents, near miss incidents, safety observations, and is actively involved in evaluating risk and developing necessary action plans. Safety goals are set with continuous improvement in mind, by focusing on increasing current goals and developing new leading indicators. Safety observations and near miss reporting have increased to "best ever" levels. A new initiative, the Serious Injury and Fatality (SIF) Exposure Assessment Initiative, will focus on developing a SIF decision tree and decision logic, SIF exposure metrics and rates, identifying SIF precursors, using critical controls field verification check sheets, and strengthening corrective actions. Utilizing new technology in our fleet (vehicle telematics) to improve employee safety will provide data analytics in real-time on driver behavior, fleet utilization, geo-fencing and vehicle health.

SDG&E has a healthy safety culture that encourages continuous improvement based on feedback from the front lines and from findings from investigations of incidents and near misses. The work to develop an API 1173-based electric operations SMS will align risk and asset management approaches to enhance proactive continuous improvements through risk mitigation based on predictive analysis rather than on experience of incidents or near-misses.

H. Emergency Preparedness and Response

SDG&E conducts public awareness efforts through education and outreach to enhance the safety of its customers and general public. These efforts are designed to engage with our customers and the public to inform them about our shared safety responsibilities. For example, SDG&E's Public Safety campaigns focus on informing and educating the public about the danger of downed power lines, pole contact from vehicles and the hazards associated with digging near gas lines. These campaigns include videos, TV and radio spots, newspaper ads, billboards and collateral geared toward a variety of scenarios used for different audiences. Of equal importance are outreach activities with local first responder agencies, county coordinators (emergency management), and other public officials that occur on a yearly basis, focusing on how SDG&E partners through planning, training, and exercises prior to emergency incident response. This includes alignment of Utility ICS and Unified Command goals and objectives, understanding protocols and procedures, establishing effective Liaisons and Gas and Electric Safety Zones and processes, and reviewing infrastructure location information, hazard awareness and prevention, leak recognition and response, emergency preparedness and communications, damage prevention and integrity management. In addition, SDG&E also partners with these stakeholders throughout the year on joint drills, exercises, tabletops, and preparedness fairs in order to enhance our coordination and response during emergencies. Target audiences include but are not limited to:

- The County Office of Emergency Services;
- All Fire Departments and personnel (firefighters to Chief Officers);
- All Local Agency Emergency Dispatch Centers/personnel; and
- All Law Enforcement Agencies.

Emergency Preparedness – SDG&E's PSPS program is an element of utility wildfire mitigation plans authorized by the CPUC to address the threat of wildfire and customer/public safety, as discussed in Chapter SDG&E-1. SDG&E's PSPS Communication plan consists of a public outreach and education campaign, implemented June through November. Communications will also include notifications for Public Safety Power Shutoff events. These communications target customers, first responders, public officials and government, public safety partners, as well as the Access and Functional Needs community.

The SDG&E First Responder Outreach Program is beginning its 7th year of service to all First Responder agencies in San Diego County. This Outreach Program has expanded significantly since its inception, as described above, by increasing target audiences, as described above, establishing an Operational Field & Emergency Readiness (OFER) program, and strengthening relationships with key stakeholders internally and externally. The OFER program objective is to provide targeted training and contingency planning activities for the local first responder agencies, as well as improved scene management and the use of the UICS for SDG&E responders. Strategic partnerships with agency leadership allow for increased communication, awareness of gas and electric safety protocols and collaboration on mutual emergency preparedness to ensure employee and public safety. These objectives are accomplished through our previously described annual First Responder training and exercise programs, including the following meetings and collaborative outreach programs:

- Monthly briefings and input meetings with the San Diego County Fire Chief's Association on SDG&E response, planning, training and exercise programs;
- Quarterly briefings with the County Fire Training Officers' committee;
- Annual briefings with the San Diego Police and Sheriff's Association; and
- Regular meetings and collaborative efforts with the County Office of Emergency Services.

Further details about these programs can be found in SDG&E's Customer & Public Safety Chapter of this RAMP Report (SDG&E-5).

Response Plans – SDG&E developed and maintains an Emergency Operations Center (EOC) for use during significant emergencies to allow Company employees to efficiently collaborate and take appropriate action for the response and mitigation of that emergency. During an EOC activation, over 50 subject matter experts may be brought into the EOC, from across the Company, to provide strategic direction, coordination and to facilitate all aspects of the emergency response through event duration. When activated, some basic responsibilities of the EOC include:

- Acquire and allocate critical resources;
- Consistent and aligned internal and external communications;
- Manage crisis information;
- Strategic and policy-level decision-making; and
- Provide centralized coordination of all aspects of the emergency.

The EOC is the hub from which all incident management, response, and communication is coordinated and/or directed. As such, the EOC serves a critical support function to ensure that SDG&E can respond effectively and efficiently to any hazard it may encounter, thereby protecting the safety of its employees, stakeholders, customers, the public, contractors, and any other resources or individuals in its service territory. After Action Reviews (AAR) are core to our Continuous Quality Assurance and Improvement process in Emergency Management. Following an incident or an emergency, AAR's are developed and facilitated to identify the following:

- What went well;
- What needs improvement; and
- Specific Action Items toward improvement (these are entered into a data base and tracked to completion).

I. Competence, Awareness, and Training

SDG&E's employees and contractors receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. Front-line employees are trained in behavior-based safety programs, such as Stop the Job, which is a program that empowers anyone to stop the job at any time, without fear of retaliation, if they see a condition that might be unsafe. Further details about SDG&E's training programs can be found in the Employee Safety Chapter (SDG&E-3).

J. Documentation and Record Keeping

For safety and compliance purposes, SDG&E has implemented various recordkeeping controls for its system in accordance with, for example, the following CPUC regulations:

- General Order (GO) 95 – Rules For Overhead Electric Line Construction

    - o Rule 80.1 defines the record keeping requirement for the required inspection of joint-use poles.
- GO 128 – Rules For Construction of Underground Electric Supply and Communication Systems
    - o Rule 17.7 provides requirements and responsibility for records pertaining to the location of underground facilities.
- GO 165 – Inspection Requirements For Electric Distribution and Transmission Facilities
    - o Section III and Section IV provide the records management requirements for the inspection and maintenance of electrical assets for distribution and transmission facilities, respectively. Additionally, Section III.D requires submittal of an annual report identifying the asset inspection work completed.
- GO 166 – Standards for Operation, Reliability, and Safety During Emergencies and Disasters
    - o Standard 11 requires annual reporting reflecting compliance with the G.O. and any modifications to the emergency plan.
- GO 174 – Rules for Electric Utility Substations
    - o Section III provides requirements for substation inspection program records and reporting requirements.

There are also many CPUC decisions (*e.g.*, D.16-01-008) and additional requirements around data and records management resulting from various CPUC directives and laws (*e.g.*, AB 1650). In addition to the existing rules, SDG&E must also comply with new or developing records management rules.

SDG&E's records management policies include, but are not limited to, processes and systems containing records, definition and identification of records, organizational records (both paper and electronic) and document retention and disposal policy. The goal of records management policies and practices is to provide consistent responsibilities for records management, and to require the assignment of specific accountability for oversight and administration of records management.

SDG&E also has record coordinators across the company. These record coordinators manage records and related issues and are based within each of their respective business areas.

The purpose is to give each operational area day-to-day control over records for which it has responsibility and knowledge. While not their primary job function, the record coordinators work closely with Financial Systems to promote and support the Company's records policies and procedures. In effect, this means that the management of operational asset records is decentralized. Sempra Energy's Audit Services group performs periodic audits to verify compliance with policies related to records management and retention. Historically, these audits have occurred approximately every three years. Lastly, SDG&E uses physical storage space, both on-site and off-site, for records. SDG&E manages the records storage so that it complies with SDG&E's policies related to retention and disposal.

V. COMPENSATION POLICIES RELATED TO SAFETY

SDG&E's strong safety culture is demonstrated through use of compensation metrics and key performance indicators to drive improved safety performance. As the Commission stated in D.16-06-054, "[o]ne of the leading indicators of a safety culture is whether the governance of a company utilizes any compensation, benefits or incentive to promote safety and hold employees accountable for the company's safety record."[22] Benefit programs that promote employee health and welfare also contribute to SDG&E's safety performance and culture.

In her TY 2019 GRC testimony, Compensation and Benefits witness Debbie Robinson explained how SDG&E's compensation and benefits programs are designed to focus employees on safety, and that SDG&E has increased emphasis on employee and operational safety measures in their variable pay plans, commonly referred to as the Incentive Compensation Plans (ICP), thus bolstering their already strong safety culture and safety performance.[23] Ms. Robinson testified that SDG&E has increased the weighting of the employee and operational safety measures in their variable pay plans since the TY 2016 GRC, such that safety measures comprised 70% of the company performance component by the time the TY 2019 GRC was submitted.[24] Providing even stronger alignment between SDG&E's safety programs and the ICP

22 D.16-06-054 at 153.

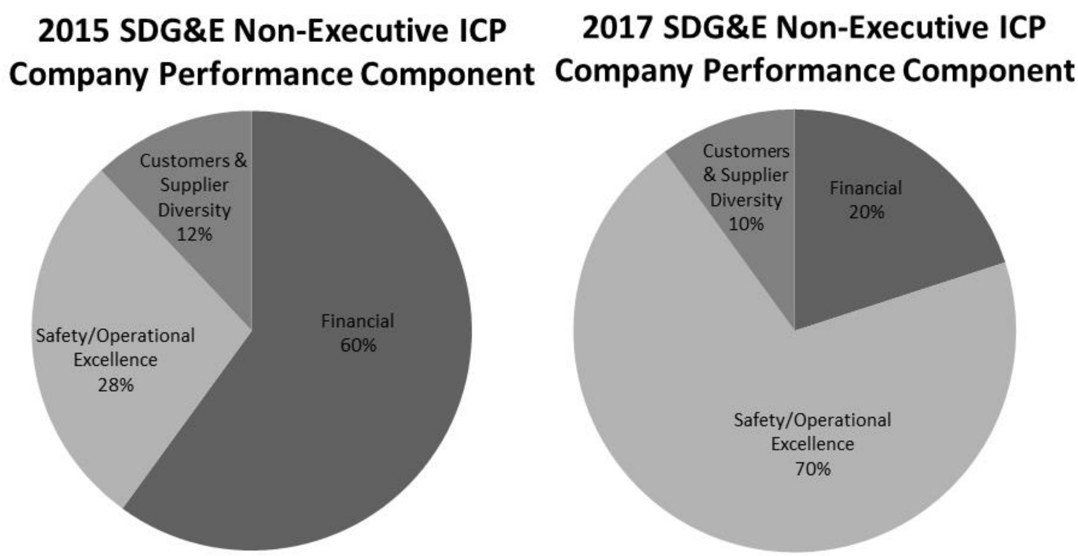
23 A.17-10-007/-008 (cons.), Ex. 208 (SCG/SDG&E Robinson Direct) at DSR-10.

24 *Id.* at DSR-11.

helps to strengthen the Company's safety culture and signal to employees that safety is the number-one priority.

Figure 2, below, taken from Ms. Robinson's TY 2019 GRC testimony,[25] shows that, as of the TY 2019 GRC, the ICP weighting for performance measures related to safety more than tripled since 2015:

Figure 2: ICP Weighting Comparisons, 2015 to 2017



VI. EXECUTIVE AND SENIOR MANAGEMENT ENGAGEMENT IN THE RISK ASSESSMENT, PRIORITIZATION, MITIGATION AND BUDGETING PROCESS

In her TY 2019 GRC testimony, SDG&E's risk management policy witness Diana Day testified that SDG&E's executive management, and specifically the Company's Executive Safety Council, are "committed to and accountable for the development and maintenance of safety culture."[26] Diana Day further testified that SDG&E's leadership holds regular safety meetings at many levels, including Executive Safety Council meetings, which have been in place for over a decade, annual Safety Summits, and annual Contractor Safety Summits, which have included

---

25 *Id.*

26 A.17-10-007/-008 (cons.), Ex. 03 (SCG/SDG&E Day/Flores/York Revised Direct) at DD-28.

hundreds of participants, representatives from other California utilities and the Safety and Enforcement Division of the CPUC.[27] SDG&E's Executive Safety Council, consisting of top company leadership, meets quarterly to engage directly with front-line employees and supervisors, including especially SDG&E's labor and represented workforce, to listen and reinforce key safety tenets and have an open dialogue on safety issues, performance and culture.

Appendix E to Diana Day's direct TY 2019 GRC testimony described how SDG&E's risk management framework and the annual development and updating of the enterprise risk registry provides a structured way for the organization to reflect on different types of risk and the strategies to control or mitigate those risks, as both a "bottom up" and a "top down" process.[28] Subject matter experts and risk managers from throughout the organization provide insight on risk drivers, impacts, and mitigants for risks that are being assessed. Risk owners and the senior management team at each utility then discuss enterprise level risks and mitigants for those risks. Risk owners and risk managers then have the opportunity to ensure that mitigations for top risks are transparent in the business process and are prioritized in decision making.

The Enterprise Risk Registry is a communication tool that is shared amongst the management team and with employees. On an annual basis, the Vice President of Enterprise Risk Management & Compliance provides the SDG&E Board with a risk update that focuses on key enterprise-level risks and associated mitigants. The Sempra Energy Board of Directors also receives periodic risk updates based on the written reports and management presentations from its operating subsidiaries, including SDG&E. Training and education regarding management of risks is an ongoing endeavor. Senior executives continue to be involved in at least three executive risk sessions each year to review top risks identified for the utilities, ranking and prioritization of the risks, and funding for the mitigations.

The involvement of leadership in the planning process was described in the TY 2019 GRC testimony, as follows:

---

27 *Id.*

28 *Id.* at DD-E-5.

For non-balanced base capital, the Executive Finance Committee (EFC) establishes a total annual capital expenditure target consistent with our authorized GRC funding for that period. From this total allocation, funding is prioritized based on risk-informed priorities and continuous input from operations.

- Step 1 – Initial capital allocations begin with input from Functional Capital Committees (FCCs), which are organized by the nature and type of capital investment or function. These teams of managers and subject matter experts perform a high-level assessment of the capital requirements for serving customers to ensure that infrastructure is maintained and developed to provide safe, reliable service with the highest risk mitigation at the lowest attainable cost. Each FCC elicits broad input for developing each function's capital plan and formulates a prioritized grouping of annual spending requirements.
- Step 2 – The capital requirements identified by the FCCs are provided to the Capital Planning Committee (CPC), a cross-functional team of directors representing each operational area with capital requests. The CPC reviews the FCC submissions, cross-prioritizes projects among the FCCs, and establishes a final ranking for proposed capital work. Projects determined to have the highest ratings on key priority metrics will receive the highest priority for funding. These key priority metrics include: safety, cost effectiveness, reliability, security, environmental, and customer experience.
- Step 3 – The CPC presents its recommendations for capital spending consistent within each functional area and consistent with the overall funding target to the EFC, which reviews the recommendations and either approves the proposed capital funding allocations or requests changes.[29]

[29] A.17-10-007/-008 (cons.), Ex. 379 (SDG&E Gentes Second Revised) at RCG-3 – RCG-4.

Once the capital allocations are approved, the individual operating organization is chartered to manage its respective capital needs within the allotted capital. The real-time prioritization of work within the context of the budget allocations is completed by the front-line and project managers on an ongoing and continuous basis. Regulatory compliance deadlines, customer scheduling requirements, and overall infrastructure condition are all factors taken into consideration as work elements are prioritized. Progress on existing capital projects is monitored and reviewed on a monthly basis by the CPC and EFC, and any new projects stemming from incremental Commission directives or changing business needs are evaluated and assessed throughout the year to determine whether current capital allocation should be reprioritized. Before starting a project or making any commitments, the project manager must secure specific project approval signatures in accordance with the Company's Internal Order process and approval and commitment policies.

VII. UTILITY BOARD ENGAGEMENT AND OVERSIGHT OVER SAFETY PERFORMANCE EXPENDITURES

SDG&E's Board of Directors determines safety performance measures and targets to be included in each year's ICP and review and approve the results. The Board meets on a quarterly basis where meetings begin with a safety briefing and include a regular review of year-to-date safety performance as well as current safety and risk-related topics. As a part of their oversight roles, the Board may exercise discretion to reduce or eliminate any payout for employee and/or contractor safety measures in the event of a work-related fatality or serious injury.

A. SDG&E's Board of Directors Safety Committee and the Community Wildfire Safety Advisory Council

Governor Newsom signed Assembly Bill (AB) 1054 into law on July 12, 2019. AB 1054 contains numerous statutory provisions and amendments designed to enhance the mitigation and prevention of catastrophic wildfires – including wildfires linked to utility equipment – in California. AB 1054 added Section 8389 to the Public Utilities Code. Section 8389(e) establishes the requirements for annual safety certifications and, *inter alia,* requires electrical corporations to establish a safety committee of its board of directors. SDG&E established its Safety Committee in July 2019 and received its initial safety certification from the Commission via a letter from the Executive Director dated July 26, 2019.

SDG&E's Safety Committee advises and assists SDG&E's Board of Directors in the oversight of safely providing electric and natural gas services to customers.[30] Per the Safety Committee Charter, the duties and responsibilities of the Committee include reviewing and monitoring:

> (a)(i) the Company's safety culture, goals, and risks; (ii) significant safety-related incidents involving employees, contractors, or members of the public; and (iii) the measures to prevent, mitigate or respond to safety-related incidents; and (iv) periodic reports on safety audits.[31]

In addition, SDG&E recently established the Community Wildfire Safety Advisory Council, comprising independent community members who possess extensive public safety and wildfire experience, to advise the Safety Committee. The Community Advisory Council held their first meeting on September 10, 2019 and will meet two to four times per year. Both the Safety Committee and the Community Wildfire Safety Advisory Council are intended to provide additional safety oversight to SDG&E.

VIII. CONCLUSION

SDG&E endeavors to continually improve processes and procedures that further develop our strong safety culture and enhance employee, contractor, customer and public safety. As further demonstrated throughout the chapters of this RAMP Report, SDG&E is making strategic investments in culture, technology, system upgrades and community partnerships to enhance the safety of our employees, contractors, customers and the communities we serve and plans to propose new SMS projects and programs in its TY 2022 GRC. SDG&E is focused on developing these practices and initiatives to improve safety and strengthen a cultural awareness that nothing is more important than keeping our employees, contractors and the public safe.

---

30 *See* Advice Letter 3461-E, filed November 5, 2019 and pending approval, at Attachment B, Revised Safety Committee Charter (adopted July 17, 2019).

31 *Id.* at Attachment B, p. 3.

Risk Assessment Mitigation Phase (RAMP-G) Lessons Learned

November 27, 2019

TABLE OF CONTENTS

I. INTRODUCTION

San Diego Gas & Electric Company (SDG&E or Company) puts forth these lessons learned, in accordance with Decision (D.) 16-08-018, which can be applied to future Risk Assessment Mitigation Phase (RAMP) Reports, including those of the other California investor-owned utilities (IOUs).[1] The lessons learned presented herein illustrate improvement opportunities that may be incorporated into future RAMP planning efforts, risk processes, and/or other longer-term goals.

As discussed in Chapter RAMP-A, the Company's 2019 RAMP Report vastly differs from its 2016 RAMP Report, as it implements the methodology and processes adopted in D.18-12-014,[2] the Safety Model Assessment Proceeding (SMAP) Settlement Agreement Decision (SA Decision), including developing and applying a new Multi-Attribute Value Function (MAVF).[3] This 2019 RAMP Report[4] also reflects lessons learned from the Company's 2016 RAMP Report[5] and incorporates certain feedback from the California Public Utilities Commission's (CPUC or Commission) Safety and Enforcement Division (SED), and the RAMP filings of Pacific Gas and Electric Company (PG&E) and Southern California Edison Company (SCE). While the 2019 RAMP Report represents a prudent step forward in implementing a quantitative risk management framework, the Company is committed to continuously improving by incorporating best practices and lessons learned, and to collaborating and sharing knowledge with the Commission, IOUs, and other stakeholders.

---

1 D.16-08-018 at 151. "Lessons learned by one company will also inform the RAMP filings of the other companies."

2 D.18-12-014 contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

3 The MAVF is discussed further in Chapter RAMP-C.

4 This 2019 RAMP Report will be incorporated into SDG&E's Test Year (TY) 2022 General Rate Case (GRC).

5 California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation, Investigation (I.) 16-10-015/-016 (cons.), (November 30, 2016).

II. OVERALL LESSONS LEARNED FROM THE 2016 RAMP REPORT

The Company's 2019 RAMP Report improves upon its 2016 RAMP Report by, among other things, implementing feedback provided in SED's Risk Assessment and Safety Advisory Report (SED RAMP Safety Advisory Report).[6] Improvements include reviewing and developing some risk definitions, providing more detail on how programs correlate to the stated risk, advancing probabilistic and quantitative approaches to risk management (including alternatives), more closely aligning the identification of costs with the Company's General Rate Case (GRC) presentation, and producing workpapers concurrently with the RAMP Report.

A. Modification of Risks

The Company received feedback on its 2016 RAMP Report that its Employee, Contractor, Customer, and Public Safety risk was overly broad.[7] In response, the Company has separated these into three distinct risks: Employee Safety (Chapters SCG-2 and SDG&E-3), Contractor Safety (Chapters SCG-3 and SDG&E-2), and Customer and Public Safety (Chapters SCG-4 and SDG&E-5). The Company found other risks which, if broken up, could be more effective risk assessment and alignment of mitigations. For example, in the 2016 RAMP Report, Third Party Dig-in was an individual risk chapter for both SoCalGas and SDG&E. In this 2019 RAMP Report, the risk of incidents resulting from a Third Party Dig-in has been further refined into two separate risk chapters, a Third Party Dig-in on a High Pressure Pipeline chapter and a Third Party Dig-in on a Medium Pressure chapter for each Company, for additional granularity and mitigations that are more specific to the type of pipeline. The decision to separate these risks was driven by the fact that there are vast differences in the quantity of the two asset classes, the volume of tickets impacting each class, the damages to each class, the potential consequences of each risk, some risk drivers, and while a majority of the Controls and Mitigations are common, there are some that are different.

---

[6] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation 16-10-015 and I.16-10-016 (SED RAMP Safety Advisory Report) (March 8, 2017).

[7] SED RAMP Safety Advisory Report at 41; I.16-10-015/I.16-10-016. Opening Comments of the Office of Safety Advocate (OSA) (April 17, 2017) at 6.

Given that risks are dynamic and revisited at a minimum annually, risks may be modified as necessary with some being separated for additional granularity and others being combined. For additional examples, please refer to the Appendix B-1.

B. Correlation of Controls and Mitigation to Risk

The SED RAMP Safety Advisory Report commented that "for several mitigations, there needs to be more effort in showing the correlation between the risk and the mitigations proposed."[8] To respond to this critique, the Company provides in this 2019 RAMP Report a detailed description of the Control or Mitigation in Section V of the respective risk chapters, as well as additional explanation in Section VI of how the Control or Mitigation impacts the risk (*see* Sections VI(a) and (b) of individual risk chapters).

C. Quantitative Framework

Generally, concerns were raised in the 2016 RAMP proceeding with respect to the Company's heavy reliance on subject matter expertise to determine risk reduction,[9] and, because of that reliance, the usefulness of Risk Spend Efficiency (RSEs).[10] While SED stated that RSEs are "admittedly an evolving area," SED has indicated a preference for "quantified data."[11] SED also recommended that "in the future" the Company "need[s] to do a better job clarifying and ranking the risk mitigations that are measured by the RSE and at the same time do a better job identifying metrics that correlate with the performance of the respective risk mitigation."[12]

---

8 SED RAMP Safety Advisory Report at 6.

9 *Id.* at 14.

10 I.16-10-015/I.16-10-016. *See* Reply Comments of SDG&E and SoCalGas (May 9, 2017) at 5-6; Opening Comments of the Office of Safety Advocate (April 17, 2017) at 13; Comments of the Indicated Shippers and Southern California Generation Coalition (April 24, 2017) at 3; Opening Comments of the Coalition of California Utility Employees (April 17, 2017) at 4; Comments of the Utility Consumers' Action Network (April 24, 2017) at 14; and Comments of the Office of Ratepayer Advocates (April 24, 2017) at 2-3, 26.

11 SED RAMP Safety Advisory Report at 18.

12 *Id.* at 6.

Similarly, in the TY 2019 GRC, the California Public Advocates Office (CalPA)[13] recommended that the Companies "focus on quantitativeness and comparability"[14] for future RAMP filings. CalPA cautioned the Companies about the continued use of the 7x7 matrix, stating that it was "largely based on subjective judgement and does not provide [a] quantifiable, clear, and appropriate way of measuring and comparing risks."[15] Therefore, CalPA recommended that the 7x7 be phased out by the next RAMP filing.[16] Via discovery, CalPA asked the Company when it anticipated it could implement some of CalPA's recommendations, such as the following: comparing RSE scores across risks; reducing groupings of mitigations for purposes of calculating RSEs; calculating RSEs for alternatives; including the timeframe over which risks/mitigations are measured; producing complete, unlocked RAMP workpapers at the time of RAMP submission; reporting of added, removed, or changed risks since the last RAMP filing; and identifying of subject matter expert (SME) input used and any supporting metrics/data.[17] The Company noted in response that "many of the recommendations are anticipated to be included in the next RAMP."[18]

The SA Decision and the methodologies therein create a process that makes considerable strides toward a more quantitative risk approach compared to the Company's 2016 RAMP Report. In particular, the 7x7 matrix was not used for determining the pre-mitigation or post-mitigation risk scores in this 2019 RAMP Report. Instead, the Company implemented the methods from the SA Decision, including statistical distributions and Monte Carlo simulations to help quantify risk events. Further, the Company has also leveraged quantifiable data where such data existed, whether its own or from a third-party, and verified the appropriateness of the results

13 Formerly the Office of Ratepayer Advocates (ORA).

14 A.17-10-007/-008 (cons.). Exhibit (Ex.) 398 (ORA/Stannik Direct Testimony) at 11.

15 A.17-10-007/-008 (cons.). Ex. 398 (ORA/Stannik Direct Testimony) at 5.

16 *Id.* at 1 and 5.

17 *Id.* at 10-11 and footnote 20.

18 *Id.* at 10 and 11.

with its subject matter experts. Where no data existed or was incomplete, subject matter expertise was necessary. However, the SA Decision acknowledges the fact that subject matter expertise has value and plays a role in risk analysis,[19] and eliminating it entirely would hurt the value and accuracy of the quantitative analysis. With more reliable, quantitative data, the comparability of RSEs across risks has increased. As shown in Appendix D-1 and as required by the SA Decision,[20] the Company is providing a ranking of all programs by RSE, effectively comparing programs across risks.

Moreover, the Company has progressed in this RAMP Report on all the items noted by CalPA in the GRC. When performing RSEs, the Company made a concerted effort to calculate RSEs for each program and grouped or "bundled" activities, only when needed. For example, many of the activities in the Wildfire risk chapter provide SDG&E with more knowledge of its systems or local conditions – for example, situational awareness tools and inspections. These activities alone may not reduce the risk in a quantifiable manner. In order to quantify the risk reduction benefits, such activities need to be grouped with others. It is the Company's intention to minimize grouping activities together for purposes of calculating an RSE.

Additional information is included in the workpapers accompanying this RAMP Report. Information regarding the length of time used for measurement of program risk reduction benefits is provided in the risk chapters' RSE-related workpapers. Identification of data sources used for purposes of risk quantification are also provided in the RSE-related workpapers, as well as in Section IV and in the individual risk chapters. Changes to risks since the last Company's 2016 RAMP filing is provided in Appendix B-1. Improvements related to alternatives, workpapers, and data collection are further discussed below.

D. Alternative Analysis

The SED RAMP Safety Advisory Report offered the feedback that, although the Company met the CPUC requirements related to providing alternatives in its last RAMP Report,

---

19 D.18-12-014 at Attachment A, A-8-A-9 (Identification of Potential Consequences of Risk Event and Identification of the Frequency of the Risk Event).

20 D.18-12-014 at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

an expanded discussion of alternative mitigations should include estimates of risk reduction and RSE.[21] Given this feedback, the Company is presenting more information in this 2019 RAMP Report regarding its alternative analysis. In Section VIII of the respective risk chapters, the Company puts forth, at a minimum, two alternatives. Section VII of each risk chapter describes the alternative and why it will not be pursued as well as the costs, risk reduction, and RSE. For these identified alternatives, the Company endeavored to provide new ideas and programs rather than relying on changing the pace and/or scope of the Risk Mitigation Plans. This exercise was challenging at times, for several reasons; for example, in instances where most or all mitigations and controls are mandated in a prescriptive manner, or where the Company already has an expansive or longstanding set of controls and/or mitigations.

E. Costs Presentation

Determination of costs presented in this 2019 RAMP Report was highly influenced through lessons learned from the Company's 2016 RAMP Report, its TY 2019 GRC, and its overall configuration of internal accounting and tracking systems.

Generally, the Company records operations and maintenance (O&M) costs in cost centers and capital expenditures on a budget code basis. This method is not mitigation-focused, but rather is organization-based for O&M and total project-based for capital. The Company presents its GRCs consistent with this approach. Internal labor costs are recorded in this manner and, for the most part, are not tied specifically to mitigation activities. Accordingly, additional granularity is largely unavailable without making a series of assumptions. Therefore, to identify costs for certain RAMP controls related to employee time and associated labor costs, many assumptions are required.

For example, in the 2016 RAMP Report, the Company estimated labor-related costs for controls.[22] To do so, the Company gathered information related to how many employees took a given training class and multiplied that by the duration of the class and an average labor rate.

---

[21] SED RAMP Safety Advisory Report at 6.

[22] California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company Investigation, Lessons Learned (RAMP-F) I.16-10-015 and I.16-10-016 (November 30, 2016) at 2-3.

This estimation method was used because the exact costs are not available in this manner in the Company's accounting systems. However, using this approach became problematic when the Company integrated this assumption-based forecast into the GRC, because the Company then had to similarly estimate the costs in a given cost center or workpaper (a group of one or more cost centers), associated with the internal labor activity.

Based on the foregoing, the Company took a different approach for this RAMP Report. As discussed in Chapter RAMP-A, internal labor for these certain controls (*e.g.*, internal labor to attend training, adhering to internal protocols or standards, internal time spent at meetings, etc.) is generally excluded from the baseline and forecasted cost estimates for Controls and Mitigations in the 2019 RAMP Report. While costs are not identified herein, the activities are discussed since they are associated with mitigating the RAMP risk.

Further, costs presented here are those the Company expects to include in its TY 2022 GRC application, as compared with the 2016 RAMP Report. Costs requested and recovered through regulatory means outside of the GRC, such as separate applications or from the Federal Energy Regulatory Commission (FERC), are generally not identified in the 2019 RAMP Report. While the Company discusses activities that mitigate the risk in an effort to provide a complete risk mitigation plan herein, associated costs for these non-GRC costs are not included herein.

Another lesson learned from its prior RAMP filing is the need to attempt to show activities and corresponding cost forecasts in this 2019 RAMP Report, either within a single risk chapter and/or allocated between risks.[23] In the 2016 RAMP filing, the Company did not attempt to split or apportion the costs of an activity to each risk. Rather, costs for activities that provided risk mitigation across multiple risks were included in all applicable risk chapters.

While the costs may reside within the risk chapter of primary benefit in this RAMP Report, other risk chapters may qualitatively discuss how the activity affects the risk in the chapter receiving the indirect benefit. Alternatively, for some activities, an allocation was determined and the applicable risk chapters each took a portion of the activity and associated cost. For purpose of moving towards probabilistic RSE calculations, the Company aimed to

[23] *Id.* at 3-4.

present costs in a single instance, even though these activities may provide risk mitigation benefits to multiple risks. That said, the Company did include activities and costs on a limited basis in a few risk chapters where the costs could not be attributed to simply one risk. An example includes the Company's safe driving program, which mitigates both the risks of Employee Safety and Customer and Public Safety. It should be noted that although activities and costs may be included in multiple risk chapters, they will only be included once in the GRC. All these cost-related changes between the Company's 2016 RAMP Report and the 2019 RAMP Report are to improve upon prior showing as well as to better align with the presentation of the Company's GRC.

F. Workpapers

SED recommended that in the future "all utilities provide similar information in workpapers as part of their RAMP filings,"[24] and that technical documentation of risk modeling should be provided.[25] The Company followed SED's recommendations and is submitting workpapers for costs and modeling for RSEs concurrently with this RAMP Report. Further, the Company reviewed the workpapers of SCE and followed a similar format for purposes of consistency and ease of review by the Commission and intervenors.

III. LESSONS LEARNED FROM SED'S FEEDBACK ON OTHER IOU RAMP REPORTS

The RAMP Reports of PG&E and SCE further improved upon the Company's first RAMP Report. Both PG&E and SCE provided quantitative models and new value-added aspects. PG&E and SCE utilized the common risk terms of "Controls" and "Mitigations" and made certain determinations based on those distinctions, for purposes of calculating RSEs.

---

[24] SED RAMP Safety Advisory Report at 5.

[25] I.16-10-015/-016 (cons.). Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of San Diego Gas & Electric Company and Southern California Gas Company (March 15, 2017) at 20.

PG&E limited their RSE calculations to Mitigations, rather than also including Controls.[26] SCE performed RSE calculations on non-compliance[27] Controls and Mitigations.

SED's evaluation reports on PG&E's and SCE's RAMP Reports provided information that the Company used to inform aspects of this 2019 RAMP Report. With respect to PG&E, SED "strongly recommend[ed] that PG&E provide MARS [Multi-Attribute Risk Scores] and RSE for all controls on the same basis developed for mitigations for their future RAMP filings"[28] and expressed concerns with PG&E's approach to cross-cutting risk modeling, stating "the cross-cutting model [should be] reviewed within the S-MAP."[29] SED also concluded that PG&E's risk "evolution [] brought additional complexity…[with] refined attempts to illustrate how the components of the analysis fit together."[30] For SCE's RAMP, SED was concerned that SCE submitted two different conflicting proposals in the WMP [Wildfire Mitigation Plan] and RAMP filings.[31]

Based on SED's feedback towards PG&E's and SCE's approaches to calculating RSEs, the Company attempted to perform RSEs on individual programs, regardless of whether they were controls, mitigations, and whether they were mandated or not. However, establishing an appropriate methodology for longstanding mandated activities posed challenges, in many cases. Therefore, the Company performed RSEs on Mitigations, non-mandated Controls, and mandated Controls, where practical. The Company also provides several chapters in this RAMP Report (Chapters RAMP-C, RAMP-D, and RAMP-E) related to RSEs, their underlying assumptions,

---

26 2017 Risk Assessment and Mitigation Phase Report of Pacific Gas and Electric Company (PG&E's RAMP Report) (November 30, 2017) at A-6.

27 SCE defined "compliance" as "currently established measure that is modifying or reducing risks, which is required by law or regulation." SCE Workshop Presentation (December 14, 2018) at 10.

28 California Public Utilities Commission, Risk and Safety Aspects of Risk Assessment and Mitigation Phase Report of Pacific Gas & Electric Company Investigation 17-11-003 (March 30, 2018) at 4.

29 *Id.* at 133.

30 *Id.* at 3.

31 California Public Utilities Commission, Risk and Safety Aspects of Southern California Edison's 2018-2020 General Rate Case Application 16-09-001 (January 31, 2017) at 8.

and an evaluation of RSEs at this stage. These chapters are provided in an effort to clearly explain the determinations on conducting RSEs.

SDG&E also attempted to address the feedback SCE received on its WMP. SDG&E filed its first Wildfire Mitigation Plan in February 2019. In the Wildfire risk chapter in SDG&E's RAMP Report (Chapter SDG&E-1), SDG&E transparently noted if activities therein were also included in SDG&E's 2019 WMP. Further, there have been considerable developments from a regulatory perspective regarding general wildfire risk. For example, the CPUC has initiated several wildfire-related proceedings including but not limited to Rulemaking (R.) 18-10-007 (WMP OIR), R.18-12-005 (De-Energization OIR), and R.19-07-017 (Wildfire Fund OIR). Given the level of activity and potential impacts from other regulatory proceedings, considerable coordination is necessary. It remains unclear as to how these coordinated efforts will be addressed. For example, SDG&E is submitting its RAMP Wildfire chapter in November 2019 and will likely be filing its second WMP in early 2020. However, it is also highly likely that SDG&E will not receive feedback from the CPUC's SED on the Wildfire Risk Mitigation Plan presented herein until after the next WMP is submitted. While these issues with overlap and timing may decrease over time, heavy coordination is needed and takes a considerable effort to confirm alignment.

IV. LESSONS LEARNED THROUGHOUT THE COURSE OF PREPARING THE TY 2022 RAMP REPORT

Through the course of preparing this RAMP Report, the Company identified additional lessons learned for future RAMP submissions. Although many of these must be addressed as longer-term goals, the Company is beginning to plan for such efforts.

A. Scoping of Risks

The Company's risk evaluation and registry process, facilitated by the Enterprise Risk Management organization, continues to evolve. Throughout the RAMP process and as discussed in the workshop held on March 5, 2019, pursuant to the SA Decision (Pre-RAMP Workshop),[32] the scoping and definitions applied in each risk are the foundation for determining how to

[32] D.18-12-014 at Attachment A, A-10 (Risk Selection Process for RAMP).

conduct the required safety, reliability, and financial assessments. Although the Company annually reevaluates its risks through its Enterprise Risk Management process, it also recognizes room for continuous improvement. Accordingly, the Company has reviewed its risks to clarify the scope of each risk for analysis in the RAMP Report, after the Pre-RAMP Workshop. Based on the data used to determine the pre-mitigation risk score, the risk scope for purposes of the RAMP Report may have been refined, as necessary. This is further discussed in Chapter RAMP-C. Going forward, the Company will determine how best to address aligning availability of data and the scoping of the risks in the Enterprise Risk Register (ERR).

B. MAVF

The Company's approach to developing a multi-attribute value function (MAVF) for purposes of RAMP Report analysis is described in Chapter RAMP-C. The Company found it challenging to develop a MAVF, within the requirements of the SA Decision, that is useful for analyzing every activity it performs. Conceptually, a MAVF should be designed to apply to everything from assessing a new billing system, to hydrotesting, to facilities upgrades, to hiring more staff. In reality, this is a substantial and complex undertaking. And, the Company had a limited time to develop, test, and implement a MAVF for purposes of this filing. Accordingly, the Company adhered to the minimum top-level attributes of Safety, Reliability, and Financial in this RAMP Report.[33] However, the Company will continue to learn from experience and refine its MAVF over time.

It may be possible in the future to add complexity to the Safety attribute, perhaps by considering additional lower-level attributes such as illness, lost time of employment, or mental health. Additionally, the Company is aware that some organizations differentiate between safety incidents in some manner, such as incidents that impact employees versus those that impact the general public. The Company did not feel that a consensus was reached on how to differentiate between safety incidents. Future regulatory proceedings and RAMP Reports, including those from other utilities, may help with progress in this area.

---

33 *Id.*

In addition to the attributes presenting challenges, determining scaled units and the relative importance for the MAVF was also difficult. There are available studies that help guide decision-making on the relative importance between certain attributes. For example, as described in Chapter RAMP-C, studies exist that evaluate electric reliability in terms of dollars, the financial attribute. However, doing so would require a determination between reliability, financial, and safety attributes, consistent with the MAVF principles in the SA Decision. A range of potential scaled units were therefore determined for the Safety attribute, demonstrating the Company's belief that there is not one right answer to these questions. Rather, there is a range of potential possibilities that the Company should consider to inform its risk mitigation assessments. The Company believes that direction from the Commission on appropriate weights and scales for presenting risks in the RAMP Report could be helpful in future RAMP filings. The range of scaled units for the Safety attribute is discussed in greater detail in Chapter RAMP-C.

C. Tranches

This is the first RAMP Report to include the concept of tranching. While the Company understood and could identify different risk profiles among its activities, costs were largely not available in that manner. For example, for the risk of a Third Party Dig-in on a High Pressure Pipeline (Chapters SCG-7 and SDG&E-9), mitigations such as the Public Awareness Compliance could potentially have been tranched by geographical areas or demographics.

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing risk of injuries or fatalities to the public, employees, and contractors. Given the vast number of activities SoCalGas performs to mitigate the Third Party Dig-in on a Medium Pressure Pipeline risk, SoCalGas grouped like activities with like risk profiles into mitigation programs. The Company tracks costs for these activities consistent with Title 49 CFR § 192.616, which identifies the following four groups: the affected public, emergency officials, local public officials, and excavators. In order to have identified costs at the tranches for geographical area or demographics, considerable assumptions would have been required; thus, the Company elected to tranche based on the four categories outlined in the code, which are representative of homogeneous risk profiles within this activity. The Company will evaluate how to improve upon this in the future.

D. Data Collection

The Commission identified the need for RAMP filings to include information regarding steps to "improve the collection of data and provide a timeframe for improvement" for business areas with less data, so that "the utilities can position themselves to make major improvements in risk assessment" for later S-MAP filings.[34] Quantitative risk analysis relies heavily on data. Therefore, the ability to locate and use meaningful data will always be in consideration. Although many data sources are available for a wide array of uses, it is common to find data that is not precisely of the type that is desired or needed at a particular point. The Company strives to add new data sources as needs arise and attempts to look ahead to what kind of data will be needed in the future. Throughout the creation of this RAMP Report, several instances arose where data was either unavailable or incomplete. Therefore, the Company used a combination of its own data and national data in this RAMP Report. When national or external data was used, the Company attempted to apply company-specific characteristics and supplemented it with subject matter expertise, consistent with the SA Decision,[35] as explained in Chapter RAMP-A. Although national data was scaled to the characteristics of the Company's system or service territory, the Company will look for ways to further customize the use of national data, going forward.

Where data or metrics do not exist to track the performance of the activities presented in this RAMP Report, the Company seeks to develop such metrics for future applicability. For the Third-Party Dig-ins risk, for example, the Company is examining whether its existing data collection systems allow for the tracking of a more granular locate and mark process, to enable more precise identification of root causes and provide a better understanding of process improvements that may be necessary.

---

34 D.16-08-018 at 146. *See also* Conclusions of Law (COL) at 38.

35 *Id.* at Attachment A, A-8 – A-9 (Identification of Potential Consequences of Risk Event, Identification of the Frequency of the Risk Event).

The Company believes this data is needed to evaluate the program's effectiveness as well as to meet future CPUC reporting requirements. To that end, the Commission and stakeholders have taken several steps to increase transparency and the availability of information. Specifically, the Commission instituted the Safety Performance Metrics Report[36] and the Risk Spending Accountability Report[37] requirements. Both of these reports are due annually on March 31, going forward. The Safety Performance Metrics Report will provide "26 safety performance metrics to measure achieved safety improvements."[38] This report will also summarize "how reported data reflect[s] progress against the risk mitigation and management goals approved in the applicable Risk Assessment Mitigation Phase filing and General Rate Case (GRC) application and to identify and provide additional information for any metrics that may be linked to financial incentives."[39] As part of the efforts related to the Safety Performance Metrics Report, the Company is reviewing available data and is actively participating in the S-MAP Metrics Technical Working Group to refine and develop metrics. Regarding the Risk Spending Accountability Report, the report was established in D.14-12-025 to "improve utility accountability of ratepayer money spent on risk mitigation."[40] In D.19-04-020, the Commission added the requirement to report on work units as part of the Risk Spending Accountability Report.[41] With the requirement of work units, the Company will provide more data in future GRCs and Risk Spending Accountability Reports.

E. Secondary Impacts

As discussed in Chapter RAMP-A, for this RAMP Report, the Company generally excluded secondary impacts from its risk quantification assessments. Secondary impacts are "downstream" of the initial risk event. These impacts are challenging to quantify, as there are

---

36 *See* D.19-04-020.

37 D.14-12-125 as modified by D.19-04-020.

38 D.19-04-020 at 2.

39 *Id.*

40 *See* D.14-12-025.

41 D.19-04-020 at 36, 38-39, Findings of Fact 27 and 28, COL 15, and Ordering Paragraphs 10 and 11.

data limitations and overlaps between multiple risks. The Company will continue collaborating with stakeholders to continue to refine processes and develop improved methodologies for capturing data to support quantifying secondary impacts.

The Office of Safety Advocates (OSA) provided feedback that it would like to see Electric Grid Failure and Restoration (Blackout/Failure to Black Start) included in this RAMP Report. Electric Grid Failure and Restoration is the risk of a blackout or the loss of electric service throughout the SDG&E service territory and the inability to restore electric services. While the Electric Grid Failure and Restoration risk was included in SDG&E's 2018 annual risk registry assessment cycle, it was not selected as a RAMP risk for two reasons. First, OSA's feedback was provided several months after the Company had presented its proposed risks at a public workshop and consequently had made the determination of what risks to include in RAMP. There was not adequate time to conduct the extensive RAMP analysis adopted in the SA Decision. Second, the safety elements of this risk are largely related to secondary impacts. For example, a prolonged outage could be attributed to an extended Public Safety Power Shutoff event. In that scenario, the primary reason for the outage was to minimize the likelihood of a wildfire event. The secondary impact was the prolonged outage for customers.

F. Risk Reduction and RSEs

Estimating risk reduction generally presents various challenges, which also are present in calculating RSEs. These challenges are further discussed in Chapter RAMP-E. A methodology to estimate risk reduction was determined based on available data. This required the Company to evaluate risk reduction and RSEs on a case-by-case basis. The methodology required understanding how the activity impacted the risk and the effectiveness of a certain program. When data was available, less subjectivity was applied. Nevertheless, subject matter expertise is required to derive estimates for risk reduction benefits. Amongst the challenges, assessments of human-based activities, such as training and communicating with the public, were particularly difficult to estimate. As experienced by PG&E in its 2017 RAMP Report (described above), the Company has not identified a precise method of predicting future benefits for human-based activities. It is difficult to estimate how effective training is, because it is frequently difficult to ascertain if one or more risk events were caused by, or prevented due to, training. In some cases, the impact is clear; but in the majority of cases, the conclusions are largely speculative. It is also not easy to surmise the duration for which training is considered effective.

As stated in the Data Collection section above, most RSE calculations required an extensive evaluation of company data. In many cases, the data necessary to support RSE calculations with a high level of confidence was often unavailable (*i.e.*, data was not currently collected) and/or difficult to find and obtain. This process required a high level of involvement of entire teams of individuals from across the organization, which was the case among all the risk chapters. As a result of these considerations, the RSE process was lengthier than initially predicted. This process, however, has identified opportunities for the Company to improve data collection and aggregation, which will support better business operations and make data readily available for future RAMP filings.

Risk Assessment Mitigation Phase

(Chapter SDG&E-1)

Wildfires Involving SDG&E Equipment

November 27, 2019

TABLE OF CONTENTS

Risk: Wildfire

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan of San Diego Gas & Electric Company (SDG&E or Company) for Wildfire risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021, and 2022 as a three-year total; whereas, operations and maintenance (O&M) costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Wildfire risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order (GO). Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

SDG&E's Wildfire risk is defined as the risk of wildfire, especially those initiated by SDG&E equipment, resulting in injuries or fatalities, widespread property destruction, and a multibillion-dollar liability.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[3] for each Control and Mitigation presented herein, SDG&E has identified the element(s) of the Risk Bow Tie that the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequences
DT.1	Downed Conductor
DT.2	General Equipment Failure
DT.3	Weather-Related Failure of SDG&E Equipment
DT.4	Contact by Foreign Object
DT.5	Failure of Third-Party Attachments
DT.6	Vegetation Contact
DT.7	Not Observing Operational Procedures
DT.8	Extreme Force of Nature Events
DT.9	Lack of Internal or External Coordinated Response
DT.10	Climate Change Adaptation Impacts on Wildfires Caused by SDG&E Equipment
PC.1	Serious injuries[4] and/or fatalities
PC.2	Damage to third party real and personal property
PC.3	Damage and loss of SDG&E assets and facilities
PC.4	Operational and reliability
PC.5	Claims and Litigation
PC.6	Erosion of public confidence

---

3 *Id.* at Attachment A, A-11 ("Bow Tie").

4 A "serious injury" is defined in the California Code of Regulations as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) Section (§) 330(h).

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SDG&E has performed a detailed pre- and post-mitigation analysis of Controls and Mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E identified baseline controls, which are expected to continue, and proposes additional projects and/or programs (*i.e.*, mitigations) for this risk as follows:

Table 2: Summary of Controls and Mitigations

ID	Control/Mitigation Name
SDG&E-1-C1	Operating Conditions
SDG&E-1-C2	Recloser Protocols
SDG&E-1-C3	Other Special Work Procedures
SDG&E-1-C4	Distribution System Inspections – Corrective Maintenance Program
SDG&E-1-C5	Distribution System Inspections – Quality Assurance/Quality Control
SDG&E-1-M1	Distribution System Inspections – Infrared/Corona
SDG&E-1-M2	Distribution System Inspections – Drone Inspections
SDG&E-1-M3	Distribution System Inspections – Circuit Ownership
SDG&E-1-C6	Substation System Inspections
SDG&E-1-C7	Transmission System Inspections
SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)
SDG&E-1-M4	Strategic Undergrounding
SDG&E-1-C9	Cleveland National Forest Fire-Hardening
SDG&E-1-C10 / M5	Fire Risk Mitigation
SDG&E-1-C11 / M6	Pole Risk Mitigation and Engineering
SDG&E-1-M7	Expulsion Fuse Replacement
SDG&E-1-M8	Hotline Clamps
SDG&E-1-C12 / M9	Wire Safety Enhancement
SDG&E-1-M10	Covered Conductor
SDG&E-1-C13 / M11	Fire Threat Zone Advanced Protection
SDG&E-1-M12	LTE Communication Network
SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements
SDG&E-1-C14 / M14	Replacement and Reinforcement
SDG&E-1-M15	Backup Power for Resilience – Generator Grant, Critical Infrastructure, and HPWREN
SDG&E-1-M16	Backup Power for Resilience – Microgrids
SDG&E-1-M17	Lightning Arrester Removal/Replacement Program

[5] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

ID	Control/Mitigation Name
SDG&E-1-M18	SCADA Capacitors
SDG&E-1-C15	Tree Trimming
SDG&E-1-C16	Pole Brushing
SDG&E-1-M19	Enhanced Vegetation Management
SDG&E-1-M20	Fuel Management Program
SDG&E-1-C17	Fire Science & Climate Adaptation Department
SDG&E-1-C18 / M21	Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements
SDG&E-1-C19 / M22	Camera Networks and Advanced Weather Station Integration
SDG&E-1-C20 / M23	High-Performance Computing Infrastructure
SDG&E-1-M24	Ignition Management Program
SDG&E-1-C21/M25	Asset Management
SDG&E-1-M26	Monitoring and Correcting Deficiencies
SDG&E-1-M27	Wildfire Mitigation Personnel
SDG&E-1-M28	NMS Situational Awareness Upgrades
SDG&E-1-M29	Situational Awareness Dashboard
SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols
SDG&E-1-C23 / M30	Communication Practices
SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols
SDG&E-1-C25 / M31	Emergency Management Operations
SDG&E-1-C26	Disaster and Emergency Preparedness Plan
SDG&E-1-C27	Customer Support in Emergencies
SDG&E-1-C28 / M32	Wildfire Infrastructure Protection Teams (Contract Fire Resources)
SDG&E-1-C29 / M33	Aviation Firefighting Program
SDG&E-1-C30	Industrial Fire Brigade
SDG&E-1-C31 / M34	Wireless Fault Indicators

Finally, pursuant to the SA Decision,[6] Section VIII presents alternatives to the mitigation plan for the Wildfire risk that were considered and summarizes the reasons that the alternatives were not included in the mitigation plan.

II. RISK OVERVIEW

The 2018 enactment of Senate Bill (SB) 901 requires SDG&E to submit an annual wildfire mitigation plan (WMP) to provide comprehensive information on SDG&E's efforts to

---

[6] *Id.* at 33.

mitigate wildfire risk.[7] In its Order Instituting Rulemaking (OIR) to implement the WMP provisions of SB 901, the Commission recognized the urgency and severity of the wildfire risk in California, stating:

> Devastating wildfires have become a regular occurrence in California . . . wildfires have grown larger and more intense over the last several decades, resulting in loss of life and property, ecological devastation, increases in future fire risk, and significant greenhouse gas emissions.[8]

On February 6, 2019, SDG&E submitted its first WMP pursuant to SB 901, which the Commission subsequently approved in D.19-05-039. SDG&E's 2019 WMP explains, as reiterated herein, that the catastrophic wildfires that devastated San Diego County in 2007 have resulted in enduring and lasting changes throughout SDG&E's operations, systems, facilities, organization, goals, and objectives. Since 2007, SDG&E has built a Company-wide focus on addressing and minimizing wildfire-related risks, such that wildfire safety, prevention, mitigation, and recovery are top priorities for SDG&E. SDG&E is now considered a leader in proactively addressing fire threats in the communities it serves.

SDG&E's business strategies and programs continue to evolve to reflect a risk-informed approach, wherein wildfire is identified as a key safety risk for the Company. SDG&E performs a broad range of activities, subject to the direct supervision of senior management, related to fire prevention and mitigation. Such mitigation efforts include operational and engineering practices, inspections, system hardening, vegetation management, situational awareness, public safety power shutoff (PSPS), emergency preparedness and response, and customer outreach and public awareness. SDG&E shares its personnel, resources, information, communications facilities, and fire-defense assets to help enhance the capabilities of local communities to defend against any recurrences of catastrophic wildfire events in Southern California. In coordination with many stakeholders, community leaders and the public, SDG&E shares and discusses, both formally and informally, its methods, programs and mitigation efforts with interested parties. This helps

7 The initial requirement to submit annual wildfire mitigation plans was set forth in SB 901, California Public Utilities (P.U.) Code § 8386(b). This P.U. Code section was subsequently amended by Assembly Bill (AB) 1054.

8 Rulemaking (R.) 18-10-007, Order Instituting Rulemaking (October 25, 2018) at 1-2.

to foster continuous improvement and maximize effectiveness. This outreach provides a platform for better coordination and idea sharing among emergency and first responder groups as well as local officials and cities and counties that are located within SDG&E's service territory.

More recently, on July 11, 2019,[9] the California State Legislature passed an urgency bill to address wildfire risk, AB 1054, which was signed into law by Governor Newsom on July 12, 2019 and became effective immediately. In AB 1054, the California Legislature stated that "[t]he increased risk of catastrophic wildfires poses an immediate threat to communities and properties throughout the state."[10] They further acknowledged that "[t]he state has dramatically increased investment in wildfire prevention and response, which must be matched by increased efforts of the electrical corporations,"[11] and "[t]he state's electrical corporations must invest in hardening of the state's electrical infrastructure and vegetation management to reduce the risk of catastrophic wildfire."[12] Specifically, the Legislature requires each electrical corporation, such as SDG&E, to "construct, maintain, and operate its electrical lines and equipment in a manner that will minimize the risk of catastrophic wildfire posed by those electrical lines and equipment"[13] as well as to "annually prepare and submit a wildfire mitigation plan…"[14] The mandates of AB 1054 are consistent with SDG&E's continually evolving efforts to manage and mitigate the threat of wildfire risk since 2007.

While SDG&E will be submitting WMPs pursuant to P.U. Code § 8386(b), SDG&E puts forth a mitigation plan for its Wildfire risk herein in compliance with D.18-12-014, D.16-08-018, and D.14-12-025. The mitigation plan presented in this Chapter began with SDG&E's 2019 WMP and has been updated to reflect new programs and strategies anticipated in 2020 through

9 AB 1054, Stats. 2019-2020, Ch. 79 (Cal. 2019).

10 *Id.* at § 1(a)(1).

11 *Id.* at § 2(a).

12 *Id.* at § 2(b).

13 P.U. Code § 8386(a), as modified by AB 1054.

14 *Id.* at § 8386(b), as modified by AB 1054.

2022, consistent with SDG&E's TY 2022 GRC. Any updates put forth herein will also be reflected in future WMP filings.

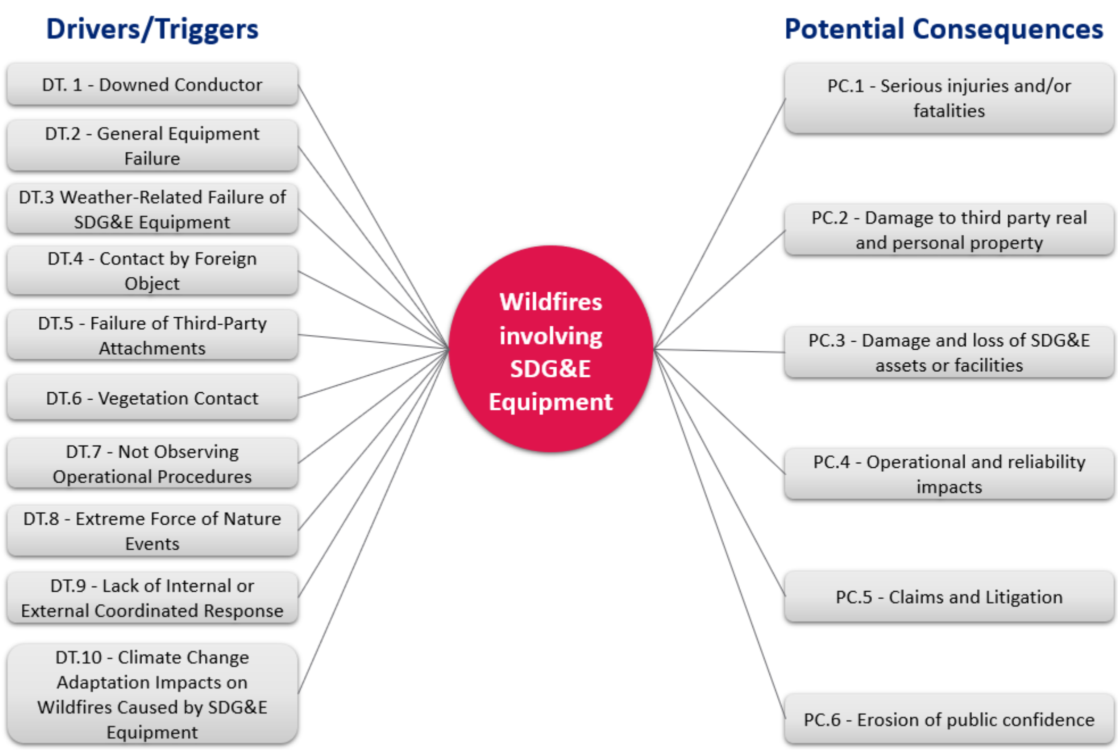
III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Wildfire risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.[16]

Figure 1: Risk Bow Tie



---

15 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

16 *Id.* at Attachment A, A-11 ("Bow Tie").

B. Asset Groups or Systems Subject to the Risk

The SA Decision[17] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. These assets include:

- Substation – comprises the substation asset infrastructure system, which includes transformers, breakers, batteries, relays, capacitors, disconnect switches, and associated auxiliary equipment.
- Transmission Overhead (TO) – comprises the overhead transmission asset infrastructure system, which includes conductors or wires, pole structures, lattice towers, insulators, switches, and associated auxiliary equipment.
- Distribution Overhead (DO) – comprises the overhead distribution asset infrastructure system, which includes conductors or wires, pole structures, transformers, switches, capacitors, and associated auxiliary equipment.
- Operational Technology (OT) – comprises the auxiliary control system or network to the electric assets that process operational data, which includes telecommunications, energy management systems (EMS), remote supervisory control and data acquisition (SCADA), and advanced technologies (microprocessor-based relays with synchrophasor/phasor measurement unit (PMU) capabilities, real-time automation controllers, auto-sectionalizing equipment, line monitors, direct fiber lines, and wireless communication radios).

C. Risk Event Associated with the Risk

The SA Decision[18] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the Risk Bow Tie in Figure 1 above, the risk event (center of the bow tie) is a wildfire involving SDG&E's equipment that results in any of the Potential Consequences listed on the right. SDG&E strives to reduce or eliminate potential sources of ignition coming from its facilities, especially at times of peak weather when a small ignition can

---

17 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

18 *Id.* at Attachment A, A-11 ("Bow Tie").

turn into a catastrophic wildfire. Accordingly, while the activities discussed herein primarily address instances where SDG&E equipment was associated with an ignition, some of the activities may help all wildfires, even if SDG&E is found to not be the contributing cause. For example, SDG&E's response activities, including aviation assets, would help mitigate a wildfire in SDG&E's service territory regardless of the cause or ignition source. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[19]

The SA Decision[20] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Wildfire, SDG&E identified potential leading indicators, referred to as Drivers or Triggers (DT). These include, but are not limited to:

- **DT.1 – Downed Conductor:** A downed conductor (or "wire down") occurs when a conductor drops or breaks from its designed location on a pole and cross arm and ends up on the ground, sometimes in an energized mode. A wire down can result from a variety of factors, many of which are outside of SDG&E's control.
- **DT.2 – General Equipment Failure:** Electric equipment failure can be a source of a downed conductor or ignition. Failure of components such as connectors, hot line clamps, and insulators can result in wire failure and end up in a wire down situation, sometimes in the energized mode.
- **DT.3 – Weather-Related Failure of SDG&E Equipment:** Weather plays a large part in the potential failure of SDG&E equipment. Excessive wind, lightning, and exposure to weather over time can degrade the integrity of the electrical components and lead to failure of one or more of the electrical parts causing a failure of the conductor.

[19] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[20] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.4 – Contact by Foreign Object:** Foreign objects coming into contact with SDG&E's facilities can also present sources of ignition. For example, Mylar balloons are highly conductive and can cause phase-to-phase faulting, on contact. In the worst-case this can cause the conductor to fail and land in an energized mode, causing arcing and sparking in dry conditions. In addition, vehicular contact can bring down conductors, and sometimes the entire pole, resulting in conductors laying on the ground in an energized mode.
- **DT.5 – Failure of Third-Party Attachments:** As mandated by the CPUC, SDG&E must allow communication infrastructure providers to attach to utility poles when space is available. These providers may not properly install or inspect their equipment. This has led to contact of these attachments with the electrical facilities, leading to fire-related incidents.
- **DT.6 – Vegetation Contact:** During storms and severe wind events, branches are shed by trees in the vicinity of SDG&E facilities. These can fall on conductors, leading to conductor failure or, in the case of palm fronds, phase-to-phase contact and a cascade of sparks. In addition, trees that are many feet away from an energized conductor sometimes uproot and fall on the conductor, causing failure or sparking.
- **DT.7 – Not Observing Operational Procedures:** SDG&E revises its protocols and procedures based on certain conditions. For example, during fire weather watch or red flag warnings, SDG&E and its contractors may not perform welding or other activities that may generate potential ignition sources. If an employee or contractor does not adhere to the operational procedure, it may cause an adverse consequence.
- **DT.8 – Extreme Force of Nature Events:** SDG&E's overhead electrical facilities are fully exposed to the elements. Significant weather and wind-related events can cause a variety of problems related to equipment failure and downed conductors. Also, continual exposure to natural elements can

degrade or weaken key components, conditions that may not be found until the following scheduled inspection and repair cycle.

- **DT.9 – Lack of Internal or External Coordinated Response:** A well-coordinated response to a downed conductor aids in the suppression of a fire as well as the de-energization of the conductor in a safe manner. Lack of coordination could lead to uncontrolled fire, electrical exposure to first responders, and possibly injury or death.
- **DT.10 – Climate Change Adaptation Impacts on Wildfires Caused By SDG&E Equipment:** Despite SDG&E's proactive approach to mitigating fire risk, increases in temperature and prolonged periods of drought in the decades to come will likely lead to high risk fire areas expanding from the foothills and mountains into the lower elevation coastal canyons and wildland interfaces that were previously considered at lower risk for fire growth. Prolonged periods of drought will also likely result in a longer wildfire season, potentially extending the focus of our threat monitoring and potential response from the fall months to year-round – with the greatest increased threat in the spring and summer months. These climate trends have already been realized across the region, culminating in a previously unseen wildfire outbreak across coastal San Diego County in May of 2014. In response to increased wildfire activity, SDG&E has year-round availability of an Erickson Skycrane helitanker (Skycrane) that can immediately address ignitions under high wildfire threat conditions. The Skycrane holds a maximum of 2,650 gallons of water and can be airborne in just 15 minutes, to mitigate the impact of a potentially fast-moving fire. SDG&E also leases a Blackhawk helicopter to assist in construction of wildfire mitigation projects but can also assist in putting out fires with the capability of holding 850 gallons of water. Based upon the most recent climate science, these trends are likely to continue and worsen into the future.

E. Potential Consequences

If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences (PC), in a reasonable worst-case scenario, could include:

- Serious injuries and/or fatalities;
- Damage to third party real and personal property;
- Damage and loss of SDG&E assets or facilities;
- Operational and reliability impacts;
- Claims and Litigation; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of SDG&E's wildfire risk that occurred during the development of SDG&E's 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[21] including enhancements to the Interim Decision D.16-08-018.[22] SDG&E has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework that underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 3: Pre-Mitigation Analysis Risk Quantification Scores[23]

Wildfire	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	5493	**7215**	10085
LoRE		**30**	

[21] *Id.* at Attachment A.

[22] *Id.* at 2-3.

[23] The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

CoRE	183	**241**	336

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[24] The section below provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 4: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of wildfires that meet the CPUC Fire Incident Data Collection requirement for wildfire reporting. A wildfire must be reported if all three of the following criteria are met: • A self-propagating fire of material other than electrical and/or communication facilities; • The resulting fire traveled greater than one linear meter from the ignition point; and • The utility has knowledge that the fire occurred.[25]
Out-of-Scope for purposes of risk quantification:	Wildfires that do not meet the CPUC Fire Incident Data Collection requirement for wildfire reporting are excluded from this analysis.

Step 2A of the SA Decision requires a utility to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data).[26] SDG&E's safety risk assessment primarily utilized historical data provided by the California Department of Forestry and Fire Protection (CAL FIRE), which has various resources useful for analysis. A notable resource used from CAL FIRE are known as "Redbooks," which are published annually and provide fire names, cause of fire, acres burned, structures burned, and human safety information for each fire. The data from the Redbooks is also summarized by

24 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

25 California Public Utilities Commission, *2014-2016 Fire Incident Data Collection, available at* https://www.cpuc.ca.gov/fireincidentsdata/.

26 D.18-12-014 at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

County and Region. CAL FIRE also provides maps and Geographic Information Systems (GIS) data at their Fire and Resource Assessment Program (FRAP) website.[27] GIS files provide the key element of the geographic location of each fire in CAL FIRE's records, and therefore can be used to analyze fires based on location-specific characteristics such as vegetation class or weather patterns. CAL FIRE's incident reports are also valuable because they provide additional facts about events. For example, CAL FIRE's incident page discussing the Sawday fire, which occurred in San Diego in 2019, has information regarding the ignition location and links to situational updates.[28]

Other data sources used to estimate wildfire risks are web-based news articles that discuss the facts surrounding wildfire events. Although the CAL FIRE Redbooks have fire-related facts, web-based news articles can help explain the events with more details, such as the type of structures destroyed, the extent of injuries, or the estimated cost of the event.

Regarding financial losses, it is difficult to determine the precise cost of wildfire events. Different groups have different points of view on costs and may not always include all considerations. Wildfire events primarily can have costs resulting from the following: a) property damage, b) personal injury or fatality, c) suppression costs, d) environmental damage and remediation, e) lost economic output from various reasons (including work closures and employee unavailability), and f) personal relocation due to evacuations. There is no known single source for all financial impacts from wildfire. SDG&E used available data to approximate financial impacts.

B. Sources of Input

The SA Decision[29] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The following provides an explanation of how likelihoods and consequences from wildfire risk were estimated. Wildfire risk is unique among the risks presented in the RAMP Report, because: a) it has an extremely wide range of impacts (*i.e.*, some

---

27 California Department of Forestry and Fire Protection, *available at* https://frap.fire.ca.gov/.

28 California Department of Forestry and Fire Protection, *Status Updates, available at* https://www.fire.ca.gov/incidents/2019/10/25/sawday-fire/.

29 D.18-12-014 at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

fires have no impacts while others cause serious injury and billions of dollars of damage); b) it is situationally dependent on many changing factors (*i.e.*, weather, vegetation), c) drivers to the risk are frequently outside a utility's control (*e.g.*, animal, human, and plant contacts), and d) significant impacts are rare, which leads to low-confidence estimations regarding future risk.

An outline of how the Wildfire risk was modeled and then used for the RAMP Report is outlined in the following steps:

- Data Gathering: Historical data was used as a starting point for consideration of likelihoods. Data considered was both from reportable ignitions (since 2014) and from large fire history (since 1970) reported, for example, by CAL FIRE, and described in detail above.
- Changes from historic likelihood: Changes were considered from the historic likelihood of fires. Changes from historic likelihoods are primarily due to: a) system hardening programs, including PSPS, that have been undertaken during the timeframe used (to elaborate, the timeframe used for analysis was between 1970 and 2018, and system hardening programs began in earnest in 2008); b) climate change; c) increased overhead miles relative to previous timeframes; and d) change in vegetation relative to previous timeframes. Because each of these changes are not precisely known, models were used to estimate the actual range of current likelihoods, with 10,000 estimates stored for use in the next step.
- Modeling of Consequences: Consequences were also modeled by using historical fires to create or "fit" a probability distribution from large fires considering financial loss. The probability distribution is SDG&E's estimation of the types of financial losses that may occur if a large utility-associated wildfire occurs. The probability distribution is not a precise statistical forecast, but it is a useful estimation for wildfire risk discussions. The probability distribution that is currently used is not permanent and will be modified as new information becomes available.

- <u>Monte Carlo Simulation</u>: In Microsoft Excel, Monte Carlo modeling was performed to identify the likelihood and consequence of large fires, using the following approach:
    - 10,000 runs, which simulate individual years, were performed.
    - 10,000 probabilities, one for each run, were created based upon the likelihood information addressed above. During each run, a random number was generated and used to compare between it and the likelihood stored for that run. If the random number is smaller than the likelihood value, the model assumes that a large wildfire occurred during that run. The average of the likelihood values used in this step is approximately 0.069, which indicates that at least one large wildfire will occur in one out of every 15 years. Some of the years that have at least one large wildfire will have multiple large wildfires in that year. The total number of large wildfires that the model produced was 935 over 10,000 runs.
    - If a large wildfire was modeled to occur, a method to determine the number of wildfires that occurred during that run was undertaken. That method created a random value drawn from the Poisson distribution with the parameter of 1 (*i.e.* $\lambda(1)$). The maximum value between that random draw and the number 1 was then used to represent the number of large wildfires that occurred during that run.
    - Depending on the number of wildfires to run (as determined in the previous step) the consequence probability distribution was then used for sampling. The sum of the sampled values was used for the financial consequence for the run and stored for further analysis.
    - Most runs returned $0 due to the fact that large fires are modeled to occur approximately once every 15 years. In the runs where a large wildfire was modeled to occur, the average financial consequence was approximately $3 billion.
    - The output from the Monte Carlo modeling was then tabulated and put into a format to be analyzed.

- <u>Meeting the SA Decision's Requirements</u>: For the RAMP Report to meet the requirements of the SA Decision,[30] aspects of the Monte Carlo output were utilized. The following steps were undertaken to meet the SA Decision's requirements:
    - Because the scope of the Wildfire risk in the RAMP Report includes all CPUC-reportable fires, and not solely large destructive fires, an adjustment was made from the other internal modeling. For purposes of the RAMP, the LoRE is set to the recent history of SDG&E's CPUC reportable fires, which is approximately 30. Because the total number of modeled large fires was 935 out of 10,000 runs, and 30 reportable fires of all sizes occur each year, this data estimates that one out of every approximately 320 reportable wildfires will be a large destructive fire.
    - CoRE was partially calculated from the Monte Carlo modeling by extracting the expected values of the output consequences. This was done differently for each attribute:
        - <u>Financial</u>: The expected value of all Monte Carlo outputs was determined to be $225 million.
        - <u>Reliability</u>: Data was extracted from SDG&E's internal reliability database for fire-related outages to determine reliability impacts.
        - <u>Safety</u>: Due to the large uncertainty around safety during wildfires, a rule of thumb was applied to the financial data. Based on subject matter interpretation of historical data, for each $1 billion loss due to wildfire, it was assumed that 4.25 safety units would occur. This ratio was applied to the Monte Carlo output, producing an expected value of 0.96 safety units per year.

---

[30] D.18-12-014 at Attachment A, A-11 ("Calculation of Risk"). Chapter RAMP-C of this Report describes the quantitative framework applied to this Wildfire risk chapter.

- CoRE Output: These obtained values were then used as inputs the Risk Quantification Framework to determine the CoRE value of 241.

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[31] This section describes SDG&E's Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SDG&E's Wildfire risk is defined as the risk of a wildfire, initiated by SDG&E equipment, resulting in fatalities, widespread property destruction, and a multibillion-dollar liability. To mitigate, minimize, and manage this risk, SDG&E takes a multi-layered approach designed to defend against single point of failure. In other words, SDG&E does not rely on one mitigation strategy in its service territory; rather, it strategically performs a variety of activities to prevent wildfires. For example, SDG&E inspects and remediates vulnerabilities on its system, while at the same time performing vegetation management activities, hardening infrastructure, and (as a last resort will de-energizing customers for safety (PSPS), if deemed necessary.

To accomplish this, SDG&E employs a three-pronged approach, integrating efforts in:

- **Operations and Engineering** – how SDG&E builds, operates and maintains its electric system to be fire-hardened;
- **Situational Awareness and Weather Technology** – focuses on SDG&E's ability to monitor and understand the fire environment; and
- **Customer Outreach and Education** – concentrates on communication and collaboration with regional stakeholders and customers.

This three-pronged approach involves programs and strategies that allow SDG&E to better understand the Wildfire risk, fire risk conditions, and fire behaviors to provide the Company and its customers with time and information to take appropriate action. For example, it allows SDG&E to construct, maintain, and operate a fire-hardened electric distribution and

[31] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

transmission system in a manner that minimizes the possibility of igniting a fire. It also allows SDG&E to educate customers and stakeholders on the Wildfire risk as well as support customers affected by it.

SDG&E's Risk Mitigation Plan includes the whole of SDG&E's wildfire-related programs and strategies, taken together. The Risk Mitigation Plan discussed below includes both controls that are expected to continue and mitigations for the period of SDG&E's TY 2022 GRC cycle.[32] The controls are those activities that address this risk and were in place as of 2018, most of which have been developed over many years, to address this risk and including work to comply with laws that were in effect at that time.

Consistent with the presentation in its 2019 WMP,[33] SDG&E presents its Risk Mitigation Plan herein in the following categories, each of which are further described below:

- Operations and Engineering;
- Inspections;
- System Hardening;
- Vegetation Management;
- Situational Awareness and Asset Prioritization;
- Public Safety Power Shutoff; and
- Preparedness and Response.

In an effort for continuous improvement, SDG&E has revisited the above-mentioned categories and enhanced them where appropriate. For example, SDG&E has modified the category of "Situational Awareness" as presented in the 2019 WMP to "Situational Awareness and Asset Prioritization." The change to this category better aligns with how SDG&E uses situational awareness, and its tools, for planning and prioritization. Additionally, some of the activities have been re-assigned to different categories, where appropriate. An example is the

---

32 *Id.* at 33. A "Control" is defined as a "[c]urrently established measure that is modifying risk." *Id.* at 16. A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event." *Id.* at 17.

33 *See* R.18-10-007, Administrative Law Judge's Ruling on Wildfire Mitigation Plan Template, and Adding Additional Parties as Respondents (January 17, 2019) at Attachment A.

aviation programs are now included in the category of Preparedness and Response, rather than in the Operations and Engineering category.

In addition, there are recent events that may change the quantity and timing of certain fire hardening mitigation strategies presented in this RAMP Chapter. Based on statewide lessons learned from October 2019 PSPS events, SDG&E is currently evaluating the possibility of mitigating PSPS customer impacts on a circuit-by-circuit basis, to include a combination of undergrounding, covered conductor, remote sectionalizing, system hardening, and backup generation. Any significant changes in program scopes, costs, and RSE calculations will be updated in SDG&E's upcoming Wildfire Mitigation Plan and GRC filings.

A. Operations and Engineering

1. SDG&E-1-C1 – Operating Conditions

As described in the 2019 WMP,[34] SDG&E monitors the potential for wildfires throughout its service territory daily and adjusts its operating behaviors accordingly, using its situational awareness capabilities and a formalized escalation approach.[35] It is in part this information that allows SDG&E to be flexible and successful in its operations. As conditions for wildfires increase, SDG&E can deploy additional layers of safeguards, or, as a last resort, it might be required to de-energize certain areas of its service territory in the interest of public safety.

SDG&E uses a variety of inputs to determine the appropriate operating environment given current and expected wildfire conditions. These tools are used for operational decision-making so that SDG&E personnel can plan and prepare. Among these inputs for situational awareness are the Fire Potential Index (FPI) and Santa Ana Wildfire Threat Index (SAWTI). These are briefly summarized below and are discussed in greater detail in activity SDG&E-1-C17 below.

---

[34] R.18-10-007, San Diego Gas & Electric Company's Wildfire Mitigation Plan (February 6, 2019) ("SDG&E's 2019 WMP") at Attachment A, pp. 20-21 and 52.

[35] Costs were not identified for this activity because it is embedded in internal labor. A Risk Spend Efficiency calculation is therefore not being performed.

- **Fire Potential Index:** a daily detailed and rolling seven-day forecast prepared by SDG&E of weather conditions relevant to SDG&E's operations.
- **Santa Ana Wildfire Threat Index:** a web-based tool, developed in a public/private collaboration, that classifies the wildfire threat potential associated with the Santa Ana winds. The SAWTI is updated daily by the United States Forest Service (U.S. Forest Service) Geographic Area Coordination Center. They generate a six-day forecast of large wildfire potential, which will result in one of four classification levels from "marginal" to "extreme."

Another tool is field observations. SDG&E strategically positions field personnel throughout its service territory based on system conditions, weather, and wildfire potential, which may be considered a threat to SDG&E facilities. Field observers inform operational decisions by providing real-time input regarding onsite conditions, such as debris, vegetation, and system conditions.

SDG&E established Operating Conditions to monitor wildfire potential and, among other things, inform decisions regarding recloser settings, sensitive relay settings, testing procedures, and work restrictions. These Operating Conditions are: Normal Condition, Elevated Condition, Extreme and Red Flag Warning (RFW) Condition. Each are summarized below:

- Normal Condition (FPI forecast is in the range of 1 through 11): declared when SDG&E determines that the burn environment is not conducive for wildfires within its service territory.
- Elevated Condition (FPI forecast is in the range of 12 to 14): declared when SDG&E determines that the burn environment has become conducive to wildfires within its service territory.
- Extreme and RFW Conditions (FPI forecast is 15 or above): declared when SDG&E determines that a combination of high winds, low relative humidity, and the burn environment will create critical wildfire weather conditions in its service territory.

These Operating Conditions inform how SDG&E operates the system impacting its recloser protocols, restrictions on the type of work being performed in high risk locations, and the use of contract firefighting resources.

2. SDG&E-1-C2 – Recloser Protocols

Consistent with the description in the 2019 WMP,[36] SDG&E previously completed a large deployment of overhead distribution reclosers, focusing heavily on the High Fire Threat District (HFTD).[37] A recloser is a switching device that is designed to detect and interrupt momentary faults. The device has the ability to reclose automatically and open back up if a fault is still detected. The automated reclosing feature can be disabled, so if a device detects a fault it will trip open and remain open and minimize the potential for an ignition. These overhead distribution reclosers allow SDG&E to operate its system in a variety of configurations depending on input from its meteorologists, known localized conditions, and its declared operating condition (please refer to discussion above in control SDG&E-1-C1 – Operating Conditions). They also provide SDG&E the ability to sectionalize various elements of its distribution system to efficiently manage system operations and reliability, which results in quicker restoration times for customers. Additionally, SDG&E has associated these remote supervisory control and data acquisition (SCADA) controlled sectionalizing devices with specific wind anemometer locations, allowing for targeted applications of the Public Safety Power Shutoff (PSPS) to the areas that pose the most significant real-time system condition risk of wildfire.

Under Normal Conditions, overhead distribution reclosers operate to clear faults by isolating the fewest number of customers while reducing overall exposure to the electric system. Under Elevated Conditions or higher and now most of the year, all distribution reclosing functions are disabled on circuits located within the HFTD but may include other circuits if the burn environment is conducive to large wildfires. This is done so that if a fault occurs on the

---

36 SDG&E's 2019 WMP at Attachment A, pp. 21-22.

37 The program of Automated Reclosers discussed in SDG&E's 2019 WMP is included in this control given that these reclosers were installed beyond the period of this rate case cycle (*i.e.*, the last five years) pursuant to the Rate Case Plan. Additionally, costs were not identified for this activity because it is embedded in internal labor. A Risk Spend Efficiency calculation is therefore not being performed.

system, the recloser automatically opens and stays open so the fault only occurs once and is not closed, creating another opportunity for a potential ignition. Disabling reclosing functions is not optimal for reliability but is performed for public safety and wildfire risk reduction when weather conditions are elevated or higher. In addition to disabling the reclosing function, SDG&E has seen a need to make overhead distribution reclosers operate faster and with greater sensitivity to clear faults in a manner that reduces the energy of the fault as much as possible. By reducing the resultant energy of a fault, the probability of causing significant damage to the surrounding area is reduced. Because of this need, SDG&E has developed the ability to enable more sensitive relay settings on overhead distribution reclosers. These sensitive relay settings improve both the sensitivity of fault detection and the speed at which faults are cleared.

3. SDG&E-1-C3 – Other Special Work Procedures

As described in the 2019 WMP,[38] SDG&E has designated the type of work activity that can be performed for each of the Operating Conditions discussed above in the control SDG&E-1-C1 – Operating Conditions.[39] As conditions increase in severity, work activities may still be performed, but some might have additional mitigation requirements. In other situations, work activity might cease. The following summarizes the work activity guidelines for each Operating Condition:

- Normal Condition: normal operating procedures are followed with baseline tools and equipment.
- Elevated Condition: certain work activities may require additional mitigation measures in order to proceed with work. The additional mitigation measures will be documented.
- Extreme or RFW Condition: most overhead work activities will cease, except where not performing the work would create a greater risk than doing so. In those cases where work needs to be performed, an SDG&E Fire Coordinator is consulted, and any required additional mitigation steps

---

38 SDG&E's 2019 WMP at Attachment A, pp. 22-23.

39 Costs were not identified for this activity because it is embedded in internal labor. A Risk Spend Efficiency calculation is therefore not being performed.

are implemented. Status of work, ceased or continued, will be documented.

These guidelines are generally sufficient for most routine types of activities performed in the wildland areas, which consist of undeveloped areas covered in native vegetation. For non-routine, or especially hazard work, SDG&E's Fire Coordination group is consulted to determine whether additional mitigation requirements are needed.

B. Inspections

1. SDG&E-1-C4 – Distribution System Inspections – Corrective Maintenance Program

As described in the 2019 WMP,[40] Commission General Order 165 requires SDG&E to perform a service territory-wide inspection of its electric distribution system, which is referred to as the Corrective Maintenance Program (CMP).[41] GO 165 establishes inspection cycles and record-keeping requirements for utility distribution equipment. In general, utilities must patrol their systems once a year in urban areas and in HFTD Tier 2 and Tier 3. Patrols in rural areas outside of HFTD Tier 2 and Tier 3 are required to be performed once every two years. However, as a long-standing practice, SDG&E performs patrols in all areas on an annual basis. In addition to the patrols, utilities must conduct detailed inspections at a minimum every 3-5 years, depending on the type of equipment. For detailed inspections, the utilities' records must specify the condition of inspected equipment, any problems found, and a scheduled date for corrective action. Utilities are also required to perform intrusive inspections of distribution wood poles depending on the age and condition of the pole and prior inspection history.

CMP helps to mitigate the Wildfire risk by providing SDG&E additional information about its electric distribution system, including in the HFTD. With this information, SDG&E's corrective actions address infractions before a potential issue can occur.

Upon completion of prescribed actions necessitated by the CMP inspections, SDG&E conducts an audit to ascertain the effectiveness of the inspections. This audit is managed by

---

40 SDG&E's 2019 WMP at Attachment A, pp. 25-26.

41 A Risk Spend Efficiency calculation is not being performed on this activity because it is mandated pursuant to GO 165.

SDG&E's operational and engineering managers, who are responsible for certain districts. They typically select about 1.5% of the combined (overhead and underground) territories and assess their conditions to see if the appropriate improvements have been properly carried out.

Because CMP is performed throughout SDG&E's service territory, for purposes of SDG&E's RAMP showing, this control has been split between SDG&E's Wildfire and Electric Infrastructure Integrity risk chapters. This Wildfire risk chapter only includes activities and associated costs for inspections performed in the HFTD.

2. SDG&E-1-C5 – Distribution System Inspections – Quality Assurance/Quality Control

Consistent with the 2019 WMP,[42] SDG&E has implemented a Quality Assurance/Quality Control (QA/QC) inspection program in HFTD Tier 3 prior to fire season. These proactive inspections are completed on a three-year cycle, exceed the requirements of GO 165, and are designed to identify potential structural and mechanical problems before they fail. SDG&E has performed QA/QC inspections of its overhead electric distribution poles in high risk fire areas with a focus on identifying items for which maintenance would improve fire safety and reliability, with a goal of mitigating the probability that SDG&E's overhead electric system, facilities, and equipment would be the source of ignition for a fire. These inspections were conducted from 2010 through 2016 as a result of a settlement agreement adopted by the CPUC, D.10-04-047. In 2017, SDG&E decided to proactively continue the QA/QC inspections as part of its normal program. In 2018, when the CPUC adopted the current statewide fire threat map, SDG&E began applying the QA/QC three-year cycle to the newly defined HFTD Tier 3. During 2016 to 2018, SDG&E performed QA/QC inspections on an average of 15,000 poles annually (approximately one-third of the distribution poles) in its then-existing "extreme" and "very high" fire threat areas.

In addition to the inspection, SDG&E performs a system maintenance patrol (as specified by GO 165) for the entire overhead electric distribution system in the HFTD on an annual basis. Safety-related issues identified on those patrols are scheduled for follow up repair.

[42] SDG&E's 2019 WMP at Attachment A, p. 27.

3. SDG&E-1-M1 – Distribution System Inspections – Infrared/Corona

SDG&E is piloting new periodic infrared (IR) inspections for distribution equipment, with the intent of creating a formalized program beginning in 2020. As this program is new, it was not included in SDG&E's 2019 WMP. This program consists of using IR and corona technology, with both technologies currently being used for transmission and substation inspections. IR technology identifies thermal hotspots in equipment and connections. Corona technology, while similar to IR, differs in that it identifies, using ultraviolent light, components that may have been damaged, resulting in increased tracking. SDG&E intends to utilize both technologies to inspect distribution circuits, with the goal of early detection of potential issues on electrical connections and equipment that cannot be seen from SDG&E's traditional visual inspections. Accordingly, IR and corona technology will complement existing programs by allowing SDG&E to proactively identify hotspots on circuits, connections, and equipment.

The IR and corona inspections will generate repair orders to address any infractions discovered as part of the inspection. Overall, these inspections and associated repairs will reduce the potential for equipment failure of SDG&E's overhead system, including wires down, which can cause ignitions. These inspections will be conducted primarily via land but may also be conducted from the air. Given that this is a pilot program, repairs resulting from these inspections are not estimated herein. SDG&E will provide forecasts for resulting repairs in the GRC, as appropriate.

Based on the initial results of the 2019 pilot program, SDG&E plans to annually inspect approximately twenty percent of the linear mileage of distribution circuits within the HFTD, on a five-year cycle, beginning in 2020. SDG&E will prioritize inspections in Tier 3 of the HFTD, before moving to Tier 2.

4. SDG&E-1-M2 – Distribution System Inspections – Drone Inspections

SDG&E will be using non-traditional approaches to inspections to identify infractions that are not visible via ground-based inspections. To improve visual inspections, SDG&E will be employing drones to capture imagery of every overhead structure in the HFTD from multiple angles, including from above the structure, that can help identify issues posing a potential ignition risk. This imagery data will be stored in a new centralized database application to allow for data analytics to determine trends and patterns of infractions to quickly identify systemic issues and support more proactive replacements, including more programmatic approaches to reducing ignition risk. Drone inspections will also be performed for quality assurance of any major overhead construction project within the HFTD to confirm equipment is built to standards and any infractions are timely corrected.

SDG&E started a pilot program in 2019 (which may continue into 2020) to inspect 30,000 structures within the HFTD Tier 3. As SDG&E learns from the pilot program, a drone inspection program and cycles will be established. This pilot program is new and was not included in SDG&E's 2019 WMP.

Further, these inspections will generate repair orders to address the various infractions discovered as part of the inspection, which will reduce the risk of ignition caused by equipment or structural failure of SDG&E's overhead system. Given that this is a pilot program, repairs related to drone inspections are not estimated herein. SDG&E will provide forecasts for repairs resulting from drone inspections in the next GRC, as appropriate.

5. SDG&E-1-M3 – Circuit Ownership

This program offers the opportunity for SDG&E's field employees and management of field employees to submit circuit vulnerabilities via a Mobile Data Terminal (MDT) program or mobile application (both iOS and Android). Specifically, this program facilitates supplemental submission of circuit vulnerabilities (in addition to the existing inspection programs) so that they can be timely repaired, to prevent a potential ignition and minimize the risk of wildfire. This program accordingly allows SDG&E to leverage its workforce to self-report identified vulnerabilities related to its system. Each vulnerability would be evaluated through a consistent method and then prioritized and repaired. While the identified vulnerabilities may not be considered formal infractions, through this program, SDG&E will document and remediate any such findings before issues occur. This program is newly presented herein and was not included in the 2019 WMP.

6. SDG&E-1-C6 – Substation System Inspections

As described in the 2019 WMP,[43] SDG&E's Substation System Inspection and Maintenance Program is mandated by the CPUC through GO 174 and promotes safety for

[43] *Id.* at Attachment A, pp. 27-28.

SDG&E personnel and contractors by providing a safe operating and construction environment. This is accomplished through routine inspections at reoccurring cycles. A security check is planned once per week, and a more detailed inspection is planned monthly or bimonthly, which takes a visual look at equipment and attempts to identify any problems, like oil leaks.

Substation System Inspections, while conducted primarily for reliability, also provide incidental wildfire mitigation benefits. Specifically, this inspection program mitigates the risk of equipment failure, which has the potential to cause ignitions, by identifying equipment deterioration to make the repair or replacement before failures occur. In this instance, equipment failure can lead to fires in oil-filled substation equipment; however, those fires would be contained within the substation footprint. This is why SDG&E considers its inspection and maintenance programs to have incidental wildfire mitigation benefits when performed within the HFTD and wildland urban interface.[44]

Additional goals of this program include: meeting the requirements of GO 174, achieving a level of station availability satisfactory to SDG&E's health and safety programs and maintenance standards, and assuring compliance with all sections of the California Independent System Operator (CAISO) Transmission Control Agreement (TCA).

Because substation system inspections are performed throughout SDG&E's service territory, for purposes of SDG&E's RAMP showing, this control is also discussed in SDG&E's Electric Infrastructure Integrity risk chapter. To that end, given that this program is largely related to equipment failure, the costs for this activity are entirely included in the Electric Infrastructure Integrity risk chapter.

7. SDG&E-1-C7 – Transmission System Inspections

As described in the 2019 WMP,[45] all SDG&E transmission system facilities covered by the transmission inspection practice[46] are routinely inspected using visual and infrared inspection

---

[44] Wildland urban interface refers to a zone of transition between wildland (unoccupied land) and human development, which is at risk of wildfire.

[45] SDG&E's 2019 WMP at Attachment A, p. 28.

[46] Because this control is related to assets in the jurisdiction of the Federal Energy Regulatory Commission (FERC), SDG&E is not including the associated costs, as further described in Section VI below. Accordingly, a Risk Spend Efficiency calculation is not being performed.

techniques. Infrared and air inspections are completed annually on all transmission circuits. Ground-based visual inspections are completed on three-year cycles. Non-routine inspections are scheduled depending on operational need. Inspections/patrols of all structures, attachments, and conductor spans are performed to identify facilities and equipment that may not meet California Public Resources Code (PRC) §§ 4292 and 4293 or GO 95 and GO 128 rules. When non-conformances are identified through these inspections, jobs are designed to remediate these issues based on severity levels. SDG&E annually evaluates its maintenance practice to confirm inspection and repair intervals meet or exceed regulatory requirements.

This inspection program mitigates the risk of equipment failure by identifying equipment deterioration to make the repair/replacement before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions. This is why SDG&E considers its inspection and maintenance programs to be wildfire mitigation activities when performed within the HFTD and wildland urban interface.

While transmission inspections are performed throughout SDG&E's service territory, inside and outside the HFTD, for purposes of SDG&E's RAMP, this control is discussed in both SDG&E's Wildfire and Electric Infrastructure Integrity risk chapters.

C. System Hardening

SDG&E designs and constructs its overhead electric and communications facilities to maximize public, employee, and contractor safety, as explained in the 2019 WMP.[47] In many situations, SDG&E develops standards that supersede the minimum requirements dictated by a general order, to incorporate known local conditions and further maximize safety. To reflect the more stringent design and construction standards adopted by the Commission and to improve the performance of the SDG&E electric system in terms of meeting fire-prevention goals, the SDG&E Facilities Design Manual was modified in 2012 to include an entirely new section aimed at providing guidance for hardening distribution circuits against the risk of fire. These modifications include both proactive measures designed to reduce the incidence of ignitions and reactive measures by which SDG&E can respond to and mitigate the threat of fires, such as only allowing specific types of conductor.

---

[47] SDG&E's 2019 WMP at Attachment A, p. 30.

SDG&E continues to evaluate and incorporate new technologies and equipment for its electric system that may improve electric reliability and safety, giving special attention to technologies that may contribute to SDG&E's fire safety goals and objectives.[48] SDG&E's electric distribution engineering department evaluates and creates new equipment and use standards for emerging and pre-commercial technologies. Using equipment failure data, the department makes recommendations regarding which technologies should be incorporated into the SDG&E system and which could be improved prior to application. SDG&E's system hardening plan was developed with these design and construction standards in mind.

1. SDG&E-1-C8 – Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)

SDG&E is committed to fire-hardening its 69kV transmission and associated 12kV distribution system located in the HFTD. This hardening effort is a multi-faceted approach that starts with enhanced design criteria that accounts for greater wind speeds and includes the use of high tensile strength conductor, increased wire-to-wire spacing, and the use of steel poles. Previously, lines were constructed to withstand working loads under stress of 56 miles per hour (mph) wind speeds. The new electric lines are designed to withstand working loads under the stress of 85 mph wind speeds, and in some specific cases, up to 111 mph, based on known local wind conditions. The new lines are being designed utilizing steel poles instead of wood. Steel poles are a more reliable construction material, giving more confidence in their designed strength, and are more resilient should a fire occur, leading to faster restoration times. These new steel pole facilities are being installed in conjunction with the application of higher strength conductors and increased spacing between lines, beyond the requirements of GO 95, resulting in a decrease in the likelihood of energized lines coming into contact with one another or arcing after being struck by flying debris. In addition, SDG&E's current design standards now reflect the use of the enhanced design criteria, steel poles over wood poles, high strength conductor, and increased conductor spacing in the HFTD.

---

48 *Id.* at Attachment A, p. 30.

As of October 2019, SDG&E has hardened 55% of its 69kV transmission system within the HFTD by installing over 2,900 new steel poles and plans on further investment to continue these efforts. SDG&E anticipates installing 800 steel poles in the HFTD from 2020 to 2022, consistent with the forecast stated in SDG&E's 2019 WMP.[49]

SDG&E notes that the tie lines hardened in this program are driven by FERC-jurisdictional projects, given that hardening efforts address the 69kV transmission system and the associated 12kV distribution system located in the HFTD. This Chapter provides only the CPUC-jurisdictional elements related to this program.[50]

2. SDG&E-1-M4 – Strategic Undergrounding

SDG&E is strategically evaluating certain distribution lines for undergrounding, equaling approximately six miles, where undergrounding such lines would reduce a significant risk and/or limit exposure to a PSPS event. These are highest risk circuits within Tier 3 of the HFTD that have already been subject to multiple PSPS events. The undergrounding work associated with this 2019 RAMP Report will focus on mitigating PSPS customer impacts, by supporting critical infrastructure such as community centers, schools, fire stations, gas stations, and businesses. SDG&E is forecasting this portion of its strategic undergrounding program to start construction in 2020 and to continue for many years, above the levels put forth in the 2019 WMP.[51] The rural locations within the HFTD, environmentally sensitive locations, and potentially non-advantageous terrain (*e.g.*, granite rock, equipment up a hillside) for the existing distribution overhead equipment, are all potential drivers that could delay construction. While SDG&E continues to evaluate these locations for economic and general feasibility, SDG&E is looking to potentially further increase the miles to strategically underground. This may result in a

---

[49] *Id.* at Attachment A, pp. 32-33.

[50] Costs identified herein for this activity are limited to distribution-related portions under the CPUC-jurisdiction. Because the distribution components are dependent on and borne from an approved FERC-jurisdictional transmission-related program, SDG&E is not calculating a Risk Spend Efficiency on this program.

[51] SDG&E's 2019 WMP at Attachment A, p. 33. This program was referred to as Underground Circuit Line Segments in the 2019 WMP.

significant ramp-up of this initiative over several years. Any differences in the implementation goals of this program from this RAMP Report will be reflected in future WMP and GRC filings.

In addition, SDG&E's Tariff Rule 20D allows for conversion of existing primary voltage overhead facilities to underground facilities along public streets and roads, and on public lands and private property in more fire-prone areas where undergrounding is the preferred method to reduce fire risk and enhance reliability. SDG&E formed a team with expertise in the undergrounding of distribution systems and facilities and fire science to evaluate the undergrounding of circuit segments located in the HFTD within primarily the County of San Diego jurisdiction. These experts provided the County of San Diego with an understanding of the potential for undergrounding portions of the overhead system to mitigate the risk of fire, and the results are being used on circuit analysis to propose undergrounding portions where feasible. Conferences with County management and leadership are in progress to gain agreement on individual project prioritization and scope of work. Design on these conversions are scheduled to begin in 2020, with anticipated construction in 2021.

3. SDG&E-1-C9 – Cleveland National Forest Fire-Hardening

As described in the 2019 WMP,[52] SDG&E currently operates and maintains a network of electric facilities located within the Cleveland National Forest (CNF). In 2016, SDG&E received a Master Special Use Permit (MSUP) to operate and maintain facilities within CNF. Specifically, the MSUP allows SDG&E to develop a series of projects and activities aimed at increasing the safety and reliability of existing electric facilities within and near the CNF. SDG&E has received final approval for these projects and associated permits, and work has been ongoing since 2016. The projects include the fire-hardening of facilities and select undergrounding of several existing 12kV and 69kV electric facilities spread throughout an approximately 880 square-mile area in the eastern portion of San Diego County. The existing electric lines located within CNF also extend outside of CNF boundaries. Generally, the CNF program will increase the safety and reliability of SDG&E's system by fire-hardening existing electric infrastructure that currently serves the U.S. Forest Service, emergency service facilities

52 *Id.* at Attachment A, pp. 33-34.

(*i.e.*, fire, communication, and other), campgrounds, homes, businesses, and other customers within the CNF and surrounding areas.

The project design was based on various recommendations addressing fire prevention and the U.S. Forest Service's environmental requests. Using an analytical matrix reflecting elements of fire risks and environmental concerns, SDG&E and the U.S. Forest Service collaborated to determine which sections of the electric system should be upgraded. Each segment required a custom solution based on many factors, including the location of the customer being served by the distribution system, the topography of the land, and various biological, cultural, and environmental factors.[53]

Construction commenced on the CNF program in late 2016 and is planned to continue through 2021. Through October 2019, SDG&E has fire-hardened a total of 104.5 miles of electric transmission and distribution lines, including 59.7 miles of 69kV transmission lines and 655 structures replaced with steel and 44.8 miles of 12kV distribution lines and 283 structures replaced with steel. For 2019, SDG&E plans to replace an additional 12.2 miles of 69kV transmission lines and 200 structures as well as 13 miles of distribution lines and 90 structures.[54]

4. SDG&E-1-C10/M5 – Fire Risk Mitigation

In 2013, SDG&E established the Fire Risk Mitigation (FiRM) program, an overhead distribution, fire-hardening, and rebuilding effort. The goal of the FiRM program is to fire-harden facilities in the HFTD by replacing aged line elements, utilizing advanced technology, and designing for known local weather conditions. FiRM is also tasked with developing a multi-year plan for the rebuilding of circuits with the greatest fire-related risk. Prioritization and scoping of each FiRM project is driven largely by analysis using SDG&E's Wildfire Risk Reduction Model (WRRM).

---

[53] As noted in SDG&E's 2019 WMP, the U.S. Forest Service relies on the Project Activity Level (PAL) system, which was designed to help fire and timber resource managers establish the level of industrial precaution for the following day. PAL applies to the Cleveland National Forest. *See id.* at Attachment A, p. 23.

[54] The CNF program is largely related to transmission assets in the HFTD under the jurisdiction of FERC. Costs identified and Risk Spend Efficiencies performed herein for this activity are limited to distribution-related portions under the CPUC-jurisdiction.

Factors considered in the prioritization and scoping process include, but are not limited to, recent occurrences of a "wire-down," wind and weather conditions, fire risks, outage history, conductor size and type, condition of equipment, environmental conditions, and resulting customer impacts. FiRM projects are scoped on a circuit-by-circuit basis by considering various risk factors. Risk mitigation methods include replacement or removal of small conductor and older wood poles, and employing targeted fire risk mitigation methods of the circuit, including removal of equipment, long span remediation or reinforcement, and advanced technology implementation (namely, falling conductor protection, synchrophasor/phasor measurement unit (PMU) enabled relaying/monitoring, high impedance fault detection, and light imaging detection and ranging (LiDAR) survey data captured via Unmanned Aerial Vehicles (UAVs and helicopters) before and after construction.

As of the end of October 2019, the FiRM program is approximately 28% complete, having replaced over 8,000 poles and 400 miles of reconductor. SDG&E plans to continue this effort for the foreseeable future, as there are still approximately 1,000 miles of aged high-risk conductor remaining within the HFTD in SDG&E's service territory. At this current rate of reconductoring approximately 84 miles of high-risk conductor per year, it will take SDG&E approximately 13 years to complete this focused effort with the current resources and budget. However, given the recent California fires beginning in 2017 and the elevated risk climate change has brought to the state, SDG&E has been planning to accelerate this effort to remediate these older line elements by 2025 (years 2019-2025). This accelerated plan was put forth and approved in SDG&E's 2019 WMP.[55] The increased scope of work would begin engineering and design in 2019 and construction in 2020.

5. SDG&E-1-C11/M6 – Pole Risk Mitigation and Engineering

SDG&E's Pole Risk Mitigation and Engineering (PRiME) program was developed to assess pole strength and integrity considering loading conditions, third party attachments, localized weather conditions, and remaining pole strength throughout SDG&E's service territory. PRiME does not overlap with existing programs, such as FiRM or CNF.

---

55 SDG&E's 2019 WMP at Attachment A, pp. 34-35.

PRiME will focus its efforts in HFTD Tier 3 and Tier 2. Assessments and prioritization on SDG&E's highest risk poles within Tier 3 and Tier 2 of the HFTD will be completed prior to poles located outside of the HFTD. Poles identified that require construction activities after assessment and follow-up analysis[56] will be remediated as they are identified.

SDG&E anticipates performing approximately 700 pole remediations in 2019, 1,700 pole remediations in 2020, 2,100 pole remediations in 2021, and 2,100 pole remediations in 2022. At the current rate, it is anticipated that remediation activities will be completed in eleven years within the HFTD. However, SDG&E is planning to accelerate this effort to complete remediation activities by 2027 (years 2019-2027), as discussed and approved in its 2019 WMP.[57] The increased scope of work would begin engineering and design in 2019 and construction in 2020.

6. SDG&E-1-M7 – Expulsion Fuse Replacement

SDG&E's distribution system is dynamic and can experience a contact with a foreign or unimproved object, resulting in a fault. When the distribution system experiences a fault or overcurrent, there are fuses connected to the system to protect its integrity and isolate the fault. These expulsion fuses are designed to operate by creating a significant expulsion within the fuse, resulting in the fuse opening and isolating the fault, and in turn limiting further damage to other equipment. Because of this internal expulsion, the fuses are equipped with a venting system that sends a discharge of energy out of the fuse and into the atmosphere. This external discharge has the potential to ignite flammable vegetation.

To mitigate this potential, SDG&E has developed a three-year program to proactively replace existing branch expulsion fuses within the HFTD with CAL FIRE approved power fuses.[58] There are approximately 8,900 branch expulsion fuses in SDG&E's HFTD, and this new

---

56 PRiME utilizes LiDAR and outage data to perform engineering assessments to identify and prioritize structure remediations. This was referred to as Facility Analysis in the 2019 WMP. *See id.* at Attachment A, pp. 30-31.

57 *Id.* at Attachment A, p. 35.

58 Power fuses are equipment that have been previously granted an exemption from CAL FIRE.

program is designed to lessen the chance for an ignition source in the HFTD by reducing external discharges during fuse operation.

In 2019, this program will prioritize the replacement of the branch expulsion fuses to the CAL FIRE approved power fuses by completing the removal of non-CAL FIRE approved fuses in HFTD Tier 3 and then moving to HFTD Tier 2. SDG&E anticipates completing this program by 2021, replacing roughly 2,400 per year when including 2019. This program was presented for the first time in SDG&E's 2019 WMP. [59] SDG&E is proposing herein to continue this program consistent with its 2019 WMP.

7. SDG&E-1-M8 – Hotline Clamps

Through equipment failure analysis related to wire down outages, SDG&E has identified high risk connectors known as "hotline clamps" that SDG&E intends to replace as part of this program. These hotline clamps have been identified because they have been associated with creating a weak connection resulting in a wire down event. This wire down event can lead to an energized wire on the ground or coming into contact with a foreign object, thus becoming an ignition source.

From the data gathered during SDG&E's QA/QC inspections, SDG&E has identified approximately 3,700 structure locations with this type of connector within the HFTD. This program to replace these connectors and potentially reconductor as well as replace existing poles is planned to begin in 2019 and will continue through 2025, consistent with SDG&E's 2019 WMP.[60]

8. SDG&E-1-C12/M9 – Wire Safety Enhancement

The Wire Safety Enhancement (WiSE) program is designed to mitigate risk by hardening electric distribution overhead infrastructure and protection systems. WiSE addresses public safety risks in wildland urban interfaces where conductor or connection equipment failures may cause wildfires.

Conductor equipment failure can pose serious risks due to potential ignitions in areas that are vulnerable to fire and due to contact that could cause serious injuries or fatalities. Although

---

59 SDG&E's 2019 WMP at Attachment A, pp. 35-36.

60 *Id.* at Attachment A, p. 36.

WiSE was originally developed to harden the distribution system outside the HFTD Tiers 2 and 3, recent events such as the California wildfires of 2017 and 2018 have provided evidence of the increasing risk to communities within the wildland urban interface. These factors, coupled with record wind speeds and dry vegetation measured in San Diego's coastal canyons in recent months, have created a need to refocus this program to mitigate potential ignitions within the wildland urban interface, a distinct area located outside the HFTD.

The resulting infrastructure enhancements under the WiSE program may include wire upgrade, connector replacements, switch placements or replacements, long span removals, strategic undergrounding, and modifications to advanced protection systems. Design considerations will be driven by area-specific conditions that could include anti-corrosion materials for connectors or conductors, replacement of wood poles where fire-hardening is beneficial, replacing bare wire with covered conductor to reduce wires down caused by foreign object contact (*e.g.*, avian, vegetation, Mylar balloon), and strengthening conductors that are vulnerable to high wind storm events.

WiSE will focus on utilizing multi-attribute risk modeling to drive optimal risk reduction, with considerations for factors including, but not limited to: historic wire down events, projected wire down failures by asset type, proximity to vegetation, condition or age of assets, inspection records, susceptibility of corrosion, meteorology conditions, length of the conductor span, proximity to dense or sensitive public areas (*e.g.*, schools, residences, parks), and conductors that cross major freeways or roadways. The risk model will be focused on these risk parameters within the wildland urban interface boundary first.

In 2019, WiSE will prioritize the highest risk circuit elements within the wildland urban interface and commence hardening efforts to replace roughly 32 miles of overhead conductor by 2022. SDG&E is planning to continue the WiSE program at a pace consistent with its 2019 WMP.[61]

9. SDG&E-1-M10 – Covered Conductor

SDG&E acknowledges the benefits of a targeted approach to installing covered conductor in areas that have electric infrastructure with high tree-strike potential (*i.e.*, near dense

[61] *Id.* at Attachment A, pp. 36-37.

vegetation) and near at-risk vegetation. SDG&E has over five miles of covered conductors installed where its overhead electrical equipment is in close proximity to dense vegetation and where outage history supports this type of installation. SDG&E believes the use of covered conductor in certain applications can be beneficial and will continue to utilize covered conductors in those applications. From dramatically reducing ignitions from a "wire-slap" to foreign objects (*e.g.*, avian, vegetation, Mylar balloons), covered conductor provides value in mitigating the potential for a fire.

At the time SDG&E filed its 2019 WMP,[62] it was at the early stages of evaluating covered conductor technology. SDG&E is updating its forecasts herein to provide additional details on the application of covered conductor, with a goal of roughly 22 miles by 2022, to further adjust construction standards and refine the scope for future applications. The scope of work is being developed utilizing SDG&E's Vegetation Risk Index (VRI) in conjunction with vegetation management data within the HFTD. While this technology continues to be evaluated, SDG&E is looking to potentially further increase the implementation of covered conductor. Any differences in the implementation goals of this program from this RAMP Report will be reflected in future WMP and GRC filings.

10. SDG&E-1-C13/M11 – Fire Threat Zone Advanced Protection

The Fire Threat Zone Advanced Protection (FTZAP) program develops and implements advanced protection technologies within electric substations and on the electric distribution system. FTZAP aims to reduce and/or mitigate the risks of utility-caused fire incidents, to create higher visibility and situational awareness in fire-prone areas, and to allow for the implementation of new relay standards in locations where protection coordination is difficult due to lower fault currents attributed to high impedance faults.

More advanced technologies, such as microprocessor-based relays with synchrophasor/phasor measurement unit (PMU) capabilities, real-time automation controllers, auto-sectionalizing equipment, line monitors, direct fiber lines, and wireless communication radios, comprise the portfolio of devices SDG&E has and will continue to install in substations and on distribution circuits to allow for a more comprehensive protection system along with

---

62 *Id.* at Attachment A, pp. 37-38.

greater situational awareness via SCADA in the fire prone areas of the HFTD. This portfolio of advanced technology allows SDG&E to implement new protection systems, such as:

- **Falling Conductor Protection (FCP)** designed to trip distribution overhead circuits before broken conductors can reach the ground energized;
- **Sensitive Ground Fault Protection** for detecting high impedance faults resulting from downed overhead conductors that result in very low fault currents;
- **Sensitive Profile Relay Settings** enabled remotely on distribution equipment during red flag events to reduce fault energy and fire risk;
- **High Accuracy Fault Location** for improved response time to any incident on the system;
- **Remote Event Retrieval and Reporting** for real-time and post-event analysis of system disturbances or outages;
- **SCADA Communication** to all field devices being installed for added situational awareness; and
- **Protection Integration with Private long-term evolution (LTE)** as a means of facilitating the communication infrastructure needs (note: this activity is further described below).

SDG&E asserts that the installation of equipment capable of enabling Falling Conductor Protection (FCP) allows for the remaining technologies mentioned in the list above to likewise be enabled. Further, it should be noted that these technologies continue to be researched and developed, and therefore are subject to upgrades to increase functionality. These potential advancements may impact cost forecasts.

From 2020 to 2022, FTZAP aims to replace aging substation infrastructure such as obsolete 12kV substation circuit breakers, electro-mechanical relays, and Remote Terminal Units (RTUs). New circuit breakers incorporating microprocessor-based relays, RTUs, and communication radios facilitating the requirements of SDG&E's advanced protection systems will be installed in SDG&E substations within the HFTD. On distribution circuits within the HFTD, FTZAP coordinates with the FiRM and PRiME programs to strategically install and/or replace sectionalizing devices, line monitors, direct fiber lines, and communication radios to facilitate the requirements of SDG&E's advanced protection systems.

SDG&E plans to enable FCP on 73 distribution circuits fed by 33 substations in the HFTD Tier 3 by 2023. By upgrading these circuits and substations with advanced SCADA devices capable of implementing FCP, SDG&E will also advance its existing capabilities with regard to remotely enabled sensitive profile settings, distribution synchrophasors, remote event retrieval, and fault location. SDG&E anticipates implementing this program consistent with the discussion in its 2019 WMP.[63]

11. SDG&E-1-M12 – LTE Communication Network

SDG&E plans to deploy a privately-owned long-term evolution (LTE) network using a licensed radio frequency (RF) spectrum. This will improve the overall reliability of SDG&E's communication network, which is critical for fire prevention and public safety. SDG&E's communication network provides the foundational communications medium to remotely detect and operate the distribution grid and direct first responders when faults occur. The LTE network will allow SDG&E to not only implement enhanced protection technology but also to deploy resources and equipment that best fits a particular incident.

The LTE network significantly increases the capacity and reliability of remote communication, which is critical for the technology discussed in the FTZAP program section. In addition, there are currently holes in the coverage of third-party communication providers in the rural areas of east county San Diego that limit SDG&E's ability to communicate with field personnel during red flag crew deployments and Emergency Operations Center activations. The installation of LTE in the HFTD Tiers 2 and 3 will reduce these gaps, allowing for more timely and reliable communication and information from SDG&E's field crews to emergency management leadership in these critical situations. This is done through the installation of LTE base stations and the installation of fiber optic infrastructure. The forecasts associated with the LTE communication network program are consistent with what SDG&E put forth in its 2019 WMP.[64]

---

63 *Id.* at Attachment A, p. 38.

64 *Id.* at Attachment A, p. 39.

12. SDG&E-1-M13 – Public Safety Power Shutoff Engineering Enhancements

In addition to other PSPS mitigation strategies, this program mitigates the impact to customers and communities involved in PSPS events by installing additional remote sectionalizing devices within the HFTD. This allows PSPS events to be more precise and potentially localized, which reduces the outage impact to customers. SDG&E is evaluating locations for these sectionalizing devices and based upon the results of the analysis. SDG&E plans to install approximately 30 units over the three-year period from 2020-2022, with the potential for future installations dependent on updated weather information, vegetation analysis and customer impact. This program was included for the first time in SDG&E's 2019 WMP.[65]

13. SDG&E-1-C14/M14 – Replacement and Reinforcement

As explained in the 2019 WMP,[66] the Replacement and Reinforcement program replaces deteriorated wood poles as well as other asset-related components identified through SDG&E's various inspection programs (*e.g.*, CMP and QA/QC inspections). Specific to poles, wood pole damage is attributed to numerous factors including, but not limited to, the loss of original preservative treatment experienced with Penta-Cellon poles, the presence of fungi decay, and bird and/or termite damage. In addition to poles, anything that is identified through various inspections are remediated to timely clear potential infractions and vulnerabilities in SDG&E's system. To do this, jobs are created and sent to SDG&E's various districts where they are then addressed and cleared. This mainly consists of internal labor and fixing or replacing various equipment, as needed.

In 2020 and 2021, the wood pole intrusive inspections are cycling through structures located in the HFTD based on the inspection cycles (*e.g.*, 3 or 5-year cycles). Pole replacements

65 *Id.* at Attachment A, p. 39.

66 *Id.* at Attachment A, p. 40. In SDG&E's 2019 WMP, this program primarily addressed pole replacements. The description of this program has been broadened herein to address remediation activities, beyond poles, that result from CMP and QA/QC inspections. These remediation or repair efforts are not new and are not forecasted to be higher as a result of the CMP and QA/QC inspection programs. The costs identified for this program are capital and O&M. However, the O&M costs are only provided for the QA/QC program for purposes of performing an RSE. An RSE is not being performed for the resulting repairs for CMP given that it is mandated pursuant to GO 165.

associated with deteriorated structures found on these intrusive inspections reduce the risk of ignitions by preventing wood pole failures. In addition, replaced poles will be constructed to SDG&E's improved site-specific design criteria, (*e.g.*, wood poles will be replaced with steel poles that meet the known local wind conditions of a particular area). For poles identified for replacement in Tier 3 of the HFTD, SDG&E intends to accelerate the replacement (including the design, engineering, and construction of the new structures) faster than the six-month time frame required by the Commission's General Orders. This will reduce the risk of wildfire by replacing poles that fail inspection and/or design criteria on an accelerated schedule within the highest risk areas.

14. SDG&E-1-M15 – Backup Power for Resilience – Generator Grant Program, Community Resource Centers, HPWREN

Fire threats may give rise to circumstances that require SDG&E to de-energize for public safety power lines that serve certain communities within the HFTD. To mitigate some of the impacts to affected communities during de-energization events, SDG&E is pursuing Backup Power for Resilience initiatives with the intent of establishing support in areas that will help mitigate the impact of these extreme weather events on its most impacted communities, while also providing overall grid resiliency and other electrical distribution grid operations and services.

Generator Grant Program

As discussed in the 2019 WMP, SDG&E created the Generator Grant Program in response to feedback received from residential customers previously impacted by Public Safety Power Shutoff events. While impacted customers may desire to obtain generators, all do not possess the financial capability to acquire one. The Generator Grant Program (GGP) was launched as a pilot program earlier in 2019 as a first attempt at reaching these impacted communities on a limited basis so that SDG&E may learn from this program and adjust in future years. The program is administered by a neutral third party to grant residential customers (*e.g.*, medical baseline customers) the funding for the express need to acquire and be able to use a portable generator during outages, in particular PSPS events.

SDG&E understands that there are inconveniences associated with de-energization, and this program is one way to provide tools to help mitigate the impact while enhancing customer resilience. That said, SDG&E strongly encourages all customers to take important steps to ready themselves before the wildfire season, such as creating an emergency kit and a thorough family emergency plan. It is the intent that such actions, when coupled with this program, will lead to a better prepared household.

The Generator Grant Program will help a subset of SDG&E's Access and Functional Needs (AFN) customers charge cell phones and other small electronic devices while they enact their personal emergency plans and also demonstrate that SDG&E is starting to look at solutions and test renewable, portable generator options, to aid customers' resiliency during Public Safety Power Shutoff events.

Although the pilot program is limited, as briefly discussed in SDG&E's 2019 WMP,[67] SDG&E intends to extend this program in 2020 and 2021, factoring in customer feedback and lessons learned. After surveying participants, it was discovered that the program was well-received. Household items that were commonly powered by the portable generators were refrigerators, medical devices, televisions, and communication devices. Based upon this positive feedback received, SDG&E will seek to expand the pilot program into a full program implementation.

Community Resource Centers

SDG&E plans to implement this Backup Power for Resilience program specifically to provide backup power to Community Resource Centers (CRCs) and other critical infrastructure in areas impacted by PSPS. SDG&E's plan to deploy these backup facilities furthers the integration of technology in support of the safe and reliable electric operations. Given that CRCs are intended to supply the public with a reprieve from the effects of PSPS, SDG&E believes it is critical to provide backup power to such facilities.

SDG&E is also expanding upon or developing new programs and strategies, leveraging backup power for resilience to mitigate the risk associated with Public Safety Power Shutoffs. These programs are specifically related to resilient internet connectivity at fire stations, the expansion of the Community Resource Center Network and the potential development of a grant program for portable generators targeted at select residential customers.

---

[67] *Id.* at Attachment A, pp. 40-41.

While this program was included in SDG&E's 2019 WMP,[68] it is anticipated to be further expanded in the 2020 through 2022 timeframe.

HPWREN

SDG&E, in collaboration with University of California San Diego (UCSD), supports the High-Performance Wireless Research and Education Network (HPWREN). This is the communication backbone that supports a comprehensive mountaintop camera network and wireless communication network that provides internet to fire stations across the backcountry of San Diego County. Sixteen of the mountaintop cameras are known as pan-tilt-zoom "Alert SDG&E Cameras," which are capable of remote directional and zoom control. These cameras enhance situational awareness for both SDG&E, local fire agencies, and the public as access to the camera feeds is publicly available. The network of cameras is most widely known for its ability to allow first responders to identify and triangulate the location of wildfires.

This program enhances connectivity and reliability of the HPWREN network by implementing backup power for single points of failure via solar power and the replacement of additional outdated equipment enabling redundant feeds. Additional upgrades included within this project will replace outdated uninterruptible power supplies (UPS) and network switches at strategic backbone sites. One additional site planned for upgrade includes the installation of a new multilayer link which will eliminate a single point of failure for internet connectivity to 10 fire stations. The HPWREN program will continue enhancements and upgrades in 2020 and for the foreseeable future as this program provides vital situational awareness and enhances community resiliency.

This program is new and was added after the submission of SDG&E's 2019 WMP.

15. SDG&E-1-M16 – Backup Power for Resilience – Microgrids

This Backup Power for Resilience[69] program will provide backup power in the form of microgrids to critical infrastructure (*e.g.*, fire stations, urgent care centers, and others) in and near

[68] *Id.* at Attachment A, pp. 40-41.

[69] The National Academy of Sciences defines "resilience" as the ability to prepare and plan for, absorb, recover from, and more successfully adapt to adverse events.

areas impacted by PSPS. These microgrid projects focus on investing in infrastructure to provide backup power to strategic locations. To determine these strategic locations, SDG&E analyzes potential areas using the following criteria:

- Identify the critical facilities and the impact of PSPS events in that area;
- Determine the proximity of the locations (to determine necessary undergrounding);
- Identify available land and its proximity to the point of interconnection;
- Determine the load profile and electric needs of these facility;
- Determine solution (*e.g.*, solar with storage, generator with storage, storage); and
- Determine the feasibility of the solution from a cost perspective.

SDG&E has considered many critical facilities using the criteria above. However, there are three projects that SDG&E is proposing at this time, Cameron Corners being the largest. Cameron Corners is located in the HFTD, in the eastern part of San Diego County. The microgrid includes a medical care facility, fire station as well as local food establishments, convenient stores and gas stations. The project will consist of a 725 kW AC solar photovoltaic array with 2,000 kWh energy storage resource. The fully renewable microgrid solution will support resiliency at these key facilities and therefore will provide significant benefits to the surrounding rural community. During a de-energization event, the facilities will be able to seamlessly island from the distribution grid. The project is expected to be in operation by the end of 2020.

SDG&E notes that microgrids are of particular interest to the Legislature and the Commission. The Legislature enacted SB 1339, which requires the Commission, in consultation with the California Energy Commission, and the California Independent System Operator, by December 1, 2020, to take a number of specific actions to facilitate the commercialization of microgrids for distribution customers of large electrical corporations. To implement this directive, the Commission initiated R.19-09-009. This rulemaking will "include[] programs, rules, and rates related to microgrids that will help the accomplish the state's broader policy goals."[70] Therefore, it appears that the Legislature and the Commission are supportive of the use of microgrids. SDG&E believes its microgrid projects will aid in achieving broader state policy goals.

Consistent with the Backup Power for Resilience projects above in activity SDG&E-1-M15, these microgrid projects will help customers most impacted by extreme fire weather and PSPS events receive resilience benefits. This program was briefly included in SDG&E's 2019 WMP[71] and is being further expanded in this RAMP filing.

16. SDG&E-1-M17 – Lightning Arrester Removal/Replacement Program

In designing its electric distribution system, SDG&E incorporates unique equipment to protect the infrastructure from external forces. This equipment ranges from shields for avian protection to covered conductor. Each type of equipment has its own unique role. One type of device that protects the distribution system from external forces, such as damages caused by the effects of a lightning strike or a surge from a fault, is a lightning arrester. These devices are installed on the distribution system throughout the SDG&E service territory. Some locations have more installations than others based on the increased probability of lightning strikes, in order to protect other major equipment from abnormal surges and failing. When thermally overloaded, as a result of an excessive increase in energy experienced during an event, these units can become an ignition source. The existing design of arresters require additional measures to protect the distribution system from becoming an ignition source.

Through SDG&E's effort of continuing to improve and explore alternate solutions and evaluate new technology, a new product was introduced that received CAL FIRE approval. Utilizing this new product, SDG&E is proposing a program to replace these arrestors in strategic locations within the HFTD with a CAL FIRE approved lightning arrester. The CAL FIRE approved device comes with an external device that operates prior to the arrester overloading, dramatically reducing the potential of becoming an ignition source.

---

[70] R.19-09-009, Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 (September 12, 2019) at 2.

[71] SDG&E's 2019 WMP at Attachment A, pp. 40-41.

This program, newly presented in this filing, is planning to start design and construct in 2020 and ramping up installation to potentially replace all at risk locations in 10 years.

17. SDG&E-1-M18 – SCADA Capacitors

The SCADA capacitors program will replace existing non-SCADA capacitors with a more modern SCADA switchable capacitor. The current capacitors are designed to provide continuous voltage and power factor correction for the distribution system. During a failure of a capacitor from either mechanical, electrical, or environmental overstress, an internal fault is created resulting in internal pressure and the potential to rupture the casing. This rupture of molted metal has the potential to be an ignition source. The modernization of these capacitors will introduce a monitoring system to check for imbalances and internal faults and open based on the protection settings. In addition, the SCADA capacitor will provide a method for remote isolation and monitoring of the system providing additional situational awareness during extreme weather conditions. The program will first prioritize replacing fix capacitors within the system to capacitors with switches. Both types of capacitors will be modernized to a SCADA switchable capacitor.

This new program is intended to commence in 2020 and be completed by 2022. SDG&E is planning on modernizing 98 capacitors in the HFTD, approximately 30 in each 2020 and 2021, and 38 in 2022. SDG&E will start by replacing fixed capacitors, which are considered to be the most at-risk capacitors in SDG&E's service territory, followed by switchable capacitors. Given this program is new, it was not included in SDG&E's 2019 WMP.

D. Vegetation Management

1. SDG&E-1-C15 – Tree Trimming

SDG&E performs a variety of controls that are accounted for in the Tree Trimming Balancing Account (TTBA). These controls stem from compliance requirements largely outlined in the PRC § 4293, GO 95, Rule 35, and North American Electric Realiability Corporation (NERC) FAC003-4, which require SDG&E to actively maintain a vegetation management program aimed at keeping trees and brush clear of electric power lines. Because tree trimming is performed throughout SDG&E's service territory annually, for purposes of SDG&E's RAMP showing, this control has been split between SDG&E's Wildfire and Electric

Infrastructure Integrity risk chapters, 60% and 40%, respectively. This allocation was applied consistently with other activities in this Chapter (*e.g.*, CMP and Asset Management). Consistent with SDG&E's 2019 WMP,[72] the activities within tree trimming are discussed in greater detail below.

Tree Database

Beginning in 1998, SDG&E developed and implemented an internal vegetation work management system to track and manage trees that are in proximity to its electric infrastructure. SDG&E's database contains records for approximately 460,000 known, specific trees located near its electric power lines. SDG&E's inventory database and work management system are referred to collectively as PowerWorkz, which includes an Esri-based electronic mapping mobile application and server-based workflow tool. Inventory trees are defined as those with the potential of impacting the power lines by encroachment and/or tree failure within three years of the inspection date. All trees in SDG&E's database are monitored using known species growth rates, with additional consideration given to the amount of rainfall occurring during periods affecting overall tree growth, and past pruning practices. Each inventory tree is assigned a unique alpha-numeric identification number within the electronic database, which allows the activity history of each tree to be tracked. Accordingly, this database allows SDG&E to monitor and identify which trees to address in efforts to reduce vegetation-related ignitions. Inspections and maintenance activities are performed annually for purposes of regulatory compliance.

Patrols and Pruning

To comply with Commission rules as well as state and federal laws, SDG&E developed and maintains a vegetation management work plan, which is a schedule-based approach to its operations so that applicable lines within its service territory are inspected each year. SDG&E divides its service territory into 133 distinct zones known as Vegetation Management Areas (VMA). SDG&E's activities in each VMA are driven by a master schedule that identifies specific activities that are calendared to take place in each VMA every year. The activities include: pre-inspection, audit of pre-inspection work, tree pruning and removal, pole brushing, and post-trim and brushing audits. These activities are managed within PowerWorkz.

[72] *Id.* at Attachment A, pp. 41-45.

During the pre-inspection activity, trees in proximity to SDG&E's powerlines are inspected and evaluated and the tree condition in the database is updated accordingly. Each tree is visited on an annual cycle. The annual inspections include routine maintenance and hazard tree assessments to verify that trees will remain compliant for the duration of the cycle and/or pruned according to standards and clearances. Trees that will not maintain compliant or that have the potential to impact powerlines within the annual pruning cycle are identified and assigned to the tree contractor to work. If a tree requires urgent work the inspector has the latitude to issue the job to the tree contractor for priority completion. Emergency pruning occurs when a tree requires immediate attention to clear an infraction or poses an imminent threat to the electrical facilities.

SDG&E tree contractors follow American National Standards Institute (ANSI) A300 industry tree standards and the concept of directional pruning, which fosters the health of a tree while maximizing clearance and extending the pruning cycle. All tree branches overhanging conductors are considered a potential risk; therefore, SDG&E removes all branches that cross the vertical plane of the conductors from the conductor to the top of the tree. Once the work is completed, the tree crew updates the tree information and records the work performed in a mobile data terminal (MDT), then uploads this information into the Vegetation Work Management System. Where prudent and achievable, SDG&E prunes trees 12 feet (or more) to remain compliant with CPUC minimum clearance requirements. The post-pruning clearances obtained by the tree contractor are determined by factors such as species, tree growth, wind sway, and proper pruning practices. On average, SDG&E prunes approximately 175,000 trees each year and removes approximately 8,500 non-compatible trees.

The scoping operations for removing trees includes the chipping of all material and removal of the debris off-site. The only material left on site is the larger wood (> 6-8-inch diameter). Any large debris left on slopes is positioned to prevent movement of the material by gravity. All debris associated with pruning and removal operations is removed from watercourses to prevent flooding or degradation of water quality. Tree removal operations that may occur in sensitive environmental areas are reviewed to determine protocols that must be followed to protect species and habitat.

Within the HFTD, SDG&E performs routine and non-routine hazard tree inspections annually. These inspections are performed by Internationally Society of Arboriculture (ISA) Certified Arborists. Theses inspections include a 360-degree assessment of every tree within the "strike zone" of the conductors. The strike zone includes the area adjacent to powerlines both inside and outside the rights-of-way for trees that are tall enough to potentially strike the overhead facilities. Work identified during the non-routine inspections is completed prior to the start of the peak Santa Ana fire season (September 1). SDG&E requires its contractors to perform hazard tree assessment and fire awareness training annually.

SDG&E has historically utilized a contractor workforce to perform its vegetation management program activities of tree pre-inspection, tree pruning and removals, pole brushing, and quality assurance. SDG&E notes there are general concerns regarding the availability of contractors given that all the utilities within the State are working expeditiously on vegetation management activities. In the future, SDG&E may seek ways to mitigate this potential exposure to resource constraints. Further, SDG&E will likely experience additional upward cost pressures due, in part, to the enactment of SB 247. While the exact impacts of this law are still unclear, it may be interpreted that compensation for represented qualified line clearance tree trimmers will significantly increase.

Technology

SDG&E periodically utilizes LiDAR as a tool in its vegetation management operations. This technology is used to augment and enhance the inspection activity by determining the empirical spatial relationship between trees and power lines. SDG&E is researching future use of LiDAR to identify change detection on trees and as an audit tool, as well as for identifying pole movement and equipment condition. Currently, LiDAR acquisition, classifying of the data, and modeling of the data is very time consuming. SDG&E is working to improve the turnaround time for the LiDAR information so that it can be used in the field to inform decision-making.

As another tool in the management of its inventory trees, SDG&E has in recent years implemented the use of Tree Growth Regulators (TGR), which is a chemical application that dramatically reduces the new shoot growth of trees. Results have shown that the use of TGR can reduce the frequency of pruning on some species of up to three years. An added benefit of using

TGR is that it provides growth reduction, root and leaf enhancement, and in some instances can help with disease and insect protection.

SDG&E has begun to integrate data science into its vegetation management operations. SDG&E is utilizing the information from its tree inventory database, outage history and meteorology data to develop a Vegetation Risk Index (VRI) of the highest tree risk areas of its service territory. The goal of this initiative is to leverage machine learning and artificial intelligence techniques to correlate SDG&E's extensive vegetation and meteorological datasets to gain additional insights on how atmospheric conditions impact growth rate of certain species and to identify certain high-risk vegetation areas.

Quality Assurance

SDG&E utilizes a third-party contractor to perform quality assurance audits of all its vegetation management activities. These audits include a statistical analysis of a representative sampling of all completed work. A minimum random sampling of 10% is audited to determine compliance with scoping requirements. During the post-prune audit, the Certified Arborist also performs a cursory inspection of all the power lines within the VMA for any trees that will not remain in compliance with applicable regulatory requirements for the duration of the annual cycle. The results are then reviewed with SDG&E and the contractor to determine if any additional work is required.

Hazard Tree Removal and Right Tree-Right Place

Hazard tree evaluation is a critical component of SDG&E's vegetation management program operations to reduce tree-related outages and avoid fire ignitions. SDG&E has a robust tree removal program that targets problematic species such as eucalyptus and palms. SDG&E follows the industry-established "Right Tree-Right Place" program to assist customers in the selection of compatible tree species with the goal of minimizing interference with electrical infrastructure and maximizing energy savings and environmental benefits. SDG&E also offers free tree replacements if an existing tree cannot be maintained safely near powerlines.

SDG&E performs additional off-cycle patrols of select species (such as bamboo and century plants) that have fast and unpredictable growth rates and are difficult to manage near powerlines. These patrols help target and remove problematic species before they become a danger. Because of the potential threat to the power lines from detached fronds, SDG&E also proactively pursues the removal of palms located far outside its rights-of-way.

SDG&E Vegetation Management activities have greatly reduced tree-caused outages over the years. In the early 1990's, prior to industry regulation, SDG&E encountered (on average) 400-500 tree-caused outages annually. After the establishment of its vegetation program, SDG&E experienced a dramatic reduction in tree-related outages, with the best year-to-date in 2013, with only 25 outages. SDG&E conducts a thorough investigation of all tree-related outages and maintains an investigation database to track and record the events. The information helps identify the mechanics of outages and how to prevent future occurrences.

2. SDG&E-1-C16 – Pole Brushing

As described in the 2019 WMP,[73] and consistent with PRC § 4292, SDG&E utilizes the same Work Management System as tree inspections and maintenance to manage and track the inventory of all poles that require inspection and brush clearing in the State Responsibility Area.[74] The current inventory is approximately 31,000 distribution poles with nonexempt subject hardware. Inspectors determine which poles will require brushing and which are clear and require no work, updating the record in the data base. A work order is assigned to the Pole Brush Contractor to perform the clearing of identified poles requiring brush clearing.

SDG&E currently performs three activities to more effectively manage subject poles annually. This includes mechanical pole brushing, chemical application, and a re-clearing of pole brushing. Mechanical pole brushing involves clearing all vegetation from around the pole base, removing all tree limbs that encroach the cylinder up to a height of eight feet and remove all encroaching dead or diseased tree limbs from eight feet up to the top of the pole. Mechanical brushing is typically performed in the spring months. The contractor will then apply an Environmental Protection Agency (EPA) approved herbicide, the chemical application. SDG&E treats approximately 10,000 poles with a pre-emergent herbicide to minimize vegetative re-growth and reduce overall maintenance costs. The chemical application is typically done just

---

73 *Id.* at Attachment A, pp. 45-46.

74 A Risk Spend Efficiency calculation is not being performed on this activity because it is mandated pursuant to PRC § 4292.

before the rain season (during the fall and winter months) so that the application is activated and effective. Not all subject poles can be treated with herbicide due to environmental constraints, which include considerations such as slope, proximity to water, proximity to trees and other vegetation, and customer approval. Following this, re-clearing is performed in summer months by removing any additional flammable vegetation which has grown into, or blown into, the required clearance area since the last maintenance activity occurs. The need to revisit a subject pole multiple times is not uncommon, due to leaf litter blown back into the managed clearance zone during windy conditions and the growth of weeds and grasses that cannot be easily controlled by mechanical clearing or herbicide treatments. Trees adjacent to subject poles also require pruning to keep dead, dying or diseased tree limbs, branches, and foliage from encroaching into the radius of the cleared circle from the ground up to the height of the electrical conductors. This process aims to reduce growth of vegetation to minimize the potential of vegetation-related ignitions.

3. SDG&E-1-M19 – Enhanced Vegetation Management

In its 2019 WMP,[75] SDG&E proposed enhancements to its current vegetation management practices related to inspections, patrols, and trimming (specifically in the HFTD) as well as training. SDG&E proposed that, during the annually scheduled routine inspections, the pre-inspection scope for all VMAs would be increased to include trees within the strike zone of transmission and distribution electric facilities. Trees tall enough to strike overhead electric lines will be assessed for hazardous conditions and tree crown height will be reduced or removed to prevent a line strike from either whole tree failure or limb break out. This would include dead, dying and diseased trees, live trees with a structural defect, and locations with dense tree population that could strike as a result of wind exposure. Greater consideration would be given to environmental conditions that can impact a tree's relationship to the electric facilities, such as wind sway and line sag. The Commission approved SDG&E's enhanced vegetation management proposal on a pilot basis.[76]

[75] SDG&E's 2019 WMP at Attachment A, pp. 43 and 46 - 47.

[76] *See generally* D.19-05-039 at 8-10.

This same scope and criteria will be applied during an off-cycle tree patrol of all VMAs within SDG&E's service territory. These additional patrols will be timed to occur mid-cycle, with the routine inspection, so that all lines are reviewed twice annually in accordance with the enhanced scope.

SDG&E's tree-trim scope will be increased to achieve a 25-foot clearance post-prune, where feasible, between trees and electric facilities within the HFTD. This is a significant increase over the average 12 feet post-prune clearance that SDG&E currently achieves. There may be some barriers to achieving this goal. Environmental agencies, land agencies, and customers may oppose the tree pruning to this new clearance; however, SDG&E hopes to work through these issues to achieve the desired wildfire risk mitigation. Given that tree growth is by some degree uncertain and is a product of items outside of SDG&E's control (*e.g.*, weather), additional post-prune clearance provides another layer of mitigation to prevent a vegetation contact with SDG&E's overhead equipment. All tree operations will employ the concept of directional pruning, where all branches growing towards the lines will be rolled back to direct the growth away from the lines and to increase the post-trim clearance. These activities are expected to incrementally decrease the risk of tree branches contacting electric facilities, whether by growth encroachment, limb failure, or complete tree failure.

In addition, during elevated or extreme weather events that could lead to a designated RFW, SDG&E's vegetation management contractors are kept informed of the conditions, allowing them time to relocate crews into safe work areas. In instances of emergency tree pruning during extreme fire conditions, additional fire equipment and/or support from the contracted, professional fire services may be utilized.

In advance of a forecasted RFW, SDG&E will determine if vegetation management patrols are warranted to reassess tree conditions in advance of, during, or immediately following red flag events. SDG&E's Meteorology team will work with the Fire Coordination and Vegetation Management departments to determine where this activity should occur. These inspections are incremental to the routine cyclical inspections.

Further, SDG&E provides electrical equipment training to CAL FIRE representatives so that SDG&E is maintaining proper clearances of vegetation to conductors and equipment prior to the start of the fire season. While CAL FIRE inspections have been jointly performed with

SDG&E, this training is intended for CAL FIRE to better understand the operation of the electric system and which equipment should be targeted to best prevent an ignition source. This training can be used by CAL FIRE while they are conducting their day-to-day operations and inspections and is dependent on CAL FIRE's participation. CAL FIRE has communicated it will not be available for training in 2019 but will make themselves available in 2020 and future years.

This enhanced vegetation management program is consistent with the intent presented in the 2019 WMP. However, as SDG&E has begun implementing enhancements to its current practices, additional refinements made to reflect the items needed to move forward. These include additional tools, fleet, and some additional crews. As such, the costs were expanded as compared to what was estimated in the 2019 WMP.

4. SDG&E-1-M20 – Fuel Management Program

Protection of SDG&E's electric system from wildfires is critical to system reliability and first responder and public safety. Accordingly, SDG&E (in partnership with fire departments, fire safe councils, and other stakeholders) is implementing a comprehensive fuels management program to reduce wildfire fuel accumulations. This program removes, thins, or treats vegetation along SDG&E rights of way and adjacent fire-prone corridors. The reduction of wildland fuel in these areas has the potential to slow the spread of a fire and make it more likely to be contained. It also reduces the risk of electricity flowing through a smoke column and coming to ground.

This program is further expanding compared to levels described in the 2019 WMP.[77] The expanded efforts are due in part to the progress of the program, developed through partnering with cooperating agencies (*e.g.*, fire departments, CalTrans, local, state and tribal governments, and land management agencies).

E. Situational Awareness Protocols

1. SDG&E-1-C17 – Fire Science & Climate Adaptation Department

In recognition of the drought conditions, increased tree mortality, and ever-changing climate conditions, SDG&E established a Fire Science and Climate Adaption (FS&CA) department in 2018 comprised of meteorologists, community resiliency experts, fire

---

77 SDG&E's 2019 WMP at Attachment A, pp. 24-25.

coordinators, and project management personnel, as stated in the 2019 WMP.[78] This department's purpose is responding to and strategizing for SDG&E's fire preparedness activities and programs. As climate change, and community growth continue to impact the region, the FS&CA department must likewise evolve to address and provide situational awareness around emerging threats to utility infrastructure. This team will continuously evaluate new and emerging technologies, operationalizing as necessary and warranted. The FS&CA department performs a variety of activities that are accounted for in the department's cost centers. These activities are described in greater detail below.

Meteorological Capabilities and Technologies

The FS&CA department is responsible for SDG&E's meteorological capabilities and technologies,[79] including the development and management of various situational awareness tools. SDG&E owns and operates a network of 190 weather stations that are physically located on electric distribution and transmission poles and provide temperature, humidity, and wind observations every 10 minutes. This allows weather conditions to be monitored in near real-time on every distribution circuit and transmission line across the fire-prone areas of the SDG&E service territory. Each weather station location was carefully selected by SDG&E meteorologists based on their knowledge of the local terrain and its influence on meteorological conditions. By mid-2021, SDG&E is expected to increase the number of its owned and operated weather stations to approximately 225.

SDG&E's weather data is available to all SDG&E employees, weather agencies, fire agencies, educational facilities, and the general public. There are a number of locations and applications where the data may be viewed, including the publicly available SDG&E Weather Awareness System at https://sdgeweather.com. This site includes graphical images to visualize data and links to additional data, camera sites, and forecasts, and is scalable for a variety of devices, including tablet or hand-held.

The SDG&E weather network will continue to evolve in the years to come to maintain effective situational awareness and data quality. As the region faces the impacts of a changing

---

78 *Id.* at Attachment A, p. 47.

79 *See id.* at Attachment A, pp. 47-48.

climate, plans are being made to expand the weather network into high-impact wildland urban interfaces where more extreme weather and fire conditions may occur. Strategic weather station relocations are also planned to account for changes on the landscape and an increased understanding of climatological wind patterns in the SDG&E service territory.

Fire Potential Index

As described in the 2019 WMP,[80] the Fire Potential Index (FPI) was developed by SDG&E subject matter experts to communicate the wildfire potential on any given day to promote safe and reliable operations. This rolling seven-day forecast product, which is produced daily, classifies the fire potential based on weather and fuels conditions and historical fire occurrences within each of SDG&E's eight operating districts. This is also shared with local fire agencies, emergency responders, and the National Weather Service.

The FPI reflects key variables, such as the state of seasonal grasses across the service territory (green-up), fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value and those individual numeric values are summed to generate a fire potential value from zero (0) to seventeen (17), each of which expresses the degree of fire threat expected for each of the seven days included in the forecast. The numeric values are classified as "normal," "elevated," and "extreme."

The FPI development team, consisting of SDG&E meteorologists and fire coordinators, has validated the FPI values and its usefulness by recreating historical values dating back to 2002. The historical results bore a very strong correlation to actual fire events in terms of the severity of past fires and, in particular, provided very accurate information as to when the risks of uncontrolled and large-scale fires were high. SDG&E ties proactive and reactive operational practices and measures to the FPI values, with the further expectation that SDG&E will be able to reduce the likelihood its facilities and operations will be the source of ignition for a fire during times when the risk of fire (as measured by the FPI) is elevated or extreme.

Moving forward, SDG&E will continue to incorporate the latest available wildfire science, enhancing the predictors that contribute to the FPI, including live fuel moisture and the

---

80 *Id.* at Attachment A, p. 49.

state of seasonal grasses across the service territory. Modernizing the data inputs and better leveraging the high-performance computing environment will enable predictive analysis and artificial intelligence in the future.

Santa Ana Wildfire Threat Index

SDG&E, in concert with the U.S. Department of Agriculture, the U.S. Forest Service, and the University of California Los Angeles (UCLA), and in collaboration with CAL FIRE, the Desert Research Institute, and the National Weather Service, unveiled a web-based tool in September 2014 to classify the fire threat potential associated with the Santa Ana winds that are directly linked to the largest and most destructive wildfires in Southern California. The SAWTI, as explained in the 2019 WMP,[81] categorizes Santa Ana winds based on anticipated fire potential and uses several meteorological and fuel moisture variables generated from the Weather Research and Forecasting (WRF) Model to forecast the index out to 6 days. In addition to the index, a 30-year climatology of weather and fuels has been developed to help put current and future events into perspective.

The SAWTI calculates the potential for large wildfire activity based on the strength, extent, and duration of the wind, dryness of the air, dryness of the vegetation, and greenness of the grasses. Similar to the hurricane-rating system (category 1-5), the SAWTI compares current environmental data to climatological data and correlates it with historical wildfires to rate the Santa Ana wind event on a scale from "marginal" to "extreme." To help the region prepare for hazardous conditions, information from the SAWTI is issued daily to fire agencies and other first-responders, which has led to improved preparedness and operational decisions due to a better understanding of the timing and scale of a potentially catastrophic wildfire fueled by Santa Ana winds.

SDG&E will continue to collaborate with regional stakeholders so that the SAWTI is properly maintained and incorporates the latest available wildfire science.

81 *Id.* at Attachment A, pp. 49-50.

Climate Change Adaptation

SDG&E analyzes and evaluates fire-related data to determine if there are observable trends that can be linked with current climate change phenomena.[82] For example, between January 1, 2018 and December 16, 2018, 6,266 fires were reported by CAL FIRE across the state of California with a burn area totaling 876,131 acres. This is a decrease of 16 fires during the same period in 2017, but an increase of 554,474 acres burned and stands 375% of the 5-year averages of fires and acres burned with 2017's acreage being 111% of the 5-year averages.[83] Thus far in 2019, there have been 4,173 fires burning 38,610 acres, with fuel moistures and fire conditions being about a month behind their pace last year. While these numbers are exacerbated by dry conditions produced by well-below average rainfall statewide during the winter of 2017-2018, data ranging back to 1984 across San Diego County confirms that the number of high fire potential days each year has increased since the early 2000s. These trends are projected to continue as a combination of climate-related factors leads to increases in both fire season duration and severity through the end of the century.[84]

Regarding wildfire risk, California's Fourth Climate Assessment says that, "Broadly, wildfire risk will likely increase in the future as climate warms. The risk for large catastrophic wildfires driven by Santa Ana wind events will also likely increase as a result of a drier autumns leading to low antecedent precipitation before the height of the Santa Ana wind season (December and January)."[85] Because Santa Ana wind events typically deliver the warmest conditions to the coastal communities (they are responsible for 50% of days over 85° F in May

---

82 *See id.* at Attachment A, pp. 51-52.

83 CAL FIRE Incident Information: Number of Fires and Acres, *available at* https://www.fire.ca.gov/incidents/2018/.

84 Melillo et al. 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment*. U.S. Global Change Research Program, 841 pp. doi:10.930/JOZ31WJ2; Kent 2015: *Climate Change and Fire in the Southwest*. ERI Working Paper No. 34. Ecological Restoration Institute and Southwest Fire Science Consortium, Northern Arizona University: Flagstaff, AZ. 6 pp. http://www.swfireconsortium.org/. CEP (Climate Education Partners) 2014: *San Diego, 2050 is Calling.* https://www.sandiego.edu/2050/.

85 California's Fourth Climate Change Assessment, *San Diego Region Report* at 6, *available at* https://www.energy.ca.gov/sites/default/files/2019-07/Reg%20Report-%20SUM-CCCA4-2018-009%20SanDiego.pdf.

and 70% of those days in October), increases in fire potential may also extend to the coastal canyons and wildland urban interface areas that historically have not been as high of a wildfire concern. The warmer temperatures are also expected to enhance evaporation and transpiration even outside of Santa Ana events, which will deplete fuel moistures at faster rates. When coupled with longer dry periods, increases in tree mortality due to drought, and increased warmth, this will result in longer fire seasons across the region.

California's Fourth Climate Assessment also suggests that in addition to increased fire risk as a result of climate conditions, fire risk also increases due to increased population density in higher fire risk areas. This is because a majority of major fires in the Southern California region are a result of human activity, with "the two ignition sources that are associated with the largest area burned are from sparks from equipment, such as power saws or machine with gas or electric motors, and power lines."[86] The study shows that by the end of the century the expected area burned per wildfire in the San Diego region will increase by up to 50%.[87] Areas with low to medium structure density are at the highest risk. Given the current and expected future impacts of climate change, the FS&CA department actively and regularly communicates Operating Conditions to enable more informed operational decision-making.

Fire Science & Coordination

SDG&E employs a full-time staff of five fire prevention professionals, Fire Coordinators.[88] These fire coordinators are experienced firefighters and serve as a direct link between SDG&E and emergency-response agencies. They also serve as SDG&E's single point of contact for fire agencies on emergency incidents, utilize Incident Command System protocols, provide periodic updates to both firefighters and SDG&E personnel, establish radio and communications assignments, assist in the coordination of activities related to de-energizing and re-energizing power lines, coordinate with fire agencies for repopulation plans, and update on-scene personnel, control centers, service dispatch, and the SDG&E regional operations centers as to the status of each incident.

---

86 *Id.* at 27.

87 *Id.* at 28.

88 *See* SDG&E's 2019 WMP at Attachment A, pp. 24 and 67.

The Fire Science and Coordination team is active in the development of fire science based analytical tools, root cause analysis of ignition events, fire ignition data analytics, the development of fire prevention plans, professional forums, seminars, and fire safety training throughout SDG&E's service territory to incorporate this intelligence into the development and prioritization of mitigation strategies. They also participate in engineering and operational meetings to advise SDG&E personnel regarding fire threats and prevention. Through constant communication between SDG&E and emergency-response agencies in its service territory, the Fire Science and Coordination team is able to develop and implement best practices, reduce the risk of wildfire, and keep first responders safer when working around utility equipment.

2. SDG&E-1-C18/M21 – Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements

Significant intelligence related to wildfire potential is gathered from SDG&E's WRRM-Ops model. This model integrates the latest weather and GIS technology to understand wildfire growth patterns across the region (running 6,000 fire growth simulations per second, simulating 10 million fires in a single night). WRRM-Ops assesses the areas of highest fire danger before a wildfire begins so that preventative measures can be taken to enhance public safety and reliably operate the electric system. This model uses simulations generated from weather conditions, historical fire, and vegetation data to evaluate wildfire risk within the SDG&E service territory.

WRRM-Ops is also able to simulate the growth and potential impact of a wildfire anywhere in the SDG&E service territory should an ignition begin. Integrating all of the aforementioned weather data developed by SDG&E, the WRRM-Ops model can conduct an analysis to determine the immediate threats, enabling quick decision-making to help decrease the impacts of wildfire.

Because WRRM-Ops has proven to be a beneficial tool for SDG&E, it is now being utilized by utilities, regulators and emergency responders across the state. SDG&E intends to expand WRRM-Ops beyond the levels described in the 2019 WMP[89] to provide significant enhancements for this technology, including additional enhancements in fire science and data analytics. SDG&E's Fire Science & Coordination and Meteorology teams plan to partner with

---

[89] *Id.* at Attachment A, p. 50.

academia and fire agencies to further expand and share fire modeling capabilities. Enhancements will also include the creation of the SDG&E Fire Science and Innovation Lab to foster the continued evolution of fuel moisture modeling, weather stations, cameras, vegetation management data and LiDAR data to continuously improve our situational awareness.

3. SDG&E-1-C19/M22 – Camera Networks and Advanced Weather Station Integration

As explained in the 2019 WMP,[90] SDG&E utilizes a total of 107 cameras that enhance situational awareness around wildfire. Twenty of these cameras are owned by SDG&E, while 87 cameras are supported by SDG&E in collaboration with the UCSD as part of the HPWREN (see mitigation SDG&E-1-M15 above). Of these 87 cameras, 72 are static and 16 are high-definition pan-tilt-zoom "Alert SDG&E Cameras," which are capable of remote directional and zoom control.

The Alert SDG&E Camera network is a state-of-the-art camera network designed to monitor wildfire activity and enhance situational awareness for SDG&E and its first responders and the communities they serve. SDG&E partnered with UCSD and the University of Nevada to deploy this network of 16 live-stream pan-tilt-zoom mountaintop cameras, which allows for quicker identification and triangulation of wildfires. Alert SDG&E Cameras are heavily used by CAL FIRE's Monte Vista Dispatch Center to aid in better locating and sizing up wildfires for initial attack prior to the arrival of first responders.

The SDG&E weather network has been an integral aspect of the Community Fire Safety Program over the last decade. The weather information is used to calibrate models such as the FPI and the SDG&E Outage Prediction Model which gives the Company the ability to anticipate when critical fire weather conditions or strong storms are approaching the area, allowing proactive preparedness measures to be taken.

In the 2020-2022 time period, SDG&E seeks to further modernize its weather network beyond the levels put forth in the 2019 WMP.[91] This weather network, which currently consists of 190 weather stations, brings superior situational awareness for weather conditions impacting

---

90 *Id.* at Attachment A, p. 50.

91 *Id.* at Attachment A, p. 53.

SDG&E's electric and gas system. The weather network also serves as a data foundation for high-performance computer modeling that supports multiple analytical tools used across the organization. SDG&E plans to modify its weather system by adding and rebuilding weather stations and replacing aging sensors and equipment with the latest technology. This will include new dataloggers, thermometers, hygrometers, anemometers, batteries, solar panels, modems, and in some cases pyranometers.

4. SDG&E-1-C20/M23 – High-Performance Computing Infrastructure

SDG&E owns three high-performance computing clusters used to generate high quality weather data that is incorporated directly into operations. Collectively, nearly 2,000 compute core hours of high-performance computing are used per day to generate operational products, including the SAWTI, FPI, and WRRM-Ops. The forecast data generated by the supercomputers is shared with several partners, including the U.S. Forest Service, which disseminate the data through their public website, and the National Weather Service.

SDG&E plans to continue the production of forecast products into the foreseeable future. As science evolves and new technologies become available, SDG&E will use its computing clusters to integrate the new methodologies in order to maintain forecast reliability and situational awareness.

In 2022, SDG&E plans to replace its existing supercomputers which, at that point, will be at the end of their useful lives. Such a program is needed because it is essential to the ongoing development of fire science and big data analytics. The output from this high-performance computing program is required to enable the continuous evolution of fire science and analytical fire preparedness tools such as the FPI and SAWTI. The replacement of these supercomputers was not included in the 2019 WMP.[92]

5. SDG&E-1-M24 – Ignition Management Program

In 2019, SDG&E began to establish an Ignition Management Program (IMP). The purpose of this program is to track ignitions and potential ignitions as well as to perform root cause analysis on each ignition or potential ignition to detect patterns or correlations. Such ignition or potential ignition events will be documented and analyzed. When patterns or

[92] *Id.* at Attachment A, p. 48.

correlations are identified, the outcomes are communicated and assigned to mitigation owners from the business unit most logically positioned to eliminate or reduce future events of a similar nature.

In its 2019, SDG&E mentioned that it was considering additional staff to support the IMP.[93] In mid-2019, SDG&E employed a Fire Ignition Management Program Coordinator to implement and manage this program. With the staff in place, now a pilot of the IMP is underway. SDG&E expects to learn from the IMP pilot and expand the program during the next GRC cycle. The expansion of the IMP would include additional IT-related support to house and process data associated with findings from the program. However, given that the IMP program is in a pilot stage, SDG&E is unable to forecast future IT-related costs at this time. SDG&E will update its forecasts for the IMP in future GRC and WMP filings.

6. SDG&E-1-C21/M25 – Asset Management

In 2017, SDG&E formed its Asset Management Program team, as a central group, to develop and implement a holistic and sustainable asset management system for electric assets with an integrative approach for governance, strategy, analytics and continuous improvement. The new asset management system is being developed to conform with ISO 55000, an international standard that specifies the requirements for the establishment, implementation, maintenance, and improvement of an asset management system. Benefits of such a system may include enhanced asset safety, improved performance, managed risk, demonstrated compliance, and improved efficiencies and effectiveness of asset utilization and operations. Asset management is a critical element of SDG&E's focus on creating sustainable and high-quality asset safety for electric operations, and optimizing asset utilization, while mitigating asset-related risks. This is also one element of SDG&E's vision for an electric safety management system, as further discussed in SDG&E's Chapter RAMP-F (Safety Culture). A comprehensive asset management system, which includes process improvements, data analytics and system solutions, will provide the access to and integration of data throughout the asset life cycle to develop analysis and a health index for critical assets.

---

93 *Id.* at Attachment A, p. 24.

SDG&E is developing an asset health index (AHI) on its assets to identify and compare assets based on its likelihood of failure. An AHI is a score designed to track the condition and performance of an asset by applying statistical modeling and predictive analytics to multiple sources of data and used as a basis for asset management strategies. The key benefits of employing AHI include the ability to measure overall health of assets, recognize asset data parameters associated with failure modes, detect failures, and relatively compare between assets of same class in a consistent manner. Asset risk is determined when AHI and the associated asset failure consequence or impact are jointly considered. Based on this asset risk information, asset replacement or rehabilitation strategies would be evaluated, prioritized, and implemented to manage the asset in a manner that aligns with SDG&E's overall risk management strategy, supports risk-informed platform for managing assets, and reinforces safe operations, maintenance and proactive replacement strategies. Integrating this asset risk information with other inputs, such as circuit risk index for situational awareness, especially within fire-prone areas, will inform the appropriate asset-related operational decision-making and strategies for enhanced reliability and safe operations of assets on given current and expected wildfire conditions.

SDG&E's asset management program is forecasted to further expand from its description in SDG&E's 2019 WMP,[94] due to anticipated incremental data exploratory analyses and data integration of key asset attributes from multiple sources and associated costs of systems needed to further develop AHIs and sustainably support the asset data analytics.

Because asset management efforts will benefit SDG&E's entire service territory, SDG&E's RAMP showing has divided costs from this activity between the Wildfire and Electric Infrastructure Integrity RAMP risk chapters, 60% and 40%, respectively. These percentage allocations are based on the HFTD area, which accounts for about 60% of the overall service territory area in terms of electric distribution miles.

[94] *Id.* at Attachment A, p. 32.

7. SDG&E-1-M26 – Monitoring and Correcting Deficiencies

As part of its 2019 WMP, SDG&E proposed specific measures as a way to monitor the effectiveness of its WMP.[95] In monitoring all of these measures, SDG&E is able to determine the general effectiveness of the overall WMP, identify potential issues and deficiencies before too much time has occurred, and plan corrective remedies as needed. Beyond the seven key measures ready noted, SDG&E also plans to closely monitor each of its programs and initiatives detailed within the overall WMP so as to verify the progress of each program over time. All of these components collectively will allow SDG&E to determine the effectiveness of the programs brought forth this far and allow SDG&E to determine where new programs and initiatives can be developed to further expand its overall wildfire plan.

To effectively evaluate its mitigation plan, SDG&E proposes herein, consistent with its 2019 WMP,[96] to develop a database and tool for purposes of monitoring. Such tools will require some external support likely in the beginning stages. SDG&E believes these tools are necessary to monitor compliance with its WMPs now and in future years.

8. SDG&E-1-M27 – Wildfire Mitigation Personnel

SDG&E's workforce and organizational structure has evolved significantly since its first fire mitigation efforts. As explained in the SDG&E's 2019 WMP, in the infancy of these efforts, SDG&E largely utilized cross-functional teams that continued to transform into additional formal programs and personnel.[97] In 2019, SDG&E recognized that a new department focusing on fire mitigation, fire mitigation strategies, program measurement, and vegetation management would prove useful in assessing the overall effectiveness and direction of SDG&E's WMP.

In July 2019, this new department was formed using management personnel already deeply familiar with the WMP and would then add personnel as the needs arose. This new organization has been named the Wildfire Mitigation and Vegetation Management department.

---

95 *Id.* at Attachment A, pp. 75-80.

96 *Id.* at Attachment A, p. 81.

97 *Id.* at Attachment A, pp. 31-32 and 71-72.

Overseen by the Director of the Wildfire Mitigation and Vegetation Management, four groups will address aspects of the overall WMP effort:

- The Wildfire Mitigation Programs group will be involved with the various regulatory proceedings that address wildfire as well as legislative and media inquiries.
- The Vegetation Management group will manage the current tree and vegetation management inspection and trim program and will begin to address SDG&E's newly formed fuels management program.
- The WMP Strategic group will develop metrics, lead vision projects, promote new ways to enhance fire safety and explore advancements to further drive improvement and change.
- The WMP Accountability group will be responsible for monitoring fire-related metrics, tracking WMP activities, complying with reporting requirements, provide for governance specifications and procedures, and act in a lead capacity on audits of the WMP programs.

It is anticipated that the new Wildfire Mitigation and Vegetation Management department will be fully functional by the end of the first quarter of 2020

9. SDG&E-1-M28 – NMS Situational Awareness Upgrades

SDG&E's Outage/Distribution Management system uses Oracle's Network Management System (NMS) as the operational tool to manage planned and unplanned outages. Today, SDG&E's weather data, including FPI and wind speed data, are leveraged extensively, through manual processes, to set operational restrictions and make operational decisions. SDG&E plans on building key weather integrations into the NMS system to enable more accurate and real-time operational decision-making to implement reclosing policies, sensitive relay settings policies, and work cancellation decisions during extreme weather events.

In 2020, key integrations will be developed to provide NMS visibility into operational conditions to make informed operational decisions related to wildfire risk. In addition, this improved functionality will provide better visibility into active planned and unplanned work in the HFTD, to identify potential risks during events. In 2021-2022, the generation of switch plans will be automated to turn off reclosing and enable sensitive relay profiles in the HFTD. These tools will enable the necessary situational awareness to make operational changes during high risk events and provide real-time visibility into current conditions in the field, to make informed operational decisions. This program is newly presented herein and was not included in the 2019 WMP.

10. SDG&E-1-M29 – Situational Awareness Dashboard

Current Public Safety Power Shutoff protocols utilize several factors listed in activity SDG&E-1-C22 below. SDG&E is currently seeking to expand operational awareness capabilities to include risk factors of electric system failure and/or risks related to foreign causes of electric system failure, which serve to inform PSPS decisions. SDG&E plans to expand its current operational awareness by building visual dashboards that integrate the Vegetation Risk Index (VRI), historical wind conditions, and the ability to identify areas that contain vulnerable electric infrastructure. These systems will also have the capability to geolocate infrastructure with poor historical system performance and to identify at-risk infrastructure by extrapolating asset failure analytics. Additionally, SDG&E is seeking to develop, document, and deploy a circuit risk index that will quickly aggregate this data for the purposes of operationally quantifying this risk into a single metric that can be tied to various system isolation points.

The PSPS situational awareness dashboard will be built in 2019, incorporating VRI, historical wind conditions, and some elements of at-risk infrastructure. In 2020, the asset management program (see activity SDG&E-1-C21/M25 above) will identify and automate several data sources that generate risk quantification, system performance, system design and nameplate information, and maintenance data, to begin aggregating these data sources into a single location for use by a circuit risk indexing tool. Once aggregated in 2021-2022, SDG&E will employ data science to find correlations between system performance and various risk factors. This data will be utilized to create a data model that will create components of a Circuit Risk Index, which is planned for end-of-year 2022 deployment.

This program is newly presented herein and was not included in the 2019 WMP.

F. Public Safety Power Shutoff

1. SDG&E-1-C22 – Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, Public Safety Power Shutoff and Re-energization Protocols

As described in the 2019 WMP,[98] SDG&E has an obligation to operate its system safely. This obligation requires SDG&E to de-energize circuits (*i.e.*, turn off power) when necessary to protect public safety (Public Safety Power Shutoff or PSPS). Any decision to de-energize circuits for public safety is made in consultation with SDG&E's Emergency Operations Center (EOC), Meteorology, and SDG&E leadership. Typically, it is expected, but not required, that the FPI would be "extreme" or that there would be a "red flag warning" in effect when a PSPS decision is made.

A PSPS is a last resort measure to reduce wildfire risk. SDG&E considers a wide variety of inputs to determine whether to de-energize portions of its system. SDG&E leverages a multitude of situational awareness data and input from its subject matter experts when considering the need for a PSPS event. In determining whether to employ a PSPS in any area of its service territory, SDG&E considers a variety of factors such as:

- Weather conditions;
- Vegetation conditions;
- Field observations;
- Information from first responders;
- Flying debris;
- Meteorology;
- Expected duration of conditions;
- Location of any existing fires; and
- Wildfire activity in other parts of the state affecting resource availability.

Utility operating experience is required to analyze all the various inputs and decide how to manage risk to the communities affected.

---

98 *See id.* at Attachment A, pp. 54-55.

If SDG&E determines it is necessary to employ a PSPS for portions of its system, re-energization will take place after the SDG&E weather network shows that wind speeds have decreased and SDG&E weather forecasts indicate that winds will not re-accelerate at or above dangerous levels. All lines that have been de-energized are inspected for damage before re-energization may occur. Once a line is patrolled and any needed repairs are made the area will be patrolled again and then be re-energized.

2. SDG&E-1-C23/M30 – Communication Practices

In advance of the peak of fire season, in accordance with P.U. Code § 8386(c)(16)(B) and D.19-05-039, SDG&E will conduct ongoing education campaigns in a minimum of eight languages (English, Spanish, Mandarin, Cantonese, Korean, Tagalog, Vietnamese and Russian) regarding how to be prepared for emergencies in the event of a wildfire, natural disaster or major outage.

SDG&E's comprehensive wildfire communication program consists of a multi-pronged approach and is divided into three phases – prior to, during, and following the extreme weather event. The purpose of the communications program is to educate and help the public prepare for, respond to, and recover from a Public Safety Power Shut Off and/or wildfire event. In the days leading up to a forecasted PSPS and during an active event, SDG&E establishes and maintains contact with customers and community stakeholders that it believes may be impacted. Communication is maintained with public safety partners, impacted customers, affected populations (non-customers), critical facilities and infrastructure, Access and Functional Needs (AFN) populations, and community partners. Various communication platforms are utilized to communicate through the various stages of an event. Subject matters covered in communications regarding an event include, but are not limited to: event timing, the wildfire mitigation activities SDG&E is employing, and resources available to support the impacts of a PSPS. SDG&E also communicates with key stakeholders, public officials, and first responders through a variety of channels and personnel to align with their established communication protocols.

In advance of fire season, SDG&E initiates its targeted wildfire safety education and outreach campaign. The campaign begins in July and runs through November. It targets all customers and stakeholders in the service territory and enlists multiple tactics to inform residents and businesses in the region. The outreach campaign includes: print advertising, paid and organized social media, online display and video paid searches, radio spots, a High Fire Threat District newsletter, bill inserts, collateral materials for outreach events (*e.g.,* open houses and community wildfire safety fairs), collateral for vegetation management outreach, collateral for Access and Functional Needs populations, content for the sdge.com/wildfire-safety webpage and an SDG&E wildfire safety documentary leveraged for TV spots, theater trailers, and outreach events. Print advertising for the outreach campaign is provided in eight languages: English, Spanish, Mandarin, Cantonese, Korean, Vietnamese, Tagalog and Russian. The in-language advertising is placed in corresponding in-language community publications.

Extreme weather conditions can change at any time, and SDG&E's top priority is safety. SDG&E's goal is to provide impacted communities with advanced notifications. In the event of a Public Safety Power Shutoff, SDG&E will advise public safety authorities, first responders, affected communities and local municipalities in the impacted areas.

Notice to Customers

Dependent on conditions, SDG&E will communicate with customers in advance of an event – 48, and 24 hours as well as 1-4 hours in advance when possible, prior to shutting off power, upon starting safety inspections of affected powerlines and upon re-energization, as practicable.[99] The Company will also reach out to the AFN populations and the organizations that serve them during the same intervals. We communicate these notifications to customers in eight language (English, Spanish, Mandarin, Cantonese, Vietnamese, Korean, Tagalog and Russian). SDG&E has launched an ongoing campaign asking customers to update their contact information and sign up for outage notifications at *sdge.com/MyAccount*.

SDG&E uses this information to reach its customers using the Emergency Notification System (ENS) through phone, text and/or email in advance of a Public Safety Power Shutoff, if conditions allow, and throughout the event until power is restored.

In addition to notifying customers directly, outage updates are provided through social media, local news, radio and SDG&E's website at *sdge.com* and *sdgenews.com*.

[99] *See* D.19-05-042 at Appendix A, pp. A-7 to A-8.

Power Shutoff events may be avoided if weather conditions improve. In that instance, SDG&E would notify customers that weather conditions have improved in their area, and SDG&E do not anticipate the need to turn off their power for safety.

SDG&E also encourages customers to visit *sdge.com/wildfire-safety* for tips on putting together an emergency preparedness plan for their home or business.

Note that SDG&E may not have advance opportunity to provide notice when CAL FIRE or a local agency requests a Public Safety Power Shutoff due to an active wildfire or other emergency response situation. Additionally, if a problem is identified that poses an immediate safety risk, SDG&E may have to turn off the power immediately. For instance, a car crashing into a power pole may require immediate de-energization for safety.

Notice to State, Counties, and Cities

When conditions allow, SDG&E will make every attempt to notify cities, counties and emergency response partners about a potential Public Safety Power Shutoff. The Company will also reach out to government and agency contacts alerting them that conditions are being monitored that may either cause outages or require SDG&E to de-energize for safety in the coming days.

Notice to Customers Who Provide Critical Services

SDG&E has identified and has direct contact with companies and organizations that provide critical services, such as healthcare, fire stations, schools and universities, water agencies, and communications providers, within a potentially impacted area. SDG&E wants to be sure its customers providing critical services know that a Public Safety Power Shutoff may occur during extreme weather conditions, so they can take steps to prepare, such as securing backup generation. SDG&E also asks critical services customers to confirm an appropriate point of contact for these types of notifications, along with the correct contact information, so that SDG&E can provide early warning notifications, when and where possible, depending on conditions.

Notice to Medical Baseline Customers

SDG&E takes additional steps to reach customers enrolled in the Medical Baseline program. Customers are asked to evaluate the safety of their situation and have an emergency plan ready in case of an outage. When communicating with Medical Baseline customers, the

Emergency Notification Service captures a positive physical response when the customer is contacted. If a positive response is not obtained, a second live attempt is made through SDG&E's Customer Call Center. If no contact is achieved with the second attempt, SDG&E field personnel are dispatched to the address of record to deliver the message in person.

During a Public Safety Power Shutoff event, there may be a need to provide additional support to an impacted community. SDG&E may open a Community Resource Center near the affected area, if conditions prolong the estimated outage duration. Community Resource Center activations will be communicated via the SDG&E website, social media, local news and radio and the SDG&E News Center. At these Centers, residents will have access to water, light snacks and charge small electronic devices, as well as receive the most up-to-date information about the power shutoff.

Additionally, SDG&E communicates the differences between an unplanned outage and a Public Safety Power Shutoff. Despite SDG&E's best efforts to maintain reliable service, unexpected outages happen. These unplanned outages are caused by various circumstances beyond SDG&E's control, such as traffic accidents, damage to power lines and Mylar balloons caught in overhead wires. In contrast to an unplanned outage, a Public Safety Power Shutoff occurs after careful planning and analysis of the various threats to public safety. If a Public Safety Power Shutoff takes place, it will be uniquely identified on our outage map with a different marker. SDG&E encourages the public to learn more about planned and unplanned outages at sdge.com/outage-map.

Finally, a component of SDG&E's communication program for wildfire safety includes contributing to and supporting the statewide Public Safety Power Shutoff campaign established in 2019. The overarching message communicated to the public in SDG&E's service territory is that all Californians need to take important steps to get ready before the wildfire season, such as creating an emergency kit and having a thorough emergency plan. The statewide campaign refers the public to learn more about preparing for the threat of wildfire and Public Safety Power Shutoffs at www.prepareforpowerdown.com.

While SDG&E's communication practices were presented in the 2019 WMP,[100] this activity is being expanded herein to implement the legislative mandates in P.U. Code § 8386(c)(16)(B), D.19-05-039 (SDG&E's 2019 WMP Decision), and D.19-05-042 (De-Energization Phase 1 Decision). Accordingly, SDG&E is now implementing the various directives, including participating in a new statewide education campaign on de-energization.

3. SDG&E-1-C24 – Mitigating the Public Safety Impact of PSPS Protocols

As described in the 2019 WMP,[101] SDG&E manages and mitigates the impacts of a PSPS event through collaboration with key stakeholders in the wildfire response community. SDG&E partners on a regular and ongoing basis with the following agencies to address a range of fire prevention and emergency activities:

- **San Diego County Fire Chiefs' Association** – SDG&E provides monthly written and oral updates while encouraging feedback and comments on planning, response, recovery, and communications programs;
- **CAL FIRE and the San Diego County Fire Authority** – SDG&E engages in daily communications related to aerial firefighting and contract management of the year-round Skycrane and Blackhawk programs;
- **County Unified Disaster Council** – SDG&E receives and provides quarterly updates on regional planning and response programs while building relationships with 18 cities, the County of San Diego, and participating Special Districts;
- **County Office of Emergency Services** – SDG&E communicates and meets as needed, but no less than quarterly to discuss and agree on emergency planning, response, recovery, and communications needs;
- **All Fire Agencies in San Diego County** – SDG&E meets annually with fire agencies in San Diego County (including cities, fire districts, military, and tribal) to provide in-service training and exercises on electric and

[100] SDG&E's 2019 WMP at Attachment A, pp. 55-56

[101] *Id.* at Attachment A, pp. 56-58.

natural gas safety, response, Incident Command integration with utilities, and communications, to coordinate response during wildfire and other emergencies;

- **All Law Enforcement Agencies in San Diego County** – SDG&E engages in various activities including outreach efforts, trainings, and data sharing with the San Diego County Sheriff's department and all municipal law enforcement agencies; and
- **Fire Dispatch Centers** – SDG&E provides bi-annual communications training and requirements related to electric and natural gas incidents and emergencies to fire dispatch centers.

G. Preparedness and Response

1. SDG&E-1-C25/M31 – Emergency Management Operations

SDG&E manages emergencies in alignment with the state Standardized Emergency Management System (SEMS) and federal National Incident Management System (NIMS), to coordinate across all levels of utility, government, and agency activity. The Company utilizes a utility-compatible Incident Command System (ICS) structure as an all-hazards framework to manage emergency incidents and events. ICS is the combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure and serves as the mechanism to direct those functions during an emergency response. Further details regarding ICS are discussed in SDG&E's RAMP risk chapter Customer and Public Safety (Chapter SDG&E-5).

The SDG&E Emergency Management organization is responsible for coordinating emergency management activities and activation of the Emergency Operations Center. The department's mission is to support effective, efficient, and collaborative planning, preparedness, response, and recovery processes for all hazards and risks, including those associated with the Wildfire risk and Red Flag Warning incidents, enterprise-wide. Collectively, this department leads efforts and strategies to prepare for, respond to, and recover from all risks, hazards, and incidents that may impact SDG&E operations.

SDG&E's EOC serves as the location from which centralized emergency management is coordinated. To respond and recover effectively from all hazards and threats, like wildfires, SDG&E established an EOC with cross-functional teams representing every major business line within the Company and functioning within a utility-compatible ICS. The activation of the EOC assembles the internal subject matter experts to assess and provide situational awareness to internal and external stakeholders, overarching incident objectives, planning, anticipation, response, communications, and coordination.[102] External Emergency Management partners, such as the County of San Diego Office of Emergency Services (OES) and California OES (Cal OES) are provided with situational awareness up to 24-72 hours in advance or as soon as operationally feasible; additionally, those partners are embedded within SDG&E's EOC during emergency conditions.

SDG&E is further expanding this activity[103] from the description in the 2019 WMP,[104] to include four additional full-time equivalents (FTEs). Three FTEs are needed to support SDG&E's Aviation Services and were staffed in 2019. SDG&E's aviation program, as it relates to wildfire, is now considered to be a year-round program and includes two firefighting assets. Aviation staff also works extended hours when necessary. Thus, the expansion of this program includes additional FTEs, more days, longer hours, and additional assets. An additional FTE is also needed in Emergency Management, to address a continued focus on Wildfire, including PSPS events, and the increased labor hours expended on these activities. This FTE will help in developing training, leading exercises, and supporting activations, as well as to help develop plans related to non-wildfire risk factors including cybersecurity, earthquake, natural gas, tsunami, terrorism, active shooter, and other man-made and natural disasters.

---

[102] To prepare for and support emergencies, GIS is used to provide information about SDG&E's system. *See id.* at Attachment A, pp. 29-30.

[103] While Emergency Management supports all disasters, for purposes of this RAMP presentation, Emergency Management activity costs are included in the Wildfire risk chapter. This is because the majority of SDG&E's EOC activations are related to Wildfire. Accordingly, and for simplification in this filing, costs presented in this Chapter are not allocated to other risks.

[104] SDG&E's 2019 WMP at Attachment A, pp. 58-59.

2. SDG&E-1-C26 – Disaster and Emergency Preparedness Plan

As described in the 2019 WMP,[105] the Company's Emergency Response Plan (CERP) and risk-specific response plans provide a framework by which SDG&E can effectively coordinate the Company's pre-incident and response/recovery activities to a given threat or hazard.[106] Pursuant to the CERP, the Utility Incident Commander or Officer-in-Charge (OIC), is ultimately responsible for incident management and support activities respectively. While a Utility Incident Commander or OIC may delegate authority, they cannot delegate the responsibilities outlined in the Wildfire Annex or the CERP.

With respect to community outreach and public awareness, SDG&E has created a multi-level approach related to fire threats, fire prevention, and emergency preparedness. Plans for community outreach and public awareness occur before, during, and after a wildfire. Such efforts include videos, collateral, and print advertising before and after wildfires. These materials have previously educated customers about how to be prepared for wildfires and encouraged them to sign up for outage notifications and updates through SDG&E's My Account portal. SDG&E anticipates continuing these outreach messages, as described above in activity SDG&E-1-C23/M31 Communication Practices above, to further prepare customers for PSPS events.

Key elements of SDG&E's multi-level approach to community education and outreach include the following

- Fire safety stakeholder's coordination – SDG&E has worked with various stakeholders, such as local schools, water districts, disability rights advocates, consumer groups, and fire departments, to develop a joint fire prevention plan. SDG&E has implemented many of the solutions identified by the stakeholders, including deactivating automated reclosers and undergrounding portions of the electric system where feasible.
- Partners with organizations dedicated to readiness and response – SDG&E partners with approximately 98 non-profit organizations dedicated to

---

105 *Id.* at Attachment A, pp. 59-68.

106 Costs were not identified for this activity because it is embedded in internal labor.

readiness and response to wildfires and emergencies. SDG&E is also a member of California Utilities Emergency Association (CUEA), who serves as a point of contact for critical infrastructure utilities and the Cal OES and other governmental agencies before, during, and after an event.

- First responder outreach program – SDG&E works with local, state, and federal fire agencies, regional dispatch centers, law enforcement, and other emergency management partner agencies so that effective command, coordination, and communications are in place in preparing for and responding to incidents.
- Community outreach – SDG&E supports non-profit organization whose programs promote emergency preparedness and safety at home and in communities within its service territory, including Tribal Lands. In addition, SDG&E held community workshops regarding its PSPS practices. SDG&E incorporated much feedback from those workshops into its public safety initiatives.
- Community Resource Centers (CRCs) – as a result of community feedback, SDG&E has established CRCs to help communities in real-time during extreme weather events. To date, eleven customer-owned facilities in the HFTD have been utilized, located specifically in areas most likely to be affected by a PSPS to serve as CRCs. SDG&E operates these centers to offer impacted customers a place to gather, charge cell phones, and obtain current information and comfort items such as bottled water, light snacks, and ice for temporary refrigeration. These CRCs are powered by portable generation provided by SDG&E and are located in areas that are not within reasonable travel distances from areas that are not impacted by PSPS.
- Community communications – SDG&E provides regular, proactive communications to residents and businesses located in the HFTD. These communications provide information about emergency preparedness.

Further, SDG&E's workforce is an integral part of its disaster and emergency preparedness. Under the ICS framework, SDG&E's approach to a well-trained workforce involves integrating training sessions and exercises for field Utility Incident Commanders, EOC responders, and executives. All field operational responders are required to participate in Utility ICS training and follow Electric Standard Practice No. 113.1 (ESP 113.1), which specifically addresses wildland fire prevention and safety. The annual ICS training cycle of operational leaders, field responders, and supporting personnel includes cross-functional training workshops, and exercises covering all-hazards as well as the deployment of field training advisors for purposes of continuous improvement on practical application in the field. In addition, SDG&E actively trains its workforce with the appropriate electric distribution and transmission operational skills.

3. SDG&E-1-C27 – Customer Support in Emergencies

SDG&E provides emergency residential and non-residential customer protections and availability communications for wildfire victims, as ordered by the CPUC.[107] Examples of protections include billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, and specific support for low income and medical baseline customers.[108] This is also described in SDG&E's 2019 WMP.[109]

SDG&E will provide descriptions of the protections offered to affected customers on a special landing page on its website, SDG&E.com (with a contact telephone number for more details of eligibility and protections available) and promote the page with social media campaigns. In addition, SDG&E will make every effort possible to contact impacted customers to bring awareness regarding these protections. An Energy Service Specialist (ESS) or an account executive will make these calls.

---

107 Commission Resolution M-4835 (January 11, 2018). SDG&E filed Advice Letter 3177-E on January 26, 2018 in compliance with Resolution M-4835, which was made effective December 7, 2018.

108 Costs were not identified for this activity because they are not tracked in that manner.

109 SDG&E's 2019 WMP at Attachment A, pp. 68-71.

4. SDG&E-1-C28/M32 – Wildfire Infrastructure Protection Teams (Contract Fire Resources)

SDG&E contracts for wildfire prevention and ignition mitigation services, Contract Fire Resources, which are paired with SDG&E personnel during times of elevated wildfire potential. SDG&E may extend Contract Fire Resources coverage depending on Operating Conditions or when specific needs arise. These Contract Fire Resources accompany SDG&E construction crews and other electric workers to provide site-specific fire prevention and ignition mitigation during the workday and after hours. During RFW events or when the FPI is "Extreme," additional Contract Fire Resources are deployed with SDG&E personnel to mitigate the risk of fire from emergency work. The fire prevention personnel that serve as Contract Fire Resources largely mirror the classification of an ICS Type VI Fire Engine, which carries two qualified firefighters, firefighting hose, valves, and approximately 300 gallons of water.

This program is being further expanded from the level presented in SDG&E's 2019 WMP,[110] from about five months to now approximately six months. Beginning in 2019 and continuing through the years 2020 through 2022, SDG&E is planning to increase both the number of days and the number of Contract Fire Resources on property for each of those days. The Contract Fire Resources role will remain the same and will focus on prevention and ignition mitigation. Contract Fire Resources will continue to be paired with SDG&E field personnel to mitigate the risk of a fire ignition origination for SDG&E activities.

5. SDG&E-1-C29/M33 – Aviation Firefighting Program

The threat of wildfire risk throughout California and the region is ongoing and year-round. When wildfires occur north of SDG&E's service territory, there is the potential that CAL FIRE may divert other aerial firefighting resources to emerging wildfires in other parts of the state. This can lead to reduced aerial firefighting capability in the San Diego region. Accordingly, SDG&E has developed and implemented an effective, year-round aerial firefighting program to support the fire agencies in its service territory.

---

110 *Id.* at Attachment A, p. 23.

SDG&E has two aerial assets available for the purpose of helping fight fires. As described in David Geier's TY 2019 GRC testimony,[111] SDG&E has a lease, started in 2018, for year-round use of an Erickson Sikorsky S-64 crane helitanker (Skycrane). Starting in June of 2019, SDG&E also has a year-round lease for a Sikorsky UH-60 Blackhawk helitanker (Blackhawk). Both firefighting assets are Type 1 helicopters (also known as helitankers), which are defined as carrying over 700 gallons of water to fight fires. The Skycrane has the capability of dropping up to 2,650 gallons of water, and the Blackhawk has the capability of dropping 850 gallons of water. Additionally, the Blackhawk has night fly capability.

SDG&E has an agreement with the County of San Diego, CAL FIRE, and the Orange County Fire Authority for aerial firefighting within SDG&E's service territory. Dispatch of SDG&E's aviation firefighting assets is performed through CAL FIRE and supports their initial attack strategy to keep wildfires at less than 10 acres. SDG&E maintains a Flight Operations duty to assist in dispatching availability of the assets, 365 days per year. This allows the assets to be launched rapidly once dispatched by CAL FIRE. For 2018, the Skycrane responded to dispatch 33 times, dropping a total of 248,621 gallons of water during 278 drops. Through October 2019, the Skycrane and Blackhawk together dropped a total of 220,453 gallons of water during 279 drops.

SDG&E's aviation program herein is consistent with the levels put forth in the 2019 WMP.[112]

6. SDG&E-1-C30 – Industrial Fire Brigade

SDG&E has contracted an Industrial Fire Brigade (IFB), which is available 24 hours a day, 365 days a year. The IFB differs from the Contract Fire Resources in that the IFB is specially trained to fight fires involving electrical equipment (in particular substations and large transformers) as well as flammable liquids, whereas Contract Fire Resources are focused on site-specific fire prevention and ignition mitigation. The IFB members are stationed at facilities near the geographical center of SDG&E's service territory and are fully equipped to handle utility-related fire emergencies.

---

[111] Application (A.) 17-10-007/-008 (cons.), Ex. 360 (SDG&E Geier Supplemental Direct).

[112] SDG&E's 2019 WMP at Attachment A, pp. 23-24.

The IFB incorporates a portable fire suppression trailer equipped with 300 gallons of Class B alcohol resistant firefighting foam, 500 pounds of chemical extinguishing agent, a 500 gallon-per-minute monitor, and hoses designed to work with hydrants or other fire apparatus. SDG&E also provides three additional trailers to strategic fire agencies that are proximate to key SDG&E facilities to aide in emergency response.

The IFB also develops comprehensive pre-emergency response plans for each SDG&E substation and large-scale energy storage facility.

SDG&E expects this control to continue at the level described in the 2019 WMP.[113]

7. SDG&E-1-C31/M34 – Wireless Fault Indicators

This program will install wireless fault indicators on SDG&E's electric distribution system. These devices are used to continuously monitor distribution circuits and provide an alarm signal when faults occur, so damage can be more efficiently and accurately located. During extreme events, the location provided by the wireless fault indicator can be used in conjunction with data from high definition cameras to determine whether an electric system fault has led to an ignition, and to facilitate dispatch of fire suppression resources to a fire location as soon as possible. Determining the exact location quickly can save minutes in response time, which can be critical to preventing an ignition from turning into a wildfire. These indicators are powered by the line to which they are attached, connected via wireless network, and stream data back to electric distribution operations for increased situational awareness.

The wide deployment of wireless fault indicators in the HFTD complements SDG&E's sectionalizing by adding a high volume of monitored points on each distribution circuit. In addition, the majority of the distribution circuits within the HFTD are long overhead circuits, requiring additional visibility to locate failed equipment. Capturing this data would allow electric distribution operators to dispatch electric troubleshooters closer to the exact fault location, which supports quicker identification and isolation of damage during RFW events and

---

113 *Id.* at Attachment A, p. 24.

elevated system conditions. This program is consistent with the levels presented in the 2019 WMP[114] and is expected to be completed in 2021, with roughly 1,800 units installed.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary, pursuant to the SA Decision.[115] In this Section, SDG&E provides a qualitative description of the risk reduction benefits for each of the activities presented in Section V and RSEs, where applicable.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[116] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE).

SDG&E's numerous efforts described herein are all aimed to reduce the risk of Wildfires. This risk is largely focused in the areas within SDG&E's service territory that are most prone to wildfire, the HFTD, which was identified and approved by the Commission in D.17-12-024. Because of how this risk was scoped, *i.e.*, related to the HFTD, this risk is addressed in a single tranche. Non-HFTD-related efforts are generally in scope of the Electric Infrastructure Integrity risk.

In this risk Chapter, risk reduction benefits for each Wildfire control and mitigation are presented in three different ways. Specifically, either: (1) a qualitative description of risk reduction benefits is provided, *i.e.,* no RSE was calculated; (2) an RSE is presented on the particular activity; or (3) an RSE is provided on a grouping of activities. Each presentation is discussed in greater detail below.

---

114 *Id.* at Attachment A, p. 53.

115 *See* D.18-12-014 at Attachment A, A-11 – A-13.

116 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Given the vast number of activities SDG&E performs to mitigate Wildfire risk, SDG&E grouped like activities with like risk profiles into mitigation programs. Generally, grouping was performed because either the activity: (1) is not stand-alone (*i.e.*, is dependent on or related to another activity); or (2) does not reduce risk by itself (*i.e.*, it is a supporting activity). An example of a type of activity that supports but does not reduce activity on its own is inspections. For inspections, the activity that reduces risk is the associated repair work, not the inspection itself. Therefore, the costs of the inspections and the repair work were grouped together where appropriate and available. Another example of interdependent activities/programs described herein is the FTZAP and the LTE communications network. For the Falling Conductor Protection (FCP) to be largely operational, the use of a highly available and secure LTE communications network is required.

To illustrate the concept of grouping, SDG&E created the following groupings shown below in Table 5 for determining RSEs for the Wildfire risk. If not included in the table below or in the foregoing parts of this Section, an RSE was calculated for each program individually.

Table 5: Summary of Groupings

ID	Mitigation/Control	Grouping
SDG&E-1-C5	Distribution System Inspections – QA/QC	Non-Mandated Inspections
SDG&E-1-M1	Distribution System Inspections – IR/Corona	
SDG&E-1-M2	Distribution System Inspections – Drone Inspections	
SDG&E-1-M3	Distribution System Inspections – Circuit Ownership	
SDG&E-1-C14/M14	Replacement and Reinforcement	
SDG&E-1-C10/M5	FiRM	FiRM Group
SDG&E-1-M24	Ignition Management Program (60% of program costs)	
SDG&E-1-C21/M25	Asset Management (60% of program costs)	
SDG&E-1-M26	Monitoring and Correcting Deficiencies (60% of program costs)	
SDG&E-1-M27	Wildfire Mitigation Personnel (60% of program costs)	

ID	Mitigation/Control	Grouping
SDG&E-1-C11/M6	PRiME	PRiME Group
SDG&E-1-M24	Ignition Management Program (40% of program costs)	
SDG&E-1-C21/M25	Asset Management (40% of program costs)	
SDG&E-1-M26	Monitoring and Correcting Deficiencies (40% of program costs)	
SDG&E-1-M27	Wildfire Mitigation Personnel (40% of program costs)	
SDG&E-1-C13/M11	FTZAP	System Protection and Communication
SDG&E-1-M12	LTE Communications Network	
SDG&E-1-M15	Backup Power for Resilience – Generator Grant, Community Resource Centers, HPWREN	PSPS
SDG&E-1-C17	Fire Science & Climate Adaptation Department	
SDG&E-1-C18/M21	WRRM - Ops and Fire Science Enhancement	
SDG&E-1-C19/M22	Camera Networks and Advanced Weather Station Integration	
SDG&E-1-C20/M23	High-Performance Computing Infrastructure	
SDG&E-1-M29	Situational Awareness Dashboard	
SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols	
SDG&E-1-C23/M30	Communication Practices	
SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols	
SDG&E-1-C25/M31	Emergency Management Operations	
SDG&E-1-C26	Disaster and Emergency Preparedness Plan	
SDG&E-1-C27	Customer Support in Emergencies	

For purposes of this post-mitigation analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[117] SDG&E then looked at existing/continuing programs (*i.e.*, controls), and assumed that similar results would be achieved (*i.e.*, assumed a percentage of risk reduction benefit by continuing the activity). SDG&E also accounted for the risk increase that would occur over time if it stopped performing these activities. For new and/or incremental mitigations, SDG&E expects to achieve further risk reduction. The risk reduction benefits for each identified control/mitigation is included under each program heading.

B. Post-Mitigation Analysis Results – No RSEs

1. SDG&E-1-C1 – Operating Conditions

a. Description of Risk Reduction Benefits

Key Operating Conditions provide situational awareness to all employees and stakeholders that are impacted by potential wildfire risks in SDG&E's service territory, so that the appropriate precautions are employed. SDG&E adjusts the way it operates in regard to recloser protocols and special work procedures based on the Operating Conditions. Without these adjustments, it is possible that the number of ignitions could increase during conditions that could increase the threat of wildfire. Generally, during times of higher wildfire risk, as measured through situational awareness tools (*e.g.*, FPI), SDG&E operates more conservatively to avoid ignitions, resulting in a reduction to Wildfire risk and increased public, contractor, and employee safety.

Costs were not identified for this activity because it is embedded in internal labor. Therefore, an RSE calculation is not being performed.

b. Elements of the Bow Tie Addressed

Operating Conditions addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (the Risk Bow Tie) above. By utilizing situational awareness tools to inform operational decision-making, this activity reduces the likelihood of a wildfire by targeting the Drivers/Triggers of not observing procedures (DT.7), extreme force of nature events (DT.8), lack of internal or external coordinated response (DT.9), and climate change

---

117 *Id.* at Attachment A, A-12 ("Determination of Post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," "Measurement of Post-Mitigation Risk Score," "Measurement of Risk Reduction Provided by a Mitigation").

adaptation impacts (DT.10). Additionally, performing work under various Operating Conditions decreases the likelihood of Potential Consequences should a wildfire occur, such as damage to third party real and personal property (PC.2), claims and litigation (PC.5), and erosion of public confidence (PC.6).

2. SDG&E-1-C2 – Recloser Protocols

a. Description of Risk Reduction Benefits

Reclosing policies are in place to minimize the potential for an ignition under increased fire potential; which, in turn, increases public, contractor, and employee safety. SDG&E modifies its operations to reflect the risk identified in the declared Operating Condition. For reclosers, SDG&E implements two distinct mitigations. First, under Elevated Operating Conditions or higher, all distribution reclosing functions are disabled on circuits located within the HFTD but may include other circuits, if the burn environment is conducive to wildfire. The benefit of disabling reclosing is to proactively discontinue a device that has the potential of becoming an ignition source under certain conditions. The second mitigation is to implement sensitive and fast system protection settings with the goal of reducing the potential of a fault leading to an ignition. These extra sensitive settings limit the arc flash energy by reducing the isolation time. Following these recloser protocols can therefore result in safety-related benefits.

Costs were not identified for this activity because they are embedded in internal labor. Therefore, an RSE calculation is not being performed.

b. Elements of the Bow Tie Addressed

Recloser protocols address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By operating reclosers in accordance with established protocols, this activity reduces the threat of Wildfire risk by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), failure of third-party attachments (DT.5), vegetation contact (DT.6), and extreme force of nature events (DT.8). This activity also reduces the likelihood of Potential Consequences should a Wildfire occur, including damage to third party real and personal property (PC.2), claims and litigation (PC.5), and erosion of public confidence (PC.6).

3. SDG&E-1-C3 – Other Special Work Procedures

a. Description of Risk Reduction Benefits

Work restrictions are in place based on Operating Conditions to maximize public, contractor, and employee safety. As conditions increase in severity, work activities may still be performed, but some might have additional requirements to mitigate risk. Some of these requirements include the presence of Contract Fire Resources, with the purpose of preventing and addressing work-related ignitions. In other situations, work activity might cease altogether to prevent potential ignitions due to the increased fire risk.

Costs were not identified for this activity because it is embedded in internal labor. Therefore, an RSE calculation is not being performed.

b. Elements of the Bow Tie Addressed

Other special work procedures are established to address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. Establishing special work procedures in various Operating Conditions reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of vegetation contact (DT.6), not observing procedures (DT.7), extreme force of nature events (DT.8), lack of internal or external coordinated response (DT.9), and climate change adaptation impacts (DT.10). This activity also reduces the likelihood of Potential Consequences should a wildfire occur, including damage to third party real and personal property (PC.2), claims and litigation (PC.5), and erosion of public confidence (PC.6).

4. SDG&E-1-C4 – Distribution System Inspections – Corrective Maintenance Program

a. Description of Risk Reduction Benefits

Distribution System Inspections mitigate the risk of equipment failure by proactively identifying equipment deterioration. This allows for the repair/replacement before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions. Through inspections, SDG&E can plan for replacements and repairs rather than being reactive. Planning for such repair work allows SDG&E to anticipate any potential lead times for materials, to be flexible operationally as repair work is being done, and to provide notice ahead of any potential ramifications (*e.g.*, planned outages).

Because this program is mandated pursuant to GO 165, an RSE calculation is not being performed.

b. Elements of the Bow Tie Addressed

The Corrective Maintenance Program addresses several of the Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. This preventative inspection program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), failure of third-party attachments (DT.5), vegetation contact (DT.6), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10).

5. SDG&E-1-C6 – Substation System Inspections

a. Description of Risk Reduction Benefits

Substation System Inspections mitigate the risk of equipment failure by proactively identifying equipment deterioration. This allows for the repair/replacement before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions. Through inspections, SDG&E can plan for replacements and repairs rather than reacting to a failure. Planning for such repair work allows SDG&E to anticipate any potential lead times for materials, to be flexible operationally as repair work is being done, and to provide notice ahead of any potential ramifications (*e.g.*, planned outages).

Cost and RSE-related information for this control are provided in the Electric Infrastructure Integrity RAMP risk chapter (Chapter SDG&E-4).

b. Elements of the Bow Tie Addressed

Substation system inspections address several of the Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. This preventative inspection program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), vegetation contact (DT.6), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10).

6. SDG&E-1-C7 – Transmission System Inspections

a. Description of Risk Reduction Benefits

Transmission System Inspections mitigate the risk of equipment failure by proactively identifying equipment deterioration. This allows for repair or replacement of equipment before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions. Through inspections, SDG&E can plan for replacements and repairs rather than reacting to a failure. Planning for such repair work allows SDG&E to anticipate any potential lead times for materials, to be flexible operationally as repair work is performed, and to provide notice ahead of any potential ramifications (*e.g.*, planned outages).

Because this control is related to assets in the jurisdiction of the FERC, SDG&E is not including the associated costs from this activity in this Report, as further described in Section VI below. Accordingly, a Risk Spend Efficiency calculation is not being performed.

b. Elements of the Bow Tie Addressed

Transmission system inspections address several of the Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. This preventative inspection program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), vegetation contact (DT.6), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10).

7. SDG&E-1-C8 – Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)

a. Description of Risk Reduction Benefits

The Overhead Transmission and Distribution Fire-Hardening program reduces the risk of wildfire in multiple ways. First, the new structures are designed to meet the known local wind conditions in the area, reducing the probability of structure and equipment failure when exposed to extreme wind loading, which happens under certain Santa Ana wind conditions. Structure and equipment failure can lead to ignitions, and when combined with the extreme wind can lead to wildfires. Designing and building lines to withstand the extreme winds mitigates this risk. In addition, SDG&E is replacing wood poles with steel, which is a more reliable material in terms of load capacity and a more resilient material should a fire occur. SDG&E is also utilizing high tensile strength steel core conductors which reduce the risk of wires-down, a known source of ignitions. Moreover, SDG&E is utilizing expanded phase spacing which reduces the risk of phase to phase faults, another potential ignition source. SDG&E is fire-hardening the transmission system within the HFTD, where the risk for wildfires is greatest.

Costs identified herein for this activity are limited to distribution-related portions under the CPUC's jurisdiction. Because the distribution components are dependent on and borne from an approved FERC-jurisdictional transmission-related program, SDG&E is not calculating an RSE on this program.

b. Elements of the Bow Tie Addressed

The wood-to-steel program addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By implementing these hardening efforts, this program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), failure of third-party attachments (DT.5), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

8. SDG&E-1-C16 – Pole Brushing

a. Description of Risk Reduction Benefits

For the pole brushing program, SDG&E's work management system and scheduled routine maintenance reduces the risk for managed poles being overlooked and/or not being maintained. The program also provides assurance that a pole will maintain the annual compliance by means of herbicide application (where possible) and re-clear activity for poles that are not treated by herbicide, so that vegetation is kept clear within the radius. These measures help prevent the propagation of an ignition escaping the cleared radius with the added benefit of protection to the pole from an encroaching wildfire, providing safety and reliability to customers.

Because this program is mandated pursuant to PRC § 4292, an RSE calculation is not being performed.

b. Elements of the Bow Tie Addressed

Pole brushing addresses several of the Potential Consequences shown in Figure 1 (Risk Bow Tie) above by limiting a potential fuel source. Such efforts decrease the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

C. Post-Mitigation Analysis Results – Individual Programs

1. SDG&E-1-M4 – Strategic Undergrounding

a. Description of Risk Reduction Benefits

The objective of undergrounding distribution circuits in strategic locations allow SDG&E to dramatically reduce SDG&E equipment as an ignition source. Removing the possibility of the overhead conductors failing, poles from failing and vegetation contacting SDG&E equipment, reduces possibilities of ignition. These factors, and performing construction in strategic locations, allow for this program to provide safety benefits to employees and the public. This program has the added benefit of reducing the need for PSPS as a mitigation under extreme weather conditions, potentially eliminating PSPS impacts for some customers. This program also allows for reducing areas required to be patrolled or stationed during PSPS events. The reduction in patrolled locations has the potential to reduce the duration to energize distribution lines that were de-energized during the PSPS event and reduce extended exposure to SDG&E employees.

b. Elements of the Bow Tie Addressed

Strategic undergrounding addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By removing the risk of ignition related to an overhead electric equipment, this program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), failure of third-party attachments (DT.5), vegetation contact (DT.6), not observing procedures (DT.7), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10). This activity also decreases the likelihood of Potential Consequences should a Wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Underground 4.66 miles of HFTD distribution system.
Effectiveness	100% of wildfire risk is reduced when the system is undergrounded. 80% of wildfire risk is in HFTD Tier 3. 60% of wildfire risk exists after accounting for PSPS. 0.28% of Tier 3 miles in the HFTD will be undergrounded.
Risk Reduction	0.2% based on the effectiveness above.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.940**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5482.28	**7200.75**	10064.85
	RSE	17.52	**23.01**	32.16

2. SDG&E-1-C9 – Cleveland National Forest Fire-Hardening

a. Description of Risk Reduction Benefits

Cleveland National Forest Fire-Hardening program is hardening transmission and distribution lines that traverse the forest land, much of which is located in Tier 3 of the HFTD, and experiences some of the highest winds in SDG&E's service territory. This program utilizes a combination of overhead and underground applications. For the overhead hardening component, the new structures are designed to meet the known local wind conditions in the area, reducing the probability of structure and equipment failure when exposed to extreme wind loading, which happens under certain Santa Ana wind conditions. Structure and equipment failure can lead to ignitions, and when combined with the extreme wind can lead to wildfires. Designing and building lines to withstand the extreme winds mitigates this risk. In addition, SDG&E is replacing wood poles with steel, which is a more reliable material in terms of load capacity, and a more resilient material should a fire occur. SDG&E is also utilizing high tensile strength steel core conductors which reduce the risk of wires down, a potential source of ignitions. Moreover, SDG&E is utilizing expanded phase spacing which reduces the risk of phase-to-phase faults, another potential ignition source. The undergrounding goes even further than overhead hardening, by reducing the risk of equipment failures leading to ignitions and eliminating the risk of ignitions caused by foreign object in lines.

Costs identified herein for this activity are limited to distribution-related portions under the CPUC's jurisdiction. Because this program has distribution components that are independent from an approved FERC-jurisdictional transmission-related program, SDG&E is calculating an RSE on the distribution-only portions of this program.

b. Elements of Bow Tie Addressed

CNF addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. Through these hardening efforts, this program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), failure of third-party attachments (DT.5), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	0.15% of distribution in Tier 3 of HFTD to be hardened. 0.09% of distribution in Tier 3 of HFTD to be undergrounded. Total of 39.7 miles to have work performed.
Effectiveness	Estimated risk reduction of hardened overhead for 21%, and 48% for undergrounding.
Risk Reduction	Overall estimated risk reduction is 0.7%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**30.2244**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5534.42	**7269.22**	10160.56
	RSE	11.14	**14.63**	20.44

3. SDG&E-1-M7 – Expulsion Fuses

a. Description of Risk Reduction Benefits

SDG&E's distribution system can experience electrical faults (*i.e.*, equipment operating outside its design criteria) that result in the operation of an expulsion fuse to isolate the faulted location, leading to an outage. An expulsion fuse is a one-time use sacrificial device designed to isolate circuit segments from dangerous levels of fault current. The operation of an expulsion fuse discharges hot particles towards the ground, which has the potential to ignite nearby fuels, under dry field conditions. Utilizing an approved CAL FIRE expulsion fuse that has been tested and designated as an exempt classification (*i.e.*, classified as fire-safe by the primary fire protection agency) reduces the ignition risk from the expulsion fuse operation.

b. Elements of the Bow Tie Addressed

The implementation of CAL FIRE-approved expulsion fuses addresses several of the Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This hardening program decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	All expulsion fuses in Tier 3 to be replaced. Approximately 2% of wildfire risk in HFTD Tier 3 is attributed to expulsion fuse incidents.
Effectiveness	Replacing with non-expulsion fuses is estimated as 95% effective.
Risk Reduction	Overall estimated risk reduction is 0.9%, when accounting for HFTD Tier 3 and PSPS.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.7264**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5443.23	**7149.45**	9993.15
	RSE	92.16	**121.05**	169.19

4. SDG&E-1- M8 – Hotline Clamps

a. Description of Risk Reduction Benefits

Previous construction for hotline clamps connected directly to the overhead distribution system to transfer power from one bare wire location to either a transformer or another bare wire location. This direct connection to the bare wire resulted in wire down events. Replacing this equipment and removing the direct connection to the bare wire will result in removing the root cause for wire down events associated with this equipment and eliminate one cause associated with wires down in the HFTD area.

b. Elements of the Bow Tie Addressed

The implementation of the hotline clamps program addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This hardening program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1) and general equipment failure (DT.2). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	All hotline clamps in HFTD Tier 3 and 70% in HFTD Tier 2 are to be replaced. Approximately 0.07% of wildfire risk in HFTD is due to hotline clamp failures that lead to wires down.
Effectiveness	Replacing hotline clamps with updated standard will reduce wires down by 100%.
Risk Reduction	Overall risk reduction is estimated as 0.35%, when accounting for HFTD and PSPS.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17

	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.895**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5474.10	**7190.00**	10049.83
	RSE	137.89	**181.11**	253.15

5. SDGE-1-C12/M9 – WiSE

a. Description of Risk Reduction Benefits

The Wire Safety Enhancement (WiSE) program addresses significant wildfire concerns in the wildland urban interface and coastal canyons within the service territory. These locations are in close proximity to residential homes and the public leading to a smaller acreage of burning, but higher potential for property damage. The WiSE program replaces small conductor with a historically high risk of failure, with high tensile strength conductor, reducing the risk of wires down that could lead to ignitions.

A multi-attribute risk model was developed to target the best areas for the program. Conductor risk assessment, circuit historic wires down, pole age, area wind gust speeds, and fire vulnerability were all included in the model. Proximity to existing housing is also considered. SDG&E's FiRM program's design preference guidelines have been implemented for this program.

b. Elements of the Bow Tie Addressed

WiSE addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This hardening program reduces the likelihood that wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), and extreme force of nature events (DT.8). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Approximately 5% of wildfire risk resides outside the HFTD, and 0.8% of system is addressed by this activity.
Effectiveness	Estimated risk reduction of hardened overhead in non-HFTD is 0.2%.
Risk Reduction	Overall estimated risk reduction is 0.02%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.994**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5492.23	**7213.81**	10083.11
	RSE	1.96	**2.57**	3.59

6. SDGE-1-M10 – Covered Conductor

a. Description of Risk Reduction Benefits

A covered conductor system with an improved three layers of protection over the bare conductor and a fully covered system when transitioning from one span to another provides a reduction in several potential drivers of ignitions. This program aims to target the largest driver of ignitions within SDG&E's service territory, contact from objects. Covered conductor will assist in mitigating this driver but requires strategic development of scope to install in the at-risk locations. In addition, the specific type of covered conductor is new for SDG&E and requires updates to construction standards and associated work methods. For these reasons, the project is small in scope for the first several years, but it will ramp up thereafter.

b. Elements of the Bow Tie Addressed

Implementing covered conductor will address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By further hardening overhead electric equipment, it reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), contact by foreign object (DT.4), vegetation contact (DT.6), and extreme force of nature events (DT.8). Regarding vegetation-related Drivers/Triggers, please note that covered conductor primarily mitigates the risk of small branches causing phase-to-phase faults; it does not necessarily mitigate large branches and trees falling and coming into contact with electrical overhead equipment. In addition, this activity decreases the likelihood of Potential Consequences should a Wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Approximately 0.01% of overhead system in HFTD Tier 3 to be replaced.
Effectiveness	Estimated risk reduction of covered conductor in HFTD Tier 3 is 34%.
Risk Reduction	Overall estimated risk reduction is 0.36%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-	**LoRE**		**29.892**	
	CoRE	183.11	**240.51**	336.17

	Risk Score	5473.55	**7189.28**	10048.82
	RSE	24.30	**31.91**	44.61

7. SDG&E-1- M13 – PSPS Engineering Enhancements

a. Description of Risk Reduction Benefits

During a PSPS event, isolation points are utilized to de-energize equipment from extreme weather. In some situations, the only isolation point is at the substation requiring the entire circuit to be de-energized. This program works together with information from nearby weather stations to potentially reduce impacted areas by allowing for de-energizing in strategic locations and providing power to customers who may not be within the at-risk locations. In addition, this program allows for the potential of a quicker restoration of service when a PSPS event is over, because the footprint required to patrol and confirm that the de-energized area may be safely re-energized is also reduced. Even though this mitigation does not reduce the risk of wildfire, it allows SDG&E to be precise in its use of the PSPS mitigation, limiting the PSPS impacts only to the infrastructure, and its associated customers, which are exposed to the highest risk during the event.

b. Elements of the Bow Tie Addressed

Implementing the PSPS Engineering Enhancements program will address some of the Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By installing additional remote sectionalizing devices within the HFTD, it reduces the likelihood of Potential Consequences should a Wildfire occur including operational and reliability impacts (PC.4) and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Activity does not reduce wildfire risk directly but reduces impact from PSPS. For description of this activity, refer to Section V and subpart a "Description of Risk Reduction Benefits" above.
Effectiveness	N/A
Risk Reduction	N/A

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.33	**7215.25**	10085.13
	RSE	0.00	**0.00**	0.00

8. SDG&E-1- M16 – Backup Power for Resilience – Microgrids

a. Description of Risk Reduction Benefits

SDG&E utilizes PSPS as a last resort measure to mitigate fire risk and ignition sources, to reduce impacts to customers. Microgrids to support critical infrastructure in areas affected by de-energization events can help mitigate the negative impacts on its customers. Microgrids provide meaningful benefits to impacted communities because they can lessen the burden of de-energization events. For example, a microgrid that supports a fire station and Urgent Care Center can help sustain emergency services in the local community; a fueling station can provide necessary refueling for residents' vehicles and backup electric generators; a telecommunications hub can provide continued cell service to residents; a convenience store can provide necessities such as ice, food, batteries and other essentials; food establishments can serve as congregating areas and provide community members a place of relief during a grid outage. These are examples of the qualitative benefits that one microgrid project (here, the Cameron Corners Microgrid in the HFTD) can provide and the positive impact it will have on the surrounding community.

SDG&E is identifying such areas in the HFTD that have multiple critical facilities that are in or near the high wildfire threat areas. Microgrids in these targeted locations that meet discrete criteria (*i.e.*, locations that would provide ongoing service to multiple critical facilities in an area that can be islanded prudently and safely) can offer a designated place of refuge and support ongoing essential services during PSPS events.

b. Elements of the Bow Tie Addressed

Implementing backup power for resilience in the form of microgrids will address some of the Potential Consequences shown in Figure 1 (Risk Bow Tie) above. Microgrids reduce the likelihood of Potential Consequences should a Wildfire occur including operational and reliability impacts (PC.4) and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Activity does not reduce wildfire risk directly but reduces impact from PSPS. For description of this activity, refer to Section V and subpart a "Description of Risk Reduction Benefits," above.
Effectiveness	N/A
Risk Reduction	N/A

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.33	**7215.25**	10085.13
	RSE	0.00	**0.00**	0.00

9. SDG&E-1-M17 – Lightning Arrester Removal/Replacement Program

a. Description of Risk Reduction Benefits

Removing at-risk equipment from the system provides a safer environment for ratepayers and the community. The function of the lightning arrester is to absorb abnormal surges on the distribution system. These surges can lead to an overload, resulting in debris or shrapnel being sent into the environment. This hot debris can ignite nearby fuels under dry conditions. The new CAL FIRE approved lightning arrestors mitigate these impacts, reducing the risk of ignitions.

b. Elements of the Bow Tie Addressed

Implementing the lightning arrester removal/replacement program will address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. The removal of these assets reduces the likelihood that a wildfire will occur, by targeting the Driver/Trigger of general equipment failure (DT.2). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	An estimated 2.6% of wildfire risk is due to lightning arrestor incidents, and approximately 4% of those in the HFTD will be replaced.
Effectiveness	Estimated effectiveness of 100% where new lightning arrestors were installed.
Risk Reduction	Overall estimated risk reduction is 0.05%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12

Post-Mitigation	**LoRE**		**29.9856**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5490.69	**7211.79**	10080.29
	RSE	19.31	**25.36**	35.44

10. SDG&E-1-M18 – SCADA Capacitors

a. Description of Risk Reduction Benefits

Capacitors are designed to provide voltage support and improve power factors throughout SDG&E's service territory. During a failure of a capacitor from either mechanical, electrical, or environmental overstress, an internal fault is created, resulting in internal pressure and the potential that the casing may rupture. This rupture of molted metal has the potential to become an ignition source. The modernization of these capacitors will introduce system protection devices that check for imbalances and internal faults. Should a fault occur, the protection devices will isolate the capacitor from the system, de-energizing the capacitor and eliminating the failure mode that could lead to ignitions.

b. Elements of the Bow Tie Addressed

Implementing SCADA capacitors will address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This program reduces the likelihood that a wildfire will occur by targeting the Driver/Trigger of general equipment failure (DT.2). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	An estimated 0.66% of wildfire risk is due capacitor incidents in the HFTD. Activity will replace all older non-SCADA capacitors.
Effectiveness	80% risk reduction per replacement.
Risk Reduction	Overall estimated risk reduction is 0.3%, when accounting for PSPS.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	LoRE		**29.9097**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5476.79	**7193.53**	10054.77
	RSE	39.02	**51.26**	71.64

11. SDG&E-1-C15 – Tree Trimming

a. Description of Risk Reduction Benefits

Routine and proactive off-cycle inspections, pruning and removal have shown to greatly reduce the number of trees causing outages on SDG&E's electrical system. Since 1995, SDG&E has seen a significant reduction in tree-caused outages, down from 500 recorded annually to a historical record low of 25 in the year 2013. The overall benefits include maintaining full compliance with regulatory agencies, improved reliability to customers, and a lower risk for a potential vegetation contact resulting in a possible ignition.

b. Elements of the Bow Tie Addressed

Tree trimming addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. Tree trimming efforts reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), vegetation contact (DT.6), and extreme force of nature events (DT.8). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of

SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	100% of Tree Trimming in the HFTD.
Effectiveness	Ceasing the current tree trimming program would result in an increase of vegetation-caused outages to the level that existed prior to the program's implementation.
Risk Reduction	The wildfire risk is estimated to increase 50% if the program was ceased.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**15**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	2746.66	**3607.63**	5042.56
	RSE	151.32	**198.75**	277.80

12. SDG&E-1- M19 – Enhanced Vegetation Management

a. Description of Risk Reduction Benefits

SDG&E's enhanced vegetation management program includes post-prune clearance to 25 feet in the HFTD and the off-cycle patrols. This program will result in reduced vegetation encroachments into the regulatory minimum clearances, reduced damages caused to the overhead electrical by tree branch failures, and reduced tree-related outages. All these efforts will help to reduce tree-related ignitions. Other benefits include improved reliability (*e.g.*, improved SAIFI, the System Average Interruption Frequency Index), increased tree worker safety (internal and private), and increased public safety. In addition, this program will also allow SDG&E to reduce the frequency of visits to customers' properties and extended annual pruning cycles.

Further, enhanced vegetation management provides more information. For example, SDG&E's Vegetation Risk Index (VRI) has helped to identify and target five known species in the SDG&E data base that result in the majority of tree caused outages; Eucalyptus, Palms, Pines, Oaks, and Sycamore. SDG&E also leverages technology, including meteorological capabilities, to identify specific circuits with risk for tree-strike potential.

The Vegetation Management team is focusing its efforts to perform enhanced vegetation management including, where appropriate, tree removal and tree replacement projects. The tree removal and replacement projects will, over time, modify the landscape improving electrical safety and service reliability, while adding value to the customer property.

b. Elements of the Bow Tie Addressed

Implementing enhanced vegetation management efforts will address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This program would reduce the likelihood that wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), vegetation contact (DT.6), and extreme force of nature events (DT.8). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Approximately 13% of wildfire risk is due to vegetation incidents.
Effectiveness	Estimated 5% reduction in wildfire due to implementation of this activity.
Risk Reduction	Overall estimated risk reduction is 5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**28.500**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5218.66	**6854.49**	9580.87
	RSE	51.39	**67.50**	94.35

13. SDG&E-1-M20 – Fuel Management Program

a. Description of Risk Reduction Benefits

SDG&E's fuel management program will reduce wildfire risk in multiple ways. First, should a fault occur on the electric system for any reason, this program aims to reduce the chance of an ignition by mitigating the availability of fuel to ignite. Thinning out or completely removing non-native vegetation, which often does not survive as well as native vegetation through the long dry periods associated with the southern California climate, minimizes some of the more dangerous dry dead fuels, which are more likely to ignite. The second benefit is on the fire suppression side; fuels management can reduce the speed and size of a developing fire should an ignition occur near SDG&E's facilities. Reducing the initial speed of the wildfire propagation adds critical minutes to allow for fire suppression resources to arrive on scene and to contain fires before they escalate to potentially catastrophic levels.

b. Elements of the Bow Tie Addressed

The fuel management program addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of vegetation contact (DT.6) and climate change adaptation impacts (DT.10). This activity also decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Estimated 95% of wildfire risk is in scope of Fuel Management.
Effectiveness	Approximately 1% of pole locations will have managed fuel using this program. Of those locations, estimated 40% risk reduction when Fuel Management is applied.
Risk Reduction	Overall estimated risk reduction is 0.38%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.9088**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5476.63	**7193.32**	10054.47
	RSE	13.93	**18.29**	25.57

14. SDG&E-1-M28 – NMS Situational Awareness Upgrades

a. Description of Risk Reduction Benefits

This program aims to provide an accurate and timely response as SDG&E's Operating Conditions indicate higher fire potential including disabling reclosing, enabling sensitive relay profiles, cancelling work in appropriate regions and also incorporating situational awareness data for use in operational tools to make appropriate decisions in real time. Integrating operating conditions into Oracle's Network Management System (NMS) helps to streamline operational changes based on current conditions to facilitate the appropriate response during critical times, which ultimately enhances public and employee safety.

b. Elements of the Bow Tie Addressed

NMS situational awareness upgrades address several of the Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. These activities reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of lack of internal or external coordinated response (DT.9) and climate change adaptation impacts (DT.10).

c. RSE Inputs and Basis

Scope	Activity does not directly reduce risk but contributes to overall awareness of electric system. For description of this activity, refer to Section V and subpart a "Description of Risk Reduction Benefits" above.
Effectiveness	N/A
Risk Reduction	N/A

d. Summary of Results

		Low Alternative	**Single Point**	**High Alternative**
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.33	**7215.25**	10085.13
	RSE	0.00	**0.00**	0.00

15. SDG&E-1-C28/M32 – Wildfire Infrastructure Protection Teams

a. Description of Risk Reduction Benefits

Contract Fire Resources are paired with SDG&E personnel when they perform activities that present the risk of igniting a fire. The primary objective of using Contract Fire Resources is to prevent activities being performed by SDG&E and its contractors from causing an ignition event. Secondarily, these crews have the capability and training to safely mitigate a small ignition, should one occur. Through the use of Contract Fire Resources, the risk of ignition and the likelihood of a fire spreading are reduced.

b. Elements of the Bow Tie Addressed

Wildfire infrastructure protection teams address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. These teams reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of lack of internal or external coordinated response (DT.9) and climate change adaptation impacts (DT.10). They also decrease the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	An estimated 0.95% of wildfire risk is addressed with the Wildfire Infrastructure Protection Teams. This portion of the risk arises from instances when utility actions might contribute to ignitions - such as when restoration or construction efforts are undertaken. The protection teams are on site to reduce this risk.
Effectiveness	The Wildfire Infrastructure Protection Team is estimated to be 80% effective at preventing an ignition when they are present during utility work during wildfire conditions in the HFTD.
Risk Reduction	Overall estimated risk reduction is 0.76% based on the information above.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.772**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5451.58	**7160.41**	10008.48
	RSE	34.46	**45.27**	63.27

16. SDG&E-1-C29/M33 – Aviation Firefighting Program

a. Description of Risk Reduction Benefits

The Aviation Firefighting Program dedicates two Type 1 firefighting helicopters (helitankers) to the SDG&E service territory. These helitankers are an integral part of the CAL FIRE strategy of initial attack and keeping fires to less than ten acres throughout SDG&E's service territory. Type 1 helitankers have the largest water drop capability and allow rapid response and effective dispensing of water on a fire. This response allows CAL FIRE to attack the fire and protect people and structures from a potentially spreading fire. Additionally, the rapid suppression of wildfires reduces the loss of utility infrastructure, which helps to reduce the consequences of an ignition and facilitates safe, reliable utility service. These helitanker assets are available to the SDG&E service territory 365 days per year with no threat of moving off contract or to other areas of the state.

b. Elements of the Bow Tie Addressed

SDG&E's aviation firefighting program addresses several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. By working with stakeholders, such as CAL FIRE, to provide firefighting assets, this program reduces the likelihood that a wildfire will occur by targeting the Drivers/Triggers of lack of internal or external coordinated response (DT.9) and climate change adaptation impacts (DT.10). In addition, this program decreases the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	It is estimated that 100% of the wildfire risk is potentially affected by fire suppression aviation.
Effectiveness	SMEs estimate that 4% of wildfire risk is reduced with the current aviation firefighting program. Quantitatively, this reduction is shown by reducing the likelihood.
Risk Reduction	Overall risk reduction is estimated to be 4%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**28.800**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5273.59	**6926.64**	9681.72
	RSE	27.33	**35.89**	50.17

17. SDG&E-1-C30 – Industrial Fire Brigade

a. Description of Risk Reduction Benefits

The Industrial Fire Brigade (IFB) is a contract resource that is available 24/7/365 for response to fire emergencies within SDG&E's substations and other large installations. In the event of an ignition, the IFB is requested and works with the SDG&E Fire Coordinator and the fire agency having jurisdiction to assist with the safe and efficient extinguishment of the fire. Being able to quickly address the active fire in the utility installations prevents the fire from spreading and becoming a wildfire. The rapid extinguishment also facilitates timely repair and restoration of the system and prevents extended outages.

b. Elements of the Bow Tie Addressed

The industrial fire brigade addresses several of the Potential Consequences shown in Figure 1 (Risk Bow Tie) above. This program reduces the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Estimated 0.2% of wildfire risk is addressed through the IFB, which focuses primarily on substation and other industrial settings that have a reduced risk of spreading to wildfire.
Effectiveness	Estimated 57% effectiveness in situations where the IFB is utilized.
Risk Reduction	Overall estimated risk reduction is 0.15%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**30.0342**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5499.59	**7223.48**	10096.62
	RSE	18.35	**24.11**	33.70

3.

18. SDG&E-1-C31/M34 – Wireless Fault Indicators

a. Description of Risk Reduction Benefits

Wireless fault indicators are a proven technology that helps narrow the search area to determine where a system failure has occurred, so SDG&E can quickly identify a search area and dispatch crews to find system failures. This technology is important to SDG&E's operational mitigation measures that decrease wildfire ignition risk. SDG&E employs measures such as the use of sensitive protection schemes and the removal of reclosing on circuit devices, which increase the frequency of forced outages, decrease the damage caused by system failures, and increases customer impact from "temporary" faults (faults that remove themselves from the system such as a metallic balloon contact). During times of heightened wildfire risk, SDG&E also patrols all infrastructure for damage prior to restoring power. In instances where large areas are de-energized due to sensitive protective relay settings, wireless fault indicators are used to concentrate focus to a much smaller portion of the electric circuit, which allows for: a faster response to the site if an ignition exists; a greater chance of determining and correcting a fault cause (when damage on the overhead electric system is not immediately obvious); and, potentially, faster customer restoration (which could offset customer reliability impacts caused by wildfire mitigation measures).

b. Elements of the Bow Tie Addressed

Wireless fault indicators address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. These activities reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of lack of internal or external coordinated response (DT.9) and climate change adaptation impacts (DT.10). Wireless fault indicators also decrease the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Activity does not directly reduce risk but contributes to overall awareness of electric system. For description of this activity, refer to

	Section V and subpart a "Description of Risk Reduction Benefits," above.
Effectiveness	N/A
Risk Reduction	N/A

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.33	**7215.25**	10085.13
	RSE	0.00	**0.00**	0.00

D. Post-Mitigation Analysis Results – Grouping of Programs

1. Non-Mandated Inspections

This grouping consists of all non-mandated inspections of SDG&E overhead distribution equipment in the HFTD. All of SDG&E's non-mandated inspection programs mitigate the risk of equipment failure by identifying equipment deterioration, which allows for the repair/replacement before failures occur. Equipment failure can lead to electrical faults, which can lead to ignitions. All of the programs in this mitigation plan bring a unique improvement or enhancement to the current mandated five-year overhead visual inspection cycles. Given that the goals of these programs are consistent, *i.e.*, proactively finding and remediating issues on the electric system before a failure can occur, these programs were grouped together for purposes of RSE calculations. Also, the programs of IR/Corona, drone inspections, and circuit ownership are pilot inspections that commenced in 2019, for which there is little to no data available at this time regarding the level of repairs resulting from these non-mandated inspections. Therefore, these non-mandated inspections were grouped with the QA/QC program, to capture the repair and remediation work (*i.e.*, the risk reducing activity).

a. Description of Risk Reduction Benefits

QA/QC

QA/QC inspections improve on mandated inspections in three ways. The cycle of the inspection is increased, from once every five years to once every three years. More frequent inspection cycles allow less time for a potential infraction to go unnoticed. The second benefit is the QA/QC program focused in the highest risk area of the service territory, HFTD Tier 3. When infractions are found and repaired from these inspections, those repairs have the highest impact because they occur in the areas where ignitions are more likely to lead to the wildfires. The third benefit is that QA/QC inspections are focused entirely on infractions that could lead to ignitions, which means the inspection is more focused on Wildfire risk reduction than the mandated inspections.

IR/Corona

The IR/Corona program improves on mandated inspections by utilizing technology to see infractions that could lead to equipment failures and ignitions that cannot be seen through visual inspections. From a visual inspection, connections can look secure. But an IR/Corona inspection can detect hot connections caused by corrosion or other contaminates that could lead to connector failures and wires down.

Drone Inspections

The drone inspection program improves on mandated inspections by utilizing a drone to get an entirely new perspective on the overhead electrical equipment. Current visual inspection methods are limited to a view from the bottom looking up at the infrastructure. Through the pilot, the drone inspections have already revealed potential issues that could have only been identified by a top-down perspective, such as hollowed-out pole tops, deep cracks in the tops of cross arms, and flashed-over insulators. This new view will allow SDG&E to more comprehensively address these issues proactively, rather than reacting to a failure.

Circuit Ownership

This program allows SDG&E personnel to self-report system vulnerabilities and encourages employees to speak up if they see anything. By following up on these vulnerabilities, SDG&E learns more about its system and timely clears potential issues before a failure can occur. This provides enhanced system reliability and safety and addresses issues that otherwise could potentially result in an ignition.

Replacement and Reinforcement

This program remediates infractions found from existing inspection programs (*i.e.*, the Corrective Maintenance Program and QA/QC inspections). The benefit is that at-risk equipment identified in an inspection is replaced, thus reducing the likelihood that an issue would occur shortly thereafter. All infractions are fixed for the benefit of system safety and to maximize employee, contractor, and public safety.

The remediation costs related to the Corrective Maintenance Program are not included in the determination of an RSE, because it is a mandated inspection program. Further, because SDG&E is proposing new programs herein that provide fresh perspectives on finding potential issues on SDG&E's system (*i.e.*, IR/Corona, drone, and circuit ownership inspections), it is unknown at this time how to best estimate what remediation efforts will be needed in the future. SDG&E also believes that historical data is not indicative of future levels of remediation efforts, because utilizing historical visual inspection remediation rates would not be an apples-to-apples comparison of this infrared and corona inspection. Costs related to remediation efforts for the new inspection programs would currently be speculative and thus are not included. SDG&E plans to develop cost estimates from the current pilot programs and develop better-informed estimates in the GRC.

b. Elements of Risk Bow Tie Addressed

SDG&E's non-mandated inspections address several of the Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. As proactive inspections, all these programs reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), and weather-related failure of SDG&E equipment (DT.3). In addition to addressing DT.1 through DT.3, QA/QC inspections, drone inspections, and circuit ownership also address the Drivers/Triggers of contact by foreign object (DT.4), failure of third-party attachments (DT.5), vegetation contact (DT.6), extreme force of nature events (DT.8), and climate change adaptation impacts (DT.10). Replacement and Reinforcement, in addition to being associated with DT.1 through DT.3, also mitigate the Drivers/Triggers of failure of third-party attachments (DT.5) and extreme force of nature events (DT.8).

c. RSE Inputs and Basis

Scope	Every overhead asset will be inspected per the program schedule.
Effectiveness	It is estimated that these inspections will reduce risk by 0.75%.
Risk Reduction	Estimated reduction of 0.75%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.775**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5452.13	**7161.14**	10009.49
	RSE	15.60	**20.49**	28.64

2. FiRM and PRiME Groups

Certain efforts do not by themselves reduce risk, yet they play an important role in SDG&E's goals of minimizing Wildfire risk. Such initiatives include the ignition management program (SDG&E-1-M24), asset management (SDG&E-1-C21 / M25), monitoring and corrective deficiencies (SDG&E-1-M26), and wildfire mitigation personnel (SDG&E-1-M27). These activities, taken as a whole, assist in implementing SDG&E's Wildfire Risk Mitigation Plan, particularly FiRM and PRiME. For example, asset management helps to prioritize the replacement of poles, which is then used in the implementation of FiRM and PRiME. As stated above, because these four initiatives alone do not reduce risk, for purposes of calculating RSEs, SDG&E made two groupings, a FiRM group and PRiME group, and allocated the costs of these programs 60% to FiRM and 40% to PRiME. The allocation was based on a weighted average of the total costs of FiRM and PRiME (*i.e.*, when combined, FiRM equaled approximately 60% of the total costs). While these four activities benefit more than FiRM and PRiME, these hardening efforts represent the most significant programs from a cost perspective.

a. Description of Risk Reduction Benefits

FiRM

The FiRM program targets small conductor for replacement, which through analysis of historical data has been identified as an asset with a higher likelihood of failure as compared to other types of conductor, a leading cause of wire down events and a potential ignition source. The program is prioritized based on computer models allowing SDG&E to determine the locations with the greatest impacts should a fire occur. This approach maximizes risk reduction by targeting assets with the highest probability of failure and prioritizing the replacements in the areas of greatest impact. This program replaces the conductor with high tensile strength conductor, enhances phase spacing to reduce the risk of foreign object in line contacts and is designed to meet the extreme local wind conditions that can occur during Southern California's Santa Ana wind conditions, all of which reduces the chances of ignitions caused by failures on the electric system.

PRiME

It is the goal of the PRiME program to remediate the highest risk poles in the HFTD. The highest risk poles are those most likely to cause a failure during a weather event. The PRiME program is designing to all current GO 95 standards and known local wind conditions to significantly reduce fire risk of the pole. Additionally, other associated risks such as wire spacing and clearances between poles are designed to meet current specifications.

Both the FiRM and PRiME programs are using sophisticated technology such as LiDAR and PLS-CADD to remediate risks. SDG&E has many distribution poles and lines that were designed well before LiDAR and PLS-CADD were created. The recent adoption of these tools allows SDG&E to design distribution infrastructure with the same level of detail as transmission infrastructure. These tools enable a systemwide look at associated poles which may be impacted as poles ahead and behind are remediated.

Ignition Management Program

The Ignition Management Program will capture data related to ignitions and near-ignitions originating from SDG&E equipment. This data will be analyzed to determine root cause, and findings will be addressed by the appropriate subject matter expert. By assessing potential trends in ignitions, this program will help SDG&E be more informed about its wildfire risk and better able to target, prioritize, and evaluate mitigations intended to reduce the risk of ignitions.

Asset Management

An AHI is a score designed to track the condition and performance of an asset by applying statistical modeling and predictive analytics to multiple sources of data and used as a basis for asset management strategies. The key benefits of employing AHI include the ability to measure overall health of assets, recognize asset data parameters associated with failure modes, detect failures, relatively compare between assets of same class in a consistent manner, and utilize analytics to measure operational condition. Using AHI on its assets, SDG&E can identify and compare assets based on its likelihood of failure. Asset risk is then determined when AHI and the associated asset failure consequence or impact are jointly considered. Integrating this asset risk information with other inputs, such as circuit risk index for situational awareness, especially within fire-prone areas, will inform the appropriate asset-related operational decision-making and strategies for enhanced reliability and safe operations of assets on given current and expected wildfire conditions.

Monitoring and Correcting Deficiencies

This program provides SDG&E a tool to monitor and track metrics and effectiveness of SDG&E's wildfire mitigation programs. This will then help inform prioritization and evaluate what is working and potentially what measures need to be re-worked. It will also verify compliance with the metrics put forth in SDG&E's WMP.

Wildfire Mitigation Personnel

This department was formed to provide a central point of contact for mitigating the risk of Wildfire at SDG&E, including developing and enhancing SDG&E's wildfire mitigation strategies. Additionally, these new full-time equivalents will be responsible for implementing

SDG&E's wildfire risk reducing activities. This demonstrates SDG&E's commitment to mitigating this risk as well as its intent to be accountable for executing its Wildfire Mitigation Plan. The department will help SDG&E reduce ignitions, improve asset health in the HFTD, and enhance public safety.

b. Elements of the Bow Tie Addressed

The grouping of FiRM and PRiME address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. All these programs reduce the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), weather-related failure of SDG&E equipment (DT.3), failure of third-party attachments (DT.5), and extreme force of nature events (DT.8). In addition to addressing DT.1 through DT.3, DT.5, and DT.8, FiRM also addresses the Driver/Trigger of climate change adaptation impacts (DT.10). The ignition management program, asset management, monitoring and correcting deficiencies, and wildfire mitigation personnel, in addition to being associated with DT.1 through DT.3, DT.5, and DT.8, also mitigate the Drivers/Triggers of contact by foreign object (DT.4), vegetation contact (DT.6), not observing procedures (DT.7), and climate change adaptation impacts (DT.10). Moreover, with the exception of the ignition management program, all the activities in this grouping decrease the likelihood of Potential Consequences should a wildfire occur, including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

FiRM Group

Scope	FiRM will be applied to approximately 27% of HFTD Tier 3.
Effectiveness	It is estimated that the FiRM program will reduce risk by 80% in the areas that it is performed.
Risk Reduction	Estimated risk reduction of 5.7%, while accounting for PSPS in HFTD Tier 3.

PRiME Group

Scope	PRiME to be applied to approximately 18% of HFTD Tier 3 poles.
Effectiveness	It is estimated that PRiME will reduce risk by 80% to the poles that are hardened.
Risk Reduction	Estimated risk reduction of 1.9%, while accounting for PSPS in HFTD Tier 3.

d. Summary of Results

FiRM Group

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	LoRE		**28.278**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5178.05	**6801.15**	9506.31
	RSE	25.69	**33.74**	47.16

PRiME Group

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	LoRE		**29.430**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5388.95	**7078.16**	9893.51
	RSE	13.70	**18.00**	25.15

3. System Protection and Communication

The grouping of System Protection and Communication consists of the FTZAP and the LTE communications network programs. These programs are interdependent, as many of the elements of the FTZAP program, such as Falling Conductor Protection, require the use of the LTE communications network to be largely operational. Because these two programs associated with each other operationally, they were grouped together to calculate the RSE.

a. Description of Risk Reduction Benefits

FTZAP utilizes technology to enhance system protection. One example of FTZAP technology is FCP. FCP is meant to detect and isolate energized conductors in the event an overhead conductor break. This improves public safety in that when wire failures occur, the wire is de-energized before it can reach the ground.

As explained above, FTZAP and the LTE communications network programs are interconnected. The LTE communications program is foundational to the implementation of FTZAP. In addition to being integral for FCP, the LTE communication network supports advance SCADA controls and the ability to send PMU data over a wireless network.

The LTE communications network allows SDG&E to enhance the current reliability and security of several foundational technologies meant to manage the electrical grid, enhance safety for the public and our crews, and allow the implementation of new protection systems that rely on high-speed broadband networks. The LTE program consolidates multiple wireless networks into one, which helps to streamline support and management. It is also being implemented with a Highly Available (HA) design. This means longer uptimes on backup power and multiple layers of redundancy. Through this new network, our operators will have higher resolution data that will increase their situational awareness around potential events in the field. In addition, the LTE network provides for crew safety by enabling Mission Critical Push to Talk (MCPTT), as its HA design can allow communications when other networks are congested.

b. Elements of the Bow Tie Addressed

The FTZAP and LTE communication network programs will address several of the Drivers/Triggers and Potential Consequences shown in Figure 1 (Risk Bow Tie) above. Through the use of technology to enhance system protection, the likelihood that a wildfire will occur by targeting the Drivers/Triggers of downed conductor (DT.1), general equipment failure (DT.2), and extreme force of nature events (DT.8) is reduced. The LTE communication network also addresses the Driver/Trigger of lack of internal or external coordinated response (DT.9). In addition, these activities decrease the likelihood of Potential Consequences should a wildfire occur including serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6).

c. RSE Inputs and Basis

Scope	Approximately 25% of HFTD Tier 3 will have FTZAP installed.
Effectiveness	FTZAP is estimated to reduce risk by 90% where it is applied.
Risk Reduction	Estimated risk reduction is 5.8%, while accounting for PSPS and risk levels in HFTD Tier 3.

d. **Summary of** Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**28.2517**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5173.19	**6794.77**	9497.40
	RSE	20.15	**26.47**	37.00

4. Public Safety Power Shutoff (PSPS)

PSPS activities are grouped because they have the common goal of improving PSPS processes, either from a decision-making or customer impact perspective. Many of the programs (Backup Power for Resilience – Generator Grant, Community Resource Centers, High-Performance Wireless Research and Education Network; Communication Practices; Mitigating the Public Safety Impact of PSPS Protocols; and Customer Support in Emergencies) are designed to help to mitigate customer impacts related to a PSPS event. Other programs (Fire Science & Climate Adaptation Department, WRRM – Ops and Fire Science Enhancement, High-Performance Computing Infrasture, Situational Awareness Dashboard, Emergency Management Operations, and Disaster and Emergency Preparedness Plan) provide tools so that SDG&E can make informed decisions either during or in preparation of a PSPS event. Further, the act of de-energization and re-energization, presented herein as the "Strategy for Minimizing Public Safety Risk, PSPS and Re-Energization Protocols" program, does not include costs, and was grouped with other programs that include costs and enable this action. Lastly, because these programs are related and many of the programs by themselves do not reduce risks, they were grouped to determine the RSE.

a. Description of Risk Reduction Benefits

Backup Power for Resilience – Generator Grant, Community Resource Centers, High-Performance Wireless Research and Education Network (HPWREN)

Backup Power for Resilience will generally provide an alternative power source to certain segments of customers in the HFTD who are potentially impacted by PSPS events. Doing so will have reliability benefits for those customers. It will also provide secondary safety benefits given that these programs are targeted to help critical customers and infrastructure.

Generator Grant Program

The Access and Functional Needs (AFN) segment of the communities SDG&E serves in the HFTD have been identified as being disproportionately impacted by PSPS events. The Generator Grant Program will provide a renewable battery and solar charging briefcase capable of storing electricity to help this customer segment ride through short duration events. This program, if successful, may also prevent the AFN customer segment from having to rely on inexpensive, fossil fuel powered, backup generators. Standard combustible fuel powered generators naturally increase fire risk in the backcountry, particularly if they are used in an unsafe manner. This program may therefore help eliminate the need for future purchases of fossil fuel powered generators for short duration events.

Community Resource Centers

CRCs help to mitigate PSPS event impacts to customers, so that they can charge cell phones, gather snacks and water, and acquire general information – including PSPS event updates – directly from an SDG&E representative. Opening CRCs in SDG&E's communities is the right thing to do, as it lessens the burden and provides solutions for customers when their lives are impacted by PSPS events.

High-Performance Wireless Research and Education Network (HPWREN)

The HPWREN program reduces the risk that an ignition within SDG&E's service territory might rapidly expand to a wildfire. This network of cameras and communication technology enable the rapid identification and triangulation of a wildfire, which then enables first responders to react quickly. Additionally, the backbone communication network supports back country fire station communications and training, which directly impacts the first responders' ability to respond to reports of any wildfire quickly and effectively.

Fire Science & Climate Adaptation Department

The integration of subject matter experts into SDG&E operations has been very beneficial to safely operating the electric system in a high fire risk environment. Having a team of meteorologists and firefighters adds to situational awareness and decision support, helping keep SDG&E's communities safe and informed. This expertise enables the utility to anticipate, prepare and react to critical wildfire conditions through a mosaic of analytical and situational awareness tools. The use of these tools, such as the original utility weather network, the mountain top camera network, the Fire Potential Index and the Santa Ana Wildfire Threat Index, is expanding statewide. Evolution, innovation and integration of new science will continue to be required moving forward, to keep our communities safe in the face of climate change.

WRRM – Ops and Fire Science Enhancement

SDG&E pioneered the use of fire behavior modeling in utility operations through the initial development of the Wildfire Risk Reduction Model. The technology has proven critical and is now expanding across the state and across the wildfire agencies. Continued development of this technology will be paramount to the ongoing preparedness that enables SDG&E's system operators to remain informed. The big data capabilities of this tool have supported the safe implementation of various SDG&E programs, including PSPS, and will continue to support programs into the future.

Camera Networks and Advanced Weather Station Integration

Over the past ten years, beginning in 2010, SDG&E has built the largest utility weather network existing anywhere in the world. The data SDG&E has collected and operationalized over the last decade has significantly contributed to SDG&E's wildfire mitigation initiatives, including prioritizing system hardening efforts and implementing PSPS. The original weather network equipment has now come to end of life, and a full rebuild of the weather network is required, with new equipment. This new weather network will be critical to the safe and reliable operation of the electric system over the next decade and beyond.

High-Performance Computing Infrastructure

SDG&E's High-Performance Computing Program has been foundational to creating analytical tools that have sharpened SDG&E's situational awareness, and now, that of utilities across the state and the country. The analytics conducted on these computers provide advance warning of critical fire conditions that enables an operational response. This technology evolves very quickly, and new computers will be required in 2022 to maintain SDG&E's program.

Situational Awareness Dashboard

Situational awareness dashboards increase the accuracy and timeliness of PSPS decisions. PSPS serves as a preventive mitigation measure by isolating electric infrastructure during times of heightened wildfire risk, stopping that infrastructure from serving as a wildfire ignition source. Dashboarding helps to inform operational decisions by quantifying the relative risks of a foreign- or infrastructure-caused source of equipment failure. It also quickly informs operations of the proper isolating devices necessary to use to mitigate that risk, increasing the speed of decision-making and communication related to PSPS.

Strategy for Minimizing Public Safety Risk, PSPS and Re-Energization Protocols

Strategies regarding PSPS and re-energization protocols are designed to maximize safety. As mentioned above, PSPS is used as a last resort and is generally limited to specific time periods experiencing an elevated or higher FPI. While PSPS may negatively impact near-term reliability, it provides safety benefits, by eliminating electrical equipment as an ignition source.

Specifically, it provides benefits related to employee, contractor, and public safety, as well as safety to SDG&E's system. For re-energizations, SDG&E requires patrols to take place prior to a re-energization. The patrol evaluates whether, from a safety perspective, SDG&E's equipment should be re-energized. These prescriptive protocols strive to keep communities and SDG&E's employees safe.

Communication Practices, Mitigating the Public Safety Impact of PSPS Protocols, and Customer Support in Emergencies

As recognized by the Commission, "[d]e-energization has far reaching and significant impacts on affected communities."[118] To help mitigate such impacts resulting from PSPS and wildfire events, SDG&E employs many programs and strategies. Communication-related efforts are one such tool. SDG&E believes communication with customers and stakeholder groups is critical. The Commission agrees, stating the following in D.19-05-042, the Phase 1 decision of the De-Energization Rulemaking:

> The utilities must work to build relationships with public safety partners, critical facilities, community-based organizations (preferably in partnership with public safety partners) and the public, including AFN populations, in order to ensure that all are as prepared as possible to face a de-energization event if and when it occurs;[119]
>
> and
>
> The utilities must develop partnerships with public safety partners at the local and state level to enable these agencies and entities to sufficiently prepare for de-energization event;[120]
>
> and
>
> The Commission, therefore, requires that the utilities work with public safety partners, including CAL FIRE and CalOES, to develop outreach and educational materials to make citizens aware of how to prepare for a prolonged loss of power in advance of the 2019 wildfire season.[121]

---

[118] D.19-05-042 at 68.

[119] *Id.* at 90.

[120] *Id.*

[121] *Id.* at 92.

SDG&E will comply with the Commission's directives above and strives to continuously improve its communications.

Another strategy SDG&E utilizes to mitigate PSPS events is to provide customer support during emergencies, including wildfires. These customer support programs offered by SDG&E may not reduce ignitions, but they do help impacted customers during a time of need. SDG&E endeavors to make a positive difference in the communities it serves and support its customers. These goodwill programs allow SDG&E to assist where it can to positively impact customers.

Emergency Management Operations

To accomplish comprehensive and sustainable emergency readiness, SDG&E must maintain a continuous cycle of planning, training, and exercising. This is necessary so that the Company's responders understand and maintain competency in their emergency response roles and responsibilities. The development, implementation, and sustainment of Company-wide emergency management preparedness and operational policies and procedures combined with effective training and exercise programs allows SDG&E (those from the Field Incident Command and Emergency Operations Center, to Company leadership) and SDG&E's first responder partner agencies to respond and recover in a safe, timely and effective manner from wildfire, PSPS, and other man made or natural events that may impact SDG&E's ability to provide services to its customers.

Disaster and Emergency Preparedness Plan

Through the development and maintenance of Disaster and Emergency Preparedness Plans, SDG&E and its workforce understand their roles and responsibilities during incidents, emergencies, disasters, and catastrophes that may impact the safety of customers, employees and the reliability of SDG&E's infrastructure. Disaster and Emergency Preparedness Plans combined with SDG&E's effective training and exercise programs, which include all First Responders in its service territory, help maintain a high level of safety, competency and confidence in our field and Emergency Operations Center responders during emergency and disaster responses. Additionally, these programs provide increased efficiencies of response, control, and restoration of services.

b. Elements of the Bow Tie

A majority of the activities within the PSPS grouping reduce the likelihood that a wildfire will occur by targeting certain Drivers/Triggers shown in Figure 1 (Risk Bow Tie) above. The activities of Fire Science & Climate Adaptation Department, Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements, Camera Networks and Advanced Weather Station Integration, High-Performance Computing Infrastructure, and Situational Awareness Dashboard all, at a minimum, address the Drivers/Triggers of lack of internal or external coordinated response (DT.9) and climate change adaptation impacts (DT.10). Communication Practices and Mitigating the Public Safety Impact of PSPS Protocols decrease the likelihood that the Drivers/Triggers of not observing procedures (DT.7) and lack of internal or external coordinated response (DT.9) will occur, while Emergency Management Operations, Disaster and Emergency Preparedness Plan, and Customer Support in Emergencies address only the Driver/Trigger of lack of internal or external coordinated response (DT.9).

The PSPS grouping also addresses several of the Potential Consequences provided in Figure 1 (Risk Bow Tie) above. Specifically, all the activities in this grouping decrease the likelihood of the Potential Consequence erosion of public confidence (PC.6). A majority of the activities, including Fire Science & Climate Adaptation Department, Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements, Camera Networks and Advanced Weather Station Integration, High-Performance Computing Infrastructure, Situational Awareness Dashboard, Mitigating the Public Safety Impact of PSPS Protocols, Emergency Management Operations, and Disaster and Emergency Preparedness Plan reduce the likelihood of the following Potential Consequences, should a wildfire occur: serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), claims and litigation (PC.5), and erosion of public confidence (PC.6). The activities of Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols addresses all of the Wildfire risks' identified Potential Consequences: serious injuries and/or fatalities (PC.1), damage to third party real and personal property (PC.2), damage and loss of SDG&E assets or facilities (PC.3), operational and reliability impacts (PC.4), claims and litigation (PC.5), and erosion of public confidence (PC.6). Appendix A presents a table that includes each activity in this grouping and the corresponding Drivers/Triggers and/or Potential Consequences addressed from the Risk Bow Tie.

c. RSE Inputs and Basis

Scope	A large majority of wildfire risk can be addressed with PSPS.
Effectiveness	PSPS is utilized in select locations during high-risk weather, with final decisions to PSPS made in real time. The effectiveness of PSPS is 100% for the time and the areas in which it is applied.
Risk Reduction	Estimated risk reduction of 50%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**15.000**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	2746.66	**3607.63**	5042.56
	RSE	100.08	**131.45**	183.73

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E's Risk Mitigation Plan takes into account recent data and trends related to Wildfire, affordability impacts, possible labor constraints and the feasibility of mitigations. SDG&E has performed RSEs in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors, including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

SDG&E's Risk Mitigation Plan can be subject to constraints. Many activities in this Risk Mitigation Plan can have significant lead times (in excess of a year) to obtain necessary materials or approval (*e.g.*, permitting) prior to commencing work. This is especially true with respect to System Hardening initiatives and the Fuel Management program. SDG&E's ability to timely implement this Wildfire Risk Mitigation Plan may be dependent on factors like permitting, landowner agreements, and fire weather. In addition, SDG&E is experiencing a shortage of available, qualified contractors to perform work. For example, there is already significant competition in the State to obtain qualified design, engineering, and construction resources, as well as vegetation management resources. SDG&E expects this trend to continue in future years. Further, many of SDG&E's mitigants are costly. SDG&E strives to balance implementing fire mitigation measures with the associated costs of such measures. To do so, SDG&E prioritizes its work by addressing the highest risks first. To that end, SDG&E is strategic about employing its mitigation programs – which programs, where, and how much – and considers affordability when doing so.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigations activities, associated costs, and the RSEs, by tranche.

SDG&E does not account for and track costs by activity; rather, SDG&E accounts for and tracks costs by cost center and capital budget code. The costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

SDGE
A Sempra Energy utility

Table 6: Risk Mitigation Plan Summary[122]
(Direct 2018 $000)[123]

ID	Mitigation/Control	Tranche	2018 Baseline Capital [124]	2018 Baseline O&M	2020-2022 Capital [125]	2022 O&M	Total[126]	RSE[127]
SDG&E-1-C1	Operating Conditions	T1	0	0	0-0	0-0	0-0	-
SDG&E-1-C2	Recloser Protocols	T1	0	0	0-0	0-0	0-0	-
SDG&E-1-C3	Other Special Work Procedures	T1	0	0	0-0	0-0	0-0	-
SDG&E-1-C4	Distribution System Inspection - CMP	T1	0	1,600	0-0	380-460	380-460	-
SDG&E-1-C5	Distribution System Inspection - QA/QC	T1	0	450	0-0	330-400	330-400	15.60-28.64
SDG&E-1-M1	Distribution System Inspection - IR/Corona	T1	0	0	0-0	220-270	220-270	See RSE in SDG&E-1-C5
SDG&E-1-M2	Distribution System Inspection - Drone Inspections	T1	0	0	1,500-1,800	6,500-7,900	8,000-9,700	See RSE in SDG&E-1-C5
SDG&E-1-M3	Distribution System Inspection - Circuit Ownership	T1	0	0	0-0	480-580	480-580	See RSE in SDG&E-1-C5
SDG&E-1-C6	Substation System Inspection	T1	*See* Electric Infrastructure Integrity risk chapter (Chapter SDG&E-4)					

122 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

123 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

124 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

125 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

126 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

127 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital [124]	2018 Baseline O&M	2020-2022 Capital [125]	2022 O&M	Total[126]	RSE[127]
SDG&E-1-C7	Transmission System Inspection	T1	0	0	0-0	0-0	0-0	-
SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening	T1	0	0	3,000-3,700	0-0	3,000-3,700	-
SDG&E-1-M4	Strategic Undergrounding	T1	0	0	17,000-21,000	0-0	17,000-21,000	17.52-32.16
SDG&E-1-C9	Cleveland National Forest Fire-Hardening	T1	15,000	0	81,000-98,000	0-0	81,000-98,000	11.14-20.44
SDG&E-1-C10 / M5	Fire Risk Mitigation	T1	52,000	0	250,000-300,000	0-0	250,000-300,000	25.69-47.19
SDG&E-1-C11/M6	Pole Risk Mitigation and Engineering	T1	2,600	0	160,000-190,000	0-0	160,000-190,000	13.70-25.15
SDG&E-1-M7	Expulsion Fuse Replacement	T1	0	0	12,000-14,000	0-0	12,000-14,000	92.16-169.19
SDG&E-1-M8	Hotline Clamps	T1	0	0	0-0	2,400-3,600	2,400-3,600	137.89-253.15
SDG&E-1-C12/M9	Wire Safety Enhancement	T1	32	0	12,000-15,000	0-0	12,000-15,000	1.96-3.59
SDG&E-1-M10	Covered Conductor	T1	0	0	17,000-21,000	0-0	17,000-21,000	24.30-44.61
SDG&E-1-C13/M11	Fire Threat Zone Advanced Protection	T1	1,100	0	29,000-35,000	0-0	29,000-35,000	20.15-37.00
SDG&E-1-M12	LTE Communication Network	T1	0	0	86,000-104,000	0-0	86,000-104,000	See RSE in SDG&E-1-C13 / M11
SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	T1	0	0	1,200-2,100	0-0	1,200-2,100	0.00-0.00
SDG&E-1-C14/M14	Replacement and Reinforcement	T1	10,000	0	29,000-35,000	190-240	29,000-35,000	See RSE in SDG&E-1-C5
SDG&E-1-M15	Backup Power for Resilience - Generator Grant	T1	0	0	16,000-24,000	1,000-1,600	17,000-26,000	See RSE in SDG&

ID	Mitigation/Control	Tranche	2018 Baseline Capital[124]	2018 Baseline O&M	2020-2022 Capital[125]	2022 O&M	Total[126]	RSE[127]
	Program, CRCs, HPWREN							E-1-C22
SDG&E-1-M16	Backup Power for Resilience - Microgrids	T1	0	0	26,000-31,000	150-180	26,000-31,000	0.00-0.00
SDG&E-1-M17	Lightning Arrester Removal / Replacement Program	T1	0	0	2,900-3,500	0-0	2,900-3,500	19.31-35.44
SDG&E-1-M18	SCADA Capacitors	T1	0	0	4,700-5,600	0-0	4,700-5,600	39.02-71.64
SDG&E-1-C15	Tree Trimming	T1	0	29,000	0-0	16,000-20,000	16,000-20,000	151.32-277.80
SDG&E-1-C16	Pole Brushing	T1	0	3,800	0-0	3,400-4,100	3,400-4,100	-
SDG&E-1-M19	Enhanced Vegetation Management	T1	0	0	0-0	4,800-5,800	4,800-5,800	51.39-94.35
SDG&E-1-M20	Fuel Management Program	T1	0	0	0-0	1,100-1,300	1,100-1,300	13.93-25.57
SDG&E-1-C17	Fire Science and Climate Adaptation Department	T1	0	1,700	0-0	1,600-1,800	1,600-1,800	See RSE in SDG&E-1-C22
SDG&E-1-C18/M21	WRRM - Ops and Fire Science Enhancement	T1	0	0	4,500-6,000	0-0	4,500-6,000	See RSE in SDG&E-1-C22
SDG&E-1-C19/M22	Camera Networks and Advanced Weather Station Integration	T1	0	0	2,100-2,600	0-0	2,100-2,600	See RSE in SDG&E-1-C22
SDG&E-1-C20/M23	High-Performance Computing Infrastructure	T1	22	0	5,100-7,300	0-0	5,100-7,300	See RSE in SDG&E-1-C22
SDG&E-1-M24	Ignition Management Program	T1	0	0	0-0	290-350	290-350	See RSE in

ID	Mitigation/Control	Tranche	2018 Baseline Capital [124]	2018 Baseline O&M	2020-2022 Capital [125]	2022 O&M	Total[126]	RSE[127]
								SDG&E-1-C10 / M5 & SDG&E-1-C11 / M6
SDG&E-1-C21/M25	Asset Management	T1	0	580	8,800-11,000	520-550	9,300-12,000	See RSE in SDG&E-1-C10 / M5 & SDG&E-1-C11 / M6
SDG&E-1-M26	Monitoring and Correcting Deficiencies	T1	0	0	0-0	710-860	710-860	See RSE in SDG&E-1-C10 / M5 & SDG&E-1-C11 / M6
SDG&E-1-M27	Wildfire Mitigation Personnel	T1	0	0	0-0	950-1,200	950-1,200	See RSE in SDG&E-1-C10 / M5 & SDG&E-1-C11 / M6
SDG&E-1-M28	NMS Situational Awareness Upgrades	T1	0	0	1,400-1,700	0-0	1,400-1,700	0.00-0.00
SDG&E-1-M29	Situational Awareness Dashboard	T1	0	0	5,700-6,900	290-350	6,000-7,300	See RSE in SDG&

ID	Mitigation/Control	Tranche	2018 Baseline Capital[124]	2018 Baseline O&M	2020-2022 Capital[125]	2022 O&M	Total[126]	RSE[127]
								E-1-C22
SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols	T1	0	0	0-0	0-0	0-0	100.08-183.73
SDG&E-1-C23/M30	Communication Practices	T1	0	190	0-0	4,500-5,400	4,500-5,400	See RSE in SDG&E-1-C22
SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols	T1	0	0	0-0	0-0	0-0	See RSE in SDG&E-1-C22
SDG&E-1-C25/M31	Emergency Management Operations	T1	0	2,400	0-0	2,700-3,300	2,700-3,300	See RSE in SDG&E-1-C22
SDG&E-1-C26	Disaster and Emergency Preparedness Plan	T1	0	0	0-0	0-0	0-0	See RSE in SDG&E-1-C22
SDG&E-1-C27	Customer Support in Emergencies	T1	0	0	0-0	0-0	0-0	See RSE in SDG&E-1-C22
SDG&E-1-C28/M32	Wildfire Infrastructure Protection Teams	T1	0	910	0-0	1,100-1,300	1,100-1,300	34.46-63.27
SDG&E-1-C29/M33	Aviation Firefighting Program	T1	3,600	5,100	0-0	7,200-8,700	7,200-8,700	27.33-50.17
SDG&E-1-C30	Industrial Fire Brigade	T1	0	320	0-0	310-370	310-370	18.35-33.70
SDG&E-1-C31/M34	Wireless Fault Indicators	T1	440	0	1,100-1,400	0-0	1,100-1,400	0.00-0.00

ID	Mitigation/Control	Tranche	2018 Baseline Capital [124]	2018 Baseline O&M	2020-2022 Capital [125]	2022 O&M	Total[126]	RSE[127]
		TOTAL COST	85,000	46,000	780,000-940,000	57,000-71,000	830,000-1,010,000	

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SDG&E also notes that there are activities related to this Wildfire risk that will be carried over to the GRC, for which the costs are primarily internal labor (*e.g.*, employee time spent for internal training, performing inspections or monitoring). The costs associated with these internal labor activities are not captured in this Chapter because SDG&E does not track labor in this manner. These activities related to the Wildfire risk are: Operating Conditions; Recloser Protocols; Other Special Work Procedures; Strategy for Minimizing Public Safety Risk During High Wildfire Conditions. Public Safety Power Shutoff and Re-enerization Protocols; Mitigating the Public Safety Impact of PSPS Protocols; Disaster and Emergency Preparedness Plan; and Customer Support in Emergencies. Additionally, there are non-CPUC jurisdictional activities described in the RAMP Report; the costs associated with these activities are not presented, as they will not be carried over to the GRC. These mitigation activities related to this risk are transmission system inspections and the transmission portions of various projects, such as Wood to Steel and CNF.

In addition, as discussed in Section VI above, Table 7 below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-1-C1	Operating Conditions	Excluded internal labor – no identified cost

SDG&E-1-C2	Recloser Protocols	Excluded internal labor – no identified cost
SDG&E-1-C3	Other Special Work Procedures	Excluded internal labor – no identified cost
SDG&E-1-C4	Distribution System Inspections - Corrective Maintenance Program	Mandated activity pursuant to GO 165
SDG&E-1-C6	Substation System Inspections	Mandated activity pursuant to GO 174, see EII risk chapter
SDG&E-1-C7	Transmission System Inspections	FERC/Non-GRC activity – no identified cost
SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)	FERC/Non-GRC activity – no identified cost
SDG&E-1-C16	Pole Brushing	Mandated activity pursuant to PRC § 4292

VIII. ALTERNATIVE ANALYSIS

Consistent with D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the mitigations for the Wildfire risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also considered modifications to the presented plan and constraints, such as budget and resources.

The scenario of undergrounding the overhead electric infrastructure in the HFTD in its entirety, as a means to eliminate Wildfire risk in the most prone areas, has been previously discussed but was not considered as a formal alternative in this Report. While there would be notable benefits to undergrounding in the HFTD, the idea is largely infeasible and would be extremely costly. Undergrounding the entire HFTD would cost in the tens of billions of dollars. In addition, given the terrain, remote location, and environmental requirements (*e.g.*, permitting and environmental impacts), SDG&E may not be able to execute undergrounding in the entire HFTD. Further, large-scale undergrounding would take a long time to construct, during which SDG&E and the public would continue to bear unaddressed risk. Rather than undergrounding the entire HFTD, SDG&E's Risk Mitigation Plan utilizes a targeted approach to strategically underground critical areas while leveraging other hardening techniques, such as FiRM, covered conductor, and technology solutions.

A. SDG&E-1-A1 – In-Line Disconnect Removal/Replacement Program

SDG&E has different types of equipment throughout its service territory used as sectionalizing devices. One specific sectionalizing device is called an in-line disconnect. These devices provide a sectionalizing location on a distribution circuit and are normally closed (*i.e.*, they are not used in conjunction with a recloser or a voltage regulator as a bypass). During an outage restoration or in locations with limited clearances, these devices have been used to assist with sectionalizing efforts to reduce the numbers of customers impacted during an outage or when requested by field crews to provide isolation points. This specific type of sectionalizing device is not installed directly on the pole like other devices, but rather is installed on the conductor roughly 20 inches away from the pole, similarly to a splice/connector.

With roughly 160 in-line disconnects in the HFTD, SDG&E considered proposing a program to remove these in-line disconnects within the HFTD. The removal of these units pertains to the equipment not being CAL FIRE approved and the potential for an ignition to occur.

This program was dismissed because SDG&E found different means to address the issue. While in-line disconnects can cause sparks upon operation, SDG&E is not aware of in-line disconnects being a source of an ignition while closed and energized. Given that the risk only occurs while operating these disconnects under voltage, SDG&E has implemented work restrictions, as described in activity SDG&E-1-C3 above, which restricts these types of operation during FPI elevated or higher. With work restrictions, this alternative would be unnecessary, as the risk is otherwise mitigated.

1. RSE Inputs and Basis

Scope	Estimated 1% of wildfire risk is due to incidents involving in-line disconnects. Approximately 3% of in-line disconnects in HFTD Tier 3 and 2.7% of in-line disconnects in HFTD Tier 2 to be replaced.
Effectiveness	Estimated effectiveness of 100% where in-line disconnects are replaced.
Risk Reduction	Overall risk reduction is estimated to be 0.01%.

2. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.996**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5492.54	**7214.21**	10083.68
	RSE	7.79	**10.24**	14.31

B. SDG&E-1-A2 - Bridged Fuse Removal/Replacement Program

As stated in alternative SDG&E-1-A1, SDG&E has different types of equipment throughout its service territory that are used as sectionalizing devices. Another type of equipment is a bridged fuse (*i.e.*, a solid blade disconnect), which provides a sectionalizing location on a distribution circuit. During outage restoration or isolation of known damaged equipment, these units have assisted operations with reducing the customer impact and providing isolation points for crews to perform construction or maintenance work. These types of sectionalizing devices are installed to replace fuses when coordination from downstream fuses cannot occur. There are roughly 400 bridge fuses within the HFTD.

SDG&E considered proposing to remove these bridged fuses within the HFTD through a formal replacement program. The removal of these units pertains to the equipment not being CAL FIRE approved and potentially becoming an ignition source. After an operation requiring these devices to be opened and then closed, the limited visibility and existing design of the devices can result in a poor connection. If the contacts are not properly connected and then energized, there is potential for a hot connection that could potentially fail.

However, SDG&E is not moving forward with this program because this type of failure has never caused an ignition, so the historical data does not support this type of program. In addition, SDG&E is implementing another distribution inspection mitigation measure, referred to as the IR/Corona program (see activity SDG&E1-M5), which should detect this type of failure before it happens, thus mitigating much of the same risk as the considered alternative program.

1. RSE Inputs and Basis

Scope	An estimated 0.03% of wildfire risk is due to bridged fuses.
Effectiveness	80% risk reduction per replacement.
Risk Reduction	Estimated overall risk reduction of 0.01%, when accounting for PSPS.

2. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**30**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	**LoRE**		**29.997**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5492.78	**7214.53**	10084.12
	RSE	12.95	**17.01**	23.78

C. SDG&E-1-A3 – Increase Frequency of QA/QC Inspections

SDG&E considered modifying its QA/QC inspection program to increase the frequency of inspections within the HFTD Tier 3. Under this alternative, the frequency of inspections within the HFTD Tier 3 would increase from a three-year cycle to an annual cycle. The rationale for accelerating the inspection cycle would be to identify any infractions that pose an ignition risk sooner to eliminate the ignition risk. This would represent a significant increase in inspections, moving from approximately 15,000 poles annually to 45,000 poles annually.

After further consideration, SDG&E decided to dismiss accelerating the QA/QC program at this time. As shown above in the Risk Mitigation Plan, SDG&E is piloting new inspection programs including IR/Corona and drones. By utilizing new technology, SDG&E intends to provide a different way to assess its system that may be preferred in the interim to annual QA/QC inspections. Following the pilot of these new inspection programs, SDG&E will reevaluate to see if changes to its inspection programs are warranted. Further, because the HFTD QA/QC inspections are performed on a three-year cycle, and CMP also includes inspections in the HFTD on a five-year cycle, certain structures in the HFTD would already be reviewed more frequently than a three-year cycle. Accordingly, SDG&E dismissed accelerating its QA/QC inspections at this time, in favor of its Risk Mitigation Plan.

1. RSE Inputs and Basis

Scope	Annual inspection program schedule.
Effectiveness	The preliminary estimate is that these inspections will reduce risk by 0.025%.
Risk Reduction	Preliminary estimated reduction of 0.025%.

2. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**30.000**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5493.32	**7215.25**	10085.12
Post-Mitigation	LoRE		**29.9925**	
	CoRE	183.11	**240.51**	336.17
	Risk Score	5491.95	**7213.45**	10082.60
	RSE	15.82	**20.78**	29.04

Table 8: Alternative Mitigation Summary[128]
(Direct 2018 $000)[129]

ID	Alternative	2020-2022 Capital[130]	2022 O&M	Total[131]	RSE[132]
SDG&E-1-A1	In-Line Disconnect Removal/Replacement Program	2,200-2,600	0-0	2,200-2,600	7.79-14.31
SDG&E-1-A2	Bridged Fuse Removal / Replacement Program	890-1,100	0-0	890-1,100	12.95-23.78
SDG&E-1-A3	Increase Frequency of QA/QC Inspections	0-0	1,000-1,200	1,000-1,200	15.82-29.04

128 Forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

129 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

130 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total.

131 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

132 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-1-C1	Operating Conditions	DT.7, DT.8, DT.9, DT.10, PC.2, PC.5, PC.6
SDG&E-1-C2	Recloser Protocols	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8, PC2, PC.5, PC.6
SDG&E-1-C3	Other Special Work Procedures	DT.6, DT.7, DT.8, DT.9, DT.10, PC.2, PC.5, PC.6
SDG&E-1-C4	Distribution System Inspections – Corrective Maintenance Program	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8, DT.10
SDG&E-1-C5	Distribution System Inspections – Quality Assurance/Quality Control	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8, DT.10
SDG&E-1-M1	Distribution System Inspections – Infrared/Corona	DT.1, DT.2, DT.3
SDG&E-1-M2	Distribution System Inspections – Drone Inspections	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8, DT.10
SDG&E-1-M3	Distribution System Inspections – Circuit Ownership	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8, DT.10
SDG&E-1-C6	Substation System Inspections	DT.1, DT.2, DT.3, DT.4, DT.6, DT.8, DT.10
SDG&E-1-C7	Transmission System Inspections	DT.1, DT.2, DT.3, DT.4, DT.6, DT.8, DT.10
SDG&E-1-C8	Overhead Transmission and Distribution Fire-Hardening (Wood to Steel)	DT.1, DT.2, DT.3, DT.5, DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M4	Strategic Undergrounding	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C9	Cleveland National Forest Fire-Hardening	DT.1, DT.2, DT.3, DT.5, DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C10/M5	Fire Risk Mitigation	DT.1, DT.2, DT.3, DT.5, DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C11/M6	Pole Risk Mitigation and Engineering	DT.1, DT.2, DT.3, DT.5, DT.8, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M7	Expulsion Fuse Replacement	PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-M8	Hotline Clamps	DT.1, DT.2, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C12/M9	Wire Safety Enhancement	DT.1, DT.2, DT.3, DT.8, PC.4, PC.5, PC.6

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-1-M10	Covered Conductor	DT.1, DT.2 DT.3, DT.4, DT.6, DT.8, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C13/M11	Fire Threat Zone Advanced Protection	DT.1, DT2, DT.8; PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M12	LTE Communication Network	DT.1, DT.2, DT.8 DT.9, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M13	Public Safety Power Shutoff Engineering Enhancements	PC.4, PC.6
SDG&E-1-C14/M14	Replacement and Reinforcement	DT.1, DT.2, DT.3, DT.5, DT.8
SDG&E-1-M15	Backup Power for Resilience – Generator Grant, Critical Infrastructure, and HPWREN	PC.4, PC.6
SDG&E-1-M16	Backup Power for Resilience – Microgrids	PC.4, PC.6
SDG&E-1-M17	Lightning Arrester Removal/Replacement Program	DT.2, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-M18	SCADA Capacitors	DT.2, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C15	Tree Trimming	DT.1, DT.2, DT.3, DT.6, DT.8, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C16	Pole Brushing	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M19	Enhanced Vegetation Management	DT.1, DT.2, DT.3, DT.6, DT.8, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-M20	Fuel Management Program	DT.6, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C17	Fire Science & Climate Adaptation Department	DT.7, DT.8, DT.9, DT.10, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C18/M21	Wildfire Risk Reduction Model – Operational System (WRRM – Ops) and Fire Science Enhancements	DT.9, DT.10, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C19/M22	Camera Networks and Advanced Weather Station Integration	DT.9, DT.10, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C20/M23	High-Performance Computing Infrastructure	DT.9, DT.10, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-M24	Ignition Management Program	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8, DT.10

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-1-C21/M25	Asset Management	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7 DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M26	Monitoring and Correcting Deficiencies	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7 DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M27	Wildfire Mitigation Personnel	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7 DT.8, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-M28	NMS Situational Awareness Upgrades	DT.9, DT.10
SDG&E-1-M29	Situational Awareness Dashboard	DT.9, DT.10, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C22	Strategy for Minimizing Public Safety Risk During High Wildfire Conditions, PSPS and Re-Energization Protocols	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C23/M30	Communication Practices	DT.7, DT.9, PC.5, PC.6
SDG&E-1-C24	Mitigating the Public Safety Impact of PSPS Protocols	DT.7, DT.9, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C25/M31	Emergency Management Operations	DT.9, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C26	Disaster and Emergency Preparedness Plan	DT.9, PC.1, PC.2, PC.3, PC.5, PC.6
SDG&E-1-C27	Customer Support in Emergencies	DT.9, PC.6
SDG&E-1-C28/M32	Wildfire Infrastructure Protection Teams (Contract Fire Resources)	DT.9, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C29/M33	Aviation Firefighting Program	DT.9, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C30	Industrial Fire Brigade	PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-1-C31/M34	Wireless Fault Indicators	DT.9, DT.10, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

Risk Assessment Mitigation Phase
(Chapter SDG&E-2)
Contractor Safety

November 27, 2019

TABLE OF CONTENTS

Risk: Contractor Safety

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas & Electric Company's (SDG&E or Company) Contractor Safety risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 (and the Settlement Agreement included therein (SA Decision)).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its TY 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, operations and Maintenance (O&M) costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a

---

[1] D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[2] D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Contractor Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this TY 2022 RAMP Report are identified in Section VII below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

For purposes of this RAMP Report, SGD&E's Contractor Safety risk is defined "as the risk of a safety event, caused by a contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company."

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[3] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Contractor crew deviation from policies/procedures
DT.2	Contractor and sub-contractor crew inexperience
DT.3	Lack of oversight of contractor work
DT.4	Inadequate contractor training/supervision
DT.5	Inadequate use of job site safety plans/job safety analysis
DT.6	Inadequate or inaccurate utility and/or substructure location information
DT.7	Unsafe operation of equipment or motor vehicle
DT.8	Contractor crew fatigue/complacency
DT.9	Contractor impairment due to environmental factors
PC.1	Serious injuries[4] and/or fatalities
PC.2	Property damage
PC.3	Additional compliance safety inspections
PC.4	Operational and reliability impacts
PC.5	Adverse litigation
PC.6	Penalties and fines
PC.7	Erosion of public confidence

[3] D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

[4] A "serious injury" is defined in the California Code of Regulations as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) § 330(h).

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

Control ID	Control/Mitigation Name
SDG&E-2-C1	Contractor Safety Oversight Program
SDG&E-2-C2	Contractual Requirements
SDG&E-2-C3	Third-Party Administration and Tools
SDG&E-2-C4	Stop the Job
SDG&E-2-C5	Near Miss/Close Call Reporting Program
SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings

SDG&E will continue the baseline controls identified above and describes additional projects and/or programs (*i.e.*, mitigations) as follows:

Table 3: Summary of Mitigations

Mitigation ID	Mitigation Name
SDG&E-2-M1	Expanded Contractor Oversight Program
SDG&E-2-M2	Updated Class 1 Contractor Safety Manual, Development of Class 2 Contractor Safety Manual
SDG&E-2-M3	Near Miss/Close Call Reporting Portal/App All contractor safety data from ISN and predictive solutions rolled up into real-time dashboard

5 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Finally, pursuant to the SA Decision,[6] SDG&E presents considered alternatives to the Risk Mitigation Plan for the Contractor Safety risk and summarizes the reasons that the alternatives were not incorporated in the Risk Mitigation Plan in Section VIII.

II. RISK OVERVIEW

The Contractor Safety risk was included in SDG&E's 2018 ERR and, for purposes of this RAMP filing, is defined as the risk of a safety event, caused by a contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company. While 2018 is used as the base year for mitigation planning presented in the RAMP, risk management has been occurring, successfully, for many years within the Company and is continuously evolving. SDG&E takes compliance and managing risks seriously, as evidenced by the many actions taken to mitigate each risk. The baseline mitigations are determined based on the relative expenditures during 2018; however, SDG&E does not currently track expenditures in this way, so the baseline amounts reflect the best effort of each utility to benchmark both capital and O&M costs during a year.

The Commission has ordered that RAMP be focused on safety-related risks and mitigating those risks.[7] For many risks, safety and reliability are inherently related and cannot be separated, and the mitigations reflect that fact. Compliance with laws and regulations is also inherently tied to safety and SDG&E takes those activities very seriously. In all cases, the 2018 baseline mitigations include activities and amounts necessary to comply with the laws in place at that time. Laws can rapidly evolve, however, and if new laws have been passed since September 2018 the RAMP baseline has not taken these into account.

As noted above, the purpose of RAMP is not to request funding. Any funding requests will be made in the TY 2022 GRC. The forecasts for mitigation are therefore not for funding purposes but are rather to provide an anticipated range of costs for the future GRC filing. This range will be refined with supporting testimony in the GRC.

---

6 *Id.* at p. 33.

7 D.16-08-018.

Not included in the Contractor Safety risk is the inadvertent contact of intact, energized SDG&E equipment potentially causing serious injury or fatality. While the consequences of this risk event could fall under the risk definition for this chapter, the risk event is captured in the Electric Infrastructure Integrity chapter (SDG&E-4). Additionally, excluded from the Contractor Safety risk is the risk of potential injuries or fatalities associated with medium-pressure or high-pressure natural gas pipelines. While the consequences of this risk event could fall under the risk definition for this chapter, the risk event is captured in the Medium-Pressure Gas Pipeline Chapter (SDG&E-6) and the High-Pressure Pipeline Incident (SDG&E-8) chapters of this report. The Contractor Safety risk chapter focuses on mitigations that address safety, education, training, oversight, and other internal procedural enhancements, whereas SDG&E's Electric Infrastructure Integrity and High-Pressure and Medium-Pressure Pipeline Incident chapters focus on infrastructure improvements, and thus those risk events are more appropriately captured within those chapters.

Finally, this RAMP Report is the first instance where SDG&E has had to apply the SA Decision to its risk analysis of this risk (and all of its risks in RAMP). SDG&E looks forward to feedback from the Commission on its application of the SA to this risk.

III. RISK ASSESSMENT

In accordance with the SA Decision,[8] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Contractor Safety risk.

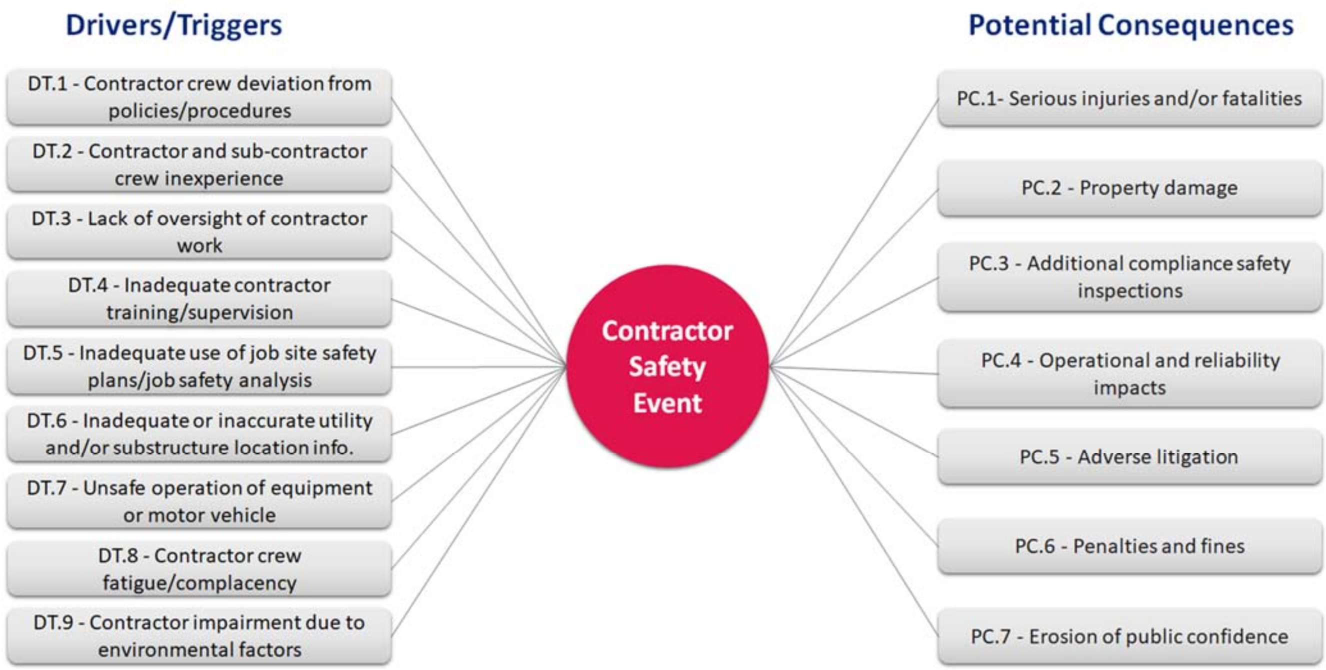
A. Risk Bow-Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the elements of the Risk Bow Tie addressed is provided in Appendix A.

---

[8] D.18-12-014 at 16 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups of Systems Subject to the Risk

The SA Decision[9] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. This is a "cross-cutting" risk and therefore is associated with human systems, rather than particular asset groups.

C. Risk Event Associated with the Risk

The SA Decision[10] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the Risk Bow Tie) is a contractor safety event that results in a serious injury or fatality along with any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

---

9 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

10 *Id.* at Attachment A, A-11 ("Bow Tie").

D. Potential Drivers/Triggers[11]

The SA Decision[12] instructs the utility to identify which element(s) of the associated Risk Bow Tie each mitigation addresses. When performing the risk assessment for Contractor Safety, SDG&E identified potential leading indicators, referred to as Drivers or Triggers. These include, but are not limited to:

- **DT.1 – Contractor crew deviation from policies/procedures:** SDG&E has many safety-related policies and procedures for employees and contractors to follow. Failure of a contractor to adhere to a company safety policy or procedure could result in a safety-related event.
- **DT.2 – Contractor and sub-contractor crew inexperience:** Contractors and sub-contractors used by SDG&E are expected to hire experienced employees to perform the work required. Failure of contractors to hire and utilize experienced employees for their work may lead to a safety-related event.
- **DT.3 – Lack of oversight of contractor work –** Oversight by SDG&E is an integral part of managing work performed by contractors, not only from a work quality perspective, but also to verify that safe work practices are being followed. A lack of oversight of a contractor's work can lead to departures from safe work practices and result in a safety-related event.
- **DT.4 – Inadequate contractor training/supervision –** SDG&E expects its contractors to provide training to and to supervise its employees to reduce the likelihood of an incident. Inadequate training or the lack of sufficient supervision can be a cause of a safety-related event.
- **DT.5 – Inadequate use of job site safety plans/job safety analysis –** Insufficient knowledge of the work environment or improper planning for

---

11 An indication that a risk could occur. It does not reflect actual or threatened conditions.

12 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

potential job hazards may lead to contractors sustaining safety-related event while on the job.

- **DT.6 – Inadequate or inaccurate utility and/or substructure location information –** Contractors need to have the proper information about the assets or systems they work on for the benefit of SDG&E. Inadequate or inaccurate utility and/or substructure information can lead to safety-related events to contractor employees.
- **DT.7 – Unsafe operation of equipment or motor vehicle –** Contractors may utilize their own company vehicles and equipment or vehicles and equipment owned by SDG&E. The unsafe operation of such may lead to a safety-related event.
- **DT.8 – Contractor crew fatigue/complacency –** Contractors working excessive hours can create unsafe work environments. Also, complacency may reduce the level of awareness to hazards which can lead to a safety-related event.
- **DT.9 – Contractor impairment due to environmental factors –** Factors such as heat, night work, high-risk work locations (*e.g.* busy roadways), etc., may lead a contractor to become impaired and as a result increase the likelihood of a safety-related event.

E. Potential Consequences

Potential Consequences are listed to the right side of the Risk Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries and/or fatalities;
- Property damage;
- Additional compliance safety inspections;
- Operational and reliability impacts;
- Adverse litigation;
- Penalties and fines; and

- Erosion of public confidence.

These Potential Consequences were used in the scoring of the Contractor Safety risk that occurred during the development of SDG&E's 2018 Energy Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[13] including enhancements to the Interim Decision 16-08-018.[14] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Risk Quantification Scores[15]

Contractor Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	231	**1408**	3371
LoRE		**1.2**	
CoRE	200	**1223**	2926

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[16] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

13 *Id.* at Attachment A.

14 *Id.* at 2-3.

15 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

16 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of a work-related – as defined by Occupational Safety and Health Administration (OSHA) – safety incident involving a Class 1 contractor(s) that causes serious injuries or fatalities while conducting work on behalf of SDG&E. SDG&E is focusing its enhanced Contractor Safety Program on Class 1 Contractors. Class 1 Contractors are: *"A Class 1 Contractor is a contractor engaged to perform work that can reasonably be anticipated to expose the Contractor's employees, Subcontractors, SDG&E employees, or the general public to one or more hazards that have the potential to result in Serious Safety Incident. Examples of a Class 1 Contractor include contractors performing work involving energized equipment or hazardous chemicals."*
Out-of-Scope for purposes of risk quantification:	The risk of a work-related safety incident involving a non-Class 1 contractor(s), or the risk of a work-related safety-incident involving a Class 1 Contractor(s) while conducting work for a company other than SDG&E. Safety incidents involving a Class 1 contractor(s) that are not work-related (as defined by OSHA regulation) and impacts to the public resulting from work-related safety incidents involving Class 1 contractor(s).

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data).[17] SDG&E's safety risk assessment primarily utilized data from the Bureau of Labor Statistics (BLS), OSHA, and the Department of Labor (DOL).

Calculating serious injury and fatality incidence rates required data on total employment by sector. Therefore, the BLS Employment & Earnings data was used to determine total employment by sector. This data was filtered by NAICS (North American Industry Classification System) sector codes determined by analyzing SDG&E Class 1 Contractor data from ISN (ISNetworld – third-party administrator of the SDG&E contractor safety program) to

[17] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

find the NAICS codes for companies contracted with SDG&E. Based on this data and SME input from the Contractor Safety Programs and Safety Services groups, total hours of Class 1 Contractor work for SDG&E were estimated at 9.031 million hours per year.

From the BLS industry data, total employees per sector were converted to total hours per sector using the following guidance from the BLS: Total hours by Sector = Total Employees by sector * 40 hours per week * 50 weeks per year. The total contractor hours were then allocated to the Class 1 Contactor sectors contracted by SDG&E.

Injuries, Illnesses, and Fatalities (IIF) program historical data from the BLS was used to determine the serious injury and the fatality incidence rates per year. From this data, the serious injury frequency was calculated as the ratio of serious injuries to recordable incidents by sector during 2015-2016. Industry serious injury and fatality rates were applied to total SDG&E Class 1 Contractor work hours to obtain the respective incidence rates for SDG&E.

OSHA Enforcement Data, supplemented with OSHA Severe Injury Reports, from the DOL was used to determine the distribution of safety consequence resulting from a single safety event. The NAICS code structure used in the data from the BLS is consistent with the NAICS codes in the OSHA enforcement data used for determining the distribution.

A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences. The safety consequence scoring was based on a publication from the Federal Aviation Administration (FAA): a fatality is represented by 1.000 and a serious injury is represented by 0.253. Internal subject matter expert (SME) input was provided to estimate the financial consequence of a contractor safety incident. Based on SME input, reliability is not impacted by contractor safety related incidents.

B. Sources of Input

The SA Decision[18] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Injuries:

---

[18] *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
- Link: https://www.bls.gov/iif/oshsum.htm#15Summary_Tables
- Report Title: TABLE Q1. Incidence rates of total recordable cases of nonfatal occupational injuries and illnesses by quartile distribution and employment size, 2009-2016, All establishment sizes

- Fatalities:
  - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
  - Link: https://www.bls.gov/iif/oshcfoi1.htm#2015
  - Report Title: Census of Fatal Occupational Injuries-TABLE A-3. Fatal occupational injuries to private sector wage and salary workers, government workers, and self-employed workers by industry, all United States
- Distribution Fitting Data:
  - Agency: Department of Labor (DOL)
  - Link: https://enforcedata.dol.gov/views/data_catalogs.php
  - Report Title: OSHA Enforcement Data: osha_accident, osha_accident_injury, osha_inspection
- Severe Injury Assumption:
  - Agency: Occupational Safety and Health Administration (OSHA)
  - Link: https://www.osha.gov/severeinjury/index.html
  - Report Title: Severe Injury Reports
- Support Data:
  - Agency: Bureau of Labor Statistics- Office of Publications & Special Studies
  - Link: https://www.bls.gov/opub/ee/archive.htm

- Report: Employment & Earnings- Table B-1b. Employees on nonfarm payrolls by industry sector and selected industry detail, not seasonally adjusted, 2011-2016

- North American Industry Classification System - NAICS
  - Agency: US Census Bureau
  - Link: https://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart_code=22&search=2017%20NAICS%20Search

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[19] This section describes SDG&E's Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SDG&E's Contractor Safety risk is defined as the risk of a safety event, caused by a Class 1 Contractor or subcontractor not following safety standards and/or procedures, which results in serious injuries and/or fatalities while conducting work on behalf of the Company. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SDG&E's TY 2022 GRC cycle.[20] The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SDG&E-2-C1: Contractor Safety Oversight Program

The contractor oversight program is the way SDG&E standardizes its approach to contractor safety. SDG&E uses both the Contractor Safety Program Standard G8308, the internal standard for SDG&E, and the Class 1 Contractor Safety Manual for contractors to hold

---

[19] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

[20] *Id.* at 33. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

all business units and Class 1 Contractors to the same requirements and/or standards. Business units such as Major Projects, Construction Services, and Vegetation Management, also have field safety oversight of all construction work performed by Class 1 Contractors working for those respective groups. This oversight includes instituting safeguards that all contracted work is performed in accordance with SDG&E standards, OSHA regulations, applicable laws, Commission Orders (such as GO 95, Rules for Overhead Electric Line Construction), and GO 128 (Rules for Construction of Underground Electric Supply and Communications Systems).

The safeguards can include:

- Administrative activities associated with construction services-managed construction work.
- Pre-qualification of all Class 1 contractors according to SDG&E's Contractor Safety Program:
    - Contractors that meet the criteria targets in the table below are granted points toward an overall compliance grade in SDG&E's third-party administrator.
    - Contractors that fall below the criteria targets do not receive points toward an overall compliance grade in SDG&E's third-party administrator.

Criteria	Target	Below Target
3-Year TRIR (Total Recordable Incident Rate)	Equal to or less than BLS industry average for applicable NAICS code	Greater than BLS industry average for applicable NAICS code
3-Year DART (Days Away Restricted/Transfer Rate)	Equal to or less than BLS industry average for applicable NAICS code	Greater than BLS industry average for applicable NAICS code
EMR (Experience Modification Rate)*	Equal to or less than 1.1	Greater than 1.1
5 -Year Fatality Data	Zero (0) fatalities within the last five (5) years	One (1) or more fatalities within the last five (5) years
5-Year Non-Fatal, Serious Safety Incident Data (e.g., life altering/life threatening, including incidents affecting the public)	Zero (0) non-fatal, serious safety incidents within the last five (5) years	One (1) or more non-fatal, serious safety incidents within the last five (5) years
3-Year OSHA Serious, Willful, or Repeat Citations	Zero (0) serious, willful, or repeat OSHA citations within the last three (3) years	One (1) or more serious, willful, or repeat citations within the last three (3) years
3-Year OSHA Non-Serious Citations	Zero (0) non-serious OSHA citations within the last three (3) years	One (1) or more non-serious citations within the last three (3) years
Written Safety Programs	Company has comprehensive written safety programs that are in compliance with environmental, health, and safety laws and regulations and are specific to the hazards associated with the work to be performed	Company does not have comprehensive written safety programs that are in compliance with environmental, health, and safety laws and regulations and are specific to the hazards associated with the work to be performed
Drug and Alcohol Plan	Company has a comprehensive written drug and alcohol plan that is in compliance with applicable laws and regulations	Company does not have a comprehensive written drug and alcohol plan that is in compliance with applicable laws and regulations
Subcontractor Management Plan	Company has a written plan to monitor subcontractors and hold them accountable for the same requirements as themselves	Company does not have a written plan to monitor subcontractors and hold them accountable for the same requirements as themselves
Employee Disciplinary Action Plan	Company has a written employee disciplinary action plan	Company does not have a written employee disciplinary action plan
Safety Culture Evaluation	Company has a positive safety culture that it is working to advance	Company does not have a positive safety culture that it is working to advance

* **Experience modification rate** (EMR) is a number insurance companies use to represent a business' prior workers' comp claims and potential for future injuries.

- Pre-Work Safety Meeting notice and Acknowledgment Form.
- SDG&E notifies contractors of known jobsite hazards, then meets with contractors to discuss hazards and mitigations that are jointly acknowledged before performing work.
- Safety oversight and observations for contractors:
  - SDG&E has formed Contractor Safety Services (CSS) to oversee safety for Class 1 Contractors.

- CSS currently has 2 team leads and a mixture of internal safety advisors and third-party safety advisors that perform safety observations of Class 1 Contractors.

- Incident review and investigation for all Class 1 work performed:
  - Contractors must notify SDG&E of all incidents.
  - Reports are initiated for applicable incidents.
  - Serious Near-Miss events, Serious Safety Incidents, Fatalities, and other serious incidents by contractors as determined by SDG&E are investigated internally.
- Post-Job Evaluations:
  - A review by the SDG&E construction team on the contractor's jobsite performance is conducted post major project or annually. This review has the ability to affect the contractor's qualification status and therefore their ability to continue working with SDG&E.

B. SDG&E-2-C2: Contractual Requirements

The contractual requirement control is in place to add updated language to all contracts in order to hold all Class 1 Contractors accountable to follow SDG&E's Class 1 Contractor Safety Manual. SDG&E requires the following:

- All new and existing contracts and Master Service Agreements (MSAs) between SDG&E and a primary contractor include Contractor Safety Program-related requirements as part of the contract terms and conditions.
- Contractor contract language includes references to the Contractor Safety Program Requirements that are hosted in the Class 1 Contractor Safety Manual.
- A CSS Manager consults on updates to any contract terms or conditions that are considered in new or existing contracts.

C. SDG&E-2-C3: Third-Party Administration and Tools

SDG&E currently uses certain third-party administration tools to verify that contractors comply with SDG&E's established safety requirements according to the Class 1 Contractor

Safety Manual and the contractual requirements. SDG&E currently uses Predictive Solutions for safety observations and Veriforce for gas operator qualifications as third-party software administration tools to address risk in a more cost-effective manner than has been found utilizing an internal workforce.

Predictive Solutions is used by SDG&E as the primary software application for safety observations of Class 1 Contractors. This customizable tool can house a specifically designed safety observation form for each Business Unit in order to capture all relevant data. There is also a core group of questions that is used to track and trend safety contractor observations enterprise wide. Predictive Solutions allows SDG&E to easily collect safety observations, track and trend, then communicate the results of observations in a clear format so SDG&E can potentially mitigate at-risk behaviors or incidents.

Veriforce is a third-party vendor that offers comprehensive solutions for Operator Qualifications (OQ), Drug & Alcohol (D&A), Training, Auditing, and Consulting programs to Operators and contractors nationwide. In 2012, SDG&E partnered with Veriforce to manage all gas contractors' OQ and D&A programs. The Veriforce partnership allows SDG&E to improve the overall OQ program for gas contractors by requiring them to abide by a common OQ program and tracks their D&A status to maintain compliance. Some key features of using the Veriforce system are: the ability for contractors to have proof of qualifications on the job site; the ability to track qualification failures; and visibility to the D&A status of each contractor company and its employees.

SDG&E partnered with Veriforce in response to increased scrutiny and auditing by internal and/or external parties of the OQ and D&A programs which revealed inconsistencies among contractors. Veriforce provided SDG&E with solutions to address these audit findings and improved the OQ and D&A programs by implementing an electronic platform for testing and an electronic database for tracking this data. The Veriforce platform also allows for portability of qualifications between SDG&E and Southern California Gas Company.

SDG&E uses a third-party administrator, ISNetworld, to house and verify the established SDG&E pre-qualification requirements for our Class 1 Contractors. ISNetworld also gives SDG&E a place to communicate with our contractors, including:

- Communication of new rules, regulations and requirements;
- Reports from contractors on SDG&E specific incidents and hours in order for SDG&E to track and trend performance;
- A bulletin board that houses documents communicated to all connected contractors; and
- An action item tool for targeted communication to specific contractors.

ISNetworld monitors new and changing OSHA requirements and verifies SDG&E's Class 1 Contractors meet minimum OSHA requirements for written safety programs for the work performed and grades Class 1 Contractors according to the pre-qualification criteria SDG&E establishes.

The main elements in the scoring criteria of pre-qualification collected by ISNetworld are:

- The nationwide review of the three previous years of Total Recordable Incident Rate (TRIR);
- The nationwide review of the three previous years of Days Away Restricted or Transferred Rate (DART);
- Previous year Experience Modification Rate (EMR);
- Previous 5-year fatalities review;
- Previous 5-year Serious Safety Incidents (SSI) review;
- Previous 3-year OSHA citations;
- Written safety program reviews according to the work type performed; and
- Safety culture questionnaire review.

The nationwide-level data captured by the third-party administration program is reviewed by SDG&E to standardize the pre-qualification process and to use for selecting Class 1 Contractors.

D. SDG&E-2-C4: Stop the Job

The Stop the Job (STJ) Process is a protocol SDG&E has established for all contractors. It gives authority to everyone onsite to stop a job or task if an unsafe work condition or activity is identified. All work must immediately cease in the area of concern once the STJ is declared until site supervision and the involved contractor(s) have done an investigation, the identified situation is abated, controlled, or otherwise determined to be safe, and the situation and outcome are explained to affected personnel.

E. SDG&E-2-C5: Near Miss/Close Call Reporting Program

SDG&E requires its contractors to report all incidents per the Class 1 Contractor Safety Manual including Near Miss/Close Call incidents immediately, then monthly in a report. This information is then tracked and used during SDG&E's Class 1 Contractor safety observations and also communicated out to contractors if applicable.

SDG&E defines a Near Miss/Close Call as follows:

- Non-Serious Near Miss: A Work-Connected incident in which Property Damage less than $50,000 or an injury or illness (other than a Serious Safety Incident) could have occurred, but did not.
- Serious Near Miss: A Work-Connected incident in which Property Damage, a Spill/Release resulting in damages of $50,000.00 or more, or a Serious Safety Incident could have occurred but did not.

F. SDG&E-2-C6: Contractor Safety Summit and Quarterly Safety Meetings

This control includes a summit and quarterly safety meetings for contractors. These events create a forum to share industry leading best practices with our contractors, communicate new requirements, give our contractors the opportunity to collaborate with SDG&E on safety, and foster an improved safety culture for contractors and SDG&E. The Contractor Safety Summit is a broad-scoped meeting with focused attendance from SDG&E and Class 1 Contractor Executives and Management. The quarterly safety meetings are attended by SDG&E and Class 1 Contractor Executives and Management, but also include field level personnel.

G. SDG&E-2-M1: Expanded Contractor Oversight Program

This mitigation is part of enhancing and expanding SDG&E's current control SDG&E-2-C1. SDG&E has additional Business Units that utilize Class 1 Contractors (Customer Programs, Electric Operations, Electric Generation, Emergency Management, Aviation Services, Environmental Services, Facilities, Gas Operations, and Transmission Substation Operations) that would benefit from having a safety professional observe their work. With an additional 2

FTEs (1 Team Lead and 1 Field Safety Observers) and 4 Third-Party Field Safety Observers to cover the additional Business Units, SDG&E could support safety oversight and observations of the additional Class 1 Contractor activities. SDG&E has similar oversight in other Business Units which show a measurable safety improvement of Class 1 Contractor Total Recordable Incident Rates (TRIR) and improved safety culture.

Additionally, SDG&E would like to develop a real-time dashboard that consolidates all the current data collected in order to make timely decisions, share current contractor data enterprise wide, and more accurately identify risk with our contractor base to potentially mitigate future incidents.

H. SDG&E-2-M2: Update/Develop Contractor Safety Manual

SDG&E plans to update the Class 1 contractor safety manual annually or as needed with new requirements and/or updating regulatory and SDG&E requirements. SDG&E also aims to develop a manual for Class 2 contractors that are not currently covered under the enhanced contractor safety program or Class 1 Contractor Safety Manual.

Class 2 Contractors are defined as: a contractor engaged to perform any other work (than defined as Class 1). Examples of Class 2 Contractors include contractors engaged to perform administrative tasks or IT work.

I. SDG&E-2-M3: Near Miss/Close Call Reporting Portal/App

SDG&E plans to create a portal and/or app where Class 1 Contractors can submit Near Miss/ Close Call incidents. Near Miss/Close Call incidents are already required to be reported to SDG&E but are collected on incident report form. A new reporting mechanism could promote the submittal of Near Miss/Close Call incidents, a leading indicator that reflects a proactive safety program and culture.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Where SDG&E has not calculated an RSE for activities, the Company has provided a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[21] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of Tranches is presented below.

SDG&E's comprehensive Contractor Safety program consists of pre-qualification of Class 1 contractors, oversight, observations, pre-work safety meetings and efforts all aimed to reduce risk of a safety event caused by a contractor while conducting work on behalf of SDG&E. Given the vast number of activities SDG&E performs to mitigate Contractor Safety risk, SDG&E grouped like activities with like risk profiles into mitigation programs. Since all Class 1 contractors have the potential for serious safety incidents and fatalities and each of SDG&E's Contractor Safety risk mitigations have the same goal of reducing the frequency and consequence of safety events caused by contractors, all controls and mitigations have the same risk profile and are not further tranched. Additionally, since SDG&E's Contractor Safety risk is a "cross-cutting" risk that applies to contractors and is not asset-focused, the concept of tranching does not directly apply to this risk.

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[22] SDG&E then looked at existing/continuing programs (*i.e.*, controls), with the expectation of similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SDG&E also accounted for the risk increase that would occur over time if we stopped performing these activities. For new and/or incremental mitigations, we expect to achieve further risk reduction. The specific risk

---

21 D. 18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

22 *Id*. at Attachment A, A-12 ("Determination of post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," "Measurement of Post-Mitigation Risk Score," "Measurement of Risk Reduction Provided by a Mitigation").

reduction benefit percentages used for each identified control/mitigation are included under each program heading below.

1. SDG&E-2-C1: Contractor Safety Oversight Program

a. Description of Risk Reduction Benefits

SDG&E has always provided oversight of our contracted work, with each Business Unit responsible for managing those elements of their safety oversight programs that differed other Business Units. By creating the Contractor Safety Services (CSS), SDG&E has provided Business Units using Class 1 Contractors with a consistent Contractor Safety Program that is easily understood by SDG&E and its contractors, regardless of Business Unit. Each of the elements included inSDG&E-2-C1 (including pre-qualification of Class 1 Contractors, use of pre-work safety meeting notices and acknowledgement forms, implementation of consistent safety oversight procedures and policies, formalization of incident review and investigation, and development of post-job evaluations) supports SDG&E not only in the selection/engagement of contractors with acceptable safety records, but also with the ongoing management of worksite safety and evaluation. Furthermore, SDG&E's use of a single enterprise-wide system as a repository for Class 1 Contractor safety information allows all of SDG&E's Business Units to access information on an as needed basis, promoting sharing of information and enhanced safety awareness.

To date, SDG&E has implemented elements of SDG&E-2-C1 in all Business Units that use Class 1 Contractors, to include the requirement for all Class 1 Contractors to acknowledge the Class 1 Contractor Safety Manual. More specifically, approximately 75% of Class 1 Contractor work is subject to the entirety of the CSS Oversight Program, with higher risk work prioritized for oversight and observations (due to resource constraints addressed in SDG&E -2-M1), including Major Projects, Constructions Services, and Vegetation Management. SDG&E estimates the Oversight Program has contributed to an approximate 30% reduction OSHA recordable rate in Business Units where CSS has fully implemented its Oversight Program. As this control is relatively new and still developing, the sustained reduction in the OSHA rate is still being evaluated. SDG&E realizes with enhanced oversight we could see a fluctuation in rates.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. The contractor oversight program is the way SDG&E standardizes its approach to contractor safety. This oversight includes instituting safeguards that all contracted work is performed in accordance with SDG&E standards, OSHA regulations, applicable laws, Commission Orders (such as GO 95, Rules for Overhead Electric Line Construction) and GO 128 (Rules for Construction of Underground Electric Supply and Communications Systems). SDG&E's contractor safety oversight program therefore addresses elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and lack of oversight of contractor work (DT.3) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.3362**	
	CoRE	200.387	**1222.56**	2926.19
	Risk Score	267.76	**1633.61**	3910.02
	RSE	9.20	**56.13**	134.34

2. SDG&E-2-C2: Contractual Requirements

a. Description of Risk Reduction Benefits

SDG&E has updated the contractual requirements of all contract templates and Master Service Agreements for Class 1 work to include language that holds SDG&E's Class 1 Contractors accountable for following SDG&E's policies, procedures, and safety practices, including the enhancements implemented through the Contractor Safety Program. All Class 1

Contractors have executed contracts including the new language and without this control, SDG&E may have difficulty enforcing its safety policies, procedures, and practices.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-2-C2 because this control in itself does not have a monetary value/cost that could be calculated in any reasonable manner.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. The contractual requirement control is in place to add updated language to all contracts in order to hold all Class 1 Contractors accountable to follow SDG&E's Class 1 Contractor Safety Manual. SDG&E's contractor requirements therefore address one element of the left side of the Risk Bow Tie contractor crew deviation from policies/procedures (DT.1) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as adverse litigation (PC.5).

3. SDG&E-2-C3: Third-Party Administration and Tools

a. Description of Risk Reduction Benefits

SDG&E uses different third-party administration tools (Predictive Solutions and Veriforce) to manage contractor data and verify compliance with SDG&E and outside party rules and regulations. SDG&E estimates that the use of Predictive Solutions, Veriforce, and ISNetworld combine to contribute to a 3% risk reduction. Furthermore, Predictive Solutions and ISNetworld, which are used by the majority of utilities in California and are considered leading practice contractor safety management systems, support SDG&E in proactive identification of safety trends, provide a centralized system to store and review safety data to verify compliance, and allow the Company to address Class 1 Contractor at-risk behavior before the occurrence of an incident. Finally, using third-party administration tools (rather than SDG&E resources) allows the Company to verify Contractor data, conduct trend analyses, and manage safety compliance more cost-effectively. SDG&E has determined that ISNetworld is the most cost-effective method of ensuring contractor compliance with safety regulations and SDG&E policies, practices, and procedures. As with the use of Predictive Solutions and Veriforce, using ISNetworld (rather than SDG&E employees) allows the Company to conduct pre-qualification, assess Contractor safety performance not only on the SDG&E system but nationwide, and track safety assessments in the most cost-effective manner.

Prior to performing any work for SDG&E, ISNetworld conducts a review and verification of all Class 1 Contractors' pre-qualification requirements (as defined by SDG&E), conducts a nationwide search of each Contractor's safety performance, reviews Contractors' safety compliance programs, and validates each for accuracy and completeness. SDG&E establishes grading criteria for ISNetworld to assess Contractors using an "A," "B," "C," and "F" grading system to measure Contractors' safety performance. Contractors, which are graded annually and following any safety incident, receiving and maintaining an "A" or "B" grade are deemed qualified and approved to work for SDG&E. Contractors that receive a "C" or "F" grade must obtain a waiver through SDG&E by either three directors (for a "C" grade) or three vice presidents (for an "F" grade). Failure to obtain a variance for either a "C" or "F" requires that the Contractor leave SDG&E properties within 45 days. Business Units are advised of grades and variances and are responsible for removal where no variance is granted. The use of ISNetworld verifies Class 1 Contractor compliance with SDG&E safety rules and regulations, maintenance of a safe record in compliance with OSHA requirements and regulations and provides SDG&E with a centralized system to house contractor documents, pre-qualification requirements, and communications, thereby reducing the risk of safety incidents on SDG&E work.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. SDG&E currently uses certain third-party administration tools to verify contractors comply with SDG&E's established safety requirements according to the Class 1 Contractor Safety Manual and the contractual requirements. SDG&E's initiatives using third-party administration and tools reduce risk, give SDG&E a way to verify contractor data in a way that is more effective than performing this service would be in-house, and provides a way to monitor new and changing OSHA requirements, verify SDG&E's Class 1 Contractors meet minimum OSHA requirements for written safety programs for the work performed, and grades Class 1 Contractors according to the pre-qualification criteria SDG&E establishes. SDG&E's

third-party administration and tools therefore address elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), inadequate contractor training/supervision (DT.4), inadequate use of job site safety plans/job safety analysis (DT.5), and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1557**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	231.60	**1412.98**	3381.94
	RSE	32.24	**196.72**	470.84

4. SDG&E-2-C4: Stop the Job

a. Description of Risk Reduction Benefits

Every Class 1 Contractor and employee at SDG&E has the authority to stop the job or stop a task that they believe is unsafe or requires a pause for clarification regardless of level. This action is supported by management, the union, the Class 1 Contractor Safety Manual, and CSS. Planning and understanding the work being performed are key to understanding and mitigating the risks associated with job site safety. They define the task description, discover what can go wrong (hazard description), how risk exposure can arise, contributing factors, consequences and hazard controls.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-2-C5 because this control in itself does not have a monetary value / cost that could be calculated in any reasonable manner.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. The Stop the Job (STJ) Process is a protocol SDG&E has established for all contractors. It gives authority to everyone onsite to stop a job or task if an unsafe work condition or activity is identified. This program promotes a stronger safety culture in all workers and gives all employees the right to stop the job when they have a concern or question. SDG&E's stop the job process therefore addresses elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and inadequate contractor training/supervision (DT.4) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

5. SDG&E-2-C5: Near Miss/Close Call Reporting Program

a. Description of Risk Reduction Benefits

Near miss reporting helps prevent future incidents by alerting CSS of an event that had the potential to result in injury, illness, or damage but did not. Integrating Near Miss reporting into the Contractor safety culture provides CSS with an opportunity to investigate, conduct lessons learned, mitigate, communicate and educate Contractors about the risk/hazard, improve future practices, and avoid similar incidents – thereby reducing risk. In addition, Near Miss reporting provides SDG&E and its Contractors with an opportunity to discuss (during the quarterly meetings and annual summit discussed in SDG&E-2-C7) potential incidents and actions that should be taken to mitigate future risk. A key element of having a Near Miss reporting program is ensuring that Contractors do not associate reporting a Near Miss with occurrence of an incident or adverse action (since that association will drive Contractors to avoid reporting), which is intended to be addressed through SDG&E-2-M3.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-2-C5 because this control in itself does not have a monetary value / cost that could be calculated in any reasonable manner.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. SDG&E requires its contractors to report all incidents per the Class 1

Contractor Safety Manual including Near Miss/Close Call incidents immediately. SDG&E's initiatives to reduce incidents starts with identifying potential incidents in order to mitigate future incidents from occurring. SDG&E's near miss/close call reporting program therefore addresses elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and unsafe operation of equipment or motor vehicle (DT.7) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

6. SDG&E-2-C6: Contractor Safety Summit and Quarterly Safety Meetings

a. Description of Risk Reduction Benefits

The four annual meetings (three Quarterly Safety Meetings and one Contractor Safety Summit) create a forum in which SDG&E and Contractors can share industry leading best practices, discuss new safety policies and regulations, discuss lessons learned and opportunities for improvement, and collaborate to improve the Company's and its Contractors safety culture. SDG&E estimates that approximately 95% of all Contractors, representing 99% of work performed, attend at least one meeting per year. Not only do the meetings place emphasis on safety and demonstrate SDG&E's engagement in developing a safety culture, but they have also resulted in identifiable enhancements in Contractor safety practices – following a discussion of training practices and options, a Contractor built a training facility to enhance its safety practices.

SDG&E has performed a Risk Spend Efficiency Evaluation on SDG&E-2-C6 and believes this control brings a 1% reduction in risk.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. Summit and quarterly meetings for contractors create a forum to share industry-leading best practices with our contractors, communicate new requirements, give our contractors the opportunity to collaborate with SDG&E on safety, and foster an improved safety culture for contractors and SDG&E. These meetings promote a stronger joint safety culture and greater opportunity to learn from one another. SDG&E's contractor safety meetings therefore address elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and inadequate contractor training/supervision (DT.4) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1557**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	231.60	**1412.98**	3381.94
	RSE	58.51	**356.94**	854.34

7. SDG&E-2-M1: Expanded Contractor Oversight Program

a. Description of Risk Reduction Benefits

As noted previously, expansion of the Contractor Oversight Program, through the addition of two SDG&E Full Time Equivalents and two contractor resources, to those Business Units utilizing Class 1 Contractors but not currently under the Program (Customer Programs, Electric Operations, Electric Generation, Emergency Management, Aviation Services, Environmental Services, Facilities, Gas Operations, and Transmission Substation Operations) is expected to result in a measurable impact on Class 1 Contractor OSHA recordables, would be able to oversee all Class 1 Contractor work, and verify compliance with contractor safety program enterprise-wide. Since the implementation of the Oversight Program, SDG&E has seen an approximately 16% decrease in OSHA recordables. Considering the types of work performed by the Class 1 Contractors for the Business Units that would be integrated in the expanded Program and the amount of work that would become subject to enhanced oversight, SDG&E estimates a further 2% reduction in OSHA recordables through this mitigation.

b. Elements of the Bowtie Addressed

SDG&E-2-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. Expanding SDG&E's current Contractor Oversight Program to include additional Business Units that utilize Class 1 Contractors would aim to provide the same standardized safety oversight, improve safety culture, and potentially mitigate future incidents as those already in the program. SDG&E's expansion of its contractor oversight program therefore addresses elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and lack of oversight of contractor work (DT.3) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1289**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	226.21	**1380.12**	3303.29
	RSE	3.02	**18.44**	44.12

8. SDG&E-2-M2: Update/Develop Contractor Safety Manual

a. Description of Risk Reduction Benefits

As noted previously, SDG&E's CSS, in collaboration with the Legal Business Unit, will update the Company's Class 1 Contractor Safety manual to confirm it addresses updated or new regulatory requirements. The cost of this mitigation is limited, as the work will be performed by existing SDG&E FTEs. The risk reduction would be associated with ensuring that Class 1 Contractors are updated on new and/or updated safety regulations on a timely basis.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-M2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. SDG&E updates the Class 1 Contractor Safety Manual annually, or as needed, with new requirements and/or updating regulatory and SDG&E requirements. Additionally, SDG&E aims to develop a manual for Class 2 contractors that are not currently covered under the enhanced contractor safety program or Class 1 Contractor Safety Manual. SDG&E's update/development of contractor safety manual efforts therefore address elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and inadequate use of job site safety plans (DT.5) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

9. SDG&E-2-M3: Near Miss/Close Call Reporting Program Portal/App

a. Description of Risk Reduction Benefits

As noted previously, SDG&E's Class 1 Contractors currently report Near Misses and Close Calls through the SDG&E incident report form. The connection of Near Misses/Close Calls to an incident (through the use of the same form) has historically acted as a deterrent to reporting by Class 1 Contractors – who have communicated hesitation at reporting Near Misses/Close Call incidents on the incident report form, since there is an insinuation that by completing the incident report form, an incident occurred. By developing or implementing an existing Near Miss/Close Call reporting application, SDG&E expects to see an increase in the number of Near Miss/Close Calls incidents reported by Class 1 Contractors, which will lead to enhanced awareness of safety issues and provide SDG&E with the ability to effectively manage Class 1 Contractor safety and promote a its safety culture. The use of Near Miss/Close Call reporting applications is considered a leading practice in the industry.

b. Elements of the Risk Bow Tie Addressed

SDG&E-2-M3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section 1. SDG&E plans to create a portal and/or app which could promote the submittal of Near Miss/Close Call incidents, a leading indicator that reflects a proactive safety program and culture. SDG&E's near miss/close call reporting portal/app therefore addresses elements of the left side of the Risk Bow Tie such as contractor crew deviation from policies/procedures (DT.1), and unsafe operation of equipment or motor vehicle (DT.7) and aims to reduce the Potential Consequences identified in the right side of the Risk Bow Tie such as serious injuries or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1481**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.06	**1403.59**	3359.47
	RSE	7.25	**44.26**	105.94

VII. SUMMARY OF RISK MITIGTION PLAN RESULTS

SDG&E's Risk Mitigation Plan takes into account recent data and trends related to Contractor Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SDG&E has performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigation activities, associated costs, and RSEs by tranche.

SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[23]
(Direct 2018 $000)[24]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[25]	2018 Baseline O&M	2020-2022 Capital[26]	2022 O&M[27]	Total[28]	RSE[29]
SDG&E-2-C1	Contractor Safety Oversight Program	T1	1,670	0	7,830-10,000	840-1,020	8,670-11,020	9.20-134.34
SDG&E-2-C2	Contractual Requirements	T1	0	0	0	0	0	-

23 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

24 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

25 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

26 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

27 As previously stated, internal labor (*e.g.*, employee time spent to complete training courses, employee time spent to perform inspections) are not included in SDG&E's O&M cost forecasts since these costs would rely on cost assumptions (e.g., number of employees, x length of training course, x average hourly wage). Further, SDG&E does not track labor in this manner and thus would not be able to include such internal labor costs in future spending accountability reports.

28 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

29 RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

SDG&E-2-C3	Third-Party Administration and Tools	T1	5	20	0	20-25	20-25	32.24-470.84
SDG&E-2-C4	Stop the Job	T1	0	0	0	0	0	-
SDG&E-2-C5	Near Miss/Close Call	T1	0	0	0	0	0	-
SDG&E-2-C6	Contractor Safety Summit and Quarterly Meetings	T1	0	10	0	10-20	10-20	58.51-854.34
SDG&E-2-M1	Expanded Contractor Oversight	T1	0	0	3,240-4,140	220-310	3,460-4,450	3.02-44.12
SDG&E-2-M2	Updated Class 1 Safety Manual, Development of Class 2 Manual	T1	0	0	0	0	0	-
SDG&E-2-M3	Near Miss/Close Call Reporting Portal/App	T1	0	0	0	90-130	90-130	7.25-105.94
		TOTAL COST	**1,680**	**30**	**11,000-14,000**	**1,200-1,500**	**12,000-16,000**	

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SDG&E notes that there are activities related to this Contractor Safety risk that will be carried over to the GRC for which the costs are a combination of external and internal labor (e.g., employee time spent for training, performing inspections or monitoring). These costs associated with these internal labor activities are not captured in this chapter because SDG&E does not track labor in this manner.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 7: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-2-C2	Contractual Requirements	Excluded internal labor; no identified costs
SDG&E-2-C4	Stop the Job	Excluded internal labor; no identified costs
SDG&E-2-C5	Near Miss/Close Call Reporting Program	Excluded internal labor; no identified costs

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the mitigations for the Contractor Safety risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SDG&E-2-A1: Development of an internal program to pre-qualify and oversee contractor safety.

SDG&E reviewed the feasibility of not using a third-party administrator. During SDG&E's internal evaluation, it was determined that SDG&E did not have the proper resources or personnel to administer the pre-qualification and verification of requirements of its contractor workforce. Furthermore, the cost of using a third-party administrator was $30,000.00 compared to our estimated addition of 10 FTE's at $1,390,000.00 to accomplish the same tasks.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1500**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.44	**1405.89**	3364.98
	RSE	0.27	**1.62**	3.88

B. SDG&E-2-A2: Use alternative third-party administrator to pre-qualify contractors

During the implementation of our enhanced contractor safety program, SDG&E considered using other third-party administrators, including Avetta and Browz. Additionally, SDG&E benchmarked with other California Investor Owned Utilities on the third-party administrators they were using. Each of the alternatives offered similar basic functionality: a pre-qualification system centered around verifiable data to include OSHA documents and safety rates. After assessing the services offered and associated costs of those options, SDG&E decided to execute an agreement with ISN instead of others because (1) 52% of our current contractors were already enrolled and would not incur additional costs, (2) PG&E and SCE were already using ISN, thus keeping consistency with our common contractors, and (3) ISN had the industry-leading platform that best fit our needs.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.152**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.83	**1408.28**	3370.71
Post-Mitigation	LoRE		**1.1481**	
	CoRE	200.39	**1222.56**	2926.19
	Risk Score	230.06	**1403.59**	3359.47
	RSE	22.80	**139.11**	332.95

Table 8: Alternative Mitigation Summary
(Direct 2018 $000)[30]

ID	Mitigation	2020-2022 Capital[31]	2022 O&M	Total[32]	RSE[33]
SDG&E-2-A1	Develop an all internal program to pre-qualify an oversee contractor safety	0	1,390-1,530	1,390-1,530	0.27-3.88
SDG&E-2-A2	Use alternative third-party administrator to pre-qualify contractors	0	30-40	30-40	22.80-332.95

[30] The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

[31] The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

[32] Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

[33] The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
SDG&E-2-C1	Contractor Safety Oversight Program	DT.1 – DT.9 PC.1 – PC.7
SDG&E-2-C2	Contractual Requirements	DT.1 PC.5, PC.6
SDG&E-2-C3	Third-Party Administration and Tools	DT.1, DT.2, DT.4, DT.5, DT.6, DT.9, PC.1 – PC.7
SDG&E-2-C4	Stop the Job	DT.1, DT.3, DT.4 PC.1 – PC.7
SDG&E-2-C5	Near Miss/Close Call Reporting Program	DT.1, DT.2, DT.7 PC.1 – PC.7
SDG&E-2-C6	Contractor Safety Summit and Quarterly Safety Meetings	DT.1, DT.2, DT.3, DT.4 PC.1 – PC.7
SDG&E-2-M1	Expanded Contractor Oversight Program	DT.1 – DT.9 PC.1 – PC.7
SDG&E-2-M2	Updated Class 1 Contractor Safety Manual, Development of Class 2 Contractor Safety Manual	DT.1 – DT.9 PC.1 – PC.7
SDG&E-2-M3	Near Miss/Close Call reporting portal/app. All contractor safety data from ISN and predictive solutions rolled up into real-time dashboard	DT.1, DT.2, DT.7 PC.1 – PC.7

Risk Assessment Mitigation Phase
(Chapter SDG&E-3)
Employee Safety

November 27, 2019

SDGE

A Sempra Energy utility

TABLE OF CONTENTS

Risk: Employee Safety

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas & Electric's (SDG&E or Company) Employee Safety risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014 and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from this 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Employee Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII, below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

A. Risk Definition

For purposes of this RAMP Report, SDG&E's Employee Safety risk is defined "as the risk of an employee safety incident that causes serious injuries[3] or fatalities while on duty."

---

[3] A "serious injury" is defined in the California Code of Regulations as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." 8 California Code of Regulations (CCR) § 330(h).

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Elements of the Risk Bow Tie

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Employees deviate from company policies or procedure
DT.2	Hazards in the work environment (*e.g.*, work locations, roadways)
DT.3	Non or improper use of personal protective equipment
DT.4	Unsafe operation of equipment or motor vehicles
DT.5	Damage to SDG&E equipment and/or infrastructure
PC.1	Serious injuries[5] and/or fatalities
PC.2	Property damage
PC.3	Operational and reliability impacts
PC.4	Adverse litigation
PC.5	Penalties and fines
PC.6	Erosion of public confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[6] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SDG&E-3-C1	Mandatory employee health and safety training programs and standardized policies
SDG&E-3-C2	Drug and alcohol testing program

4 *Id.* at Attachment A, A-11 ("Bow Tie").

5 8 CCR § 330(h).

6 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SDG&E-3-C3	Safety culture
SDG&E-3-C4	Employee Behavior Based Safety (BBS) program
SDG&E-3-C5	A comprehensive Environmental & Safety Compliance Management Program (ESCMP)
SDG&E-3-C6	Employee safety training and awareness programs
SDG&E-3-C7	Employee wellness programs
SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments
SDG&E-3-C9	Safe driving programs
SDG&E-3-C10	Personal protection equipment
SDG&E-3-C11	Jobsite Safety Programs including Near Miss and Stop the Job
SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking

SDG&E will continue the baseline controls identified above and puts forth additional projects and/or programs (*i.e.*, Mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional
SDG&E-3-M2	Safety in Action Program Enhancement
SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)
SDG&E-3-M4	Implementing findings from VPP program assessments
SDG&E-3-M5	Energized Skills Training and Testing Yard
SDG&E-3-M6	Employee Wildfire Smoke Protections – Cal/OSHA emergency regulation

Finally, pursuant to the SA Decision,[7] SDG&E presents considered alternatives to the Risk Mitigation Plan for the Employee Safety risk and summarizes the reasons that the alternatives were not included in the Risk Mitigation Plan in Section VIII.

7 *Id.* at 33.

II. RISK OVERVIEW

Employee safety is a core value at SDG&E. SDG&E's safety-first culture focuses on its employees, customers, and the public, and is embedded in every aspect of the Company's work. Employees should be able to go home to their families and loved ones after work each day and be able to return to work safely the next day. Safety is not compromised for production, customer satisfaction, or other goals and no activity is so important that it should jeopardize employee or customer safety.

The Employee Safety risk was included in SDG&E's 2018 ERR and for purposes of this RAMP filing is defined as the risk of an employee safety incident that causes serious injuries or fatalities while on duty. This Employee Safety risk chapter focuses on mitigation activities that address safety, education, training, and other internal procedural enhancements.[8] SDG&E's Employee Safety risk mitigation programs are founded on proven employee-based programs, safety training, workforce education, and SDG&E's Illness & Injury Prevention Program (IIPP). Per Title 8 of the California Code of Regulations (CCR),[9] the elements of SDG&E's IIPP include:

- Commitment/assignment of responsibilities;
- Safety communications systems with employees;
- System for assuring employee compliance with safe work practices;
- Scheduled inspections/evaluation system;
- Accident investigation;
- Procedures for correcting unsafe or unhealthy conditions;
- Safety and health training and instruction; and
- Recordkeeping and documentation.

---

8 The Electric Infrastructure Integrity (EII) Chapter (SDG&E-4) of this RAMP Report covers the risk event of an employee coming into contact with energized equipment, because mitigations for this risk event are focused on infrastructure protections and improvements – even though the potential consequences of the risk event (causing serious employee injury or fatality) are similar to those of an Employee Safety risk event.

9 State of California Department of Industrial Relations, *Cal/OSHA – Title 8 Regulations – Index* (May 16, 2018), available at https://www.dir.ca.gov/title8Index/t8index.asp.

SDG&E's strong safety culture and commitment to further developing processes and programs is designed to manage the Employee Safety, Contractor Safety, and Customer & Public Safety risks. As noted above, many of the Employee Safety mitigations identified herein also help mitigate these other risks. While the Employee Safety risk definition is limited in scope for purposes of this RAMP Chapter, it is important to note that the operational risks addressed in other Chapters of this RAMP Report[10] can result in an incident where an employee is seriously injured, or a fatality is present. Following the SA Decision and our risk methodology, a potential risk scenario of the Employee Safety risk is an employee not following a company policy or procedure being severely injured and causing a disruption of service to a small number of customers.

SDG&E's safety performance measures have shown consistent improvement overall in recent years, with the exception of Controllable Motor Vehicle Incidents (CMVI). As of December 31, 2018, SDG&E's total CMVI stood at 42, compared with 2017's year-end CMVI totals of 38. SDG&E is accordingly undertaking an initiative to assess and address motor vehicle incidents, which has resulted in preliminary proposals to enhance our safe driving program (*see*, SDG&E-3-M3, as further described below). As a part of these efforts, SDG&E has recently reviewed its Smith training system as well as our vehicles and safety equipment and technologies. In 2018, SDG&E achieved its lowest DART (Days Away / Restricted / Transfer) rate on record, which reflects a reduction of 11% from 2016. In addition, SDG&E's safety field visits/observations have increased and surpassed our 2018 goal.

III. RISK ASSESSMENT

In accordance with the SA Decision,[11] this section describes the risk Bow Tie, possible Drivers, and potential consequences of the Employee Safety risk.

---

[10] *See*, SDG&E-4, Electric Infrastructure Integrity; SDG&E-6, Medium Pressure Gas Pipeline Incident; SDG&E-7, Third Party Dig-in on Medium Pressure Pipeline; SDG&E-8, High Pressure Gas Pipeline Incident; and SDG&E-9, Third Party Dig-in on High Pressure Pipeline.

[11] D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

A. Risk Bow-Tie

The risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie

B. Asset Groups of Systems Subject to the Risk

The SA Decision[12] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. This is a "cross-cutting" risk and therefore is associated with human systems, rather than particular asset groups.

C. Risk Event Associated with the Risk

The SA Decision[13] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the Bow Tie) is an employee safety event that results in any of the Potential Consequences listed on the

12 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

13 *Id.* at Attachment A, A-11 ("Bow Tie").

right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. The Risk Scenario (*i.e.*, a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency) was assessed for SDG&E's 2018 Enterprise Risk Registry. This scenario does not necessarily address all Drivers/Triggers and Potential Consequences and does not reflect actual or threatened conditions.

D. Potential Drivers/Triggers[14]

The SA Decision[15] instructs the utility to identify which element(s) of the associated Risk Bow Tie each mitigation addresses. When performing the risk assessment for Employee Safety, SDG&E identified potential leading indicators, referred to as Drivers or Triggers. These include, but are not limited to:

- **DT.1 - Employees deviate from company policies or procedure:** SDG&E has many safety-related policies and procedures for employees to follow. Failure of someone to adhere to such Company safety policies and procedures could result in a safety-related event.
- **DT.2 - Hazards in the work environment (*e.g.*, work locations, roadways):** Unsafe work environments, including work locations, roadways and parking places, customer premises, gas equipment condition, Polychlorinated Biphenyls (PCB), lead from paint, asbestos, fumigation chemicals, for example, could lead to a safety event.
- **DT.3 – Non-use or improper use of personal protective equipment –** Safety equipment serves to protect employees and contractors from avoidable injuries. Failure to wear personal protection and safety equipment can lead to a safety incident.
- **DT.4 - Unsafe operation of equipment or motor vehicles –** If someone does not follow the law and or other applicable safety practices, it could result in a safety incident.

---

[14] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[15] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.5 - Damages to SDG&E equipment and/or infrastructure –** Damage to gas and electric infrastructure and facilities could cause an unpredictable environment and, thus, can lead to a safety incident.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries and/or fatalities;
- Property damage;
- Operational and reliability impacts;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of Employee Safety that occurred during the development of SDG&E's 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[16] including enhancements to the Interim Decision 16-08-018.[17] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

16 *Id.* at Attachment A.

17 *Id.* at 2-3.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[18]

Employee Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	127	**1086**	2684
LoRE		**1.3**	
CoRE	97	**836**	2066

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[19] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Scope

In-Scope for purposes of risk quantification:	The risk of an employee safety incident (as defined by OSHA regulation) that causes serious injuries or fatalities while on duty.
Out-of-Scope for purposes of risk quantification:	The risk of a safety incident (outside of OSHA regulation; not work-related) involving an employee that causes serious injuries or fatalities while not on duty.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (*e.g.,* Pipeline and Hazardous Materials Safety Administration data).[20] SDG&E's safety risk assessment primarily utilized national level data from the Bureau of Labor Statistics (BLS), OSHA, and the DOL.

[18] The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

[19] D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

[20] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

Calculating serious injury and fatality incidence rates requires data on total employment by sector, which is provided in the BLS Employment & Earnings data. The data was filtered by North American Industry Classification System (NAICS) subsector codes "2211 Electrical Power Generation, Transmission and Distribution" to represent the SDG&E electric business and "2212 Natural Gas Distribution" to represent the SDG&E gas business. The percentage split for 2017 Common Account Allocations - General and Administrative Expense for SDG&E (75% for electric and 25% for gas) was applied to identify the total number of employees in each respective sector.

Injuries, Illnesses, and Fatalities Program (IIF) historical data from the BLS was used to determine the serious injury and the fatality incidence rates per year. From this data, for the serious injury rate, it was calculated that 1.3% of recordable incidents are serious injuries for electric-related employees and 0.5% of recordable incidents are serious injuries for gas-related employees. This serious injury assumption is calculated as the ratio of serious injuries to recordable incidents during 2015-2016, by sector.

OSHA Enforcement Data, supplemented with OSHA Severe Injury Reports, from the DOL was used to determine the distribution of injuries or fatalities resulting from a single employee safety event. The NAICS code structure used in the data from the BLS is consistent with the NAICS codes in the OSHA enforcement data used for determining the distribution.

A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences. The safety consequence scoring was based on a publication from the Federal Aviation Administration (FAA): a fatality is represented by 1.000 and a serious injury is represented by 0.253. Internal subject matter expert (SME) input was provided to estimate the financial consequence of an employee safety incident. Based on SME input, reliability is not directly impacted by employee safety related incidents.

B. Sources of Input

The SA Decision[21] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

---

[21] *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Injuries:
  - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
  - Link: https://www.bls.gov/iif/oshsum.htm#15Summary_Tables
  - Report Title: TABLE Q1. Incidence rates of total recordable cases of nonfatal occupational injuries and illnesses by quartile distribution and employment size, 2009-2016, all establishment sizes
- Fatalities:
  - Agency: Bureau of Labor Statistics- Injuries, Illnesses, and Fatalities Program (IIF)
  - Link: https://www.bls.gov/iif/oshcfoi1.htm#2015
  - Report Title: Census of Fatal Occupational Injuries-TABLE A-3. Fatal occupational injuries to private sector wage and salary workers, government workers, and self-employed workers by industry, all United States
- Distribution Fitting Data:
  - Agency: Department of Labor (DOL)
  - Link: https://enforcedata.dol.gov/views/data_catalogs.php
  - Report Title: OSHA Enforcement Data: osha_accident, osha_accident_injury, osha_inspection
- Severe Injury Assumption:
  - Agency: Occupational Safety and Health Administration (OSHA)
  - Link: https://www.osha.gov/severeinjury/index.html
  - Report Title: Severe Injury Reports
- Support Data:
  - Agency: Bureau of Labor Statistics- Office of Publications & Special Studies
  - Link: https://www.bls.gov/opub/ee/archive.htm
  - Report: Employment & Earnings- Table B-1b. Employees on nonfarm payrolls by industry sector and selected industry detail, not seasonally adjusted, 2011-2016
- North American Industry Classification System - NAICS
  - Agency: US Census Bureau
  - Link: https://www.census.gov/cgi-bin/sssd/naics/naicsrch?chart_code=22&search=2017%20NAICS%20Search

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[22] This section describes SDG&E's Risk Mitigation Plan by each selected control and mitigation for this risk, including the rationale supporting each selected control and mitigation.

As stated above, SDG&E's Employee Safety risk is defined as the risk of a work-related employee safety incident that causes serious injuries or fatalities. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SDG&E's TY 2022 GRC cycle.[23] The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

As discussed in Chapter RAMP-A, certain internal labor costs are not reflected in Section VII, below. While the costs presented herein may therefore appear lower than those presented in SDG&E's TY 2019 RAMP Report, it is important to note that this does not reflect a drop in SDG&E's employee safety risk mitigation efforts. The costs associated with these internal labor activities are not captured in this chapter because SDG&E does not currently track labor in this manner. Therefore, in order to aid RAMP to GRC integration efforts, and Risk Spending Accountability Reporting requirements, SDG&E has not captured certain internal labor costs (*e.g.*, time spent to attend training) in this 2019 RAMP Report but continues to perform these risk mitigation activities as described herein.

A. SDG&E-3-C1: Mandatory Employee Health and Safety Training Programs and Standardized Policies

SDG&E's employees receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. SDG&E's Mandatory Employee Health and Safety Training Programs and Standardized Policies comprise the

---

22 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

23 *Id.* at 33. A "Control" is defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event.

following elements, as required by the California Code of Regulations, Cal/OSHA and/or CPUC regulations:

Injury Illness Prevention Plan (IIPP): In California, every employer is required by law[24] to provide a safe and healthful workplace for its employees. Further, Title 8 of the California Code of Regulations[25] requires every employer to have an effective IIPP. SDG&E's IIPP is a written plan for preventing injury and illness that includes the following elements:

- Management commitment/assignment of responsibility;
- Safety communication system with employees;
- System for assuring employee compliance with safe work practices;
- Scheduled inspections/evaluation system;
- Accident investigation;
- Procedures for correcting unsafe or unhealthy conditions;
- Safety and health training instruction;
- Recordkeeping and documentation; and
- Safety programs.

Employee Safety Handbook/Standards: SDG&E's employee safety handbook is a collection of information, instructions, policies, and procedures intended to safeguard safe work practices and describe how to conduct work safely in the workplace. The purpose of the health and safety policies and procedures within this handbook is to guide and direct all employees to work safely and prevent injury to themselves and others.

Safety standards are specifications designed to promote the safety of work activities or processes. Standards are rules that describe the methods that SDG&E uses to protect employees from hazards and are used to communicate policy to the workforce. These standards establish the framework and guidance for employee safety performance.

Industrial Hygiene Program: SDG&E has a robust Industrial Hygiene program in compliance with Cal/OSHA regulations. Industrial Hygienists are responsible for monitoring changes in employee safety and health regulations, developing internal safety policies and

---

24 Cal. Labor Code § 6400.

25 8 CCR § 8350.

procedures to confirm compliance with the applicable regulations, and managing Company-wide implementation of key industrial hygiene programs, such as Hazard Communications, Hearing Conservation, Respiratory Protection, Mold, Asbestos and Lead Exposure Management.

Arc Flash Hazard Assessment and Standard Training: SDG&E's Arc Flash Hazard Assessments are conducted to determine and evaluate hazards and level of protection associated with the electric circuits/arcs. The Arc Flash Training is designed to educate and protect employees from the hazards of electric arc and to establish procedures for compliance with Cal/OSHA regulations. The objectives of training are to identify:

- Hazards of electric arcs associated with energized lines and equipment;
- Safety practices and protective measures including flame-resistant/arc-rated clothing; and
- Regulations and Company policy/procedures.

Confined Space Training: This mandatory California OSHA requirement identifies (1) common confined spaces and associated hazards and (2) the related Company policy and procedures. Confined Space Training is mandatory for employees who may:

- Enter or have need to enter confined spaces; and/or
- Encounter confined spaces in the course of Company business

Electric and/or Magnetic Fields (EMF): SDG&E recognizes and shares the concerns of its customers about EMF. SDG&E's EMF Safety Program includes:

- Maintaining a staff of informed representatives available to talk with customers about EMF issues and provide magnetic field measurements for customers requesting the service;
- Providing objective EMF health literature to the public and notifying customers of research milestones as this information becomes available;
- Providing employee education on EMF issues;
- Supporting, funding, and monitoring EMF research;
- Implementing low-cost and no-cost measures, where appropriate, to reduce fields associated with new construction projects; and
- Participating in communication forums and regulatory proceedings to remain current on all EMF-related issues.

B. SDG&E-3-C2: Drug and Alcohol Testing Program

SDG&E has implemented an employee drug and alcohol testing program managed in accordance with state and federal regulations. SDG&E's substance abuse prevention policy, which all employees are responsible for knowing and complying with, prohibits the use and/or possession of alcohol during working hours and/or reporting to work with alcohol or prohibited drugs in their system. Violations of this policy are cause for disciplinary action up to and including termination of employment.

In addition to the substance abuse prevention policy, SDG&E deploys Substance Abuse Prevention Training (SAPT) as a proactive measure. SAPT is an on-line, comprehensive self-paced, interactive, and user-friendly course that educates employees on drug and alcohol awareness, SDG&E's prevention program, supervisor responsibilities, identification of being under the influence, reasonable suspicion testing, random drug testing, and post-accident testing.

SDG&E's substance abuse prevention program governs the use of controlled substances and the misuse of alcohol by employees that perform safety-sensitive functions. Employees meeting the criteria under U.S. Department of Transportation Testing Regulation[26] are required to submit to alcohol, illegal, and controlled substance testing:

- **Federal Motor Carrier Safety Administration (FMCSA)** – Applies to Company employees holding a Class A, Class B or commercial Class C motor vehicle driver's license to operate vehicles with a combined gross vehicle weight rating (GVWR) of 26,0001 pounds or more; Department of Transportation placarded vehicles under hazardous material regulations; or vehicles designed to transport 16+ passengers.
- **Pipeline & Hazardous Material Safety Administration (PHMSA)** – Applies to all employees in safety-sensitive positions that perform pipeline operations, maintenance, or emergency response functions, as defined by PHMSA.

<u>Reasonable Suspicion Identification and Testing</u> applies to all employees and can be performed post-accident, as described below. SDG&E's policy requires supervisors to remove

---

[26] 49 CFR Part 40.

suspected employee from work if recognizable signs of impairment are observed after using the reasonable suspicion checklist. SDG&E's six-step process is as follows:

1. Recognition: Use of reasonable suspicion checklist to appropriately recognize signs and symptoms that could be indicative of alcohol and/or substance abuse (includes impairing prescription medication);
2. Documentation: Documented observations;
3. Consultation: Consult with appropriate individuals in the department and/or Safety Compliance department;
4. Plan of Action: In conjunction with Safety Compliance department, plan is developed that may include removal from safety sensitive functions, reasonable suspicion testing, suspension or administrative leave;
5. Meeting with Employee: Discussion of factual observation, policies, procedures and other information that are relevant to substance abuse in the workplace. Next steps will be provided along with discussion on potential consequences; and
6. Support and Supervise: Support employee with emphasis on employee accountability.

Post-Accident Testing

- **If reasonable suspicion is determined**, post-accident testing may be commenced under guidance of Safety Compliance department and/or designated employer representative (DER).
- **FMCSA** allows post-accident testing when there is an accident while driving a commercial motor vehicle requiring a CDL to operate and the following occurs:
  - a. Fatality, or
  - b. Citation is issued by law enforcement and one of the following:
    - a. Medical treatment away from scene of the accident, or
    - b. A vehicle incurring damage as a result of the accident towed from the scene.
- **PHMSA** – An "Accident" means an incident reportable under the Department of Transportation involving gas pipeline facilities or LNG facilities or an accident reportable under part 195 involving hazardous liquid pipeline facilities. Testing

must occur as soon as possible, but no later than 32 hours after an accident for those whose performance contributed to the accident or cannot be completely discounted as a contributing factor.

C. SDG&E-3-C3: Safety Culture (*e.g.*, safety meetings, committees, survey, safety pledge campaign)

As further discussed in Chapter RAMP-F, SDG&E is committed to a strong safety culture and places the highest priority on employee, customer, and public safety. To continuously strengthen our safety culture, Company employees attend safety meetings, tailgates, congresses, and are surveyed every two years to solicit their candid feedback, as further detailed below. SDG&E is already using the results of the 2018 survey to develop action plans to further strengthen its employee safety program and culture. SDG&E's efforts to establish a strong safety culture and further employee safety initiatives include:

Safety Stand-downs: A Safety Stand-down is a voluntary event for employers to talk directly to employees about safety. These events provide an opportunity to discuss hazards, protective methods, and the Company's safety policies, goals and expectations.

Safety Congress and Leadership Awards: Since 2002, this event has been held annually. It provides a forum for safety committee members, safety leaders and others to share and exchange information and ideas through networking and workshops. At this event, safety leaders are recognized for living by the Company's safety vision, turning that vision into action, embracing the SDG&E safety culture, and demonstrating safety leadership.

Safety Tailgates: Safety tailgate talks are short informational meetings held with employees to discuss a work-site related safety. The purpose of a tailgate is to inform employees of specific hazards associated to a task and the safe way to do a job. Tailgate talks also serve as a reminder to employees of what they already know while establishing the supervisor's credibility and conscientiousness about his oversight role.

Safety Meetings: The main objectives of a safety meeting are to remind employees of safe practices they have already learned and to introduce and build awareness of new techniques, new equipment, or new regulations that must be observed.

Grassroots Safety Culture Change Teams (GRSC): Launched in 2009, SDG&E's GRSC involves a safety culture journey that goes beyond the 3 E's of engineering, enforcement, and education. The emphasis is on building trust, relationships, and partnerships that affect the Company's strategic focus areas, including safety. This approach uses an "iceberg analysis" to identify cultural norms and assumptions that cannot be seen (below the waterline) that may undermine established policies and procedures. Under a guidance team and team coach, GRSC teams propose projects with goals to help move the Company's safety culture forward, improving awareness, preventing injuries, bridging communication gaps, and preserving pride in SDG&E's work.

These teams train and empower frontline employees to advance a positive safety culture in their workgroups by addressing behaviors and norms to take safety beyond compliance. This nationally recognized program is deployed in strong partnership with IBEW Local 465.

Executive Safety Council (ESC) Team Meeting Dialogs: The ESC is the governing body for all safety committees. Led by SDG&E's Chief Operations Officer and Director – Safety, the ESC advances the Company safety culture and addresses enterprise-wide safety strategy. The meeting dialogs are held at Company locations and integrate employee and supervisor dialog sessions so that employees have an opportunity to share safety experiences with Company leadership.

Bi-annual Safety Culture Survey: Every two years, SDG&E employees take a Safety Barometer Survey and share their candid insights on safety in six critical areas: Management Participation, Supervisor Participation, Employee Participation, Safety Support Activities, Safety Support Climate, and Organizational Climate. The Safety Barometer Survey is provided by the National Safety Council (NSC),[27] an independent non-profit organization that has advocated for employee and public safety for over 100 years.

The NSC takes our survey results and compares it to other participating companies in their survey database (approximately 600 companies, currently). The results of SDG&E's 2018 survey placed it in the 91st percentile and in the top 10 percent of the 580 organizations in the NSC database who participated in the survey in 2018. The overall score for SDG&E increased by 6 points from the 2016 survey. SDG&E looks to continually improve its safety program and culture. Action plans based on the 2018 NSC survey results are being developed and executed.

[27] National Safety Council, *NSC Safety Training*, *available at* https://www.nsc.org/.

The six critical areas of the NSC survey and SDG&E's 2018 rankings in those areas are:

- **Management Participation (top 8%).** Management Participation items describe ways in which top and middle management demonstrate their leadership and commitment to safety in the form of words, actions, organizational strategy, and personal engagement with safety.
- **Participation (top 9%).** Supervisor Participation items consider six primary roles through which supervisors communicate their personal support for safety: leader, manager, controller, training, organizational representative, and personal engagement with safety.
- **Safety Support Climate (top 10%).** Safety Support Climate items asked employees across the organization for general beliefs, impressions, and observations about management's commitment and underlying values with regards to safety.
- **Safety Support Activities (top 11%).** Safety Support Activities items probe the presence or quality of various safety program practices, with a focus on communications, training, inspection, maintenance, and emergency response.
- **Employee Participation (top 15%).** Employee Participation items specify selected actions and reactions that are critical to making a safety program work. Emphasis is given on personal engagement, responsibility, and compliance.
- **Organizational Climate (top 24%).** Organizational Climate items probe general conditions that interact with the safety program to affect its ultimate success, such as teamwork, morale, and employee turnover.

Safety Committees/Sub-committees:

Field and Office Site Safety Committees (60): These site-specific committees are actively engaged in safety awareness through education, promoting a healthy lifestyle, encouraging work-life balance, and always maintaining a safe work environment. To keep the committees connected, quarterly meetings are held with committee chairpersons and co-chairpersons. During these meetings safety updates are shared, training is provided, and action planning steps identified. Like all other safety committees, site committees roll out to the ESC as the governing body.

Electric Safety Subcommittee: This committee brings management and electric front-line people together to discuss safety concerns from the perspective of those closest to the risks. The objectives are to make a lasting difference in reducing unnecessary risk, resolve division-wide safety issues/concerns, and have front line employees bring information to their respective workgroups.

Gas Safety Subcommittee (GSS): Since 2015, the GSS has engaged employee representatives from each district and management on a monthly basis to discuss concerns and address potential gas operations safety hazards. The objective is to reduce unnecessary risk, resolve gas safety issues/concerns, and communicate information back to frontline employees.

D. SDG&E-3-C4: Employee Behavior Based Safety (BBS) Program

SDG&E's BBS Program is a proactive approach to safety and health management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. BBS is the "application of science of behavior change to real world safety problems." This process is a safety partnership between management and employees that continually focuses people's attentions and actions on their, and others', daily safety behavior to identify safe and at-risk behaviors. Through a peer observation program, employees observe employees working using a behavior inventory checklist to track safety behaviors and have a dialog on safe and at-risk behaviors, then recommended behavioral safety changes.

At SDG&E, there are five BBS processes throughout field operations. As part of SDG&E's long-term safety strategy, a 2019 action plan has been created for our peer led BBS program. This year will focus on individual process reviews for each of the five BBS teams to identify gaps, strengths and opportunities; review and develop BBS training; and create a guidance team for the five processes.

E. SDG&E-3-C5: A Comprehensive Environmental & Safety Compliance Management Program

SDG&E uses an Environmental and Safety Compliance Management Program (ESCMP) to address compliance requirements, awareness, goals, monitoring, and verification related to all applicable environmental, health and safety laws, rules and regulations, training, and Company standards. ESCMP is an environmental, health and safety management system to plan, set priorities, inspect, educate, train, and monitor the effectiveness of environmental, health and safety activities in accordance with the internationally accepted standard, ISO 14001. The year-end ESCMP Certification process involves submittal of information into a database used to collect and record employee and facility compliance. For this submittal, two types of checklists are available and completed in the online system: An Employee-Based checklist or a Facility-Based checklist. Through this process, the Environmental and Safety departments can review submittals in the online system and confirm all required inspections were completed, assigned training was done, and all corrective actions were addressed.

Site Managers, with support of their Safety Advisors, are responsible for conducting safety self-assessments of Company facilities and operations (Bases, Compressor Stations, Construction & Operations (C&O) Centers, Data Centers, Gas Storage, Laboratory, Liquefied Natural Gas, Multiuse Facilities, Offices and Power Plant Facilities) as set forth in the Safety Inspection and Self-Assessments Standards.

<u>Semi-annual Inspections</u> **-** Site, facility, and branch managers (or designees) conduct semi-annual safety inspections of their facilities in the first and third calendar quarters. The first semi-annual inspection is completed in Q1 and results entered into SDG&E's Safety Information Management System (SIMS) by March 31. The second semiannual inspection is completed in Q3 and results entered in SIMS by September 30 each year.

F. SDG&E-3-C6: Employee Safety Training and Awareness Programs

As previously stated, SDG&E's employees receive extensive training because we believe safety starts with proactive upstream measures to prevent a safety incident from occurring. SDG&E's employee safety training and awareness programs include:

<u>On-line/Learning Management System Training</u>: Online training refers to a course, education materials, or program delivered online via the intranet or through SDG&E's learning management system (LMS). Examples of online training include, but are not limited to, IIPP, EAP, Smith System® refresher, and ergonomics. These training programs develop skill sets while being available at any time, accessible from any location, and performed at the user's convenience. Additionally, completion of the training can be tracked in SDG&E's LMS system

to confirm compliance. SDG&E believes that being educated and providing employees with information, tools and training at their fingertips will reduce the potential for injury.

Safety in Motion (SIM): SIM is a body mechanics education program to help inform employees about body positioning to help prevent sprains, strains, and tears. It is designed to equip each field employee with a consistent process for approaching each job safely by enhancing knowledge and skills and the ability to identify and use the best body positioning. This program provides customized training based on known risk factors such as intensity of effort (*e.g.,* jackhammering), awkward posture (*e.g.,* working on a pole or digging), and/or repetition (*e.g.,* wrenching) with the objective of providing employees with alternatives to decrease injury potential. SIM's overall goal is to reduce unnecessary strain on the body through use of engineering controls, tools, and physical techniques that allow employees to "work smarter not harder."

Emergency Action Plan (EAP): It is SDG&E policy that all Company facilities have an EAP to provide for the safety of employees during emergencies and comply with state and federal safety requirements. The EAP outlines the roles and responsibilities of employee and emergency response teams during workplace emergencies. The plans include, but are not limited to: communication strategies, evacuation routes, and procedures for accounting for employees. The safety of all employees is the primary goal during a workplace emergency. SDG&E's EAP procedures are taught through web-based, in-person, or classroom training.

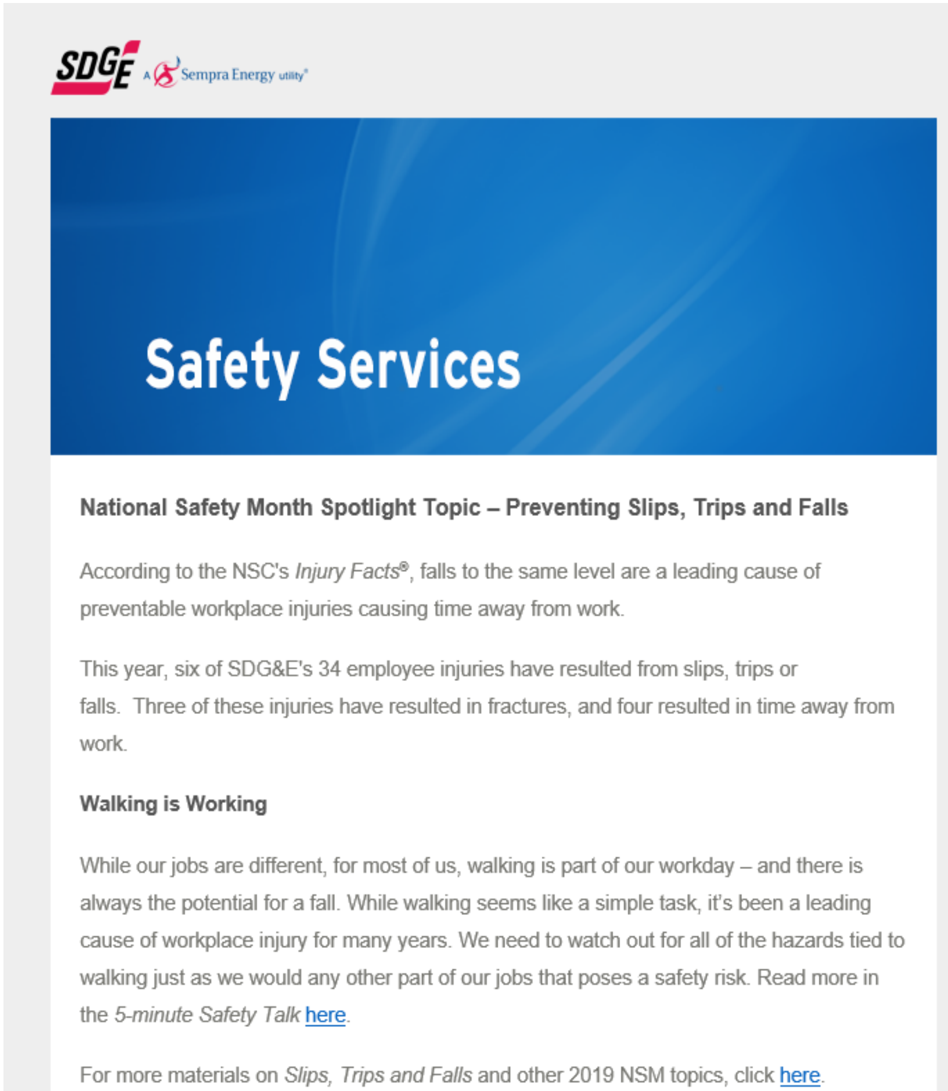
Site and Vehicle automated external defibrillators (AED) Program: AEDs are available at all SDG&E work locations and are on crew vehicles with two or more employees. Designated employees are trained on the use of the device and provided with first aid and cardiopulmonary resuscitation (CPR) training. When used, the AED device automatically diagnoses life-threatening cardiac arrhythmias of ventricular fibrillation and pulseless ventricular tachycardia and, once prompted by the trained responder, administers defibrillation (the application of electricity stopping the arrhythmia) allowing the heart to re-establish an effective rhythm. With simple audio and visual commands, SDG&E's AEDs are designed to be simple to use for the layperson. The use of AEDs is taught in SDG&E's first aid, certified first responder, and basic life support (BLS) level CPR classes.

Partnership with San Diego Project Heart Beat (SDPHB): SDG&E partners with SDPHB to retrieve our AEDs following use, review results, and submit information to medical facilities to help increase the survival rate for those who experience cardiac arrest. San Diego Project Heart Beat is a nationally and internationally recognized program. Awarded twice in 2009 for best large community PAD program by the International Association of Fire Chiefs and Sudden Cardiac Arrest Association Award (SCAA) recipient for its organizational elements and its success.

Safety Communications: Safety is a core value at SDG&E. As such, it is important to provide employees with safety-related information in a timely manner regarding standards and safe work practices. Additionally, safety communications are a tool used to inform employees about safety hazards and exposures, hazard mitigation, rules, regulations, warnings, goals, and progress reports through an array of media. SDG&E communicates information through safety bulletins, emails, newsletters, electronic bulletin boards (*e.g.,* digiboards), posted signage throughout the workplace, tailgate meetings and reports.

Figure 2 below is an example of a safety email communication distributed to all SDG&E employees:

Figure 2: Sample Employee Safety Communication



National Safety Month Spotlight Topic – Preventing Slips, Trips and Falls

According to the NSC's *Injury Facts®*, falls to the same level are a leading cause of preventable workplace injuries causing time away from work.

This year, six of SDG&E's 34 employee injuries have resulted from slips, trips or falls. Three of these injuries have resulted in fractures, and four resulted in time away from work.

Walking is Working

While our jobs are different, for most of us, walking is part of our workday – and there is always the potential for a fall. While walking seems like a simple task, it's been a leading cause of workplace injury for many years. We need to watch out for all of the hazards tied to walking just as we would any other part of our jobs that poses a safety risk. Read more in the *5-minute Safety Talk* here.

For more materials on *Slips, Trips and Falls* and other 2019 NSM topics, click here.

G. SDG&E-3-C7: Employee Wellness Programs

Wellness Programs are designed to promote the physical and mental well-being of all Company employees, supporting SDG&E's commitment to providing quality health and wellness programs to motivate employees and promote safe and healthy lifestyles. Wellness Programs coordinates on-site employee assistance services including:

- Health & Education Seminars/Lectures (*e.g.*, Stress Management, Weight Management, Nutrition, Heart Disease, High Blood Pressure);
- Fitness Subsidy Program (*i.e.,* Company subsidy for gym membership);

- Financial wellness education;
- Annual Flu Immunizations;
- Health Screenings (*e.g.,* body fat, cholesterol, blood pressure, glucose, bone density screenings);
- Work-site programs (*e.g.,* fitness classes, Weight Watchers, yoga, walking class, chair massages, reflexology);
- Special Events (*e.g.,* Safety, Health & Wellness Fairs, blood drives, lunch and learns, wellness safety events);
- Educational pamphlets/brochures on a variety of health & wellness topics;
- Employee Assistance Program (EAP);
- Formal and Mandatory EAP referrals;
- Evaluation management of mental health behaviors affecting job performance, critical incidents and fitness for duty determination;
- Safety stand-down support; and
- Wellness newsletter.

Other examples of SDG&E safety and wellness programs include, but are not limited to:

- Occupational Health Nurse (OHN) Services – Occupational health nursing is a specialty practice that delivers health and safety programs and services to employees. The practice focuses on promotion and restoration of health, prevention of illnesses and injuries, education and protection from work-related and environmental hazards.
- Telemedicine – The practice of healthcare diagnosis and physician consultation using telecommunications technology. Telemedicine eliminates any wait time to see a provider by allowing quicker, real-time, on-demand evaluation for first aid and healthcare. It supports on-site first-aid injury care and injury care management.

H. SDG&E-3-C8: OSHA Voluntary Protection Program

The Federal and California Voluntary protection programs (Cal/VPP) is a labor-management-government cooperative program designed to recognize workplaces that manage outstanding health and safety management systems for protection of workers and go beyond minimal compliance with the Federal and Cal/OSHA Title 8 California Code of Regulations. OSHA's Voluntary Protection Programs[28] (VPP) recognize employers who have implemented effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics averages for their respective industries. In VPP, management, labor, and OSHA work cooperatively and proactively to prevent fatalities, injuries, and illnesses through a system focused on: hazard prevention and control; worksite analysis; training; and management commitment and worker involvement. To participate, employers must submit an application to OSHA and undergo a rigorous onsite evaluation by a team of safety and health professionals. VPP participants are re-evaluated every three to five years to remain in the programs.

I. SDG&E-3-C9: Safe Driving Programs

SDG&E's safe driving programs aim to increase a driver's safety awareness to prevent and minimize the risk of motor vehicle incidents. With senior management's commitment and employee involvement, SDG&E is driving a safety culture committed to safe driving. This commitment includes written policies and procedures, review of motor vehicle incidents, a department of motor vehicles license pull program to confirm that all employees driving on behalf of the Company or on Company property are properly licensed, internal safe driving training, and development of training materials available to reinforce safe driving principles.

Smith System Driving Program: Smith System® was founded on the principle that most crashes are preventable if the right driving habits are learned, practiced, and applied consistently. Smith System® combines classroom and behind the wheel instruction as way to increase an experienced driver's safety awareness and change poor driving habits. With principles based on the Five Keys to Space Cushion Driving including 1) aim high in steering, 2) get the big picture, 3) keep your eyes moving, 4) leave yourself an out, and 5) make sure they see you. These principles reinforce safe driving techniques.

Close Quarter Maneuvering Drivers Training: This internal SDG&E course was customized from the Smith Systems Advanced Backing, Parking, and Close Quarters Maneuvering course. During this in-house training, advanced backing and close quarter

---

28 United States Department of Labor, *Voluntary Protection Programs*, *available at* https://www.osha.gov/vpp/

maneuvering are learned/practiced during 30-minute classroom discussion/ 3-hour driving course using the vehicle driven for work. Driving course includes blind spot identification, serpentine and vanishing cone courses. The blind spot identification exercise provides a hands-on view of the actual blind spots of the vehicle and perspective on just how many and how large the blind spots are. In the serpentine course, the driver weaves through the course going forward and learning how to use the vehicle's pivot points to safely maneuver without hitting cones. Once complete, the driver then backs the vehicle through the same course. Vanishing cone provides an opportunity for the driver to get a better understanding of distance and perception when it comes to pulling forward or backing their vehicle. This training focuses on developing and/or improving skills and techniques to maneuver safely in these challenging driving environments.

Circle of Safety Technique Training: In 1999, SDG&E adopted the Circle of Safety, which is a safe practice (walk-around to check side, front, back, and above clearances and hazards) to confirm that the area around the vehicle is safe before departing. When backing into a parking space or work area, the training guides employees to look for obstacles such as poles, other vehicles or concrete pillars. Whenever possible, employees are directed to back into a parking space or driveway to increase visibility when departing. If employees must stop or park the vehicle in a position that requires backing, the vehicle should be positioned to maximize visibility to the rear and critical areas adjacent to the vehicle.

Motor Vehicle Incident (MVI) Reviews and Reporting: Employees involved in a motor vehicle incident while at work and/or while driving on Company business are required to report the incident. These incidents are investigated and reviewed to identify the root cause and corrective actions and share lessons learned to prevent similar incidents.

National Safety Council Defensive Driving Video Library: Employees can access online driving training modules on specific topics such as backing, close quarter maneuvering, and other driving topics to educate themselves on driving best practices.

DMV Drivers' License Pull Program: The Department of Motor Vehicle (DMV) Drivers' License (DL) Employer Pull Notice (EPN) program allows SDG&E to electronically receive employees' driving records to monitor DL records of employees who drive on behalf of our organization. The monitoring allows SDG&E to determine if each driver has a valid drivers' license, reveal problem drivers or driving behavior, and improve public safety. The EPN automatically generates a driver record when there is a conviction, failure to appear, accident, driver license suspension or revocations, or any other actions taken against the driving privilege addended to an employee's drivers record.

Commercial Drivers' License Program: Driving a Commercial Motor Vehicle (CMV) requires a higher level of knowledge, experience, skills, and physical abilities than that required to drive a non-commercial vehicle. An applicant must pass both skills and knowledge testing geared to these higher standards to obtain a Commercial Driver's License (CDL). Additionally, CDL holders are held to a higher standard when operating any type of motor vehicle on public roads. Serious traffic violations committed by a CDL holder can affect their ability to maintain their CDL certification. CDL holders are also subject to obtain and maintain a valid medical examiner's certificate to validate that an individual meets health requirements and physical impairments that may affect the ability to safely drive CMVs are addressed. SDG&E receive reminders with driver license and medical certificate expirations to confirm commercial drivers have the proper certificates and certifications.

In-house Development of Safe Driving Videos: A library of on-line safety video resources are available for employees and supervisor to access at any time to use for safety training, safety moments, and briefings.

- "Active Passenger" was created to set expectations for the driver and passenger to assist each other to remain distraction free, share the SMITH keys, offer other insights and/or be a second set of eyes for driver awareness. Active Passenger is also designed to help new drivers who are not as experienced in driving large trucks.
- New Employee Orientation Safe Driving Education and Video – New employees attend general safety presentations as part of their new employee orientation, including driving safety and expectations while driving on company business and at company work locations.

J. SDG&E-3-C10: Personal Protection Equipment (PPE)

SDG&E's PPE program establishes a comprehensive approach toward controlling potential accidental employee injuries and reducing/preventing exposure to specified hazards when/where needed. PPE includes uniforms and equipment designed to protect employees while performing their job (*e.g.*, fire retardant uniforms, gloves, protective eyewear). Good safety practices should not rely on PPE alone to control all possible hazards. All employees who are required to use PPE are trained on when PPE is necessary, what PPE is necessary, how to properly don/remove/adjust/wear PPE, limitations of PPE and the proper care/maintenance/life/disposal of PPE.

K. SDG&E-3-C11: Jobsite Safety Programs including Near Miss and Stop the Job

SDG&E has in place a range of safety programs designed to identify, address, mitigate and communicate workplace risks and hazards, and to contribute proactively to overall workplace safety and employee awareness of safety issues and concerns. These programs include:

Facilities Maintenance Program: Facilities Capital projects are designed to make workspaces safer. Facilities maintenance programs are preventative, predictive and corrective maintenance and are used to address deficiencies. Some examples include structural changes, asbestos inspection and abatement, and parking lot safety amenities.

Traffic Control for employee, contractor and public safety at worksites: SDG&E, when performing work on, or adjacent to, a roadway, is responsible for installing and maintaining such devices which are necessary to provide safe passage for the traveling public through the work area and for the safety of the workers on the site. SDG&E uses both internal and external resources to fulfill this responsibility.

Work Methods and Standards: Business functions related to developing and maintaining construction standards, standards practices, and system design for electric service, primary and secondary systems.

Stop Work Authority (*i.e.,* Stop the Job/Stop the Task): SDG&E employees, regardless of rank or title, are given the authority to "stop a job" at any time if they identify a safety hazard and are encouraged to raise a red flag whenever they feel it is needed.

Close Call/Near-Miss Program: SDG&E recognizes the importance of learning from close calls and near-misses to reduce the potential for a serious incident or injury in the future. The National Safety Council describes a close call or near-miss as an unplanned event that did not result in injury, illness, or damage, but had the potential to do so. SDG&E encourages employees to report close calls in tailgates, safety meetings, and through an online process. SDG&E's online process allows employees to report anonymously through an electronic form. The information is submitted to Safety Services for review and may be shared with other employees, so they understand and benefit from lessons learned.

Incident Investigation: As part of improving its safety culture, SDG&E has established a team to create a more comprehensive and robust incident investigation standard and reporting process. Applying this process uniformly across the Company will result in more consistent investigations and will allow lessons learned to be shared broadly. In addition, regular training is provided for those conducting incident investigations to confirm consistency and more thorough investigations.

L. SDG&E-3-C12: Utilizing OSHA and Industry Best Practices and Industry Benchmarking

SDG&E collaborates with high-performers in environmental, health and safety across industry sectors and regions of the world through the National Safety Council Campbell Institute, and benchmarking with other utilities, industries, and leaders in safety performance. SDG&E benefits from building relationships with other safety leaders, accessing best practices on employee and contractor safety, and benchmarking on leading indicators and key safety program elements.

SDG&E participates in safety benchmarking forums to compare the Company's health and safety processes, assess performance against other participants to learn how to reduce incidents, improve compliance, and discuss best management practices to improve the Company's safety health. SDG&E's end goal is to send every employee home safely every day by targeting zero safety incidents. Some of the key organization we benchmark with are the Edison Electrical Institute, American Gas Association, Campbell Institute, Bureau of Labor Statistics, and other partners.

Additionally, SDG&E attends the California Independently Owned Utility (IOU) and Municipality bi-annual meeting to discuss employee and contractor safety. This dedicated forum is a utility benchmarking initiative which addressing new regulations, legislation, best management practices and other safety topics of interest.

M. SDG&E-3-M1: Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional; Certified Safety Professional

Mandatory employee training courses are those required by OSHA regulation or Company policy. Non-mandatory training courses are those not required by regulation or Company policy, but which shall be provided to employees to enhance a job skill or increase their abilities to perform their jobs safely.

Certifications, including Certified Safety Specialist, Certified Utility Safety Professional, 10- and 30-hour OSHA training, ICMS demonstrate that SDG&E's safety advisors have undertaken education requiring knowledge testing and specialized exams. Safety Advisors will also receive continuing education on the latest standards, regulations, best practices, and laws regarding safety and health in the workplace. Finally, 10-hour OSHA training will be provided to executive and leadership teams to further their safety education and create an environment to support a positive safety culture.

Safety Advisor training: The Safety Services management team expanded its role in activations during red flag warning and other emergency conditions by staffing the Safety Officer position in the Emergency Operations Center (EOC), deploying field safety officers to the impacted workgroup staging areas, and regularly communicating safety messages through safety bulletins and on-site district safety support. All safety responders and Safety Advisors are FEMA ICS 100, 200 and 775 certified. In addition, safety advisors are required to have specific education, training, and certification including, but not limited to: Certified Occupational Safety Specialist or OSHA Institute certification, progression toward Certified Utility Safety Professional, OSHA 10- and 30-hour training along with continuing internal training related to incident investigation, responding to and reporting injuries/illnesses, substance abuse prevention, identification of reasonable suspicion and others.

N. SDG&E-3-M2: Enhanced Safety in Action Program

Designed for executives and field operations directors, the enhanced Safety in Action (SIA) initiative will provide SDG&E with the necessary tools to measure Serious Injury and Fatality (SIF) exposure, understand the Company's specific SIF precursors, and design effective steps to mitigate SIF exposure. Through this program, a SIF exposure reduction safety process will be developed to define a SIF definition for SDG&E, develop a SIF decision tree, determine SIF metrics (leading and lagging), and use a precursor analysis tool to reduce SIF exposure. Goals and objectives for the SIA program will consist of clear, concise wording that demonstrates a forward-moving effort to improve safety. These goals and objectives will be defined and measured.

O. SDG&E-3-M3: Enhanced Employee Safe Driving Training (Vehicle Technology Programs)

SDG&E is planning to implement vehicle technology programs to provide a comprehensive view of the vehicle driver and fleet performance through data driven vehicle analytics. The vehicle technology platform would allow the company to evaluate driving behaviors by understanding hard braking, hard acceleration, hard cornering, speeding, and seatbelt use. This data will enable SDG&E to provide coaching and specific driver training to employees to reinforce safe driving habits. Additionally, by installing monitoring devices, vehicle information such as utilization, idle time, fuel usage, vehicle health, and vehicle location would be communicated through a dashboard and can be analyzed in real time. This technology helps improve employee safety by providing information on vehicle location, providing opportunity for driver feedback, discouraging risky driving behaviors, and detecting engine issues and fault codes so they can be corrected.

P. SDG&E-3-M4: Implementing Findings/Results from VPP Assessments

As stated above, OSHA's Voluntary Protection Programs[29] (VPP) recognize employers who have implemented effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics averages for their respective industries. In VPP, management, labor, and OSHA work cooperatively and proactively to prevent fatalities, injuries, and illnesses through a system focused on: hazard prevention and control; worksite analysis; training; and management commitment and worker involvement. To participate, employers must submit an application to OSHA and undergo a rigorous onsite evaluation by a team of safety and health professionals. VPP participants are re-evaluated every three to five years to remain in the programs.

---

[29] United States Department of Labor, *Voluntary Protection Programs*, available at https://www.osha.gov/vpp/

Q. SDG&E-3-M5: Energized Skills Training and Testing Yard

Employee Safety standards and equipment are continually evolving, and SDG&E must introduce and review new standards, procedures and/or equipment to impacted employees. SDG&E plans to convert an existing facility to an Energized Skills Training and Testing Yard for this purpose, to allow for hands-on training for electric crews, linemen foreman, and/or trouble-shooters. This converted facility would provide a space for vendors to demonstrate new equipment and show how the equipment safely operates. SDG&E believes that employees would benefit from having this hands-on training and testing yard in lieu of a classroom setting, therefore resulting in safer operation of such equipment.

R. SDG&E-3-M6: Employee Wildfire Smoke Protections – Cal/OSHA emergency regulation

In July 2019, an emergency regulation was passed by the California Occupational Safety and Health Standards Board requiring employers to provide respirators to workers exposed to unhealthy air because of wildfire smoke. California employers are already required to protect workers from hazards like unhealthy air, as demonstrated above in SDG&E-3-C1, but the new requirement seeks to shore up requirements specifically addressing fine particulate matter from wildfires, which can reduce lung function and worsen heart and respiratory conditions. The rule will require employers to obtain the air quality index (AQI) for PM2.5, which is the smallest and most noxious particulate matter, from federal, state or local officials. If the measurement is higher than 151, eligible employers must provide approved respirators, like N95 respirators. If the index is higher than 500, the use of the respirators is required.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the Settlement Agreement. SDG&E has not calculated an RSE for activities beyond the requirements of the Settlement Agreement but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[30] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. As defined in the SA Decision, a tranche is "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment."[31] Therefore, risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE).

SDG&E's comprehensive Employee Safety program consists of training courses, policies, programs and efforts all aimed to reduce risk of injury or fatality to employees while on duty. Given the vast number of activities SDG&E performs to mitigate Employee Safety risk, SDG&E grouped like activities with like risk profiles into mitigation programs. Since each of SDG&E's Employee Safety risk mitigations have the same goal of reducing employee risk of injury or fatality, all controls and mitigations have the same risk profile and are not further tranched.

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[32] SDG&E then looked at existing/continuing programs (*i.e.*, controls), and expect to get similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SDG&E also accounted for the risk increase that would occur over time if we stopped performing these activities. For new and/or incremental mitigations, we expect to achieve further risk reduction. The specific risk reduction

---

[30] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[31] *Id*. at A-4.

[32] *Id.* at Attachment A, A-12 ("Determination of Post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," "Measurement of Post-Mitigation Risk Score," "Measurement of Risk Reduction Provided by a Mitigation").

benefit percentages used for each identified control/mitigation is included under each program heading below.

1. SDG&E-3-C1: Mandatory Employee Health and Safety Training Programs and Standardized Policies

a. Description of Risk Reduction Benefits

Safety handbooks and standards help decrease employee safety risk by providing information in policy and procedure formats used to guide and direct all employees to work safely and prevent injury to themselves and others.

OSHA mandatory employee health and safety training programs and standardized policies help reduce SDG&E employee risk by providing a framework for working safely. They serve as a proactive approach to address safety and health issues and conditions in the workplace by training and educating employees, recognizing that finding and correcting hazards before an injury or illness occurs is far more effective than an after-the-fact response. Each training program (and related policy) identifies the purpose, objectives, and available informational resources and training, and provide guidelines that communicate expectations, procedures and ways to mitigate hazards in existing workplace systems to help workers avoid injury.

Industrial hygiene programs anticipate, recognize, evaluate and correct workplace conditions that may cause workers' injury or illness. These programs include but are not limited to Hearing Conservation, Respiratory, Hazard Communication – Chemical, and Asbestos/lead/mold Abatement. Industrial hygiene programs use environmental monitoring and analytical methods to detect the extent of worker exposure and employ engineering, work practice controls, and other methods to control potential health hazards. Developing and complying with mandatory occupational safety and health standards involves determining the extent of employee exposure to hazards and deciding what is needed to control these hazards, thereby protecting the workers. Industrial hygienists, or IHs, are trained to anticipate, recognize, evaluate, and recommend controls for environmental and physical hazards that can affect the health and well-being of workers.

EMF programs provide a trustworthy and balanced source of information about potential EMF health risk concerns received from employees and the public. SDG&E is committed to studying and addressing EMF in a socially responsible manner, exhibited by our support and performance of health and engineering research. SDG&E has taken steps to reduce the magnetic fields created by new facilities, and today we continue to work with government agencies and research organizations to resolve unanswered questions and develop consistent EMF policies.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-3-C1 because the program elements are mandated by law and/or regulation. SDG&E must comply with all applicable laws/regulations, and thus it is not feasible for SDG&E to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. This well-established program serves as a proactive approach to address potential workplace safety and health hazards and therefore reduce Potential Consequences by identifying potential hazards and developing training, policies and programs designed to avoid those hazards. SDG&E's health and safety training program and standardized policies therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); non or improper use of personal protective equipment (DT.3); and unsafe operation of equipment or motor vehicles (DT.4). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); and property damage (PC.2).

As stated above, this program is mandated by state and federal regulation. SDG&E complies with all applicable laws and regulations and implements the various elements of this program in aim to reduce its Employee Safety risk.

2. SDG&E-3-C2: Drug and Alcohol Testing Program

a. Description of Risk Reduction Benefits

Drug testing and substance abuse prevention training in the workplace connects to occupational safety as a key component in protecting the safety, health, and welfare of employees and the public. Drug testing programs can contribute to the reduction of employee injury and illness by providing a powerful deterrent to drug use on the job. Employers who are drug testing are committed to having sober employees in the workplace, thereby reducing occupational injuries and illnesses and to sending a clear signal they care about their employees. In addition, reasonable suspicion drug testing is a critical safety measure. An employee that may be impaired while working and must be taken out of his or her work position; the drug and/or alcohol test will verify that the employee may have used drugs or alcohol while at work or before coming to work, which in turn decreases the likelihood of an at-work injury.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-3-C2 because the program elements are mandated by law and/or regulation. SDG&E must comply with all applicable laws and regulations, and thus it is not feasible for SDG&E to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A This program represents both a proactive approach (e.g., policy, procedures, training) and a reactive approach (e.g., post-accident testing, disciplinary action) to address potential safety hazards related to the potential for employee drug and/or alcohol use. SDG&E's drug and alcohol testing program therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); property damage (PC.2); operational and reliability impacts (PC.3); adverse litigation (PC.4); penalties and fines (PC.5); and erosion of public confidence (PC.6).

While this risk is covered in this Employee Safety chapter, this program also provides risk benefit to SDG&E's Customer & Public Safety risk (SDG&E-5).

3. SDG&E-3-C3: Safety Culture

a. Description of Risk Reduction Benefits

Governed by the Executive Safety Counsel and led by SDG&E's Chief Operating Officer, SDG&E's various safety committees help inform and educate employees about safety and health issues throughout all levels of the Company and set meaningful and attainable safety goals throughout the organization. Safety committees provide the following benefits:

- support a positive safety culture;

- reduce the risk of workplace injuries and illnesses;
- encourage employees to participate in the Company safety programs;
- confirm compliance with state and federal health and safety regulations;
- provide feedback on safe work practices;
- develop safety programs tailored to individual departments;
- lead safety training;
- communicate about safety and health issues; and
- provide a forum where employees and company leadership can discuss, identify and collaborate on safety solutions.

For purposes of the RSE analysis, SDG&E looked at all existing controls, and considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities, and then looked at the activities within the control program, "safety culture," expecting an additional 1.2% risk reduction by continuing to perform these activities. The primary reason for using a 1.2% risk reduction score is the action planning taking place throughout the organization as a result of the Safety Culture Survey.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's safety culture initiatives create constant awareness, dialog, and means for employees to express questions, concerns and lessons learned. Though these activities, SDG&E encourages two-way formal and informal communication between employees to identify and manage safety risks before incidents occur. Employee feedback from these meetings/events help lead constant improvement across the company. SDG&E's safety culture programs therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); non or improper use of personal protective equipment (DT.3); and unsafe operation of equipment or motor vehicles (DT.4). These programs aim to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); property damage (PC.2); operational and reliability impacts (PC.3); adverse litigation (PC.4); penalties and fines (PC.5); and erosion of public confidence (PC.6).

These programs aim to reduce Potential Consequences by raising questions, addressing issues, communicating safety issues, and demonstrating SDG&E's safety-first culture.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	**LoRE**		**1.3147**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	128.08	**1098.68**	2716.34
	RSE	4.58	**39.24**	97.03

4. SDG&E-3-C4: Employee Behavior Based Safety Program

a. Description of Risk Reduction Benefits

Behavior Based Safety processes are part of a holistic approach for driving occupational safety and health improvements. Through peer observation, observers are able to identify safe and at-risk work behaviors that are discussed with employees and tracked in a database. Positive feedback reinforces safe work behaviors and at-risk behaviors are discussed through coaching moments, to identify why at-risk behavior occurred and to discuss a safer work method. These findings are aggregated to identify patterns of hazard exposure and serious injury or fatality (SIF) potential, which are followed by action planning to mitigate hazards. The Behavior Based Safety process enhances the safety approach through education, skills training, and in-the-field coaching and guidance that equips organizations to change unsafe behaviors through coaching.

For purposes of an RSE analysis, SDG&E looked at all existing controls and considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities. SDG&E then looked at the activities within the control program, "Employee Behavior Based Safety Program," expecting an additional 1.5% risk reduction by continuing to perform these activities. Based on subject matter expert judgment, the enhancements within the BBS programs along with the planned investments in tools and technology will provide an additional 1.5% risk reduction.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. The purpose of the BBS Program is to reduce the occurrence of at-risk behaviors by modifying an individual's actions and/or behaviors through observation, feedback, and positive interventions aimed at developing safe work habits. SDG&E's BBS Program is a proactive approach to safety and health management, focusing on principles that recognize at-risk behaviors as a frequent cause of both minor and serious injuries. SDG&E's BBS program therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); and property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.3186**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	128.46	**1101.94**	2724.39
	RSE	2.47	**21.18**	52.36

5. SDG&E-3-C5: A Comprehensive Environmental & Safety Compliance Management Program

a. Description of Risk Reduction Benefits

Each Director and Manager who reports to a Vice President (VP) or Senior VP (SVP) is assigned the role of Responsible Person (RP) for an Employee-Based Checklist. An RP is tasked with entering ESCMP information into the online system and submitting the checklist electronically to his/her VP/SVP for approval. This process provides oversight to verify that applicable safety compliance requirements are completed by employees.

SDG&E has not performed an RSE analysis on this activity, for several reasons. SDG&E's Comprehensive ESCMP tracks employee training requirements to confirm compliance and completion. The program itself does not provide any risk reduction benefit without the underlying training courses. Further, SDG&E has not specifically identified internal labor costs associated with implementing this program.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's ESCMP is a valuable tool to manage safety compliance and track that employees have performed the necessary training and tasks in order to help prevent Potential Consequences, including serious injury or fatality. SDG&E's ESCMP therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

6. SDG&E-3-C6: Employee Safety Training and Awareness Programs

a. Description of Risk Reduction Benefits

At SDG&E, safety starts with the individual. Accordingly, the Company seeks to have every employee equipped to work safely, respond during an emergency, and live a healthy lifestyle. SDG&E believes that being educated, making sure employees have information, tools and training will reduce the potential for injury. With safety as the core value of its operations, SDG&E chooses to integrate these fundamentals into the Company's safety programs and worksites. Lack of training may result in employees not understanding safety hazards of their work environment and increase the likelihood of injury.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-3-C6 because the program elements are mandated by law and/or regulation. SDG&E must comply with all applicable laws/regulations, and thus it is not feasible for SDG&E to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's Employee Safety Training and Awareness Programs aim to proactively train employees on topics necessary to safely perform their job and communicate topics of importance for safety best practices. These programs are a proactive approach aimed to minimize and help prevent Potential Consequences, including serious injury or fatality. SDG&E's employee safety training and awareness testing program therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

7. SDG&E-3-C7: Employee Wellness Programs

a. Description of Risk Reduction Benefits

SDG&E's approach to a healthy workplace has evolved from solely the physical work environment (primarily on-the-job safety concerns) to a more holistic concept that encompasses psychosocial and personal health factors. This focus is comprehensive in scope, encompassing assessment of employees' overall well-being in addition to injury prevention. It includes an increasing emphasis on safety programs that is inclusive of physical, mental and social well-being. With an integrated program in place that encompasses health promotion, occupational health and safety, we can break down silos to promote a healthy workplace. For example, if musculoskeletal disorders are occurring among employees, we can examine the ergonomics of the work process/station and correct any hazardous physical conditions.

For purposes of an RSE analysis, SDG&E looked at all existing controls and considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities. SDG&E then looked at the activities within the control program, "Employee Wellness Programs" and expect an additional 0.8% risk reduction by continuing to perform these activities. The primary reasons for using 0.8% risk reduction score is the continued focus on health and well-being for SDG&E employees (*e.g.*, annual flu shots, health screenings, nutritional classes) and the telemedicine experience providing quicker, real-time, on-demand, face-to-face first aid and healthcare along with the newly adopted 24/7 after-hours medical care services.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's wellness programs serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential Consequences. SDG&E's employee wellness programs therefore address the following elements of the left side of the Risk Bow Tie: hazards in the work environment (DT.2); and non or improper use of personal protective equipment (DT.3). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.3095**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	127.58	**1094.34**	2705.60
	RSE	1.31	**11.22**	27.73

8. SDG&E-3-C8: OSHA Voluntary Protection Program (VPP) Assessments

a. Description of Risk Reduction Benefits

The benefits of the OSHA VPP can be vast, including improvement in employee morale and motivation to work safely, improved labor/management relation, reduction in overall injuries and illnesses, higher product quality and work productivity, comprehensive evaluation by a team of health and safety consultants, and networking with government and industry. VPPs and onsite consultation services, when coupled with effective safety program, expand worker protection. The VPP designations are designed to recognize outstanding achievement by companies that have successfully incorporated comprehensive safety and health programs into their total management system. They motivate others to achieve excellent safety and health results in the same outstanding way, as they establish a cooperative relationship among employers, employees, and OSHA.

For purposes of an RSE analysis, SDG&E looked at all existing controls and considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities. SDG&E then looked at the activities within the control program, "OSHA Voluntary Protection Program Assessments" and expect an additional 0.3% risk reduction by continuing to perform these activities. A 0.3% risk reduction score was used, based on subject matter expert judgment. If not for the lengthy VPP process to obtain certification (2-3 years) and the fact the certification is limited to a single work location, the risk reduction score would have been higher.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C8 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's OSHA VPP serves as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid potential consequences. OSHA's VPP assessments are a proactive way for SDG&E to identify strengths and opportunities for enhancing safety. VPP physical inspections, document reviews, and interviews are components in this process. These assessments provide insight into baseline safety and health hazards to establish initial levels of exposures for comparison to future levels so change can be identified. Implementing findings/results and acting on results helps move safety from its current "as is" state to the desired future state.

The sites with VPP culture have knowledgeable employees and management who work together in partnership with Fed and Cal/OSHA to systematically identify and correct hazards. SDG&E has two worksites with VPP Star Certifications. SDG&E's VPP therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); and hazards in the work environment (DT.2). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post -Mitigation	LoRE		**1.3030**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.94	**1088.91**	2692.18
	RSE	8.52	**73.12**	180.77

9. SDG&E-3-C9: Safe Driving Programs

a. Description of Risk Reduction Benefits

Implementation of driver safety programs helps SDG&E keep employees safe by educating them on driving techniques and principles that decrease the risk of motor vehicle incidents, collisions, and traffic violations. Through these programs, drivers learn to improve their driving skills by reducing their driving risk by anticipating situations and making informed decisions. The Department of Motor Vehicle (DMV) Drivers' License (DL) Employer Pull Notice (EPN) program allows SDG&E to electronically receive employees' driving records to monitor DL records of employees who drive on behalf of our organization. The monitoring allows SDG&E to determine if each driver has a valid drivers' license, reveal problem drivers or driving behavior, and improve public safety. The EPN automatically generates a driver record when there is a conviction, failure to appear, accident, driver license suspension or revocations, or any other actions taken against the driving privilege addended to an employee's drivers record. These notifications allow SDG&E to stay up-to-date with drivers' records and reduce the likelihood of accidents by monitoring the status/validity of current licenses and providing information about potential issues that may need to be reviewed for action.

For purposes of an RSE analysis, SDG&E looked at all existing controls, considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities, and then looked at the activities within the control program, "Safe Driving Programs," expecting an additional 0.5% risk reduction. Subject matter expert judgment determined a 0.5% risk reduction score was appropriate due to newly developed Close Quarter Maneuvering (CQM) driver's training, which will be administered to all employees whose job classification require them to drive. CQM training is behind-the-wheel training in employees' assigned vehicle and includes blind spot identification, serpentine and vanishing cone courses.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's safe driving programs serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid potential consequences. SDG&E's safe driving programs therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); and unsafe operation of equipment or motor vehicles (DT.4). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); and property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	**LoRE**		**1.3056**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	127.20	**1091.08**	2697.55
	RSE	1.98	**16.95**	41.90

10. SDG&E-3-C10: Personal Protection Equipment

a. Description of Risk Reduction Benefits

Controlling exposures to occupational hazards is a fundamental method of protecting workers. These controls include elimination, substitution, engineering and can be administrative in an effort to minimize hazard exposures in the workplace. When such controls are not practical or applicable, PPE is employed to reduce or eliminate personnel exposure to hazards. PPE is worn to minimize exposure to hazards that cause serious workplace injuries and illnesses. These injuries and illnesses may result from contact with chemical, physical, electrical, mechanical, or other workplace hazards. SDG&E's PPE program, together with employee safety training, reduces risk to employees by confirming the proper use and fitting of PPE.

Per OSHA standards,[33] prior to requiring employees to wear PPE, SDG&E is required to:

- Perform hazard assessments and determine the PPE needed to protect workers;
- Provide training on the proper use of PPE for working on or near exposed energized parts;
- Discuss PPE needs during required job briefings; and
- Inspect and test certain PPE such as insulating (rubber) gloves and sleeves (29 CFR 1910.137) to confirm that they are not damaged or defective and will provide the needed protection.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-3-C10 because the program elements are mandated by law and/or regulation.[34] SDG&E must comply with all applicable laws/regulations, and thus it is not feasible for SDG&E to stop performing this activity or calculate the risk reduction benefits received for performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C10 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Mandatory use of PPE aims to keep employees safe and prevent Potential Consequences from workplace hazards possibly resulting in serious injury or fatality. SDG&E's required use of PPE therefore addresses the following elements of the left side of the Risk Bow Tie: non or improper use of personal protective equipment (DT.3). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

---

[33] 29 CFR § 1910.269.

[34] *Id.* at § 1910 *et. seq.*

11. SDG&E-3-C11: Jobsite Safety Programs including Near Miss and Stop the Job

a. Description of Risk Reduction Benefits

Near miss reporting is a means to help raise awareness and provides the opportunity to help prevent future incidents by communicating the facts around events that had the potential to result in injury, illness or damage, but did not. This program allows potential hazards to be investigated, mitigated, and communicated. Reporting near misses also reduces risk by promoting a safety culture that establishes opportunities to review safety systems and hazard control and to share lessons learned.

Every employee at SDG&E has the authority to stop the job or stop a task that they believe is unsafe or requires a pause for clarification regardless of level. This action is supported by management, the union, and employees throughout the company. Planning and understanding the work being performed are key to understanding and mitigating the risks associated with job site safety. They define the task description, discover what can go wrong (hazard description), how risk exposure can arise, contributing factors, consequences and hazard controls.

A job hazard analysis (JHA) or job safety analysis (JSA) is a technique used to identify the hazards/dangers of specific tasks in order to reduce the risk of injuries to workers. This analysis focuses on the relationship between the worker, the task, the tools and the work environment. Simply put, a hazard is the potential for harm often associated with a condition or activity that, if left uncontrolled, can result in injury or illness. Identifying hazards, eliminating them or controlling them as early as possible will help prevent injuries and illnesses.

In addition to eliminating, controlling and preventing hazards in the workplace, JHAs are a valuable tool for training employees about the steps required to perform their jobs safely. JHAs are often done for jobs with the highest injury or illness rates, jobs with the potential to cause severe incidents, jobs where one human error could lead to a serious incident or fatality, jobs that are new to the operation or changed, and complex jobs.

It is important to review JHAs when jobs change or if an incident occurs so that it can be updated to prevent injuries. When changes are made, or the JHA is affected by new job methods, equipment, or procedures, for example, updates should be made, and training should be given to all employees affected by the changes.

For purposes of an RSE analysis, SDG&E looked at all existing controls, considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities, and then looked at the activities within the control program, "Jobsite Safety Programs including Near Miss and Stop the Job," expecting an additional 3.8% risk reduction. Subject matter expert judgment determined increased reporting of Near Misses and more overall education and awareness of giving all employees the authority to "Stop the Job" if work conditions appear to be hazardous, would provide an additional 3.8% reduction in risk.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C11 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. SDG&E's Jobsite Safety Programs including Near Miss and Stop the Job serve as a proactive approach to identify and address potential workplace safety and health hazards and therefore avoid Potential Consequences. SDG&E's jobsite safety programs therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); unsafe operation of equipment or motor vehicles (DT.4); damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.3485**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	131.37	**1126.91**	2786.13
	RSE	0.39	**3.30**	8.17

12. SDG&E-3-C12: Utilizing OSHA and Industry Best Practices and Industry Benchmarking

a. Description of Risk Reduction Benefits

Benchmarking allows SDG&E to capture views from a wide range of industries, providing insight about programs that allow the Company to identify strength, opportunities and compare SDG&E's safety programs against others. This provides an opportunity to review programs, reassess or confirm the Company's approach to safety, and compare with other programs to continue moving SDG&E's safety culture and programs forward.

For purposes of an RSE analysis, SDG&E looked at all existing controls and considered the average year-over-year reduction in safety incidents achieved as a result of performing these activities. SDG&E then looked at the activities within the control program, "Utilizing OSHA and Industry Best Practices and Industry Benchmarking," and expect an additional 0.5% risk reduction. Subject matter expert judgment determined a 0.5% risk reduction was appropriate due to increased attendance throughout the organization at safety conferences and overall involvement in utility benchmarking initiatives and meetings.

b. Elements of the Risk Bow Tie Addressed

SDG&E-3-C12 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Utilizing OSHA and industry best practices and industry benchmarking helps SDG&E learn how to reduce incidents, improve the safety health of our organization and therefore reduce Potential Consequences. SDG&E's use of best practices and industry benchmarking therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.3056**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	127.20	**1091.08**	2697.55
	RSE	0.88	**7.53**	18.61

13. SDG&E-3-M1: Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional

a. Description of Risk Reduction Benefits

Providing and requiring health and safety training helps develop a positive health and safety culture, keeps safety professionals up-to-date on regulatory safety changes, and imparts knowledge about safety systems/processes. Training is important to building a knowledge set required to support employees and management with identification of safe and at-risk behaviors. Additionally, training helps to manage risk, enhance innovation and allow employees to acquire and sharpen skill sets. Regular education and training provide the skills employees need to do their work and creates an awareness and understanding of workplace hazards and how to identify, report, control and mitigate them.

For purposes of an RSE analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. SDG&E then looked at new mitigations and expect to achieve a further risk reduction for the mitigation, "Enhanced Employee Training" of 0.1%. Subject matter expert judgment determined a 0.1% risk reduction score was appropriate due to the increased Safety training certifications required of Safety personnel (*e.g.*, Certified Utility Safety Professional, 30-Hour OSHA, Incident Command System) and upper Management (*e.g.*, OSHA 10-Hour).

b. Elements of the Risk Bow Tie Addressed

Implementation of SDG&E-3-M1 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An enhanced OSHA mandatory training program would aim to further educate and inform our employees in order to reduce Potential Consequences. SDG&E's OSHA training enhancement would therefore addresses the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); and damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. Summary of Results

<table>
<tr><th colspan="2"></th><th>Low Alternative</th><th>Single Point</th><th>High Alternative</th></tr>
<tr><td rowspan="3">Pre-Mitigation</td><td>LoRE</td><td></td><td>1.299</td><td></td></tr>
<tr><td>CoRE</td><td>97.42</td><td>835.67</td><td>2066.09</td></tr>
<tr><td>Risk Score</td><td>126.57</td><td>1085.65</td><td>2684.13</td></tr>
<tr><td rowspan="4">Post-Mitigation</td><td>LoRE</td><td></td><td>1.2978</td><td></td></tr>
<tr><td>CoRE</td><td>97.423</td><td>835.67</td><td>2066.09</td></tr>
<tr><td>Risk Score</td><td>126.44</td><td>1084.57</td><td>2681.45</td></tr>
<tr><td>RSE</td><td>4.42</td><td>37.91</td><td>93.73</td></tr>
</table>

14. SDG&E-3-M2: Enhanced Safety in Action Program

a. Description of Risk Reduction Benefits

SDG&E has top-level management commitment and engagement in the development of an Enhanced Safety in Action Program, which will help SDG&E define a safety system that brings visibility to Serious Injury and Fatalities (SIF) exposure and develops a sustainable methodology for addressing and mitigating SIF precursors to help prevent SIF events.

For purposes of an RSE analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. SDG&E then looked at new mitigations and expects to achieve a further risk reduction for the mitigation, "Enhanced Safety in Action Program" of 1.5%. In the judgment of subject matter experts, a 1.5% risk reduction score was determined as a result of the extensive training employees will receive in SIF exposure detection and mitigation.

b. Elements of the Risk Bow Tie Addressed

Implementation of SDG&E-3-M2 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An enhanced Safety in Action program would aim to further educate and inform our employees to reduce Potential Consequences. SDG&E's Safety in Action program enhancement would therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); and non or improper use of personal protective equipment (DT.3). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	**LoRE**		**1.2796**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	124.67	**1069.37**	2643.87
	RSE	3.77	**32.33**	79.92

15. SDG&E-3-M3: Enhanced Employee Safe Driving Training (Vehicle Technology Programs)

a. Description of Risk Reduction Benefits

SDG&E is proposing to install vehicle technology (*e.g.*, telematics) to provide a comprehensive view of the vehicle driver and fleet performance through data-driven vehicle analytics. The vehicle technology platform would be deployed in all company vehicles assigned to employees who drive as part of their job and allow the Company to evaluate driving behaviors by understanding hard braking, hard acceleration, hard cornering, speeding, and seatbelt use. This data will enable SDG&E to provide coaching and specific driver training to employees to reinforce safe driving habits. Additionally, vehicle monitoring devices will provide dashboard information – such as utilization, idle time, fuel usage, vehicle health, and vehicle location – which can be analyzed in real time. This mitigation would help improve employee safety by knowing vehicle whereabouts, providing opportunity for driver feedback, detouring risky driving behaviors, and detecting engine issues and fault codes, so issues can be corrected.

For purposes of an RSE analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. SDG&E then looked at new mitigations and expects to achieve a further risk reduction for the mitigation, "Enhanced Employee Safe Driving Training" of 1.2%. In the judgment of subject matter experts, the additional data received on employee driver behavior and subsequent follow up with employees that will take place, a 1.2% risk reduction score was used. Having the ability to evaluate driving behaviors by understanding data points such as hard braking, hard acceleration, hard cornering, speeding, and seatbelt use, will allow near real-time coaching from supervisors.

b. Elements of the Risk Bow Tie Addressed

Implementation of SDG&E-3-M3 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. An enhanced employee safe driving training program would aim to further educate and inform our employees and therefore would address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); and unsafe operation of equipment or motor vehicles (DT.4). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); and property damage (PC.2).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.2835**	
	CoRE	97.423	**835.67**	2066.09
	Risk Score	125.05	**1072.62**	2651.92
	RSE	2.00	**17.14**	42.38

16. SDG&E-3-M4: Implementing Findings/Results from VPP Assessments

a. Description of Risk Reduction Benefits

VPP assessments are a proactive way to identify strengths and opportunities for enhancing safety. The VPP assessment results identify areas for safety improvement, is a collection point for information, creates a safety culture baseline and tracks completion of items identified for improvement. When applied to safety, the assessment reports are used as an action planning tool to take safety programs and culture beyond the Cal/OSHA minimum required standards.

This mitigation is designed to implement findings and recommendations resulting from VPP assessments. The worksite analysis of the VPP assessment will provide SDG&E with a safety and health hazard analysis. Implementing these findings would aim to reduce risk of employee safety incidents at SDG&E's facilities and strengthen our processes. The benefits of a VPP program include not only reduction in overall injuries and illnesses, but the opportunity to set a model of excellence that can influence practices across the company.

For purposes of an RSE analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. SDG&E then looked at new mitigations and in the judgment of subject matter experts it is expected to achieve a further risk reduction for the mitigation, "Implementing Findings/Results from VPP Assessments" of 1.0%. The primary activities contributing to the

1.0% risk reduction score is the follow up and action planning occurring as a result of the items identified needing safety improvement.

b. Elements of the Risk Bow Tie Addressed

Implementation of SDG&E-3-M4 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. By implementing findings/results from VPP assessments, SDG&E could make its workplace and facilities safer for employees in order to reduce potential consequences. OSHA's VPP assessments are a proactive way for SDG&E to identify strengths and opportunities for enhancing safety. VPP physical inspections, document reviews, and interviews are components in this process. These assessments provide insight into baseline safety and health hazards to establish initial levels of exposures for comparison to future levels so change can be identified. Implementing findings/results and acting on results helps move safety from its current "as is" state to the desired future state. SDG&E's VPP assessment implementation program would therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); and hazards in the work environment (DT.2). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.2861**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	125.30	**1074.80**	2657.29
	RSE	3.98	**34.12**	84.36

17. SDG&E-3-M5: Energized Skills Testing and Training Yard

a. Description of Risk Reduction Benefits

Having an Energized Skills Testing and Training Yard will reduce SDG&E's risk by allowing Construction Standards Administrators to fully vet pieces of equipment both mechanically and electrically. Additional hands-on testing of energized equipment will allow for the best possible Construction Standards and Electric Standard Practices to be published while also providing invaluable hands on training to our field personnel, both of which will reduce the risk of employee injury and extended outages.

For purposes of RSE analysis, SDG&E looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities. SDG&E then looked at new mitigations and expects to achieve a further risk reduction for the mitigation, "Energized Skills Testing and Training Yard" of 1.0%. The primary reason for using a 1.0% risk reduction score is that the additional testing will allow for the best possible construction standards and electric standard practices to be implemented while also providing invaluable hands-on training to field personnel, which will reduce the risk of employee injury.

b. Elements of the Risk Bow Tie Addressed

Implementation of SDG&E-3-M5 would address several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Providing employees with hands-on training to test new equipment would aim to further reduce safety incidents and reduce Potential Consequences. SDG&E's energized skills training and testing yard would therefore address the following elements of the left side of the Risk Bow Tie: employees deviate from company policies or procedure (DT.1); hazards in the work environment (DT.2); non or improper use of personal protective equipment (DT.3); unsafe operation of equipment or motor vehicles (DT.4); damage to SDG&E equipment and/or infrastructure (DT.5). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1); property damage (PC.2); and operational and reliability impacts (PC.3).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.2861**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	125.30	**1074.80**	2657.29
	RSE	1.49	**12.79**	31.63

18. SDG&E-3-M6: Employee Wildfire Smoke Protections – Cal/OSHA Emergency Regulation

a. Description of Risk Reduction Benefits

Like SDG&E's current industrial hygiene programs, the newly adopted employee wildfire smoke protection regulations will work toward controlling workplace conditions that may cause workers' injury or illness. These programs use environmental monitoring and analytical methods to obtain the air quality index during a wildfire event. SDG&E will deploy preventative measures, including deployment of N95 respiratory masks and medical evaluations, to prevent and control potential health hazards. Developing and complying with mandatory occupational safety and health standards involves determining the extent of employee exposure to hazards and deciding what is needed to control these hazards, thereby protecting the workers. Industrial hygienists are trained to anticipate, recognize, evaluate, and recommend controls for environmental and physical hazards that can affect the health and well-being of workers.

Since SDG&E is required to fully comply with the newly adopted Employee Wildfire Smoke Protections regulations, SDG&E has not performed an RSE analysis on this mitigation because it is not feasible to stop performing the activity or calculate the risk reduction benefits received for performing it.

b. Elements of the Bow Tie Addressed

SDG&E has already begun implementing SDG&E-3-M6 per Cal/OSHA regulation. SDG&E-3-M6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. Providing employees with respirators and testing the AQI aims to further reduce safety incidents and reduce Potential Consequences. SDG&E's Employee Wildfire Smoke Protections address the following elements of the left side of the Risk Bow Tie: hazards in the work environment (DT.2); and non or improper use of personal protective equipment (DT.3). This program aims to reduce the following Potential Consequences of the right side of the Risk Bow Tie: serious injuries and/or fatalities (PC.1).

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E's Risk Mitigation Plan takes into account recent data and trends related to Employee Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SDG&E has performed RSEs, in compliance with the SA Decision, but ultimate mitigation selection can be influenced by other factors including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigation activities, associated costs, and the RSEs, by tranche.

SDG&E does not account for and track costs by activity; rather, SDG&E accounts for and tracks costs by cost center and capital budget code. The costs shown in Table 6 were estimated using assumptions provided by SMEs and available accounting data.

Table 6: Risk Mitigation Plan Summary[35]

(Direct 2018 $000)[36]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M[39]	Total[40]	RSE[41]
SDG&E-3-C1	Mandatory employee health and safety training programs and standardized policies	T1	0	560	0	530-640	530-640	-
SDG&E-3-C2	Drug and alcohol testing program	T1	0	230	0	220-270	220-270	-
SDG&E-3-C3	Safety Culture	T1	0	310	0	300-360	300-360	4.58 – 97.03

35 Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

36 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

37 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

38 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

39 As previously stated, internal labor (*e.g.,* employee time spent to complete training courses, employee time spent to perform inspections) are not included in SDG&E's O&M cost forecasts since these costs would rely on cost assumptions (*e.g.*, number of employees, x length of training course, x average hourly wage). Further, SDG&E does not track labor in this manner and thus would not be able to include such internal labor costs in future spending accountability reports.

40 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

41 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M[39]	Total[40]	RSE[41]
SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	T1	0	760	0	690-830	690-830	2.47 – 52.36
SDG&E-3-C5	A comprehensive Environmental & Safety Compliance Management Program (ESCMP)[42]	T1	0	0	0	0	0	-
SDG&E-3-C6	Employee safety training and awareness programs	T1	0	240	0	230-280	230-280	-
SDG&E-3-C7	Employee wellness programs	T1	0	730	0	690-840	690-840	1.31 – 27.73
SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	T1	0	50	0	40-50	40-50	8.52 – 180.77
SDG&E-3-C9	Safe driving programs	T1	0	270	0	290-350	290-350	1.98 – 41.90
SDG&E-3-C10	Personal Protection Equipment (PPE)	T1	1,500	730	0	1,200-1,400	1,200-1,400	-

[42] Internal labor costs to take training or perform inspections as part of this program were not captured as part of this RAMP Report. Since no costs were identified, an RSE analysis was not performed.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M[39]	Total[40]	RSE[41]
SDG&E-3-C11	Jobsite Safety Programs including Near Miss and Stop the Job	T1	7,300	8,970	6,500-7,900	9,000-11,000	15,500-18,900	0.39 – 8.17
SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	T1	0	680	0	650-780	650-780	0.88 – 18.61
SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional	T1	0	0	0	25 - 30	25- 30	4.42 – 93.73
SDG&E-3-M2	Safety in Action Program Enhancement	T1	0	0	0	450-550	450-550	3.77 – 79.92
SDG&E-3-M3	Enhanced Employee Safe Driving Training (Vehicle Technology Programs)	T1	0	0	1,900-2,300	50-60	1,950-2,360	2.00 – 42.38
SDG&E-3-M4	Implementing findings from VPP program assessments	T1	0	0	290-350	0	290-350	3.98 – 84.36
SDG&E-3-M5	Energized Skills Testing and Training Yard	T1	0	0	760-920	0	760-920	1.49 – 31.63
SDG&E-3-M6	Employee Wildfire Smoke Protections– Cal/OSHA emergency regulation	T1	0	0	0	30-60	30-60	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M[39]	Total[40]	RSE[41]
		TOTAL COST	**8,800**	**14,000**	**9,500-11,000**	**14,000 – 18,000**	**24,000 – 29,000**	**-**

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SDG&E notes that there are activities related to this Employee Safety risk that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.*, employee time spent for internal training, performing inspections or monitoring). The costs associated with these internal labor activities are not captured in this chapter because SDG&E does not currently track labor in this manner. The inclusion of these internal labor costs in SDG&E's TY 2019 RAMP Report required the use of assumptions. Additionally, since these costs are not tracked, it would impede SDG&E's ability to report in future spending accountability reports. These activities are continuing to be performed but, as a result of the exclusion of internal labor, forecasted costs for these activities may appear lower in this 2019 RAMP Report. The activities related to this risk that have not captured internal labor costs are:

- SDG&E-3-C1: Mandatory employee health and safety training programs and standardized policies;
- SDG&E-3-C3: Safety culture;
- SDG&E-3-C5: A comprehensive Environmental & Safety Compliance Management Program;
- SDG&E-3-C9: Safe driving programs; and
- SDG&E-3-C11: Jobsite Safety Programs including Near Miss and Stop the Job.

SDG&E is not calculating RSEs on the following activities:

Table 7: Summary of RSE Analysis

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-3-C1	Mandatory Employee Health and Safety Training Programs and Standardized Policies	Mandated compliance activity per Cal. Labor Code § 6400, 8 CCR § 8350, CPUC EMF policy (D.93-11-013, D.06-01-042).
SDG&E-3-C2	Drug and Alcohol Testing Program	Mandated compliance activity per 41 USC § 81, 49 CFR Parts 40, 192, 193, 195, 199 and 382.
SDG&E-3-C5	A Comprehensive Environmental & Safety Compliance Management Program	No costs identified; the program itself does not provide any risk reduction benefit without the associated activities captured elsewhere.

SDG&E-3-C6	Employee Safety Training and Awareness Programs	Mandated compliance activity per 29 CFR Part 1910 *et. seq.*
SDG&E-3-C10	Personal Protection Equipment	Mandated compliance activity per 29 CFR Part 1910 *et. seq.*

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the Risk Mitigation Plan for the Employee Safety risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SDG&E-3-A1: Alert Driving Pilot Program Deployment

SDG&E piloted an Alert Driving training course. It is an online driver training to proactively improve driver behavior. High Definition video is shot on-location to show real and familiar traffic hazards that employees must identify. One module per month is assigned to employees based on the areas in which they need the most improvement, followed by the areas in which they have the most driving competency. For the pilot, SDG&E had 35 employees involved in the training program from across the organization. In order to assess the training effectiveness and value in a reasonably quick period, the vendor has agreed to issue training modules on a weekly basis, instead of monthly. Given the forecasted cost to deploy this new Alert Driver training to all SDG&E employees who currently are assigned safe drivers training on an annual basis, SDG&E is not proposing this training in its Risk Mitigation Plan at this time but is continuing to evaluate new and cost-effective ways to improve our drivers training program.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.2926**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	125.93	**1080.22**	2670.71
	RSE	0.12	**1.02**	2.53

B. SDG&E-3-A2: Safety Standards/Presentations Refresh

While the regulatory requirements are met with SDG&E's current safety standards, we have safety standards such as electrical safety (total of 7 standards) that have overlapping or duplicative content. Also, some of the safety and industrial hygiene training presentations may need to be updated and enhanced. There is a need to merge duplicative subjects, reduce the number of applicable safety standards and modernize some of the safety and industrial hygiene training presentations. This requires hiring an instructional designer (vendor) for a 9-12-month period. As such, SDG&E is not currently proposing to include this project in its Risk Mitigation Plan but will continue to evaluate this proposal to maintain the effectiveness of SDG&E's safety standards and presentations.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1.299**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.57	**1085.65**	2684.13
Post-Mitigation	LoRE		**1.2978**	
	CoRE	97.42	**835.67**	2066.09
	Risk Score	126.44	**1084.57**	2681.45
	RSE	0.99	**8.53**	21.09

Table 8: Alternative Mitigation Summary

(Direct 2018 $000)[43]

ID	Mitigation	2020-2022 Capital[44]	2022 O&M	Total[45]	RSE[46]
SDG&E-3-A1	Alert Driving Pilot Program Deployment	0	4,000 – 6,000	4,000 – 6,000	0.12 – 2.53
SDG&E-3-A2	Safety Standards/Presentations Refresh	0	100-140	100-140	0.99 – 21.09

43 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

44 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total.

45 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

46 RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE

Employee Safety: Summary of Elements of the Risk Bow Tie

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
SDG&E-3-C1	Mandatory employee health and safety training programs and standardized policies	DT.1, DT.3 DT.4 PC.1, PC.2
SDG&E-3-C2	Drug and alcohol testing program	DT.1, DT.3, DT.4, DT.5, PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-3-C3	Safety culture	DT.1, DT.3, DT.4 PC.1, PC.2, PC.6
SDG&E-3-C4	Employee Behavior Based Safety (BBS) program	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1, PC.2
SDG&E-3-C5	A comprehensive Environmental & Safety Compliance Management Program (ESCMP)	DT.1, DT.2, DT.3, DT.4, DT.5
SDG&E-3-C6	Employee safety training and awareness programs	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1
SDG&E-3-C7	Employee wellness programs	DT.3 PC.1
SDG&E-3-C8	OSHA Voluntary Protection Program (VPP) assessments	DT.1, DT.2 PC.1
SDG&E-3-C9	Safe driving programs	DT.1, DT.4 PC.1, PC.2
SDG&E-3-C10	Personal protection equipment	DT.3 PC.1
SDG&E-3-C11	Jobsite Safety Programs including Near Miss and Stop the Job	DT.1, DT.2, DT.4, DT.5 PC.1, PC.2
SDG&E-3-C12	Utilizing OSHA and industry best practices and industry benchmarking	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1
SDG&E-3-M1	Enhanced Mandatory Employee Training (OSHA): Certified Occupational Safety Specialist, Certified Utility Safety Professional, Certified Safety Professional	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1
SDG&E-3-M2	Safety in Action Program Enhancement	DT.1, DT.3 PC.1
SDG&E-3-M3	Enhanced employee safe driving training (Vehicle Technology Programs)	DT.1, DT.4 PC.1, PC.2

SDG&E-3-M4	Implementing findings from VPP program assessments	DT.1, DT.2 PC.1
SDG&E-3-M5	Energized Skills Training and Testing Yard	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1, PC.2, PC.3
SDG&E-3-M6	Employee Wildfire Smoke Protections – Cal/OSHA emergency regulation	DT.2, DT.3 PC.1

Risk Assessment Mitigation Phase
(Chapter SDG&E-4)
Electric Infrastructure Integrity

November 27, 2019

TABLE OF CONTENTS

Risk: Electric Infrastructure Integrity

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas & Electric Company's (SDG&E or Company) Electric Infrastructure Integrity (EII) risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018, and D.18-12-014 and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in the Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are for the activities performed and associated costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this

---

[1] D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

[2] *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

2019 RAMP Report, activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's EII risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or for costs that are not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on certain mandated activities. For purposes of this 2019 RAMP Report, mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), California Public Utilities Code, or CPUC General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the Commission and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

---

3 *Id*. at 16.

4 *Id.* at 17.

A. Risk Definition

For purposes of this 2019 RAMP Report, SDG&E's EII risk is defined as "the risk of an asset failure, caused by degradation, age, operation outside of design criteria due to unexpected events or field conditions (*e.g.*, force of nature), or an asset no longer complying with the latest engineering standards, which results in a safety, environmental, or reliability incident." A potential Risk Scenario[5] assessed as part of this risk is an energized wire down event caused by third-party contact, foreign object, or failure of an electric component (*e.g.*, a connector). If a member of the public comes into contact with the energized wire or in close proximity to the energized wire on the ground, the result could be injury and/or possibly death.

B. Summary of Elements of the Risk Bow Tie

Pursuant to SA Decision,[6] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger/Potential Consequence
DT.1	In-service equipment past its useful life or that becomes obsolete
DT.2	Equipment in-service beyond design specifications
DT.3	In-service equipment failing prematurely
DT.4	Active in-service equipment and associated components failing to operate as designed
DT.5	In-service equipment failing with lack of or delayed company insight
DT.6	In-service equipment contacted by customers or third parties
DT.7	In-service equipment failing in large volume (*i.e.*, simultaneous failure of numerous assets) due to acute climates or environmental conditions
PC.1	Serious injuries and/or fatalities
PC.2	Operational and reliability impacts

5 The Risk Scenario, as assessed as part of SDG&E's 2018 Enterprise Risk Registry, is a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency. The scenario may not necessarily address all Drivers/Triggers.

6 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

PC.3	Findings of non-compliance
PC.4	Penalties and fines
PC.5	Adverse litigation
PC.6	Erosion of public confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[7] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

Control ID	Control Name
SDG&E-4-C1	GO165: Distribution Inspect and Repair program – Overhead
SDG&E-4-C2	4 kV Modernization and System Hardening – Distribution
SDG&E-4-C3	Distribution Overhead Switch Replacement Program
SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)
SDG&E-4-C5	Restoration of Service
SDG&E-4-C6	Underground Cable Replacement Program - Reactive
SDG&E-4-C7	Tee Modernization Program - Underground
SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive
SDG&E-4-C9	DOE Switch Replacement – Underground
SDG&E-4-C10	Vegetation Management (Non-HFTD)
SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement
SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair
SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)
SDG&E-4-C14	Field SCADA RTU Replacement

7 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SDG&E-4-C15	Distribution Circuit Reliability
SDG&E-4-C16	Emergency Substation Equipment
SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components
SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program
SDG&E-4-C19	Underground Cable Replacement Program – Proactive
SDG&E-4-C20	Enterprise Asset Management – Substation

SDG&E will continue the baseline controls identified above and puts forth additional projects and/or programs (*i.e.*, mitigations), as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-4-M1	Overhead Public Safety (OPS) Program[8]
SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components
SDG&E-4-M4	Substation Breaker Replacements – FLISR (Fault Locations, Isolation, and Restoration)
SDG&E-4-M5	Enterprise Asset Management – Distribution

Finally, pursuant to the SA Decision,[9] SDG&E presents considered alternatives to the Risk Mitigation Plan for the EII risk and summarizes the reasons that the alternatives were not included in the Risk Mitigation Plan in Section VIII.

[8] This mitigation activity was identified in SDG&E's previous RAMP and GRC filings as the "Wire Safety Enhancement (WiSE) Central" program. With the Commission's recent rulemaking on Wildfire Mitigation Plan (R.18-10-007), SDG&E reduced the scope of the WiSE program to align with wildfire mitigation activities outside of SDG&E's High Fire Threat District (HFTD). Additional details on WiSE is located within the Wildfire Mitigation chapter (SDG&E-1) of this 2019 RAMP Report. Further details on OPS is located in Section V of this EII Chapter.

[9] D.18-12-014 at 33.

II. RISK OVERVIEW

Safety is a core value at SDG&E. SDG&E's safety-first culture focuses on its employees, customers, and the public, and is embedded in every aspect of our work. SDG&E's public website has a page dedicated to power line safety.[10] SDG&E continually aims to improve its electric infrastructure and educate employees, customers and the public about safety measures related to energized lines, both overhead and underground. The residual risk of electric infrastructure failures causing safety, environmental, or major reliability incidents has remained stable over recent years, which is evidenced by SDG&E winning its 13th consecutive "Best in the West" award.[11] Developing strong controls through programs such as SDG&E's Corrective Maintenance Program, modifying and consistently issuing new Construction Standards, and implementing other proactive resiliency measures like pole, cable, switch and aging substation infrastructure replacements, continue to mitigate SDG&E's EII risk and limit substantial growth in residual risks.

The EII risk can be characterized by several possible scenarios, including the wire down event used for risk impact and frequency scoring that involves asset failures. The wire down event is one of SDG&E's primary concerns with respect to its overhead equipment and involves is the downing of a piece of energized overhead equipment (*e.g.*, wires or conductors). If an employee, contractor or the public comes into contact with an energized wire, the results can be fatal. Accordingly, SDG&E is continuing to take proactive measures to determine the cause of any such wire down events and has a dedicated team reviewing all wire down events to determine root cause and identify any trends to potentially trigger the development of a new program. SDG&E's Electric Distribution Engineering department is dedicated to the development and implementation of strategies that support all the unique field constructions and operations practices while assuring electric distribution efficiency, access, control, cost effectiveness and safety are being considered in all final decisions. Data analysis suggests there are various drivers of wire-down events, such as third-party contact, acute weather causing

---

10 San Diego Gas & Electric Company, Downed Power Line Safety, *available at* https://www.sdge.com/safety/downed-powerline-safety.

11 *See* http://www.sdgenews.com/article/sdge-wins-national-award-best-electric-reliability-america.

foreign object contact, or introducing extensive stress, aged infrastructure, and degradation of connectors. These Drivers/Triggers are further discussed below. SDG&E's Risk Mitigation Plan aims to mitigate these aforementioned Drivers/Triggers and therefore reduce Potential Consequences.

Asset age and wire size are predictable and impactful attributes leading to the natural decline of electric infrastructure integrity. Not only can aged assets be affected by severe wearing due to weathering and electrical or mechanical use, but they may not be able to provide the benefits of various improvements made to technology over time with regard to safe design, installation techniques, material quality, and function. Also, it may be more difficult to maintain and operate aged assets due to lack of spare parts and vendors support. Given these conditions, aged infrastructure generally is operated with heightened caution, sometimes using special procedures, for the safety of workers and the public.

SDG&E's Risk Mitigation Plan focuses on safety and reliability measures designed to protect its employees, customers and the public. The controls and mitigations in SDG&E's Risk Mitigation Plan are intended to address various EII-related events, not just the scenario used for purposes of SDG&E's 2018 ERR scoring. Another potential risk event associated with this chapter is the inadvertent contact of intact, energized SDG&E equipment by an employee, contractor, or the public, potentially causing serious injury or fatality. While the Potential Consequences of this risk event (*i.e.,* serious injury or fatality) are similar to those covered in the Employee Safety, Contractor Safety and Customer and Public Safety risk Chapters of this 2019 RAMP Report, the risk event is captured in this EII Chapter. While other risk Chapters focus on mitigations that address public outreach, education, communication, training, and other internal procedural enhancements, this EII risk Chapter focuses on infrastructure protection and improvements. While the controls/mitigations presented herein focus on infrastructure protection and improvements, the risk reduction benefits also impact the human safety risks (*e.g.,* Employee Safety, Customer & Public Safety). The costs for such risk mitigation activities are reflected in this Chapter.

Activities presented in this Chapter are representative of those that are primarily scoped to address SDG&E's Customer & Public Safety risk (SDG&E-5); however, many of the activities presented herein also help mitigate other risk areas as further described below. Further, this Chapter primarily focuses on risks and mitigations unrelated to wildfire mitigation predominately outside of SDG&E's High Fire Threat District (HFTD). Wildfire-related risks and mitigations are covered in SDG&E's "Wildfires Involving SDG&E Equipment" risk Chapter (SDG&E-1). However, where the same mitigation activities are included in both the Wildfire Chapter and this EII Chapter, the costs included herein have been allocated according to HFTD and non-HFTD percentages (unless otherwise noted), consistent with SDG&E's Wildfire Mitigation Plan. For example, vegetation management is performed across SDG&E's entire service territory. Vegetation management therefore appears as an activity performed to reduce risk in both SDG&E-1 and the instant Chapter. The costs associated with the vegetation management activities in this chapter only include the non-HFTD percentage of costs.

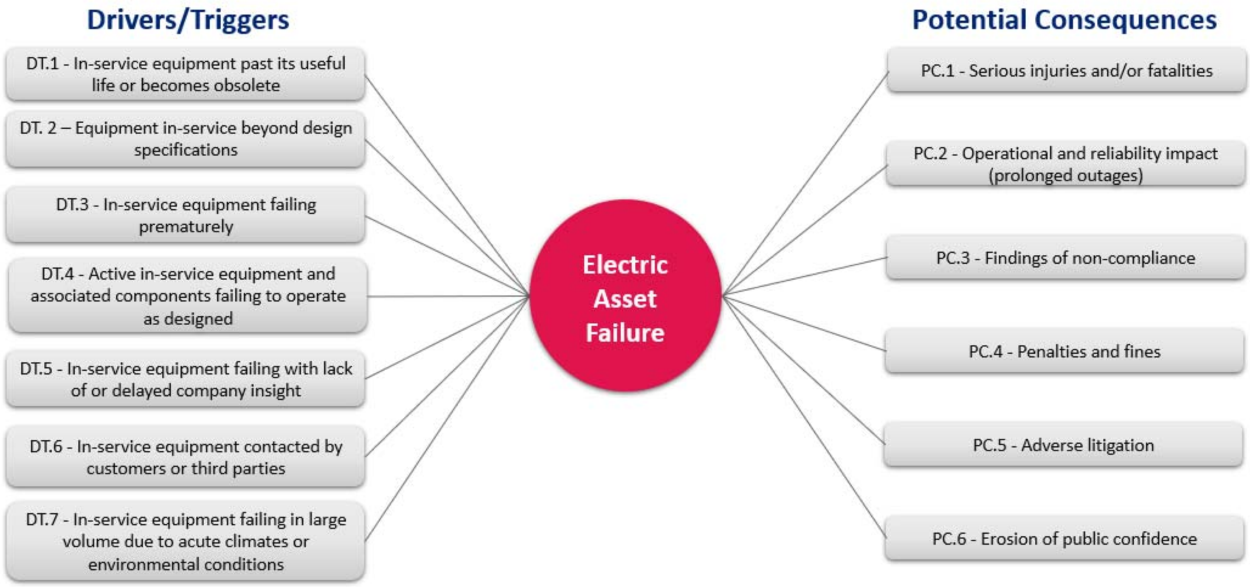
III. RISK ASSESSMENT

In accordance with the SA Decision, this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the EII risk.

A. Risk Bow Tie

The risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



B. Asset Groups of Systems Subject to the Risk

The SA Decision directs the utilities to endeavor to identify all asset groups or systems subject to the risk.[12] SDG&E's EII risk impacts all of SDG&E's electric distribution system infrastructure and assets including the overhead electric system, underground electric system, and substations. The assets include capacitors, circuit breakers, conductors, wires, transformers, structures, and poles, for example. These assets all contribute to SDG&E delivering safe and reliable power to its customers. These asset groups are further identified as follows:

- Distribution Overhead (OH) – comprises overhead distribution asset infrastructure system, which includes conductors or wires, pole structures, transformers, switches, capacitors, and associated auxiliary equipment. The electric distribution system is further defined as assets operating at a nominal voltage of 12kV and 4kV.
- Distribution Underground (UG) – comprises underground distribution asset infrastructure system, which includes cables, underground structures (vaults,

[12] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

manholes, handholes), switches, transformers, capacitors, and associated auxiliary equipment.

- Substation – comprises the substation asset infrastructure system, which includes transformers, breakers, batteries, relays, capacitors, disconnect switches, and associated auxiliary equipment.
- Operational Technology (OT) – comprises the auxiliary control system or network to the electric assets that process operational data, which includes telecommunications, energy management systems (EMS), remote supervisory control and data acquisition (SCADA), and advanced technologies (microprocessor-based relays with synchrophasor/phasor measurement unit (PMU) capabilities, real-time automation controllers, auto-sectionalizing equipment, line monitors, direct fiber lines, and wireless communication radios).

C. Risk Event Associated with the Risk

The SA Decision[13] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the Risk Event (*i.e.,* center of the Risk Bow Tie) is an electric asset failure event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. The risk scenario (*i.e.*, a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency) as assessed for SDG&E's 2018 ERR, is an energized wire-down event caused by a third-party contact, foreign object, or failure of an electric component (a connector). A member of the public contacts the energized wire or is in close vicinity of the energized wire on the ground, resulting in injuries and/or deaths. This risk scenario does not necessarily address all Drivers/Triggers and Potential Consequences and does not reflect actual or threatened conditions.

[13] *Id.* at Attachment A, A-11 ("Bow Tie").

D. **Potential Drivers/Triggers**[14]

The SA Decision[15] instructs the utility to identify which element(s) of the associated Bow Tie each mitigation addresses. When performing the risk assessment for the failure of an electric asset or accidental contact with an electrified asset by the public, SDG&E identified potential leading indicators, referred to as Drivers or Triggers. These include, but are not limited to:

- **DT.1 – In-service equipment past its useful life or becomes obsolete:** Electric assets are usually in service for several decades and possibly for several years beyond the book life of the asset. A common key indicator of failure for an electric asset pertains to the age of the specific asset. These assets can also be considered obsolete when new or updated safety, construction, and operational standards have been established in the industry or within the Company.
- **DT.2 – Equipment in-service beyond design specifications**: Electric assets are designed and constructed per SDG&E standards and in accordance with CPUC General Orders and other local or national requirements. Assets often are designed and constructed to exceed the requirements set forth by these standards; however, field conditions, such as excessive forces exerted on poles due to acute natural forces (*e.g.*, high winds above recorded values), may stress the infrastructure and cause failures.
- **DT.3 – In-service equipment failing prematurely**: SDG&E's electric assets such as underground cables, substation transformers, and overhead connectors are supplied by various manufacturers. These assets undergo routine quality testing from their respective manufacturers and operate within their design criteria; however, it is reasonable to expect some subsets to fail over time, under conditions near the upper limits of their design ratings, or for reasons unknown to SDG&E.

---

14 An indication that a risk could occur. It does not reflect actual or threatened conditions.

15 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.4 – Active in-service equipment and associated components failing to operate as designed**: Due to their sensitive nature, electric assets that are expected to operate based on protection settings to mitigate or reduce the impacts of an asset failure can be expected to either fail periodically or not operate as designed. These failures or delays in operation may cause the assets the protection settings are designed to protect to experience more damage or to extend an expected isolated event.
- **DT.5 – In-service equipment failing with lack of or delayed company insight**: Assets outside of design standards or original construction that does not result in an outage or visibility to SDG&E can lead to an extended exposure to the public (*e.g.,* a leaking transformer). Failure of these systems may cause prolonged or undetected risk exposure to the public.
- **DT.6 – In-service equipment contacted by customers or third parties:** SDG&E's electric facilities may be contacted by members of the public or other third parties. An incident of this type may involve energized overhead distribution primary conductor during the occurrence of a wire-down event or while the conductor is intact and operating under normal operating conditions.
- **DT.7 – In-service equipment failing in large volume due to acute weather events or environmental conditions:** Although it is reasonable to expect some subsets of in-service electric assets to fail, acute weather events or environmental conditions may pose added risks to SDG&E's operations. Adverse weather events may lead to large volumes of failures that extend the normal outage response time, due to limited resources or unsafe field conditions to assess and mitigate damage.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one of the drivers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

- **PC.1** – Serious injuries[16] and/or fatalities;
- **PC.2** – Operational and reliability impacts;
- **PC.3** – Findings of non-compliance;
- **PC.4** – Penalties and fines;
- **PC.5** – Adverse litigation; and
- **PC.6** – Erosion of public confidence.

These Potential Consequences were used in the scoring of the EII risk that occurred during the development of SDG&E's 2018 ERR.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[17] including enhancements to the Interim Decision 16-08-018.[18] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[19]

Electric Infrastructure Integrity	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	3180	**3720**	4620
LoRE		**1200**	
CoRE	2.7	**3.1**	3.9

16 For purposes of this 2019 RAMP Report, SDG&E defines "serious injury" as an injury that requires an overnight hospital stay.

17 D.18-12-014 at Attachment A.

18 *Id.* at 2-3.

19 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE,"

Pursuant to Step 2A of the SA Decision,[20] the utility is instructed to use actual results, available and appropriate data. SDG&E's safety risk assessment primarily utilized internal data for the assessment of safety, financial, and reliability attributes.

For the safety assessment, internal records were used to identify the impact from in-scope risk events that lead to either fatalities or serious injuries to the public, employees, or contractors. For the reliability assessment, SDG&E's reliability database was used to identify in-scope events, such as those due to equipment failure due to outside contacts. The reliability database contains useful information such as the number of customers affected and the duration of the outage. For the financial assessment, a per-event cost was estimated using historical expenditures.

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[21] The below section provides an overview of the scope and methodologies applied for risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification:	The risk of an electric asset failure due to internal or external factors, which results in serious injuries, fatalities, or reliability impacts.
Out-of-Scope for purposes of risk quantification:	The risk of reliability and safety incidents resulting from wildfires associated to electric assets.

SDG&E's EII risk quantification assessment utilized a compilation of internal data from various sources. For the safety attribute, information was gathered from internal sources to help identify historical instances of fatalities or serious injuries. For the reliability attribute, internal

"Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

[20] D.18-12-014 at Attachment A, A-8 – A-9.

[21] *Id.* at Attachment A, A-11 ("Calculation of Risk").

electric reliability data was used. For the financial attribute, some financial records were reviewed to form an estimate of an average EII event.

EII Safety Methodology: The SDG&E Risk Quantification Framework's Safety Attribute contains Fatalities and Serious Injuries as the sub-attributes. A comprehensive review of safety incidents related to EII was undertaken, including the use of safety reports collected by the SDG&E Safety department, as well as information gathered by legal. Note that the method used to assign an incident to a particular risk is done through a prioritization standpoint. All safety incidents affecting SDG&E employees or contractors are discussed in those risk chapters.

B. Sources of Input

The SA Decision[22] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- An extract from the Claims database was used for safety.
- Electric Reliability database for years 2014-2018.

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[23] This section describes SDG&E's Risk Mitigation Plan by each selected control and mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SDG&E's EII Risk is the risk of an asset failure, caused by degradation, age, operation outside of design criteria due to unexpected events or field conditions (*e.g.*, a force of nature), or an asset no longer complying with the latest engineering standards, which results in a safety, environmental, or reliability incident. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and new and/or incremental

---

22 *Id.* at Attachment A, A-8 – A-9 ("Identification of the Frequency of the Risk Event").

23 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

Mitigations for the period of SDG&E's TY 2022 GRC cycle.[24] The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

Overview of SDG&E's Electric System:

SDG&E's electric service territory is 4,100 square miles spanning two counties and 25 communities. It covers the southern portion of Orange County to the U.S.-Mexico Border, and San Diego County from the coast to the western borders of Riverside and Imperial Counties. SDG&E's roughly 1.4 million electric consumers comprise predominantly residential customers, along with a smaller number of commercial and industrial customers. Table 3 below provides an overview of SDG&E's electric system.

Table 6: SDG&E Electric Infrastructure Overview

Transmission	Distribution	Substation
Circuits (Tie lines) 500 kV: 6 230 kV: 48 138 kV: 39 69 kV: 146	Circuits 12 kV: 831 4 kV: 224	Distribution Substations 12 kV: 102 (no 4 kV) 4 kV (step downs and substations): 34
Overhead Miles: 1,831	Overhead Miles: 6,500	Transmission Substations: 25
Underground Miles: 174	Underground Miles: 10,765	

Overview of SDG&E's Risk Mitigation Plan:

SDG&E aims to build and maintain a safe and reliable electric infrastructure. To do so, SDG&E employs both conventional and innovative approaches to engineering, designing, constructing, maintaining, and operating its electric infrastructure. SDG&E creates and maintains construction standards and practices that help to maintain safe operations for electrical workers and the public. These are challenging tasks given the varying terrain, weather patterns,

24 *Id.* at 16-17 and 33. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

aging infrastructure, continually and changing load patterns, thousands of parts and pieces used to construct the electric distribution system and the resulting impacts to the safety and reliability of electric infrastructure, across the service territory.

SDG&E is an industry leader in the development of innovative engineering, construction, and operational techniques, having experienced a variety of operational challenges over the years. SDG&E invests in the continual improvement of electric transmission, substation, and distribution infrastructure, as well as in technology to safely monitor and control those assets. SDG&E routinely collaborates with several manufacturers, consultants, and various consortiums of utilities to recognize and continually pursue best practices for the purpose of enhancing employee and public safety.

These investments and practices have contributed, in large part, to SDG&E's maintenance of a consistent trend of industry-leading reliability indices (*e.g*., System Average Interruption Duration Index, commonly known as SAIDI). These achievements are a result of implementing long-term infrastructure improvements and responding to unplanned outages with urgency. Despite these successful efforts, not all electric reliability risks can be fully mitigated and, therefore some residual risks will remain.

SDG&E's Risk Mitigation Plan aims to mitigate electric asset failures associated with the electric overhead and underground system, and within the substation fence. These mitigations were developed by utilizing the potential drivers outlined in Section III.D, above, analysis from failed equipment, internal subject matter experts and outage data. When determining scope, duration and urgency for a mitigation plan, SDG&E considers several factors, such as: impacts to affordability, consequence of the asset failure, the volume of assets identified, and resource or manufacture constraints to design, physically construct and remove the identified risky asset. In addition, some asset failures require collaboration with manufacturers and industry experts to further analyze the root cause and develop the appropriate mitigation. Depending on the complexity, volume of assets, external constraints, environmental impact, comprehensive permitting and duration to construct, some mitigations require several years of planning before any construction can occur. However, the electric system is dynamic, and a new risk could be introduced daily, requiring SDG&E to be nimble and capable of altering a course of action, based on new information.

After additional research and evaluation of existing processes, SDG&E identified a need to develop Enterprise Asset Management tools to integrate all asset data, create predictive analytics and assist with further optimizing projects. Over the past year, SDG&E has constructed a dedicated department to address this specific topic and collaborated with additional departments and subject matter experts (SME) to evaluate all electric assets associated with the distribution and transmission system. This collaboration and development or enhancements to tools as well as databases, will allow SDG&E to further expand its capabilities and enhance the development of mitigations.

Climate Change Adaptation:

As stated above, SDG&E's electric service territory is 4,100 square miles spanning two counties. The SDG&E service territory features a diverse range of micro-climates and weather conditions. Customers and electric infrastructure are dispersed among sparsely populated lower deserts and mountainous regions, as well as in densely populated load centers along the coastal and inland regions of San Diego and south Orange County. Climate conditions include: sunny skies and mild temperatures, Santa Ana and elevated wind conditions that can exceed 100 miles per hour gusts near transmission and distribution infrastructure, heat waves and peak loads in spring, summer and fall months causing unexpected volumes of transformer overloads, heavy rainfall across all regions of the service territory resulting in flash floods, landslides, and the resulting electric infrastructure failures, and ice loading causing pole failures in the inland regions.

SDG&E considers the overhead electrical system to be its primary concern, from a risk perspective, because of public safety and its susceptibility to adverse weather. Adverse weather is a driver to premature failure of assets that can potentially lead to significant issues. SDG&E's underground electrical system poses operational and safety risks and is naturally subject to several environmental factors that may accelerate premature failures, such as soil conditions and flooding.

As further discussed in Chapter RAMP-A, SDG&E views climate change as a Driver/Trigger to an EII risk event. As stated above in the description of DT.7, in-service equipment failing in large volume due to acute weather events or environmental conditions, SDG&E is keenly aware of the increasing risk of catastrophic events and chronic long-term impacts resulting from climate change and aims to provide safe and reliable electric service to the communities it serves by building resiliency to such climate risks and adapting to future climate change. The primary avenue through which SDG&E can increase climate resilience is by investing in resilient electric infrastructure that will continue to provide safe, affordable, reliable energy despite increasingly severe and frequent climate impacts.

The climate vulnerability assessments undertaken by SDG&E, and the other California IOUs, as part of the U.S. Department of Energy Partnership for Energy Sector Climate Resilience, represent an important initial, voluntary step in better understanding utility exposure to climate impacts. SDG&E has already developed several of these vulnerability assessments over the past years and fully intends to continue to do so moving forward.

In addition to the partnership with the DOE, SDG&E has worked with the California Energy Commission on two separate initiatives that assessed climate hazards in the SDG&E service territory. The studies were targeted at assessing the threat of sea level rise and coastal flooding on electric and gas infrastructure and provided key insights that allow SDG&E to effectively plan and manage infrastructure in light of climate change.

SDG&E's Risk Mitigation Plan - Controls:

A. SDG&E-4-C1: GO165 Distribution Inspect and Repair Program

SDG&E's General Order (GO) 165 Distribution Inspect and Repair program replaces wood poles after identifying compromised poles from GO 165 wood pole intrusive inspections. In lieu of the existing program, short- and long-term deterioration of overhead equipment could increase likelihood of asset failure (*e.g.*, broken poles) and cause potential risks, including injury or death, to the public and workers. Degraded equipment would also increase volume and frequency of forced distribution outages, creating risks for public safety. As this program is mandated per GO 165, non-compliance poses risk of regulatory action, including fines.

The Commission's Safety and Enforcement Division (SED) provided feedback that SDG&E should include a narrative discussion on the effectiveness of inspections per CPUC guidance on Senate Bill (SB) 901. SDG&E's Overhead (OH) Visual Inspection program utilizes GO 95, Rules for Overhead Electric Line Construction, as its basis for identifying non-conformances. The OH Visual Inspection looks for a variety of conditions that could impact public and employee safety, structural integrity, and system reliability. The OH Visual

Inspection consists of a detailed, walk-around inspection of all distribution poles, pole-mounted facilities with primary and secondary conductors, CIP attachments, and distribution equipment on transmission poles. These inspections identify conditions that are out of compliance with GO 95. On average, SDG&E performs approximately 45,000 OH visual inspections on our electric distribution system per year. For an OH visual inspection, the top five conditions found are as follows:

- Damaged/Missing Sign;
- Damaged/Missing/Incorrect Station Pole ID;
- Damaged Ground Molding;
- Damaged/Missing High Voltage signs; and
- Pole steps lower than 10 feet.

SDG&E also performs a Pole Intrusive Inspection on each wood electric distribution pole. Any pole 15 years of age or older is inspected intrusively. The form of the intrusive inspection is normally an excavation about the pole base and/or a sound and bore of the pole at ground line. Currently, treatment is applied in the form of ground line pastes and/or internal pastes. SDG&E performs these inspections on a 10-year cycle. The 10-year cycle fulfills the requirements of GO 165, which are: (1) all poles over 15 years of age are intrusively inspected within ten years; and (2) all poles that previously passed intrusive inspection are to be inspected intrusively again on a 20-year cycle.

The wood pole integrity inspections are currently performed by an SDG&E contractor who also applies wood preservative treatments and installs mechanical (steel) reinforcements. The type of treatment is dependent upon the age of the pole, the individual inspection history, and the overall condition of the structure. SDG&E's Vegetation Management group administers the wood pole intrusive inspection and treatment program. For this program, SDG&E performs approximately 20,000 wood pole intrusive inspections. There are three findings from this type of inspection. They are:

- Pole replacement;
- Pole reinforcement (with steel); and
- No corrective action needed.

B. SDG&E-4-C2: 4kV Modernization and System Hardening Program – Distribution

The purpose of SDG&E's 4kV Modernization and System Hardening program is to systematically remove the 4kV distribution system from service and replace with or upgrade to modern 12kV standards. The 4kV system makes up over 20% of SDG&E distribution circuits (by circuit count) and represents approximately 5% of SDG&E system load and overall distribution system length. Half of the 4kV substations are more than 50 years old, and replacement components for those substations are no longer available. The operation of 4kV substations is of a major safety concern because the company is facing a shortage of qualified crews and electricians who are familiar with and knowledgeable about design and operation of those aging and obsolete substations. The maintenance cost is unusually high and continues to increase. The 4kV substations also present reliability and safety risks for customers, because high failure rates, lack of replacement parts, and limited options to transfer load to adjacent circuits, have the potential to cause more frequent and unnecessary extended outages. In addition, 4kV overhead circuits are more likely to experience a wire down compared to 12kV circuits due to a higher percentage of small wire conductors and smaller conductor clearances. SDG&E's 4kV modernization plan addresses all areas of 4kV substation and distribution infrastructure removals and upgrades.

The scope of the program includes: 4kV package or "unit" substation removal and modernize other aging substation infrastructure; cutover to 12kV, including complete rebuilding, relay upgrades, accommodations, and design.

C. SDG&E-4-C3: Distribution Overhead Switch Replacement Program

SDG&E's Distribution Overhead Switch Replacement Program aims to replace overhead distribution switches that have shown signs of severe or quickly emerging corrosion that may lead to catastrophic failure. SDG&E has determined through quantitative risk modeling various data attributes that characterize high risk switches and has prioritized several switches that can be removed in the near term to avoid failure. For example, SDG&E's engineering analyses of failed overhead switches have determined that various switches, such as hooksticks, often fail due to excessive corrosion of major components. Switches have failed in as little as eight years of operation along the dense salt fog coast.

Switch replacements may also require simultaneous or subsequent upgrades to relevant equipment such as poles, crossarms, wires, guys, and other hardware.

Distribution switches have higher propensity for failure and/or inoperability along the coast identified by the SDG&E-defined "Contamination District One"[25] area which includes assets within two miles of the coast. Their inoperability during an outage can extend the impact of an outage to the next upstream protection device causing a prolonged forced outage as crews are required to install additional jumpers or other workarounds. Switches that are not consistently exercised are at increased risk of being inoperable when needed. The inoperable state of the switch poses safety risks to field operating personnel due to potential flash or overexertion by the employee. Solid blade cutouts and antiquated single phase disconnect switches will be targeted to be replaced with newer model disconnects with superior material specifications, three-phase gang-operated switches (mitigating ferro resonance over-voltages and flashovers, both SCADA and Non-SCADA) as well as remote operable SCADA tie switches for improved reliability. In addition, operation of the at-risk switches will be included to assist with minimizing inoperable state during an outage. Intent to target high corrosion areas.

D. SDG&E-4-C4: Management of Overhead Distribution Service (Non-CMP)

This project is required to reinforce the electric overhead distribution system infrastructure by responsive action to system damages, deterioration and unsafe conditions outside normal restoration of service. The overall objective is to maintain continuity of safe and reliable customer service.

This project provides for the reconstruction of existing overhead distribution facilities as necessary, to:

- Correct improper voltage conditions;
- Replace overloaded overhead facilities;
- Make emergency repairs not normally associated with restoration of service;
- Repair or replace deteriorated or unsafe equipment not found through the "Corrective Maintenance Program;"

[25] "Contamination District One" is the designated area within two miles of the coastline where equipment and/or assets tend to deteriorate due to increased salt particles in the air.

- Install fault indicators/fusing/switching equipment as necessary; and
- Install a barrier around the pole to prevent reoccurrence.

E. SDG&E-4-C5: Restoration of Service

SDG&E, as an investor owned utility, has an obligation to serve. This project is required to accomplish restoration of electric service due to system interruptions caused by severe inclement weather conditions, fires, equipment failures and damages caused by a third party. This project provides for the reconstruction of existing overhead and underground distribution facilities as necessary to restore electric service to customers. The funds within this budget cover all costs associated with the following factors:

- Storm Damage (rain/wind/fire, for example);
- Damage to electric distribution facilities by others (car/equipment contacts, for example); or
- Emergency repairs of facilities that are required for service restoration (cable or equipment failures, for example).

F. SDG&E-4-C6: Underground Cable Replacement Program – Reactive

SDG&E's underground cable replacement program is designed to reactively replace equipment during outages on the distribution system. This program provides funding for the replacement of underground cable involved in a forced outage. This project is required to support SDG&E's obligation to serve, by funding the restoration of electric service after system interruptions caused by underground cable failures involved in severe inclement weather conditions, equipment failures and damages caused by a third party.

G. SDG&E-4-C7: Tee Modernization Program - Underground

SDG&E's Tee Modernization Program involves the proactive at-risk identification and replacement of 600-amp tee connectors. 600-amp tees are used in underground connections in handholes, manholes, and at-switch terminations. These tee failures often occur along feeder cables causing forced outages to large customer counts that require extensive reconstruction to permanently restore the outage. Tee connector failures have become one of the largest contributors to customer outages in the last few years. The modernization of tees through this program provides a more reliable system that has more sectionalizing capability. Additionally, tees can fail violently (*e.g.,* tee failure could lead to an arc flash), which poses a serious safety risk to our field personnel.

H. SDG&E-4-C8: Replacement of Live Front Equipment – Reactive

"Live front" equipment is equipment that has primary connections exposed, with no insulation covering. Live front equipment contains electric components enclosed in a protective (usually steel) cabinet that does not have additional protective barriers. Thus, when the cabinet is opened, energized (or live) electric connections are exposed. Live front equipment was primarily installed on SDG&E's electric distribution system during the 1960's and 1970's, has since become obsolete, and is now being replaced by 'dead-front' equipment with additional safety barriers such as removable fiberglass or composite plates, protective covers or additional compartmentalization. SDG&E's Live Front Terminator Replacement Project replaces live front pad-mounted distribution equipment with dead front pad-mounted distribution equipment, when it is encountered during normal SDG&E work.

I. SDG&E-4-C9: DOE Switch Replacement - Underground

SDG&E's "do not operate energized" (DOE) Switch Replacement Program for underground switches aims to systematically replace switches that are deemed unsafe for energized operation of the internal mechanical units. SDG&E utilizes inspection programs to identify these types of switches. These inspections include visual inspections, infrared (IR) inspection to detect points of potential overheating, measurement of switch lubrication, and physical exercising. Upon inspection, if a switch is found to not be safe for continued operation, field experts will make the determination to replace the switch with an appropriately superior or equivalent asset, depending on field conditions. This program improves worker safety while operating these switches and prevents premature failures of these assets, avoiding potential for injuries and damages to adjacent facilities.

J. SDG&E-4-C10: Vegetation Management (Non-HFTD)

SDG&E's Vegetation Management Program is responsible for inspecting and maintaining an inventory of approximately 450,000 trees that have the potential to encroach within the minimum required compliance distance between vegetation and overhead power lines. This work includes pruning healthy trees growing into overhead power lines as well as the pruning or removal of dead, dying, diseased, or structurally unsound trees that have the potential to fall into overhead lines. SDG&E is responsible for compliance with CPUC GO 95, Rule 35; Public Resources Code, sections 4292 and 4293; and NERC FAC-003. Compliance with these rules and regulations mandate a minimum clearance between vegetation and SDG&E facilities and are the primary cost drivers of the program.

SDG&E's vegetation activities are coordinated through a centralized Vegetation Management Program within the Construction Services department, under the Electric Operations organization. The Vegetation Program Manager and staff set the standards, guidelines, and processes for the overall program to see that the company is in compliance with all rules, laws, and regulations governing SDG&E practices. There are two types of work that drive the tree program costs: 1) routine work and 2) field memos and hazard tree work. Routine work includes annual-cycle pruning and removal of trees. Pre-inspection contractors perform the overhead power line patrols which identify trees to be pruned and removed. Routine tree pruning and removal is typically done by a contractor and is compensated on a unit price basis. Field memos and/or unscheduled tree pruning are reactive work, and include customer refusals, hazard tree pruning and removal, environmentally or culturally sensitive pruning activities, trees which require priority pruning, district requests, and customer safety checks.

To confirm the above activities are completed in accordance with the company's contracted scopes of work, SDG&E has a quality control program to verify the completion and certification of each work activity. An automated random sampling method is used to create audit work packages, and then the auditor field reviews records for adherence to contract specifications, quality, and compliance. In conjunction with the post-prune audit, auditing activity includes a patrol of all spans of overhead power lines for any trees that may have encroached the minimum clearance zones since the last pre-inspection activity. This activity provides a higher level of compliance for the duration of the annual cycle.

K. SDG&E-4-C11: GO165 Distribution Inspect and Repair Program – Underground Capital Asset Replacement

Short- and long-term deterioration of underground equipment could increase likelihood of asset failure (*e.g.*, a broken cable rack) and cause potential risks, including injury or death, to the public and workers. Degraded equipment would also increase volume and frequency of forced distribution outages, creating risks for public safety. As this program is mandated per GO

165, non-compliance poses risk of regulatory action, including fines. Underground connectors are inspected by infrared technology per ESP 120 (upon entry of facility) and replaced accordingly.

This inspection of AGDF/AGLF (Above ground, dead front and live front pad-mounted equipment) consists of a detailed external and internal inspection of pad-mounted facilities to identify conditions out of compliance with GO 128. The most obvious types of condition that presents a significant hazard to the public and employees are severe corrosion, possible wire entry, and identifying oil leaks. These are the types of conditions that SDG&E is continually looking for.

SDG&E performs this type of inspection on approximately 25,000 structures per year. The top five conditions found on this type of inspection are as follows:

- EXT/INT High Voltage Sign Missing;
- External Working Space Sign Missing;
- Weeds/Trees/Bushes/Dirt or Obstacle;
- Possible Wire Entry to Energized/Exposed Parts; and
- Weeds/Grass/Dirt Inside Unit.

L. SDG&E-4-C12: GO 165 Distribution Inspect and Repair Program – Underground Structure Repair

Short- and long-term structural deterioration of manholes and degradation of distribution switches cause potential risks, including the risk of injury or death, to the public and workers. Degraded equipment would also increase the volume and frequency of forced distribution outages, creating risks for public safety. As this program is mandated per GO 165 (Inspection Requirements for Electric Distribution and Transmission Facilities), non-compliance poses risk of regulatory action, including fines.

This program includes detailed inspection of subsurface structures (manholes, vaults, primary hand-holes and subsurface enclosures) containing electric distribution equipment. Structures with only cable taps, splices or pass-throughs are excluded, as they are not required by GO 165. The program's detailed inspection of these facilities identifies conditions out of compliance with GO 128 (Rules for Construction of Underground Electric Supply and Communication Systems). The most obvious examples of a condition that could present a significant hazard to the public and employees are severe structural corrosion, an unsecure entry way, and the presence of oil leaks. These are the types of conditions that SDG&E is continually looking for.

On average, SDG&E performs this type of detailed inspection on approximately 400 structures per year. The top five conditions found on this type of inspection are as follows:

- Weeds/Trees/Bushes/Dirt or Obstacle;
- EXT/INT High Voltage Sign Missing;
- Weeds/Grass/Dirt Inside Unit;
- ID/Circuit/Switch Number Missing or Incorrect; and
- External Working Space Sign Missing.

M. SDG&E-4-C13: Management of Underground Distribution Service (Non-CMP)

This project is required to reinforce the electric underground distribution system infrastructure by responsive action to system damages, deterioration and unsafe conditions outside normal restoration of service. The overall objective is to maintain continuity of safe and reliable customer service.

This project provides for the reconstruction of existing underground distribution facilities as necessary to:

- Correct improper voltage conditions;
- Replace overloaded overhead facilities;
- Make emergency repairs not normally associated with restoration of service;
- Repair or replace deteriorated or unsafe equipment not found through the Corrective Maintenance Program; and
- Install fault indicators, fusing, or switching equipment as necessary to maintain service reliability.

N. SD&E-4-C14: Field SCADA RTU Replacement

Older SCADA Remote Terminal Units (RTUs) that support communication to distribution field devices such as switches, regulators and capacitors have poor reliability often complicating outages or requiring field crews to manually switch devices that could normally be switched remotely. SDG&E's Field SCADA RTU Replacement Project replaces distribution field-deployed RTUs (outside substations), which are past their useful life and no longer supported by the vendor.

This project resolves issues with the current SCADA system, thereby allowing SDG&E to move away from legacy communication protocols that are no longer supported and improving communication reliability. This project also allows for a more transparent view to the grid, which will enhance SDG&E's reliability. Proactively modernizing SDG&E's SCADA RTUs by replacing old legacy equipment will better enable operability of the distribution network, including faster circuit outage restorations.

O. SDG&E-4-C15: Distribution Circuit Reliability

This program helps mitigate electric infrastructure integrity risk by expanding the distribution SCADA-switching infrastructure and removing reliability deficiencies. This program allows for the addition of equipment necessary to improve service reliability of electric customers and maintain reliability standards. The electric service reliability will deteriorate in the absence of comprehensive remedial solutions offered by these projects.

P. SDG&E-4-C16: Emergency Substation Equipment

This project provides funding to support the restoration of service to our customers following outages caused by equipment failures by purchasing emergency spare and mobile equipment. The number of aging transformers and switchgear on the SDG&E system is at the level that additional failures are expected, despite efforts to replace the equipment before failure. In addition, there can be lengthy lead times for replacement units, during which time the spares are necessary. Currently, the requested funding for this budget is for two 69/12 kV transformers to maintain the level of spare equipment required to support the aging fleet of transformers.

Q. SDG&E-4-C17: Reactive Substation Reliability and Repair for Distribution Components

SDG&E's Reactive Substation Reliability and Repair for Distribution Components program allows for necessary safety related improvements and replacement of failed equipment. Work authorized under this program includes replacements on structures, replacement of obsolete failed substation equipment and obsolete failed communication equipment within the substation footprint.

R. SDG&E-4-C18: GO174: Substation Relay Testing, Inspection and Maintenance Program

SDG&E's Substation System Inspection and Maintenance Program promotes safety for SDG&E personnel and contractors by providing a safe operating and construction environment, within the substation fence. Additional goals include: meeting all of the requirements of GO 174, achieving a level of station availability satisfactory to SDG&E's health and safety programs and maintenance standards, and assuring compliance with all sections of the California Independent System Operator (CAISO) Transmission Control Agreement (TCA). This is accomplished through routine inspections at reoccurring cycles. A security check is planned once per week, and a more detailed inspection is planned monthly or bimonthly, which takes a visual look at equipment and attempts to identify any problems, like oil leaks.

S. SDG&E-4-C19: Underground Cable Replacement Program – Proactive

SDG&E currently performs reactive replacement of underground cable. There are currently approximately 74 circuit miles of unjacketed feeder cable and 1,423 circuit miles of unjacketed lateral cable remaining on the SDG&E electric distribution system. The reactive program (SDG&E-3-C6) identifies and replaces failed equipment. This program (SDG&E-3-C19) would take a proactive approach by replacing underground cable that has been identified to have a high probability of failure based on electric reliability circuit analysis and cable failure data. It would also provide quality customer service and reliability to existing customers by proactively replacing cable in the underground system before it fails, and an outage occurs.

T. SDG&E-4-C20: Enterprise Asset Management - Substations

SDG&E currently has Conditioned Base Maintenance (CBM) monitoring equipment on electric distribution assets in in substation facilities, such as distribution banks, that support greater asset utilization, longevity of use and asset health indexes. This data, along with maintenance records and other data sources, are combined into a software platform to prioritize maintenance activities and stay informed on situations that might lead to potential outages or failures. Collection of this asset data also allows for long term planning on asset health to support capital investment prioritizations and risk reduction strategies.

SDG&E's Risk Mitigation Plan - Mitigations:

U. SDG&E-4-M1: Overhead Public Safety (OPS) Program

SDG&E is proposing an Overhead Public Safety (OPS) program,[26] which will effectively replace or protect the assets most prone to failure. The OPS program uses historical data collected from actual wire-down events to estimate failure rates of overhead infrastructure as they may relate to causing wire down events. Applying these failure rates to all non-HFTD and non-Wire Safety Enhancement (WiSE) circuits provides SDG&E's subject matter experts with an estimate of an individual circuit's expected likelihood of a wire-down event over a given period. SDG&E ranks these individual circuits by the total expected number of wire-down events, to identify the top quartile where risk reductions may be concentrated. This top quartile of potential wire-down events encompasses the circuits with the most exposure of high-risk assets, primarily small wire (*e.g.*, #6 Cu and #4 Cu), and most notably to address spans greater than 500 feet in length. Also, other environmental factors including high winds, accelerated corrosion in coastal areas, likelihood of public contact, and areas where wire-down events have occurred more than usual, are considered when estimating failure rates and potential for risk reduction.

SDG&E's OPS program aims to proactively replace high-risk overhead conductors prone to wire-down events measured by failure rates, historic wire down events, CMP records and lack of protection (fuse or advanced) that are in proximity to the public (*e.g.,* schools, freeways, high profile areas) that could put the public at risk of energized contact. SDG&E utilizes new construction standards, such as covered conductor, to mitigate the wire-down event (such as foreign object contact) and designs risk mitigation strategies for each circuit to achieve the greatest risk reduction for energized wire downs by reconductoring, deploying advanced protection and/or detection schemes. This program will replace existing assets with assets that have been designed to current and updated construction standards. The assets targeted in this

---

[26] As previously stated in Section I of this Chapter, SDG&E's OPS program was identified in SDG&E's previous RAMP and GRC filings as the WiSE Central program. With the Commission's recent rulemaking on Wildfire Mitigation Plan (R.18-10-007), SDG&E reduced the scope of the WiSE program to align with wildfire mitigation activities outside of SDG&E's HFTD. Therefore, the OPS program is separate and distinct form the WiSE program. Additional details on WiSE is located within the Wildfire Mitigation chapter (SDG&E-1) of this RAMP Report.

tranche (typically small wire copper spans) were designed and constructed decades ago. Therefore, replacement of these assets with those designed to current construction standards provides the benefit of improved design techniques, modern equipment and construction methods.

This program will also evaluate overhead distribution lines that cross major or high-traffic freeways. Overhead distribution crossings that have poor structural integrity or high-risk conductors will be hardened to avoid a wire down in the roadway that could put motorists at risk.

One of the primary concerns of SDG&E with respect to its overhead equipment is when a piece of overhead equipment (*e.g.*, wire) falls to the ground remains energized, also referred to as a wire-down event. If an employee, contractor or the public comes into contact with an energized wire, the results can be fatal. Accordingly, SDG&E is continuing to take proactive measures to determine the cause of such events. Data analysis suggests there are various drivers of wire-down events, such as third-party contact, acute weather causing foreign object contact or introducing extreme stress, aged infrastructure, and degradation of connectors. The most notable and consistently contributing driver of wire-down events is the failure of small wire.

The main scope of program is to replace remaining small wire with conductor that is known to be statistically less prone to failure, such as #2 5/2 AWAC conductor and depending on vegetation in the area covered conductor. In other areas, where small wire may not feasibly be replaced, at-risk connectors, sleeves, and single-phase spans of small wire (*i.e.,* commonly known failure points) will be replaced as needed. In addition to the OPS infrastructure replacement program, SDG&E is also presenting as part of this RAMP filing a program to add a more robust public safety awareness campaign to address wire-down situations. This enhanced public safety communication campaign (SDG&E-5-M2) is further addressed in SDG&E's Customer and Public Safety Chapter of this RAMP Report (SDG&E-5) and aims to educate and provide a deeper level of understanding to the public with respect to safe practices around electric infrastructure. Associated costs for SDG&E-5-M2 are included in the Customer and Public Safety RAMP Chapter and are not included herein.

V. **SDG&E-4-M2: Replacement of Live Front Equipment – Proactive**

As described above in SDG&E-4-C-8, "live front" equipment having the primary connections exposed with no insulative covering. Thus, when the equipment is opened, there are energized (or live) conductors present. SDG&E has a current live front terminator replacement program that is reactive; *i.e.*, when there is a job on the SDG&E distribution system that involves working with live front equipment, the equipment that is involved will be replaced with dead front equipment at that time. This incremental mitigation aims to proactively identify and replace live front equipment before employees are deployed to the job, thereby further reducing the potential for employee injury and/or outage.

Continued use of live front terminators causes risks to workers who rely on limited tools to operate the live equipment. As an alternative to using this equipment, switching plans can consider operating dead-front or remote-operated equipment elsewhere on the system to create electric isolation for a job or for safe operation of the live front equipment, however this would likely cause unnecessary outage exposure to additional customers. If the limited switching tools are insufficient, workers may be dangerously exposed to live primary voltage, potentially resulting in serious risks for injury or death.

W. **SDG&E-4 M3: Proactive Substation Reliability and Repair for Distribution Components**

SDG&E's proactive substation reliability and repair program consists of the following projects:

i. Streamview Bank 30 Project
ii. Pacific Beach 12 kV Replacement Project
iii. Ash 12 kV Capacitor Bank and Circuit Breaker Replacement Project
iv. New Substation

There are unique complexities associated with substation infrastructure, including heavy reliance on protective relaying devices and antiquated assets as old as 70-80 years with limited operational flexibility. Electric substation infrastructure is generally isolated from public view or contact. Electric workers, however, may be subject to electric safety hazards such as arcing, high voltage induction stray voltages, and mechanical safety hazards associated with working with heavy equipment (*e.g.*, cables) and in confined spaces, such as in metalclad switchgear.

These projects will focus primarily on distribution substation bank transformers and circuit breaker replacements. Substations are essential to the operation of the electric system and must be kept in reliable condition, as the consequences of a failure are extreme. Proactive planning is required for the replacement of equipment that has exhausted its useful life.

The New Substation project will mitigate outage impacts to the transmission and distribution system by offloading demand from neighboring substations through the distribution tie capacity, thus enhancing reliability in the downtown San Diego area. Outages could be unplanned as well as planned due to the foreseeable need to rebuild existing substations in the area. This will, as a result, allow the distribution system to continue operating at optimum conditions, which, as a result, maintains reliability, shortens outage times, and allows for operational flexibility to the system.

X. SDG&E-4-M4: Substation Breaker Replacements

SDG&E's Substation Breaker Replacement projects consist of the following:

i. San Ysidro Breaker Replacement – Replace 12kV breakers and 12kV relaying at San Ysidro Substation.

ii. Murray Breaker Replacement – Replace 12kV breakers and 12kV relaying at Murray Substation.

The Substation Breaker Replacement projects are necessary to modernize substation equipment that will help provide safe, reliable, and quality customer service by enabling the deployment of Fault Locations, Isolation, and Restoration (FLISR) technology. With FLISR technology, fault location, fault isolation, and customer restoration on a distribution circuit occurs automatically, without the intervention of a distribution system operator. This results in safely improving the distribution system reliability.

Y. SDG&E-4-M5: Enterprise Asset Management – Distribution

In 2017, SDG&E formed an Asset Management program team, as a central group, to develop and implement a holistic and sustainable asset management system for electric infrastructure assets with an integrative approach for governance, strategy, analytics and continuous improvement. The new asset management system is being developed to conform with ISO 55000, an international standard that specifies the requirements for the establishment, implementation, maintenance, and improvement of an asset management system. Benefits of such a system may include enhanced asset safety, improved performance, managed risk, demonstrated compliance, and improved efficiencies and effectiveness of asset utilization and operations.

As further discussed in SDG&E's Safety Culture Chapter (RAMP-F), Enterprise Asset Management is a critical element of SDG&E's focus on creating sustainable and high-quality asset safety and management for electric operations, and optimizing asset utilization, while mitigating asset-related risks. This is also one element of SDG&E's vision for an electric safety management system. A comprehensive asset management system will provide the access to and integration of data throughout the asset life cycle to develop analysis and a health index for critical assets.

SDG&E is developing an asset health index (AHI) on its assets to identify and compare assets based on its likelihood of failure. An AHI is a score designed to track the condition and performance of an asset by applying predictive analytics to multiple sources of data and used as a basis for asset management strategies. The key benefits of employing AHI include the ability to measure overall health of assets, recognize asset data parameters associated with failure modes, detect failures, relatively compare between assets of same class in a consistent manner, and utilize analytics to measure operational conditions.

Asset risk is determined when AHI and the associated likelihood of failure consequence are jointly considered. Based on this information, asset strategies would be evaluated, prioritized and implemented to manage the asset in a manner that aligns with SDG&E's overall risk management strategy, supports risk-informed platform for managing assets, and reinforces safe operations, maintenance and proactive replacement strategies. Integrating this asset risk information with other inputs, such as circuit risk index for situational awareness, will inform the appropriate asset-related operational decision-making and strategies for enhanced reliability and safe operations of assets on given current and expected conditions.

SDG&E believes asset management will provide a means to optimize the Company's risk, performance, and investments while meeting or exceeding safety and regulatory objectives. A comprehensive asset management system will provide the access to and integration of data throughout the asset life cycle to develop analysis and a health index for critical assets. Using a health index of its assets, SDG&E can identify which assets have a likelihood of failure and the respective consequence(s) of the failure(s). Based on this information, asset strategies would be evaluated and implemented to manage the asset in a manner that aligns with SDG&E's overall risk management strategy.

SDG&E's Power Quality (PQ) 12kV Bus Monitor Deployment and Replacement project, which is part of the Enterprise Asset Management proposal, is the continued deployment of substation bus power quality monitors that can remotely monitor and capture data that support distribution and substation asset management and power quality investigations. Future use cases with better analytic software could support momentary or incipient fault detection for better asset management and reliability functions.

This project provides an incremental expansion to our substation power quality monitoring system (PQ Nodes) and associated communication system. SDG&E will:

- Provide local wiring and network connections to existing monitors;
- Upgrade existing PQ nodes and support equipment;
- Install new IT integration and interface for new equipment;
- Install field and substation relay and communication systems;
- Install new PQ support communication equipment; and
- Provide time synchronization for existing monitors.

The substation PQ monitoring system provides benefits as follows:

- Distribution system health information. System parameters including RMS voltage , voltage & current transient events, system harmonics (including spectra), real & reactive power flow, power factor, flicker, and others.
- Event logging and notification for events occurring on transmission, distribution and customer systems that are perceptible at the distribution substation.
- Advanced analytics processes including incipient fault detection (fault anticipation) and advanced fault locating.
- A data source with analytics for historical events and steady state trends.
- Data collected via the substation PQ monitoring system is regularly utilized by several groups within the company including Commercial and Industrial (C&I) Services, Electric Transmission, and Distribution Engineering and Planning.

Continued deployment of substation bus power quality monitors that can remotely monitor and capture data will support distribution and substation asset management and power quality investigations. Future use cases with better analytic software could support momentary or incipient fault detection for better asset management and reliability functions.

Because asset management efforts benefit SDG&E's entire service territory, for purposes of SDG&E's RAMP showing, costs for this activity has been allocated between SDG&E's Wildfire (SDG&E-1) and this Electric Infrastructure Integrity risk chapter based on HFTD (60% Wildfire) and non-HFTD (40% EII) percentages.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary, pursuant to the terms of the SA Decision. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[27] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. As defined in the SA Decision, a tranche is "a logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment."[28] Therefore, risk reduction and RSEs from Controls and Mitigations are determined at the tranche level. For purposes of the risk analysis, each tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of tranches is presented in the section below.

Table 7: Summary of Mitigation Tranches

ID	Mitigation/Control	Tranche	Tranche ID
SDG&E-4-C1	GO 165: Distribution Inspect and Repair program	Non-HFTD	SDG&E-4-C1
SDG&E-4-C2	4 kV Modernization and System Hardening Program– Distribution	Non-HFTD	SDG&E-4-C2

[27] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[28] *Id.* at Attachment A, A-4.

ID	Mitigation/Control	Tranche	Tranche ID
SDG&E-4-C3	Distribution Overhead Switch Replacement Program	Hook stick switches and solid blades in Contamination District One (coast)	SDG&E-4-C3-T1
		Tie switches (gang or hook stick) in Contamination District One	SDG&E-4-C3-T2
		Switches in Contamination District One with large customer count that could benefit from SCADA	SDG&E-4-C3-T3
SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	Non-HFTD	SDG&E-4-C4
SDG&E-4-C5	Restoration of Service	Service territory-wide	SDG&E-4-C5
SDG&E-4-C6	Underground Cable Replacement Program - Reactive	Service territory-wide	SDG&E-4-C6
SDG&E-4-C7	Tee Modernization Program - Underground	Service territory-wide	SDG&E-4-C7
SDG&E-4-C8	Replacement of Live Front Equipment – Reactive	Service territory-wide	SDG&E-4-C8
SDG&E-4-C9	DOE Switch Replacement - Underground	Service territory-wide	SDG&E-4-C9
SDG&E-4-C10	Vegetation Management (Non-HFTD)	Non-HFTD	SDG&E-4-C10
SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	Service territory-wide	SDG&E-4-C11
SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair	Service territory-wide	SDG&E-4-C12
SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	Service territory-wide	SDG&E-4-C13
SDG&E-4-C14	Field SCADA RTU Replacement	Service territory-wide	SDG&E-4-C14
SDG&E-4-C15	Distribution Circuit Reliability	Service territory-wide	SDG&E-4-C15
SDG&E-4-C16	Emergency Substation Equipment	Service territory-wide	SDG&E-4-C16

ID	Mitigation/Control	Tranche	Tranche ID
SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	Service territory-wide	SDG&E-4-C17
SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Maintenance program	Service territory-wide	SDG&E-4-C18
SDG&E-4-C19	Underground Cable Replacement Program – Proactive	Unjacketed feeder cable	SDG&E-4-C19-T1
		Unjacketed branch cable	SDG&E-4-C19-T2
SDG&E-4-C20	Enterprise Asset Management – Substation	Substation	SDG&E-4-C20
SDG&E-4-M1	Overhead Public Safety (OPS) program	Small wire conductors in public proximity and those that cross freeways	SDG&E-4-M1
SDG&E-4-M2	Live Front Equipment Replacement - Proactive	Service territory-wide	SDG&E-4-M2
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components	Streamview Bank 30 Project	SDG&E-4-M3-T1
		Pacific Beach 12 kV Replacement Re-build	SDG&E-4-M3-T2
		Ash 12 kV Capacitor Bank and Circuit Breaker Replacement Project	SDG&E-4-M3-T3
		New Substation	SDG&E-4-M3-T4
SDG&E-4-M4	Substation Breaker Replacements - FLISR	San Ysidro Breaker Replacement	SDG&E-4-M4-T1
		Murray Breaker Replacement	SDG&E-4-M4-T2
SDG&E-4-M5	Enterprise Asset Management – Distribution	Distribution	SDG&E-4-M5

A. Post-Mitigation/Control Analysis Results

1. SDG&E-4-C1 - GO165: Distribution Inspect and Repair program

SDG&E's Distribution Inspect and Repair program is conducted throughout SDG&E's entire service territory, and assets within SDG&E's HFTD and non-HFTD have different risk profiles that warrant separate tranches. However, the activities (and associated costs) included within this EII risk chapter are all performed outside of the HFTD, have the same risk profile, and therefore warrant a single tranche. Mitigation activities performed within SDG&E's HFTD are found in the Wildfire Risk chapter (SDG&E-1).

a. Description of Risk Reduction Benefits

In accordance with CPUC General Order 165, SDG&E performs routine inspections of overhead electric infrastructure to assess the condition of its equipment and to proactively identify potential safety risks and reliability issues associated with poles, crossarms, conductors, connectors, and other equipment. The program reduces SDG&E's safety and reliability risks through proactive replacement of major assets such as poles in order to prevent forced interruptions and the resulting public safety hazards. SDG&E's Distribution Inspect and Repair Program is a reasonable and effective control for electric infrastructure risks because it implements comprehensive, routine inspections of various components of overhead electric infrastructure, supplemented with timely corrective actions to replace assets prone to premature failure. While the full costs of this activity are captured in this RAMP chapter, it is important to note that this activity also serves to reduce the Customer & Public safety and reliability risk (Chapter SDG&E-5).

SDG&E performs the above-described activities in accordance with CPUC General Order 165. Therefore, this is a mandated program and SDG&E has not performed an RSE analysis because it is not feasible for SDG&E to stop performing this activity and/or to calculate the risk reduction benefits received from performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C1 reduces SDG&E's safety and reliability risks through proactive replacement of major assets such as poles in order to prevent forced interruptions and the resulting public safety hazards. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and Appendix A such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing with lack of or delayed company insight (DT.5). Addressing such Drivers/Triggers by implementing comprehensive, routine inspections of various components of overhead electric infrastructure, supplemented with timely corrective actions to replace assets prone to premature failure decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

2. SDG&E-4-C2: 4 kV Modernization and System Hardening Program – Distribution

This program targets specific types of assets (4 kV wire) which all have a similar risk profile. Further, this program includes activities for assets targeted outside of the HFTD. Therefore, a single tranche is appropriate for this activity.

a. Description of Risk Reduction Benefits

The removal and reduction of the 4kV system in SDG&E's electric distribution system will reduce the probability of these assets failing, therefore reducing the safety and reliability risks. The hardening of the overhead system associated with this program also provides an increase in public and employee safety. In addition, the removal of the aging and obsolete substations will increase employee safety as the workforce of electricians who are familiar with and knowledgeable about the operation of these assets are decreasing.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C2 reduces SDG&E's safety and reliability risks through proactive removal and reduction of the 4kV system in SDG&E's electric distribution system. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and Appendix A such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing with lack or delayed company insight (DT.5). Addressing such Drivers/Triggers by removal and reduction of the 4kV system decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 16 miles of small wire out of 1461 and 6 miles of large wire. The scope includes incidental underground cable segment replacements.
Effectiveness	Per internal SME assessment, replacing these wires could reduce safety, reliability, and financial risk by up to 95%.
Risk Reduction	**Safety**: Approximately 85% of EII safety risk is associated with overhead wires and small wires, representing 75% of the wires down risk, based on assessment of company data and SME estimates. Using these assumptions, this mitigation could reduce EII safety risk by up to 0.7%.

	Reliability: This mitigation addresses approximately 75% of the wires down reliability risk, based on assessment of company data and SME estimates. Incidental underground cable replacements increase the reliability benefit by 2%. This mitigation could reduce EII financial risk by up to up to 0.9%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages, this mitigation could reduce EII financial risk by up to 0.9%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1198.97**	
	CoRE	2.65	**3.09**	3.83
	Risk Score	3176.54	**3709.42**	4597.55
	RSE	4.11	**12.56**	26.65

3. SDG&E-4-C3 – Distribution Overhead Switch Replacement Program

For purposes of an RSE analysis, SDG&E has separated this Distribution Switch Replacement Program into three tranches. The tranches break apart the various risk profiles based on asset type and customer impact within the same coastal district as distribution switches have a higher propensity for failure or becoming inoperable along the coast (Contamination District One).[29] Tranche 1 is hook stick switches and solid blades in Contamination District One. Tranche 2 is tie switches (gang or hook stick) in Contamination District One. Tranche 3 are manual switches in Contamination District One with large customer counts that could benefit from SCADA. Based on these different risk profiles, SDG&E has performed a separate RSE analysis on each tranche.

[29] "Contamination District One" is the designated area within two miles of the coastline where equipment and/or assets tend to deteriorate due to increased salt particles in the air.

a. Elements of the Risk Bow Tie Addressed

SDG&E-4-C3 reduces SDG&E's reliability risk by replacing distribution switches that have a higher propensity for failure or becoming inoperable. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing with lack of or delayed company insight (DT.5). Addressing such Drivers/Triggers by replacing distribution switches with a higher propensity for failure decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

4. SDG&E-4-C3-T1 – Hook Stick Switches and Solid Blades in Contamination District One

a. Description of Risk Reduction Benefits

As further evidenced in the table below, replacing hook stick switches and solid blades in Contamination District One reduces SDG&E's reliability risk. These asset types in a high corrosion area are targeted for replacement to avoid failure and the related safety (inoperable switches pose safety risks to field operating personnel due to potential flash hazards) and reliability (prolonged outage) risks. While outside of the scope of the risk definition covered in this RAMP chapter, this program also provides an increase to customer and public safety (SDG&E-5), and employee safety (SDG&E-3).

b. RSE Inputs and Basis

Scope	Replacing 24 hook stick switches and solid blades in coastal Contamination District One of 291 identified.
Effectiveness	Per internal SME assessment, replacing a hook stick switch could reduce reliability and financial risk associated with this asset type by up to 95%. In addition, replacing hook stick switches and solid blades has two times the reliability risk reduction impact versus replacing other switches, as there are two hook sticks per switch location. Additionally, the targeted switches are older and have a correspondingly higher failure rate, estimated at twice the average.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition.

	Reliability: Based on company data assessment, switches represent 0.3% of SAIDI and 1.4% of SAIFI, respectively. Using an average of SAIDI and SAIFI impact, this tranche could reduce EII reliability risk by 0.02%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages this mitigation could reduce EII financial risk by up to 0.02%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.76**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.38	**3719.38**	4619.38
	RSE	16.80	**16.80**	16.80

5. SDG&E-4-C3-T2 – Tie Switches (Gang or Hook Stick) in Contamination District One

a. Description of Risk Reduction Benefits

As further evidenced in the table below, replacing tie switches (gang or hook stick switches) in Contamination District One reduces SDG&E's reliability risk. These asset types in a high corrosion area are targeted for replacement to avoid failure and the related safety (inoperable switches pose safety risks to field operating personnel due to potential flash hazards) and reliability (prolonged outage) risks. The switches are targeted for replacement by age and location (*i.e.*, near the coast) since both are indicated drivers for failure. While outside of the scope of the risk definition covered in this RAMP chapter, this program also provides an increase in public and employee safety.

The associated RSE analysis for this tranche looked at the number of switches older than 15 years (3,844 switches) and identified 291 targeted, at-risk switches, and applied a 3x multiplier since gang switches have three phases, and therefore three times the risk, to develop the following formulas.

b. RSE Inputs and Basis

Scope	Replacing 3 tie switches in Contamination District One of 291 identified.
Effectiveness	Per internal SME assessment, replacing a tie switch could reduce reliability and financial risk associated with this asset type by up to up to 95%. Replacing tie switches has 3 times the reliability risk reduction impact versus replacing other switches, as there are three phases per gang switch. Additionally, the targeted switches are older and have a correspondingly higher failure rate, estimated at twice the average.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition. **Reliability:** Based on company data assessment, switches represent 0.3% of SAIDI and 1.4% of SAIFI, respectively. Using an average of SAIDI and SAIFI impact, this tranche could reduce EII reliability risk by 0.004%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages this mitigation could reduce EII financial risk by up to 0.002%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.96**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.89	**3719.89**	4619.89
	RSE	11.81	**11.81**	11.81

6. SDG&E-4-C3-T3 – Switches in Contamination District One with Large Customer Count that Could Benefit From SCADA

a. Description of Risk Reduction Benefits

As further evidenced in the table below, targeting switch replacements with large customer counts in Contamination District One reduces SDG&E's reliability risk. These asset types in a high corrosion area are targeted for replacement to avoid failure and the related safety (inoperable switches pose safety risks to field operating personnel due doe potential flash hazards) and reliability (prolonged outage) risks. While outside of the scope of the risk definition covered in this RAMP chapter, this program also provides an increase in public and employee safety.

The associated RSE analysis for this tranche looked at the number of switches older than 15 years (3,844 switches) and identified 291 targeted, at-risk switches. For this tranche, it is assumed that partial restoration can be achieved faster with SCADA capabilities and that this functionality will be placed in a spot where more than 1.000 customers will benefit.

b. RSE Inputs and Basis

Scope	Replacing 3 SCADA-enabled switches in Contamination District One of 291 identified.
Effectiveness	Per internal SME assessment, replacing a SCADA switch could reduce reliability and financial risk associated with this asset type by up to up to 95%.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition. **Reliability:** Based on company data assessment, switches represent 0.3% of SAIDI and 1.4% of SAIFI, respectively. An average of SAIDI and SAIFI impact is used to estimate a portion of the reliability benefit. An additional portion is estimated with the assumptions that 45 minutes are saved with 294 customers impacted given automation availability. With these assumptions, this mitigation could reduce EII reliability risk by 0.009%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages this mitigation could reduce EII financial risk by up to 0.001%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigatio	LoRE		**1199.89**	
	CoRE	2.65	**3.10**	3.85

	Risk Score	3179.73	**3719.73**	4619.73
	RSE	20.46	**20.46**	20.46

7. SDG&E-4-C4 - Management of Overhead Distribution Service (Non-CMP)

This program is deployed across SDG&E's entire service territory. However, for purposes of this RAMP filing, SDG&E has included activities for assets targeted within the designated HFTD within the Wildfire Risk chapter (SDG&E-1) and activities for assets targeted outside of the HFTD within this EII Risk chapter. Therefore, a single tranche is appropriate for this activity, since the assets within these two distinct risk profiles have already been segregated.

a. Description of Risk Reduction Benefits

The activities under this mitigation are responsive actions to system damage, deterioration, and unsafe conditions found outside of normal restoration of service or outside the Corrective Maintenance Program inspection cycles. Activities include replacing overloaded underground equipment beyond acceptable limits that could accelerate to failure, correction of voltage issues reported by customers, and repairs not associated with restoration of service. The overall objective is to maintain continuity of safe and reliable service.

This program reduces risk by reinforcing electric overhead distribution system infrastructure to maintain safe and reliable service. SDG&E's electric overhead distribution system can become damaged or deteriorated due to several factors such as age, environmental conditions or contact, resulting in unsafe conditions. This program therefore addresses those conditions (in a reactive manner) to reduce the risk of possible injury or fatality or operational and reliability impacts.

SDG&E has not conducted an RSE analysis on this baseline control. This program represents mandated compliance activity per CPUC General Order 95; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve). Therefore, it is not feasible for SDG&E to stop performing these activities or calculate the associated risk reduction benefits received in lieu of not performing these activities.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C4 reduces SDG&E's safety and reliability risks by reinforcing electric overhead distribution system infrastructure. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing with lack or delayed company insight (DT.5). Addressing such Drivers/Triggers by reinforcing electric overhead distribution system infrastructure decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

8. SDG&E-4-C5 - Restoration of Service

A single tranche is appropriate for this program because SDG&E has an obligation to serve and restore service in a timely and safe manner across its entire service territory. Therefore, restoring electrical service has a single risk profile that does not warrant separate tranches.

a. Description of Risk Reduction Benefits

This program reduces risk by restoring electrical service and reinforcing electric overhead distribution system infrastructure to maintain safe and reliable service. SDG&E's electric overhead distribution system can become damaged or deteriorated due to factors such as environmental conditions or contact, resulting in unsafe conditions. This program therefore addresses those conditions (in a reactive manner) to reduce operational and reliability impacts.

SDG&E, as a public utility, has an obligation to serve as a provider of last resort. This program represents mandated compliance activity per CPUC General Order 95; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve). SDG&E therefore has not performed an RSE analysis because it is not feasible for SDG&E to stop performing this activity or to calculate the risk reduction benefits received from performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C5 reduces SDG&E's reliability risk by restoring electrical service and reinforcing electric distribution system infrastructure. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in

Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing in large volume due to acute climates or environmental conditions (DT.7). Addressing such Drivers/Triggers by restoring electrical service and reinforcing electric distribution system infrastructure decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2) and findings of non-compliance (PC.3).

9. SDG&E-4-C6: Underground Cable Replacement Program - Reactive

A single tranche is appropriate for this program because SDG&E has an obligation to serve and restore service in a timely and safe manner across its entire service territory

a. Description of Risk Reduction Benefits

This program reduces risk by replacing cable following loss of electrical service from outages related to electric distribution primary underground cabling, in order to maintain safe and reliable service. SDG&E's electric underground distribution system can become damaged or deteriorated, resulting in unsafe conditions or forced outages. This program therefore addresses those conditions (in a reactive manner) to reduce the risk of possible operational and reliability impacts.

SDG&E has not performed an RSE analysis on this baseline control. SDG&E has an obligation to serve and this program replaces underground cable necessary to restore service to customers. This program represents mandated compliance activity per CPUC General Order 95; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve). Therefore, it is not feasible for SDG&E to stop performing this activity or to calculate the risk reduction benefits received from performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C6 reduces SDG&E's reliability risks by replacing underground cable necessary to restore service to customers. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment failing in large volume due to acute climates or environmental conditions (DT.7). Addressing such Drivers/Triggers replacing underground cable necessary to restore service to customers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

10. SDG&E-4-C7: Tee Modernization Program

"Tee" connectors used for electric primary distribution underground feeder cabling pose an equivalent reliability risk and pose no risks to wildfire. Therefore, a single tranche is appropriate for this activity since the assets have an equivalent risk profile.

a. Description of Risk Reduction Benefits

As further evidenced in the table below, targeting and replacing 137 at-risk tees, which are prone to failure, would reduce reliability risk. These tee failures, which often occur along feeder cables near the substation, cause forced outages to large customer counts and require extensive reconstruction in order to permanently restore the outage.

To derive the RSE score, SDG&E determined the number of tees in scope. Total tees are the sum of manhole, handhole, and vault tees. The below RSE analysis applies a condition multiplier for an assumed 50-year life, a failure rate that is flat for up to 40 years then exponentially rising by a factor of 14 over the following decade. The below formula also assumes that tees are randomly selected from worst 20% in terms of risk. Failures per year were set to the 5-year average of 75 tee outages.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C7 reduces SDG&E's reliability risk by targeting and replacing at-risk tees. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1) or in-service equipment failing prematurely (DT.3). Addressing such Drivers/Triggers by proactive replacement of at-risk tees decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 137 at-risk tees, out of 33,713 tees in the system total (0.4%).
Effectiveness	Per internal SME assessment, replacing tees could reduce reliability and financial risk associated with this asset type by up to 95%. Each location generally has 3 tees that are replaced, one per phase, thus the impact is tripled per location.

Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition. **Reliability:** Based on company data assessment, tees represent 11% of SAIDI and 13% of SAIFI, respectively. Using an average of SAIDI and SAIFI impact, this mitigation could reduce EII reliability risk by up to 0.1%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages this mitigation could reduce EII financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	**LoRE**		**1198.38**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3175.77	**3715.77**	4615.77
	RSE	16.06	**16.06**	16.06

11. SDG&E-4-C8: Replacement of Live Front Equipment - Reactive

Live front equipment, consisting of transformers and terminator cabinets, have the primary connections exposed with no insulative covering. All live front equipment poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

SDG&E continues its routine removal of "live front" terminators and transformers, as they are not designed in accordance with modern safety protocols. This program replaces these devices with dead front devices, which enable workers to maintain and operate the devices in a safer manner that limits the exposure to energized equipment. These mitigation actions are reasonable and effective because they systematically reduce or eliminate underground electric risks known to be among concerns to electric workers and/or contractors who build and maintain these assets.

Continued use of live front terminators causes risks to workers who maintain and operate the live equipment. To perform switching on live front terminators, additional and more experienced personnel are required. As an alternative to using this equipment, switching plans can consider operating dead front or remote operated equipment to isolate the job and allow for safe operation of the live front equipment. Use of this approach, however, would likely cause unnecessary outage exposure to additional customers. If the limited switching tools are insufficient, workers may be dangerously exposed to live primary voltage, causing serious risks for injury or death. While outside of the scope of the risk definition covered in this RAMP chapter, this program also mitigates SDG&E's Employee Safety risk (Chapter SDG&E-3).

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C8 reduces SDG&E's safety and reliability risks by removal of devices not designed in accordance with modern safety protocols. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 38 live front transformers, out of 2,952 live front transformers in the system total (1.3%).
Effectiveness	Per internal SME assessment, replacing live front transformers could reduce safety, reliability, and financial risk associated with this asset type by up to 100%. As efforts are focused on targeting riskier assets, a factor of 2 times is applied to account for more consequential circumstances.
Risk Reduction	**Safety:** Assuming that most contacts with energized equipment occur on the overhead system (10% underground), and assuming that transformers are a fraction (25%) of the situations where flashover or direct contact can take place on underground devices, company SMEs estimate that this mitigation could reduce EII safety risk by up to 0.06%. **Reliability:** Internal calculations estimated the impact and rate of transformer failure. Based on that analysis, live front transformers represent 0.002% of combined SAIDI and SAIFI contributions. With these assumptions, this mitigation could reduce EII reliability risk by up to 0.004%.

	Financial: Based on the assumption that financial risk is proportional to the number of outages, this mitigation could reduce EII financial risk by up to 0.006%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.96**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.84	**3719.50**	4618.92
	RSE	2.63	**8.44**	18.13

12. SDG&E-4-C9: DOE Switch Replacement - Underground

"Do not operate Energized" switches are determined not safe for operation when energized. Therefore, all identified DOE switches pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Distribution switches have a propensity for failure and/or inoperability during an outage (or may extend the impact of an outage to the next upstream protection device), causing a prolonged forced outage as crews are required to install additional jumpers or other workarounds. Switches that are constantly closed or opened (*e.g.*, tie switches) are at increased risk of being inoperable when needed. The inoperable state of the switch poses safety risks to field operating personnel due to potential flash or overexertion by the employee.

Replacing 90 "do not operate energized" (DOE) distribution switches will reduce switch inoperability and improve electric reliability by approximately 0.1% by reducing customer impact (smaller area of outage impact and higher effectiveness of fault isolation/switching plan). Worker safety is at high risk for arc flash, causing injury or death, if DOE switches are not properly addressed in a timely manner. While outside of the scope of the risk definition covered in this RAMP chapter (and therefore not included as part of the RSE analysis, as further described below), this program also helps to mitigate SDG&E's Employee Safety risk (Chapter SDG&E-3).

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C9 reduces SDG&E's reliability risk by replacement of distribution switches that have a high propensity for failure and/or inoperability during an outage. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences, such as serious injury or fatality (PC.1), or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 90 DOE switches out of 126 DOE switches in the system total (71%).
Effectiveness	Per internal SME assessment, replacing DOE switches could reduce reliability and financial risk associated with this asset type by up to 95%.
Risk Reduction	**Safety:** While this activity helps reduce employee safety, no direct impact on safety was included as part of this RSE assessment, since the identified employee safety risk (as described above) is outside of the scope of the EII risk definition. **Reliability:** Internal SMEs calculated the potential ramifications (on estimated time to restoration and customers impacted) of adjusting service restoration efforts to work around DOE switches. Based on that analysis, DOE switches represent a SAIDI savings of 0.1%. With these assumptions, this mitigation could reduce EII reliability risk by up to 0.1%. **Financial:** No direct impact on financial risk is anticipated from this mitigation.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigatio	LoRE		**1198.67**	
	CoRE	2.65	**3.10**	3.85

	Risk Score	3176.68	**3716.68**	4616.68
	RSE	7.00	**7.00**	7.00

13. SDG&E-4-C10: Vegetation Management (Non-HFTD)

SDG&E's vegetation management program is deployed throughout its entire service territory. For purposes of this RAMP filing, vegetation management activities performed within the HFTD are captured within the Wildfire Risk Chapter (SDG&E-1). The activities and associated costs presented within this EII Risk chapter only include those outside of the HFTD (*i.e.*, non-HFTD, 40%). Therefore, a single tranche for this activity is appropriate.

a. Description of Risk Reduction Benefits

The activities associated with this program include pruning healthy trees growing into overhead power lines and the pruning or removal of dead, dying, diseased, or structurally unsound trees with the potential to fall into overhead lines. These collective activities reduce vegetation contact that could lead to a wire-down incident and/or customer outages.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C10 reduces SDG&E's safety and reliability risks by reducing vegetation contact that could potentially lead to a wire-down incident and/or customer outage. This program reduces SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment failing prematurely (DT.1) and/or in-service equipment failing with lack of or delayed company insight (DT.5). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	About 20% of the vegetation management areas are being targeted, representing 47% of the tree work.
Effectiveness	Based on quality assurance estimates, vegetation management activities are 99% effective in addressing the scope of inspections and remediations. Also, based on historical information, it is assumed that without vegetation management safety and reliability issues associated with vegetation would be 7 times more frequent.
Risk Reduction	**Safety:** This component is associated with wires-down events. It is estimated that 18% of these are related to tree causes. This mitigation is

	estimated to reduce safety risk in the amount of 59% of the baseline amount. **Reliability:** SMEs calculated the potential SAIDI and SAIFI impacts of these improvements. Based on that analysis, this mitigation could reduce EII reliability risk by up to 14% of the baseline amount. **Financial:** The financial impact is assumed to be directly connected to the number of experienced electrical interruptions. Based on this assumption, this mitigation could reduce EII financial impacts by up to 9% of the baseline amount.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1027.85**	
	CoRE	2.63	**2.85**	3.21
	Risk Score	2703.93	**2927.34**	3299.69
	RSE	39.34	**65.50**	109.10

14. SDG&E-4-C11: GO165: Distribution Inspect and Repair Program – Minor Capital Asset Replacement

SDG&E performs inspections and associated repair of minor overhead and underground equipment assets within its entire service territory, as mandated by GO 165. Therefore, a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Inspection and repair of deteriorated or damaged overhead and underground minor assets helps reduce SDG&E's reliability and safety risk. Deteriorated or damaged equipment increases the likelihood of asset failure and the potential for injury or fatality to the public, employees and contractors. Deteriorated or damaged equipment also increases the volume, length, and frequency of forced outages. Since this program is mandated, non-compliance also poses risk of regulatory action, fines, and penalties (PC.4). Therefore, performing this activity reduces the risk of those Potential Consequences.

SDG&E has not conducted an RSE analysis on this baseline control. SDG&E performs this program in compliance with CPUC General Order 165. Therefore, it is not feasible for SDG&E to stop performing these activities or to calculate the risk reduction benefits received for performing these activities.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C11 reduces SDG&E's safety and reliability risks by inspection and repair of deteriorated or damaged overhead and underground assets. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

15. SDG&E-4-C12: GO165: Distribution Inspect and Repair Program – Underground Structure Repair

SDG&E performs inspections and associated repair of underground structures within its entire service territory, as mandated by GO 165. Therefore, a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Inspection and repair of deteriorated or damaged underground structures, such as manholes and handholes, helps reduce SDG&E's reliability and safety risk. Deteriorated or damaged underground structures increases the likelihood of asset failure and the potential for injury or fatality to the public, employees and contractors. Deteriorated or damaged equipment also increase the volume, length and frequency of forced outage. Since this program is mandated, non-compliance also poses risk of regulatory action, fines and penalties. Therefore, performing this activity reduces the risk of those Potential Consequences.

SDG&E has not conducted an RSE analysis on this baseline control. SDG&E performs this program in compliance with CPUC General Order 165. Therefore, it is not feasible for SDG&E to stop performing these activities or to calculate the risk reduction benefits received for performing these activities.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C12 reduces SDG&E's safety and reliability risks by inspecting and repairing deteriorated or damaged underground infrastructure. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

16. SDG&E-4-C13: Management of Underground Distribution Service (Non-CMP)

This program is deployed across SDG&E's entire service territory and SDG&E has an obligation to restore service to all customers. Therefore, a single tranche is appropriate for this risk mitigation activity.

a. Description of Risk Reduction Benefits

The activities under this mitigation are responsive actions to system damages, deterioration and unsafe conditions found outside of normal restoration of service or outside the Corrective Maintenance Program inspection cycles. Activities include replacing overloaded underground equipment beyond acceptable limits that could accelerate to failure, correction of voltage issues reported by customers, and repairs not associated with restoration of service. The overall objective is to maintain continuity of safe and reliable service.

SDG&E has not conducted an RSE analysis on this baseline control. This program is a mandated compliance activity per CPUC General Order 128; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve). Therefore, it is not feasible for SDG&E to stop performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C13 reduces SDG&E's safety and reliability risks by responding to system damages, deterioration and/or unsafe conditions. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

17. SDG&E-4-C14: Field SCADA RTU Replacement

A fleet of obsolete remote terminal units (RTUs) that provide communications to distribution field equipment have poor reliability and lack modern features to support automated switching and/or situational awareness. Replacement will better allow for remote operation of devices that supports reliability and avoids dispatching personnel for manual switching. This program targets like assets (*i.e.*, RTUs) with similar risk profiles. Therefore, a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Distribution switches in the field have outdated RTUs and limited communication capabilities. Some of the current equipment is end of life and/or does not benefit from newer technology features. The replacement of 72 distribution SCADA RTUs in substations is designed to replace old RTUs with updated technology, resulting in better and more reliable communication. Moving from a manual switch to a SCADA system allows SDG&E to know where the outages are and to open and close the switches remotely, thereby reducing the length of outages. Moving to a SCADA system also helps eliminate cyber risk, which could lead to higher risk consequences.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C14 reduces SDG&E's reliability risk by targeting and replacing outdated RTUs. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1) and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 72 distribution SCADA RTUs in substations, out of 172 total potential sites in the system (42%).

Effectiveness	Per internal SME assessment, replacing old RTUs could reduce reliability and financial risk associated with this asset type by up to 95%.
Risk Reduction	**Safety:** No direct impact on safety. **Reliability:** Internal SMEs calculated the time savings per interruption to be approximately 45 minutes with SCADA-enabled RTUs. Based on that analysis, SCADA RTU replacements represent 0.2% in SAIDI savings. Using these estimates, this mitigation could reduce EII reliability risk by up to 0.2%. **Financial:** No direct impact on financial risk is anticipated from this mitigation.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	**LoRE**		**1197.68**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3174.20	**3714.20**	4614.20
	RSE	26.65	**26.65**	26.65

18. SDG&E-4-C15: Distribution Circuit Reliability

Through identified opportunities to improve system reliability or the review of outage events with significant impacts to the system reliability, remediation projects are designed involving the placement of distribution field switches that would mitigate or reduce the severity of a future or potential outage. Due to this comprehensive review, projects are only approved with high reliability benefits with the risk profile being consistent. Therefore, a single tranche is warranted.

a. Description of Risk Reduction Benefits

As further evidenced in the table below, this project helps reduce SDG&E's reliability risk by increasing sectionalizing and communication based on historic outage data, thereby reducing the length and impact of a customer interruption. This project aims to reduce customer impact in the event of an outage and prevent reoccurrence. As described below, SMEs estimate a 45-minute savings per interruption affecting 294 customers, on average.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C15 reduces SDG&E's reliability risk by reducing customer impact in the event of an outage. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1) and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	The number targeted for improvement is 57 units.
Effectiveness	Per internal SME assessment, these improvements are 100% effective in reducing associated reliability risk.
Risk Reduction	**Safety:** No direct impact on safety. **Reliability:** SMEs calculated the potential SAIDI impact of these improvements and estimated a 45-minute savings per interruption affecting 294 customers, on average. This mitigation could therefore reduce EII reliability risk by up to 0.2%. **Financial:** The financial impact is minimal and not quantified.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	**LoRE**		**1198.07**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3175.17	**3715.17**	4615.17
	RSE	40.25	**40.25**	40.25

19. SDG&E-4-C16: Emergency Substation Equipment

This program supports substation asset replacements across SDG&E's entire service territory. A single tranche is appropriate for this risk mitigation activity since the assets are within a distinct risk profile.

a. Description of Risk Reduction Benefits

This control is focused on purchasing additional emergency spare and mobile equipment. In an incident where equipment, such as a transformer, circuit breaker, or switchgear fails, the additional emergency spare and mobile equipment would provide the Company with the ability to restore service more efficiently, enhancing customer reliability. Furthermore, as the lead time for replacement of failed transformed and switchgear has increased, the stocking of spare equipment may decrease the number of lengthy and unexpected outages. The two transformers requested for replenishing are both at a year's lead time. SDG&E has not performed an RSE analysis as the function of the control is to perform a routine operation and restore service from the emergency conditions.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C16 reduces SDG&E's safety and reliability risks by ensuring emergency and spare equipment is available to support restoration efforts. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

20. SDG&E-4-C17: Reactive Substation Reliability and Repair for Distribution Components

This control is required to maintain the safety, reliability and integrity of the distribution substations by replacing obsolete or failed equipment and making necessary small capital additions. This program is required to restore service in case of outages due to the aging equipment and/or unexpected failure of equipment and is utilized when outage(s) occur. Since this is a reactive program designed to aid in service restoration after an outage occurs, a single tranche is appropriate. SDG&E has not performed an RSE analysis on this activity, given that the function of this control is to restore service in the event of an outage.

a. Elements of the Risk Bow Tie Addressed

SDG&E-4-C17 reduces SDG&E's reliability risk by restoring service due to aging equipment or unexpected failure. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

21. SDG&E-4-C18: GO 174: Substation Relay Testing, Inspection and Maintenance Program

This program is performed service territory wide. Since this program inspects equipment service territory wide and repairs and/or replaces the equipment before failure, the inspected equipment therefore has a homogenous risk profile. Therefore, a single tranche is appropriate for this risk mitigation activity.

a. Description of Risk Reduction Benefits

The main goal of the Substation System Inspection and Maintenance Program is to promote reliability and safety for SDG&E personnel and contractors by providing a safe operating and construction environment. This testing, inspection and maintenance program mitigates the risk of equipment failure by identifying equipment deterioration to make the repair/replacement before failures occur. SDG&E's Substation Relay Testing, Inspection and Maintenance Program is mandated by CPUC General Order 174. SDG&E therefore has not performed an RSE analysis, since it is not feasible for SDG&E to stop performing this activity or to calculate the risk reduction benefits in comparison to not performing this activity.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-C18 reduces SDG&E's safety and reliability risks by providing a safe operation and construction environment for SDG&E employees and contractors. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), or in-service equipment failing with lack or delayed company insight (DT.5). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

22. SDG&E-4-C19: Underground Cable Replacement Program – Proactive

SDG&E has separated this program into two tranches for purpose of an RSE analysis – unjacketed feeder (tranche 1) and unjacketed branch (tranche 2). Unjacketed cable has a higher failure rate and therefore poses a greater reliability risk. Therefore, given the two different risk profiles, the RSE analysis for this program has applied two separate tranches, as described below.

a. Elements of the Risk Bow Tie Addressed

SDG&E-4-C19 reduces SDG&E's reliability risk by replacement of underground cable that is identified to have a high propensity for failure. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

23. SDG&E-4-C19-T1 –Unjacketed Cable - Feeder

a. Description of Risk Reduction Benefits

As further evidenced in the table below, this program would reduce reliability risk by targeting replacement of underground unjacketed cable that is identified to have a high probability of failure and proactively replacing the cable before a failure/outage occurs.

b. RSE Inputs and Basis

Scope	Replacing 6.3 miles of underground unjacketed feeder cable out of 201 miles of underground unjacketed feeder cable in the system (3.1%). Of this scope, 2.5 miles are connected to a critical airport improvement project.
Effectiveness	Per internal SME assessment, replacing a segment of underground unjacketed feeder could reduce reliability and financial risk associated with this asset type by up to 95%. Also, replacing unjacketed feeder has 2 times the reliability risk reduction impact versus replacing unjacketed branch cable, based on analysis of

	company failure rates and SAIDI impact per fault on feeder versus branch cable. Finally, the value of reliability for the airport has been estimated as being 8.1 times higher than that of the average customer based on Lawrence/Livermore surveys.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition. **Reliability:** Cables represent 14.8 SAIDI and 0.079 SAIFI, out of the SDG&E system SAIDI and SAIFI of 77.8 and 0.486, respectively, based on assessment of company data. Using an equally weighted average of SAIDI and SAIFI impact, this tranche could reduce EII reliability risk by 0.2%. **Financial:** 16% of EII financial risk is associated with unjacketed cable based on the assumption that financial events are proportional to the number of outages. This tranche could reduce EII financial risk by up to 0.04%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1197.93**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3174.79	**3714.79**	4614.79
	RSE	10.39	**10.39**	10.39

24. SDG&E-4-C19-T2 –Unjacketed Cable - Branch

a. Description of Risk Reduction Benefits

This program would reduce reliability risk by targeting replacement of underground unjacketed cable that is identified to have a high probability of failure and proactively replacing the cable before a failure/outage occurs.

b. RSE Inputs and Basis

Scope	Replacing 127 miles of underground unjacketed branch cable out of 4,281 miles of underground unjacketed feeder cable in the system (3%).
Effectiveness	Per internal SME assessment, replacing a segment of underground unjacketed branch could reduce reliability and financial risk associated with this asset type by up to 95%. Replacing unjacketed feeders has 2 times the risk reduction

	impact versus replacing unjacketed branches, based on analysis of company failure rates and SAIDI impact per fault of feeder versus branches.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition. **Reliability:** Cables represent 14.8 SAIDI and 0.079 SAIFI, out of the SDG&E system SAIDI and SAIFI of 77.8 and 0.486, respectively, based on assessment of company data. Using an equally weighted average of SAIDI and SAIFI impact, this tranche could reduce EII reliability risk by 0.5%. **Financial:** 16% of EII financial risk is associated with unjacketed cable, based on the assumption that financial events are proportional to the number of outages. This tranche could reduce EII financial risk by up to 0.4%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1194.56**	
	CoRE	2.65	**3.10**	3.86
	Risk Score	3165.89	**3705.89**	4605.89
	RSE	25.32	**25.32**	25.32

25. SDG&E-4-C20: Enterprise Asset Management – Substation

SDG&E's Enterprise Asset Management activities for electric substation critical assets are conducted throughout SDG&E's entire service territory. However, for purposes of this RAMP report, SDG&E has included mitigation activities performed within its HFTD in the Wildfire Risk chapter (SDG&E-1). Assets within SDG&E's HFTD and non-HFTD have different risk profiles. However, the activities (and associated costs)[30] included within this EII risk chapter only includes activities performed outside of the HFTD, and therefore warrants a single tranche.

[30] Costs have been allocated based on HFTD and non-HFTD percentages, with 60% of the project costs allocated to the Wildfire Chapter SDG&E-1 and 40% of the costs allocated to this EII Chapter.

a. **Description of Risk Reduction Benefits**

Integrating asset data from various enterprise sources and real-time Condition Based Maintenance monitors will provide SDG&E with consistent data analysis and dynamic analytics to inform asset health indexes for better prioritization of maintenance, repair, and replacement strategies. Optimizing these investment strategies will expand risk reduction efforts by identifying proactive mitigation activities to prevent asset failures that lead to safety and reliability risk events.

SDG&E has not performed an RSE analysis, as this activity is seen to support the larger portfolio of controls and mitigations rather than having a direct safety or reliability impact. Asset management efforts enhance SDG&E's identified controls and mitigations by providing data (such as, which assets have a higher propensity for failure), but it does not provide any direct reduction in risk without the associated activity, such as pole replacement. Without such activity, the selection of assets to maintain or replace (outside compliance requirements) is subject to models that take effort to validate data, which is subject to change due to field conditions and limitations of analytics that cannot see larger data trends.

b. **Elements of the Risk Bow Tie Addressed**

SDG&E-4-C20 reduces SDG&E's safety and reliability risks by providing SDG&E with data and analytics to inform asset health indices, to allow for prioritization of maintenance, repair and replacement and to target the most at-risk assets. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as serious injuries or fatalities (PC.1), or operational and reliability impacts (PC.2).

26. SDG&E-4-M1 – Overhead Public Safety (OPS) program

This project targets assets more prone to failure and also targets assets that are in proximity to the public (*i.e.,* freeway crossings, schools and public areas). Therefore, this program is assessed in a single tranche.

a. Description of Risk Reduction Benefits

This program will proactively replace high risk overhead conductors prone to wire down events, as measured by failure rates and historic data. SDG&E's OPS program also targets assets in proximity to the public and that could put a greater number of people at risk of contact with energized wire. One of SDG&E's primary concerns with respect to its overhead electric distribution system is an energized wire down. Accordingly, SDG&E continues to take proactive measures to determine the cause of such events and puts forth this OPS program to further target and reduce the risk of serious injury or fatality, as well as operational and reliability impacts.

For purposes of RSE analysis, spans with higher population density landmarks are assumed to have up to ten times the human exposure of a typical residential or commercial area – an elementary school or shopping center, for example. Therefore, SDG&E's RSE analysis assumes that that freeways and public proximity areas have a ten times greater risk of other small wire areas.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-M1 reduces SDG&E's safety and reliability risks by proactive replacement of high-risk overhead conductors prone to wire-down events. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences, such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 24 miles of small wire over freeways and public proximity areas out of 150 miles (16%). At the time of this assessment, SDG&E's electric distribution system has 1,461 miles of overhead small wire.
Effectiveness	Per internal SME assessment, replacing these overhead small wires could reduce safety, reliability, and financial risk associated with this asset type by up to 95%. Replacing small wires over freeways and/ or near public proximity areas have a safety risk reduction impact of 10 times versus replacing other segments, as

	those areas could have up to 10 times the human exposure during busy times of the day (based on internal estimates).
Risk Reduction	**Safety**: Based on assessment of company data and SME estimates, approximately 85% of EII safety risk is associated with overhead wires, and small wires represent 75% of the wires down risk. Using these assumptions, this mitigation could reduce EII safety risk by up to 5.2%. **Reliability:** Based on assessment of company data and SME estimates, small wires represent approximately 75% of the wires down reliability risk. This mitigation could reduce EII financial risk by up to up to 1.2%. **Financial:** Based on the assumption that financial events are proportional to the number of outages, this mitigation could reduce EII financial risk by up to 1.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1198.65**	
	CoRE	2.65	**3.07**	3.79
	Risk Score	3173.40	**3685.51**	4539.02
	RSE	9.09	**47.54**	111.63

27. SDG&E-4-M2: Replacement of Live Front Terminator Equipment - Proactive

Live front terminators are a specific subset of live front equipment that have the primary connections exposed with no insulative covering. These terminators have a readily available dead front replacement option that mitigates the risk and helps plan proactive replacement. All live front terminators pose the same safety risk, and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

As further evidenced in the table below, this mitigation would reduce SDG&E's safety and reliability risk. Proactive removal and replacement of live front equipment would reduce the potential for injury and or outage. As stated above, SDG&E continues to implement the routine removal of live front terminators and transformers, which are devices not designed in accordance with modern safety protocols. These devices are generally replaced with dead front devices, which enable workers to operate the devices in a safer manner that limits the exposure to energized equipment. These mitigation actions are reasonable and effective because they systematically reduce or eliminate underground electric risks known to be among the greatest historical concerns to electric workers and/or contractors who build and maintain these assets.

Crews need to take special precautions to work safely when encountering live front equipment. This equipment is inherently unsafe and poses risk to employees. Even when following proper procedures and precautions, this equipment still poses a risk to employee safety. Although the primary driver is employee safety, this mitigation is not included in the Employee Safety RAMP Chapter (SDG&E-3), because the activity to mitigate risk is infrastructure replacement (whereas mitigation of employee safety risk focuses on policies, procedures and training of employees).

b. Elements of the Bow Tie Addressed

SDG&E-4-M2 reduces SDG&E's safety and reliability risks by proactive removal and replacement of live front equipment. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences, such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

c. RSE Inputs and Basis

Scope	Replacing 29 live front terminators, out of 2,024 (1.4%). The scope includes incidental underground cable segment replacements.
Effectiveness	Per internal SME assessment, replacing live front terminators could reduce safety, reliability, and financial risk associated with this asset type by up to 100%. As efforts are focused on targeting riskier assets, a multiplier of 2 is applied to the effectiveness.
Risk Reduction	**Safety:** Assuming that most contacts with energized equipment occur on the overhead system (10% underground), and assuming that terminators are a fraction (25%) of the situations where flashover or direct contact can take place on underground devices, company SMEs estimate that this mitigation could reduce EII safety risk by up to 0.07%. **Reliability:** Internal calculations estimated the impact and rate of terminator failure. Based on that analysis, live front terminators represent 0.003% and 0.002% of system SAIDI and SAIFI, respectively. In addition, incidental

	underground cable replacements increase the reliability benefit by 2%. Using a SAIDI and SAIFI impact average, this mitigation could reduce EII reliability risk by up to 0.005%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this mitigation could reduce EII financial risk by up to 0.004%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.94**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.80	**3719.42**	4618.77
	RSE	4.15	**12.29**	25.85

28. SDG&E-4-M3: Proactive Substation Reliability for Distribution Components

Substations are essential to the operation of the electric system and must be kept in reliable condition, because the consequences of a failure can potentially lead to cascading outages in our system. Taking initiatives to prevent outages and minimize impact in case of an outage is fundamental to our efforts, and this mitigation allows SDG&E to take initiatives on maintaining reliability to our substations. For Substation Projects, condition assessment process and evaluation criteria are created using probability, risk analysis, financial impacts, and present value analysis to justify projects. Several variables that are weighed into the analysis is the age of equipment, safety risk with replacement of the equipment, and impact posed to the system due to the failure of equipment in a substation. The ranking of substation equipment is an ongoing process and involves identifying equipment. The following three projects, Streamview Bank 30 Replacement, Pacific Beach 12kV Breaker Replacement, and Ash 12kV Capacitor Bank Replacement, were the three substations that pose the highest risk based on the result of the condition assessment. These three projects are included as separate tranches below.

a. Elements of the Bow Tie Addressed

SDG&E-4-M3 reduces SDG&E's reliability risk by replacing substation equipment that pose the highest risk based on the result of SDG&E's condition assessment. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (CT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

29. SDG&E-4-M3-T1 – Streamview Bank 30 Re-build

a. Description of Risk Reduction Benefits

Currently, there are two transformers in the Streamview Substation, Bank 30 and 31. The current Streamview Bank 30 is roughly 55 years old and statistical data suggests that Bank 30 should be replaced within 5 years, because a typical transformer has a 60-year lifespan. If Bank 30 were to fail, all loads shared between the two Banks would be transferred to one, causing an overload. The potential customers affected by an outage would be high compared to other locations. As a result, there would be significant reliability consequences and potential for the entire substation to be out of service.

b. RSE Inputs and Basis

Scope	Replacing one transformer that is at end-of-life.
Effectiveness	Based on analysis of company historical work orders, the financial risk impact of a transformer is 105 times greater than the estimated outage cost contained in MAVF assumptions. Therefore, a multiplier of 105 is applied to financial risks. The direct effectiveness of the mitigation is assumed to be 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** Based on company data and study, SDG&E estimates this project provides 0.16 SAIDI and 0.015 SAIFI savings. With these assumptions, this project improves EII reliability risk by up to 0.1%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project improves EII financial risk by up to 7.3%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.31**	
	CoRE	2.64	**3.09**	3.84
	Risk Score	3169.56	**3709.56**	4609.56
	RSE	225.33	**225.33**	225.33

30. SDG&E-4-M3-T2 –Pacific Beach 12 kV Replacement Re-build

a. Description of Risk Reduction Benefits

There are nine 12kV Circuit Breakers in Pacific Beach Substation. The average age of the circuit breakers is roughly 45 years old. Failure on any of these circuit breakers may remove service from the respective circuit, causing outages downstream and affecting a significant number of customers. The main function of the circuit breaker is to protect any electrical circuit from damaging other assets (*e.g.*, transformers) during an unexpected overload or a short circuit within the substation. This mitigation sees that obsolete circuit breakers are replaced with new circuit breakers that are compatible with the latest technology. This will in effect, enhance the protection of other assets in the substation and minimize the impact from any electrical fault.

b. RSE Inputs and Basis

Scope	Replacing nine 12kV Circuit Breakers.
Effectiveness	Based on analysis of company historical work orders, the financial risk impact of a circuit breaker is 8 times greater than the estimated outage cost contained in MAVF assumptions. Therefore, a multiplier of 8 is applied to financial risks. The direct effectiveness of the mitigation is assumed to be 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** Based on company data and study, SDG&E estimates this provides 0.03 SAIDI and 0.0003 SAIFI savings. With these assumptions, this project improves EII reliability risk by up to 0.01%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project improves EII financial risk by up to 0.1%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.91**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.70	**3719.70**	4619.70
	RSE	82.20	**82.20**	82.20

31. SDG&E-4-M3-T3 – Ash 12 kV Cap Replacement Re-build

a. Description of Risk Reduction Benefits

The Ash 12kV project involves replacing two existing circuit breakers and two capacitor banks and replacing the two oil cap fuse switches with a new circuit breaker. Replacement of the capacitor banks allows maintaining power quality across the various circuits. In addition, the replaced circuit breakers will provide protection from fault current to minimize outage time in the case of a fault current traveling through the substation.

b. RSE Inputs and Basis

Scope	Replacing 2 capacitor banks, oil switches with breaker, and 2-12kV Breakers.
Effectiveness	Based on analysis of company historical work orders, the financial risk impact of a circuit breaker is 8 times greater than the estimated outage cost contained in MAVF assumptions. Therefore, a multiplier of 8 is applied to financial risks. The direct effectiveness of the mitigation is assumed to be 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** Based on company data and study, SDG&E estimates this project provides 0.006 SAIDI and 0.00006 SAIFI savings. With these assumptions, this project improves EII reliability risk by up to 0.002%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project improves EII financial risk by up to 0.02%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.97**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.90	**3719.90**	4619.90
	RSE	12.20	**12.20**	12.20

32. SDG&E-4-M3-T4 – New Substation

a. Description of Risk Reduction Benefits

SDG&E's existing Station B Substation and Urban Substation will approach or exceed their normal operating life in several years, and SDG&E has determined that rebuilds will be needed to address reliability concerns and to serve the electric distribution load. Building the New Substation will remove the limitations and operational constraints on neighboring substations by adding ties to allow for substation rebuilds and to maintain the level of reliability in the downtown area. The need to obtain optimum operating conditions that maintain substation reliability and reduce outage times is a key driver for this project. Without having the capability to transfer loads between these substations, reliability is at risk in the advent of a transformer, bus, (or substation) outage (either planned or unplanned).

b. RSE Inputs and Basis

Scope	This is a new substation that greatly impacts the configuration of the electrical network by increasing reliability to a location with aging infrastructure. It also allows for reconstruction and improvements on these impacted assets.
Effectiveness	Per internal SME assessment, the addition of these assets could reduce associated reliability risk by up to 100%.
Risk Reduction	**Safety:** No direct impact on safety. **Reliability:** The reliability impact on the electrical network is complex as multiple substations benefit from the construction of this asset. SDG&E estimates the long-term reliability impact to be 1.3% of

	the baseline amount considering the future in-service date of the substation. **Financial:** The financial impact on the electrical network is minimal.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1184.00**	
	CoRE	2.65	**3.11**	3.87
	Risk Score	3140.00	**3680.00**	4580.00
	RSE	21.36	**21.36**	21.36

33. SDG&E-4-M4: Substation Breaker Replacements

a. Description of Risk Reduction Benefits

By modernizing substation equipment, SDG&E's substation system will help provide safe, reliable, and quality customer service by enabling the deployment of Fault Locations, Isolation, and Restoration (FLISR) technology. The FLISR technology allows for automation without the intervention of a distribution system operator. This results in safely improving the distribution system reliability in substations through faster faulted circuit identification, faster isolation of faulted electric distribution circuits, faster load restoration when system disturbances occur, and better system performance by mitigating electric system deficiencies. As a result, this will directly improve SDG&E's system reliability, as FLISR will reduce the number of customers affected by an outage and reduce the outage duration for those affected. SDG&E's two projects are included as separate tranches below.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-M4 reduces SDG&E's reliability risk by modernizing substation equipment through deployment of FLISR technology. This program reduces SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and Appendix A, such as in-service equipment past its useful life (DT.1) or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences such as operational and reliability impacts (PC.2).

34. SDG&E-4-M4-T1 – San Ysidro Breaker Replacement

a. Description of Risk Reduction Benefits

The San Ysidro Breaker project replaces seven 12 kV circuit breakers and adds new 12kV switchgear to relocate the circuits for one of the transformers. The average age of these circuit breakers is roughly 40 years old, and their internal relay system is outdated. The new circuit breakers will contain modernized internal relays that are compatible with the FLISR technology. On top of FLISR, the addition of the switchgear will provide flexibility to the system by providing more than one source to feed the various circuits. Thus, the new equipment will provide reliability to the system by minimizing outage time and will maintain service to other circuits when short-circuit and overload fault currents occur on any circuits.

b. RSE Inputs and Basis

Scope	Remove and replace seven 12kV breakers.
Effectiveness	Based on analysis of company historical work orders, the financial risk impact of a circuit breaker is 8 times greater than the estimated outage cost contained in MAVF assumptions. Therefore, a multiplier of 8 is applied to financial risks. The direct effectiveness of the mitigation is assumed to be 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** Based on company data and study, SDG&E estimates this project provides 0.02 SAIDI and 0.0002 SAIFI savings. With these assumptions, this project improves EII reliability risk by up to 0.01%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project improves EII financial risk by up to 0.04%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigatio	LoRE		**1199.92**	
	CoRE	2.65	**3.10**	3.85

	Risk Score	3179.75	**3719.75**	4619.75
	RSE	3.55	**3.55**	3.55

35. SDG&E-4-M4-T2 – Murray Breaker Replacement

a. Description of Risk Reduction Benefits

The Murray Breaker project involves replacement of sixteen 12kV circuit breakers. Much like the replacement project in San Ysidro, this project also replaces aged, outdated breakers with new, modernized breakers with FLISR compatibility. Since each breaker is associated with a circuit, the failure of a breaker potentially would impact the entire circuit unless field ties are available for offloading.

b. RSE Inputs and Basis

Scope	Replace 16 - 12kV Circuit Breakers.
Effectiveness	Based on analysis of company historical work orders, the financial risk impact of a circuit breaker is 8 times greater than the estimated outage cost contained in MAVF assumptions. Therefore, a multiplier of 8 is applied to financial risks. The direct effectiveness of the mitigation is assumed to be 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** Based on company data and study, SDG&E estimates this project provides 0.04 SAIDI and 0.0003 SAIFI savings. With these assumptions, this project improves EII reliability risk by up to 0.01%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project improves EII financial risk by up to 0.1%.

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	**LoRE**		**1199.84**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.48	**3719.48**	4619.48
	RSE	16.53	**16.53**	16.53

36. SDG&E-4-M5: Enterprise Asset Management – Distribution

SDG&E's Enterprise Asset Management activities for electric distribution are conducted throughout SDG&E's entire service territory. However, for purposes of this RAMP report, SDG&E has included mitigation activities performed within its HFTD in the Wildfire Risk chapter (SDG&E-1). Assets within SDG&E's HFTD and non-HFTD have different risk profiles. However, this EII risk chapter only includes activities (and associated costs) performed outside of the HFTD; therefore, these program activities warrant a single tranche.

a. Description of Risk Reduction Benefits

Asset management is a critical element of SDG&E's focus on creating sustainable and high-quality asset safety for electric operations, and optimizing asset utilization, while mitigating asset-related risks. This is also one element of SDG&E's vision for an electric safety management system. A comprehensive asset management system, which includes process improvements, data analytics and system solutions, will provide the access to and integration of data throughout the asset life cycle to develop analysis and a health index for critical assets.

Benefits of such a system may include enhanced asset safety, improved performance, managed risk, demonstrated compliance, and improved efficiencies and effectiveness of asset utilization and operations. Integrating asset data from various enterprise sources will provide consistent data analysis and dynamic analytics to be informed on asset health indexes for better prioritization of maintenance, repair and replacement strategies. Optimizing these investment strategies will expand risk reduction efforts by identifying proactive mitigation activities to prevent asset failures that lead to safety and reliability risk events.

A separate RSE calculation was not performed on this mitigation as a stand-alone risk mitigation activity. Instead, SDG&E views this project as increasing the effectiveness of other mitigations and controls directly related asset replacement or maintenance. In the RSE analysis, a mitigation effectiveness percentage is a variable in the larger measure of risk reduction. Therefore, an activity that only mitigates 50% of the risk doesn't see the full risk reduction figure. This proposal would provide SDG&E with better data and asset health information, allowing SDG&E to target which assets to replace, therefore increasing the mitigation effectiveness of other projects presented herein. For example, without this mitigation, one might see a reduction in mitigation effectiveness for other projects in the absence of data to target "at risk" assets. Therefore, this risk mitigation activity is seen to support SDG&E's larger portfolio of controls and mitigations rather than having a direct safety or reliability impact. Without this mitigation, the selection of assets to maintain or replace outside compliance requirements, is subject to models that take effort to validate data that is subject to change due to field conditions and limitations of analytics that cannot see larger data trends.

b. Elements of the Risk Bow Tie Addressed

SDG&E-4-M5 reduces SDG&E's safety and reliability risks by providing SDG&E with data and analytics to inform asset health indices to allow for prioritization of maintenance, repair and replacement and to target the most at-risk assets. This program addresses SDG&E's risk of an electric asset failure by targeting the Drivers/Triggers noted above in Figure 1 and in Appendix A, such as in-service equipment past its useful life (DT.1), in-service equipment failing prematurely (DT.3), and/or in-service equipment and associated components failing to operate as designed (DT.4). Addressing such Drivers/Triggers decreases the likelihood of Potential Consequences, such as serious injuries or fatalities (PC.1) or operational and reliability impacts (PC.2).

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E's Risk Mitigation Plan takes into account recent data and trends related to electric infrastructure, technology, affordability impacts, possible labor constraints and the feasibility of mitigations. SDG&E has performed RSEs, in compliance with the SA Decision, but ultimate mitigation selection can be influenced by other factors including funding, labor resources, technology, planning, compliance requirements, permitting, and operational and execution considerations.

While SDG&E plans to present the risk mitigation activities presented herein in its TY 2022 GRC Application, SDG&E's Risk Mitigation Plan may be subject to constraints. For instance, activities in this Risk Mitigation Plan can have significant lead times (more than a year) to get materials or approval prior to work commencing. SDG&E's ability to timely implement its Risk Mitigation Plan may be dependent on factors such as permitting, landowner agreements, and weather. In addition, SDG&E is experiencing a shortage of available, qualified contractors to perform work. For example, there is already significant competition in the State to obtain qualified design, engineering, and construction resources. SDG&E expects this trend to continue in future years. This is also true in Vegetation Management. Further, SDG&E strives to balance implementing EII risk mitigation measures with the associated costs of such measures. To that end, SDG&E is strategic about its mitigation programs and takes affordability into consideration.

Table 8 below provides a summary of the Risk Mitigation Plan, including Controls and Mitigation activities, associated costs, and RSEs by tranche.

SDG&E does not account for and track costs by activity; rather, SDG&E tracks costs by cost center and capital budget code. Thus, the costs shown in Table 8 were estimated using assumptions provided by SMEs and available accounting data.

Table 8: Risk Mitigation Plan Summary[31]
(Direct 2018 $000)[32]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[33]	2018 Baseline O&M[34]	2020-2022 Capital[35]	2022 O&M[36]	Total[37]	RSE[38]
SDG&E-4-C1	GO165: Distribution Inspect and Repair program	T1	10,000	0	18,000-21,000	0	18,000-21,000	-
SDG&E-4-C2	4kV Modernization and System Hardening Program - Distribution	T1	0[39]	0	20,000-24,000	0	20,000-24,000	4.11 – 26.65

31 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

32 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

33 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

34 SDG&E does not currently track all O&M costs at the RAMP activity level and was unable to impute O&M historical costs for all activities.

36 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

36 SDG&E is not currently proposing associated O&M cost forecasts for activities where costs are not currently tracked at the level of detail presented in this 2019 RAMP Report. SDG&E will address this issue in its TY 2022 GRC Application.

37 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

38 RSE ranges are further discussed in Chapter RAMP-C and in Section VI above. Risk mitigation activities that do not have a direct safety impact included as part of the RSE assessment do not have a range.

39 Historical capital spend exists for years 2015, 2016 and 2017, as evidenced in the cost workpapers.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[33]	2018 Baseline O&M[34]	2020-2022 Capital[35]	2022 O&M[36]	Total[37]	RSE[38]
SDG&E-4-C3	Distribution Overhead Switch Replacement Program – Hook Stick Switches	T1	60[40]	0	320-390	0	320-390	16.80
SDG&E-4-C3	Distribution Switch Replacement Program – Tie Switches	T2	0	0	230-280	0	230-280	11.81
SDG&E-4-C3	Distribution Switch Replacement Program – Large Customer Count	T3	0	0	880-1100	0	880-1100	20.46
SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	T1	7,000	0	17,000-20,000	0	17,000-20,000	-
SDG&E-4-C5	Restoration of Service	T1	9,200	0	25,000-30,000	0	25,000-30,000	-
SDG&E-4-C6	Underground Cable Replacement Program - Reactive	T1	10,000	0	21,000-25,000	0	21,000-25,000	-
SDG&E-4-C7	Tee Modernization Program - Underground	T1	2,200	0	5,200-6,300	0	5,200-6,300	16.06
SDG&E-4-C8	Replacement of Live Front Equipment - Reactive	T1	510	0	1,400-1,700	0	1,780-2,200	2.63 – 18.13

[40] SDG&E is currently unable to separate historical costs by tranche. This figure represents the full Distribution Overhead Switch Replacement Program costs.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[33]	2018 Baseline O&M[34]	2020-2022 Capital[35]	2022 O&M[36]	Total[37]	RSE[38]
SDG&E-4-C9	DOE Switch Replacement - Underground	T1	10,000	0	11,000-14,000	0	11,000-14,000	7.00
SDG&E-4-C10	Vegetation Management (Non-HFTD)	T1	0	11,000	0	11,000-13,000	11,000-13,000	39.34 – 109.10
SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	T1	8,700	0	35,000-43,000	0	35,000-43,000	-
SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair	T1	4,800	0	6,900-8,300	0	6,900-8,300	-
SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	T1	3,500	0	9,600-12,000	0	9,600-12,000	-
SDG&E-4-C14	Field SCADA RTU Replacement (Underground)	T1	2,100	0	3,000-3,600	0	3,000-3,600	26.65
SDG&E-4-C15	Distribution Circuit Reliability	T1	2,500	0	8,100 – 9,900	0	8,100 – 9,900	40.25
SDG&E-4-C16	Emergency Substation Equipment	T1	250	0	1,700-2,100	0	1,700-2,100	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[33]	2018 Baseline O&M[34]	2020-2022 Capital[35]	2022 O&M[36]	Total[37]	RSE[38]
SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	T1	1,900	0	4,700-5,700	0	4,700-5,700	-
SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program	T1	0	180	0	160-190	160-190	-
SDG&E-4-C19	Underground Cable Replacement Program – Proactive – Unjacketed Feeder Cable	T1	0	0	11,000 – 13,000	0	11,000 – 13,000	10.39
SDG&E-4-C19	Underground Cable Replacement Program – Proactive – Unjacketed Branch Cable	T2	0	0	12,000 – 15,000	0	12,000 – 15,000	25.32
SDG&E-4-C20	Enterprise Asset Management – Substations	T1	70	0	360-440	830-850	1,190 – 1,290	-
SDG&E-4-M1	Overhead Public Safety (OPS) Program	T1	0	0	17,000-21,000	0	17,000-21,000	9.09 – 111.63
SDG&E-4-M2	Replacement of Live Front Equipment - Proactive	T1	0	0	1,100-1,400	0	1,100-1,400	4.15 – 25.85
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components - Streamview Bank 30 Project	T1	0	0	200-240	0	200-240	225.33

ID	Mitigation/Control	Tranche	2018 Baseline Capital[33]	2018 Baseline O&M[34]	2020-2022 Capital[35]	2022 O&M[36]	Total[37]	RSE[38]
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components - Pacific Beach 12 kV Replacement Re-build	T2	0	0	90-110	0	90-110	82.20
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components - Ash 12 kV Capacitor Bank and Circuit Breaker Replacement Project	T3	0	0	200-240	0	200-240	12.20
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components - New Substation	T4	10	0	34,000-41,000	0	34,000-41,000	21.36
SDG&E-4-M4	Substation Breaker Replacements: San Ysidro Breaker Replacement	T1	0	0	1,300-1,600	0	1,300-1,600	3.55
SDG&E-4-M4	Substation Breaker Replacements: Murray Breaker Replacement	T2	0	0	580-700	0	580-700	16.53
SDG&E-4-M5	Enterprise Asset Management – Distribution	T1	0	0	5,800-7,100	270-320	6,100-7,400	-
TOTAL COST			**73,000**	**11,000**	**273,0000 – 330,000**	**12,000 – 14,000**	**280,000 – 345,000**	

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SDG&E notes that there are non-CPUC jurisdictional mitigation activities performed that further mitigate the EII risk, but the costs associated with these activities are not presented herein, as they will not be carried over to the GRC. Such non-CPUC jurisdictional activities include, but are not limited to:

- Transmission projects
- Transmission substation projects

SDG&E is not calculating RSEs on the following activities:

Table 9: Summary of Activities without RSE Calculations

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-4-C1	GO 165: Distribution Inspect and Repair program – Overhead	Mandated activity per CPUC General Order 165
SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	Mandated activity per CPUC General Order 95; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)
SDG&E-4-C5	Restoration of Service	Mandated activity per Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)
SDG&E-4-C6	Underground Cable Replacement Program - Reactive	Mandated activity per Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)
SDG&E-4-C11	GO 165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	Mandated activity per CPUC General Order 165
SDG&E-4-C12	GO 165: Distribution Inspect and Repair Program – Underground Structure Repair	Mandated activity per CPUC General Order 165
SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	Mandated activity per CPUC General Order 128; Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-4-C16	Emergency Substation Equipment	Mandated activity per Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)
SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	Mandated activity per Cal. Pub. Util. Code §§ 451, 761, 762, 768, and 770 (Obligation to Serve)
SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program	Mandated activity per CPUC General Order 174; NERC Reliability Standards
SDG&E-4-C20	Enterprise Asset Management – Substations	No direct safety or reliability impact; mitigation effectiveness incorporated into activities that directly impact safety or reliability
SDG&E-4-M5	Enterprise Asset Management – Distribution	No direct safety or reliability impact; mitigation effectiveness incorporated into activities that directly impact safety or reliability

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the Risk Mitigation Plan for the Electric Infrastructure Integrity risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this risk plan also considered modifications to the presented plan and constraints such as budget and resources.

A. Alternative Mitigation Plan 1 – Customer Owned E-Structure Reconfigure

1. Description of Risk Reduction Benefits

"Enclosed" structures are electric facilities that contain a non-pad mount transformer located at ground level on customer property enclosed by a customer fence. They vary in state of repair but generally have exposed or aged components. Moving these transformers to pad mount or overhead facilities will mitigate the risk of exposed components. This project is not currently included in SDG&E's Risk Mitigation Plan given the minimal history of issues, challenges with requiring modifications by customers, obtaining property easements, and minimal reliability benefit.

This project focuses on replacement of 14 structures out of the identified 42 in the system. Risk of E-structures involve contact with energized equipment. Approximately 85% of the EII safety risk is associated with overhead wires and small wires, representing 75% of the wires down risk, based on assessment of company data and SME estimates. Therefore, the RSE analysis for this alternative mitigation assumed that the risk presented here is part of the 15% EII safety risk associated with non-wire down events. Given the configuration of e-structures, described above in Section V, e-structures are considered to be 20% riskier than other structures for purposes of the RSE analysis.

a. RSE Inputs and Basis

Scope	Mitigating 14 energized structures on customer-owned property out of 42 identified in the system.
Effectiveness	Per internal SME assessment, mitigating these structures could reduce safety, reliability, and financial risk associated with this asset type by up to 100%. Replacing energized structures on customer-owned property has an estimated 20% more risk reduction impact versus replacing other overhead structures, as there is an increased likelihood of contact due to asset placement.
Risk Reduction	**Safety:** Based on company data assessment and SME estimates, approximately 85% of EII safety risk is associated with overhead wires; therefore, an estimated 15% of EII safety risk is associated with other assets. Using these assumptions, this mitigation could reduce EII safety risk by up to 0.001%. **Reliability:** Reliability risk is calculated as proportional to safety risk. Using that assumption, this mitigation also has a potential impact of 0.001% on reliability risk. **Financial:** Financial risk is calculated as proportional to safety risk. Using that assumption, this mitigation also has a potential impact of 0.001% on financial risk.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	**LoRE**		**1199.98**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.96	**3719.95**	4619.94
	RSE	1.28	**1.50**	1.86

B. Alternative Mitigation Plan 2 – ABB Distribution Relay Replacement

1. Description of Risk Reduction Benefits

A fleet of 38 distribution relays manufactured by ABB that belong to step down banks and distribution circuit breakers have become end of life by the manufacturer and are no longer supported with firmware or spare parts. This mitigation would plan to replace those relays to mitigate the chance of them failing to operate if an outage event was to occur at the 12kV bus or on the connected distribution circuit. This project is not currently included in SDG&E's Risk Mitigation Plan given it does not impact public safety, the rarity of the occurrence and protection redundancy inside the substation limits the overall reliability impact and the high cost to replace.

a. RSE Inputs and Basis

Scope	Replacing 38 relays at risk of failure out of 2,230 total distribution relays (1.7%).
Effectiveness	Per internal SME assessment, replacing overhead relays could reduce safety, reliability, and financial risk associated with this asset type by up to 100%.
Risk Reduction	**Safety**: No direct impact on safety. **Reliability:** SMEs calculated the potential SAIDI and SAIFI impacts of a relay-related outage. Based on that analysis, relays may contribute 0.06 SAIDI, and 0.006 SAIFI to unreliability. Using an average of the SAIDI and SAIFI impacts, this mitigation could reduce EII reliability risk by up to 0.01%. **Financial:** Based on the assumption that financial impact is proportional to the number of outages, this project could reduce EII financial risk by up to 0.001%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.85**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3179.61	**3719.61**	4619.61
	RSE	3.15	**3.15**	3.15

C. Alternative Mitigation Plan 3 – Modernize Manual Switches

1. Description of Risk Reduction Benefits

To increase reliability on the distribution system and see that every customer has optimal reliability, SDG&E considered a program that would replace every overhead and underground manual distribution switch within its system with a SCADA switch. These enhancements would provide further visibility of the distribution system and improve situational awareness. The program would consist of prioritizing work by starting with circuits that have the highest customer count and replacing every single manual switch to a SCADA switch. This project is not currently included in SDG&E's Risk Mitigation Plan given it does not directly impact public safety, and the associated cost to perform such a replacement on every switch would provide diminishing returns for reliability and in many situations be redundant. Rather than proposing a program to replace all manual distribution switches at this time, SDG&E instead put forth a plan for strategic, prioritization-targeted replacement. SDG&E's Enterprise Asset Management - Distribution program (SDG&E-4-M5), as presented in the Risk Mitigation Plan, will allow SDG&E to identify which assets have a higher likelihood of failure. Based on this information, asset replacement strategies would be evaluated, prioritized and implemented to manage the asset in a manner that aligns with SDG&E's overall risk management strategy, supports risk-informed platform for managing assets, and reinforces safe operations, maintenance and proactive replacement strategies.

D. SDG&E-3-A3-T1 – Overhead Switches

1. RSE Inputs and Basis – Overhead Switches

Scope	Installing 297 switches in various overhead circuit locations.
Effectiveness	Per internal SME assessment, installing these switches could improve reliability in 100% of applicable instances. However, these installations are not expected to be as effective as those that target spots with large customer counts; thus, impact has been reduced to one-third per SME assessment. Additionally, the switch is not expected to see all outages taking place between the substation and the circuit endpoint; thus, outages seen have been reduced by half of the total per SME assessment.
Risk Reduction	**Safety:** While this activity may help reduce safety risk, no direct impact on safety was included as part of this RSE assessment, as it is outside of the scope of the risk definition.

	Reliability: Based on SME assessment, these switches save an average of 45 minutes of outage time per instance. Also, no SAIFI impact is expected from these installations. Based on these assumptions, this tranche could reduce EII reliability risk by 0.1%. **Financial:** the financial risk is assumed proportional to the number of saved outages; thus, no financial impact is expected.

a. Summary of results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1198.32**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3175.80	**3715.80**	4615.80
	RSE	3.14	**3.14**	3.14

E. SDG&E-4-A3-T2 – Underground Switches

1. RSE Inputs and Basis – Underground Switches

Scope	Installing 165 switches in various underground circuit locations.
Effectiveness	Per internal SME assessment, installing these switches could improve reliability in 100% of applicable instances. However, these installations are not expected to be as effective as those that target spots with large customer counts, thus impact has been reduced to one-third per SME assessment. Additionally, the switch is not expected to see all outages taking place between the substation and the circuit endpoint thus outages seen have been reduced to one quarter of the total per SME assessment.
Risk Reduction	**Safety:** No direct impact on safety considered, as it is outside the scope of this risk description. **Reliability:** Based on SME assessment, these switches save an average of 45 minutes of outage time per instance. Also, no SAIFI impact is expected from these installations. Based on these assumptions, this tranche could reduce EII reliability risk by 0.04%. **Financial:** the financial risk is assumed proportional to the number of saved outages; thus, no financial impact is expected.

a. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.53**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3178.83	**3718.83**	4618.83
	RSE	1.75	**1.75**	1.75

F. Alternative Mitigation Plan 4 – Avian Protection Program

1. Description of Risk Reduction Benefits

Bird and other wildlife contact on overhead distribution facilities must closely be managed to protect wildlife from accidental death, prevent electric outages and utility facility damage, and to prevent regulatory impacts (*e.g.*, fines). Expand avian protection equipment installation and related procedures to install mitigations on all overhead equipment. This project is not currently included in SDG&E's Risk Mitigation Plan, given it does not impact public safety, and SDG&E already requires installing covers in specific locations (*e.g.*, the Avian Protection Zone), in compliance with federal and state law.

a. RSE Inputs and Basis

Scope	All overhead poles that do not have existing avian protection.
Effectiveness	Per internal SME assessment, installing protective equipment could reduce associated reliability and financial risk by up to 95%.
Risk Reduction	**Safety:** No direct impact on safety considered, as it is outside the scope of this risk description. **Reliability:** Based on company data assessment, avian events represent 0.8% of SAIDI impacts and 1.3% of SAIFI impacts, respectively. Using an average of SAIDI and SAIFI impacts, this mitigation could reduce EII reliability risk by 0.06%. **Financial:** Based on the assumption that financial risk is proportional to the number of outages, this mitigation could reduce EII financial risk by up to 0.07%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**1200**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3180.00	**3720.00**	4620.00
Post-Mitigation	LoRE		**1199.29**	
	CoRE	2.65	**3.10**	3.85
	Risk Score	3178.15	**3718.15**	4618.15
	RSE	2.53	**2.53**	2.53

Table 10: Alternative Mitigation Summary

(Direct 2018 $000)[41]

ID	Mitigation	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-4-A1	Customer Owned E-Structure Reconfigure	500-600	0	500-600	1.28 – 1.86
SDG&E-4-A2	ABB Distribution Relay Replacement	2,800-3,300	0	2,800-3,300	3.15
SDG&E-4-A3-T1	Modernize manual switches – Overhead	32,000-38,000	0	32,000-38,000	3.14

41 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

42 The capital presented is the sum of the years 2020, 2021, and 2022, for a three-year total.

43 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

44 RSE ranges are further discussed in Chapter RAMP-C and shown in Section VI above. Risk mitigation activities that do not have a direct safety impact for purposes of the RSE analysis, as described in the RSE Inputs and Basis tables above in Section VI, do not show a range.

ID	Mitigation	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-4-A3-T2	Modernize manual switches – Underground	16,000-19,000	0	16,000-19,000	1.75
SDG&E-4-A4	Avian Protection Program	17,000 – 21,000	0	17,000 – 21,000	2.53

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Elements of the Risk Bow Tie Addressed
SDG&E-4-C1	GO165: Distribution Inspect and Repair program – Overhead	DT.1, DT.2, DT., DT.5, DT.6, DT.7 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-4-C2	4 kV Modernization and System Hardening – Distribution	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7 PC.1, PC.2
SDG&E-4-C3	Distribution Overhead Switch Replacement Program	DT.1, DT.2, DT.3, DT.4 PC.1, PC.2
SDG&E-4-C4	Management of Overhead Distribution Service (Non-CMP)	DT1, DT.2, DT.3, DT.6, DT.7 PC.1, PC.2
SDG&E-4-C5	Restoration of Service	DT.1, DT.2, DT.3, DT.5, DT.6, DT.7 PC.2, PC.3, PC.6
SDG&E-4-C6	Underground Cable Replacement Program - Reactive	DT.1, DT.2, DT.3, DT.7 PC.2, PC.6
SDG&E-4-C7	Tee Modernization Program - Underground	DT.1, DT.2, DT.3, DT.5, DT.7 PC.2, PC.6
SDG&E-4-C8	Replacement of Underground Live Front Equipment – Reactive	DT.1, DT.6 PC.1, PC.2
SDG&E-4-C9	DOE Switch Replacement – Underground	DT.1, DT.2, DT.3 PC.1, PC.2
SDG&E-4-C10	Vegetation Management (Non-HFTD)	DT.3, DT.7 PC.2, PC.3, PC.4
SDG&E-4-C11	GO165: Distribution Inspect and Repair Program – Underground Capital Asset Replacement	DT.1, DT.2, DT.3, DT.5, DT.7 PC.1, PC.2
SDG&E-4-C12	GO165: Distribution Inspect and Repair Program – Underground Structure Repair	DT.1, DT.1, DT.3, DT.5, DT.7 PC.1, PC.2, PC.3, PC.4
SDG&E-4-C13	Management of Underground Distribution Service (Non-CMP)	DT.1, DT.2, DT.3, DT.5, DT.7 PC.1, PC.2
SDG&E-4-C14	Field SCADA RTU Replacement	DT.1, DT.2 PC.2
SDG&E-4-C15	Distribution Circuit Reliability	DT.1, DT.2 PC.2
SDG&E-4-C16	Emergency Substation Equipment	DT.1, DT.2, DT.3, DT.4, DT.5 PC.2
SDG&E-4-C17	Reactive Substation Reliability and Repair for Distribution Components	DT.1, DT.2, DT.3, DT.4, DT.5 PC.2
SDG&E-4-C18	GO 174: Substation Relay Testing, Inspection and Repair Program	DT.1, DT.2, DT.3, DT.4, DT.5, PC.1, PC.2
SDG&E-4-C19	Underground Cable Replacement Program – Proactive	DT.1, DT.2, DT.3, DT.5, DT.7 PC.2
SDG&E-4-C20	Enterprise Asset Management – Substation	DT.1, DT.2, DT.3, DT.4, DT.5

		PC.1, PC.2, PC.3, PC.4, PC.5, PC.6
SDG&E-4-M1	Overhead Public Safety (OPS) Program	DT.1, DT.2, DT.3, DT.6 PC.1, PC.2
SDG&E-4-M2	Replacement of Underground Live Front Equipment – Proactive	DT.1, DT.6 PC.1, PC.2
SDG&E-4-M3	Proactive Substation Reliability for Distribution Components	DT.1, DT.2, DT.3, DT.4, DT.5 PC.2
SDG&E-4-M4	Substation Breaker Replacements – FLISR (Fault Locations, Isolation, and Restoration)	DT.1, DT.2, DT.3, DT.4, DT.5 PC.2
SDG&E-4-M5	Enterprise Asset Management – Distribution	DT.1, DT.2, DT.3, DT.4, DT.5 PC.1, PC.2, PC.3, PC.4, PC.5, PC.6

Risk Assessment Mitigation Phase

(Chapter SDG&E-5)

Customer and Public Safety

November 27, 2019

TABLE OF CONTENTS

SDG&E
A Sempra Energy utility®

Risk: Customer and Public Safety

I. INTRODUCTION

The purpose of this chapter is to present the risk mitigation plan of San Diego Gas & Electric Company's (SDG&E or Company) Customer and Public Safety risk. Each chapter in the Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.)16-08-018 and D.18-12-014 (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. SDG&E's Enterprise Risk Management (ERM) organization facilitated the annual Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in this 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, consistent with the

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

definitions adopted in the 2018 S-MAP Revised Lexicon per D.18-12-014. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Customer and Public Safety risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

---

3 *Id.* at 16.

4 *Id.* at 17.

A. Risk Definition

For purposes of this 2019 RAMP report, SDG&E's Customer and Public Safety Risk is defined as "the risk of customer safety incidents, which results in fatality, serious injury and/or facility damage."

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[5] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequences
DT.1	Deviation from Company policy or procedure
DT.2	Inexperience or lack of training
DT.3	Distracted driving
DT.4	Condition of customer premises or equipment
DT.5	Condition of Company facilities
PC.1	Serious injuries and/or fatalities
PC.2	Property Damage
PC.3	Penalties and fines
PC.4	Adverse litigation
PC.5	Erosion of public confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[6] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

---

[5] *Id.* at Attachment A, A-11 ("Bow Tie").

[6] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Table 2: Summary of Controls

ID	Control Name
SDG&E-5-C1	Public Safety Communications
SDG&E-5-C2	Field and Public Safety
SDG&E-5-C3	First Responder Outreach and Training

SDG&E will continue the 2018 controls identified above and puts forth additional projects and/or programs (*i.e.*, mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-5-M1	Expansion of Utility Incident Command
SDG&E-5-M2	Expanded Public Safety Communications

Finally, pursuant to the SA Decision,[7] SDG&E presents considered alternatives to the Risk Mitigation Plan for the Customer and Public Safety risk and summarizes the reasons that the alternatives were not included in the Risk Mitigation Plan in Section VIII.

II. RISK OVERVIEW

Customer and public safety is a core value at SDG&E. SDG&E's safety-first culture focuses on its employees, customers, and the public and is embedded in every aspect of our work. The Customer and Public Safety risk was included as part of the combined Employee, Contractor and Public Safety Risk Chapter in SDG&E's 2016 RAMP filing. SDG&E's 2018 ERR separated these risks for standalone treatment as a "lessons learned" in order to provide for more granular focus of the risks and associated mitigation activities. As discussed in the Employee Safety chapter of this 2019 RAMP Report (SDG&E-3), SDG&E's employee safety programs are founded on proven employee-based programs, safety training, and workforce education. Many, if not all, of these employee safety programs also promote the safety of the public and our customers. While the costs and activities are presented in the operational risk

[7] *Id.* at 33.

chapters and Employee Safety chapter of this 2019 RAMP Report, the benefits received by SDG&E's customers and the public remain present.

The majority of risk mitigation activities presented in the various chapters of this 2019 RAMP Report provide customer and public safety risk reduction benefit. For example, the mitigation activities presented in SDG&E's Electric Infrastructure Integrity (EII) Chapter (SDG&E-4) that focus on reducing wire down risk are designed to protect the public but are more accurately captured in the EII Chapter since the activities focus on infrastructure protection. The same applies for SDG&E's other electric and pipeline infrastructure risk chapters. Therefore, the Customer and Public Safety risk definition is limited in scope.

The scope of the Customer and Public Safety Risk for purposes of this 2019 RAMP Report includes motor vehicle incidents and after-meter incidents, which may result in significant consequences including serious injuries, fatalities, and property damage. While the scope of this risk is limited, SDG&E performs many risk mitigation activities within its baseline controls to protect the safety of its customers and the public. As an example, safety-related customer communications are an integral part of after the meter incident prevention in a customer's home, whether an SDG&E employee visits the premise or not. These communications are a proactive approach to inform our customers and the public how to detect possible safety issues within their homes, how to identify potential hazards, and how to avoid hazards that may result from damage occurring during a risk event. Similarly, SDG&E's Emergency Management organization effectively and efficiently supports the Company's ability to prevent, prepare for, respond to, and recover from incidents regardless of cause, size, or complexity. The overall purpose of emergency preparedness, including planning activities, is to safeguard the public, employees, contractors, stakeholders, reputation, and the continuation of essential business functions.

As stated above, the Customer and Public Safety risk scope includes motor vehicle incidents. To mitigate this risk, SDG&E utilizes the Smith Driving System as part of safe driving training for employees. The Smith System® was founded on the principle that most vehicle crashes are preventable if the correct driving habits are learned, practiced, and applied consistently. The Smith System utilizes a series of interlocking techniques to prevent crashes.

The concepts help drivers see, think, and act their way through various driving environments, challenges and changes that may exist regardless of where a driver travels or the type of vehicles he or she operates. Adhering to Smith Driving principles enables our employees to be better drivers and therefore aims to reduce SDG&E's employee safety risk; thereby also reducing SDG&E's public safety risk (*see* Risk Bow Tie DT.3). While the costs and associated RSE analysis for this risk mitigation activity are represented in the Employee Safety Chapter of this 2019 RAMP Report (SDG&E-3), the public safety risk reduction benefits are still present.

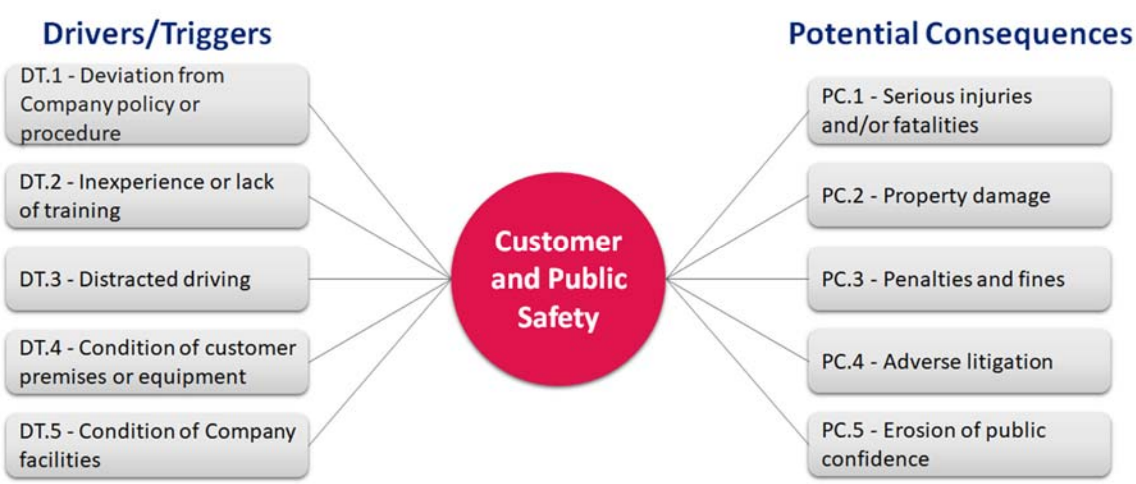
III. RISK ASSESSMENT

In accordance with the SA Decision,[8] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the Customer and Public Safety risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a Customer and Public Safety Risk event and the right side shows the potential consequences of a Customer and Public Safety Risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



8 *Id.* at 33 and Attachment A, A-11 ("Bow Tie").

B. Asset Groups or Systems Subject to the Risk

The SA Decision[9] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. Customer and Public Safety is a "cross-cutting" risk associated with human systems, rather than particular asset groups**.**

C. Risk Event Associated with the Risk

The SA Decision[10] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the Risk Event (*i.e.,* center of the Risk Bow Tie) is a customer and public safety event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this Risk Event are further described in the section below. The Risk Scenario (*i.e.,* a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency), was assessed for SDG&E's 2018 Enterprise Risk Registry. This scenario does not necessarily address all Drivers/Triggers and Potential Consequences, nor does it reflect actual or threatened conditions.

D. Potential Drivers/Triggers[11]

The SA Decision[12] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Customer and Public Safety, SDG&E identified potential leading indicators, referred to as Drivers/Triggers. These include, but are not limited to:

- **DT.1 - Deviation from policy/procedure:** Failure of an employee to adhere to Company safety policies or procedures could result in a safety-related event.
- **DT.2 - Inexperience or lack of training:** Failure to use experienced employees or provide the proper training to perform the necessary work may lead to an increase in the occurrence of safety incidents.

---

9 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

10 *Id.* at Attachment A, A-11 ("Bow Tie").

11 An indication that a risk could occur. It does not reflect actual or threatened conditions.

12 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.3 - Distracted driving:** Use of cellphones or other types of distractions while driving can lead to serious injuries, fatalities and/or property damage.
- **DT.4 - Condition of premises/equipment:** Unsafe customer equipment or premises present situations that can increase the likelihood of a safety event.
- **DT.5 - Condition of company facilities:** Company facilities, if damaged or not properly maintained, could lead to a safety event.

E. Potential Consequences

If one of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[13] and/or fatalities;
- Property damage;
- Penalties and fines;
- Adverse litigation; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of the Customer and Public Safety risk that occurred during the development of SDG&E's 2018 ERR.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[14] including enhancements to the Interim Decision 16-08-018.[15] SDG&E has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework, which underlies this Chapter,

---

13 For purposes of this 2019 RAMP Report, SDG&E defines "serious injury" as an injury that requires an overnight hospital stay.

14 D.18-12-014 at Attachment A.

15 *Id.* at 2-3.

including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[16]

Customer and Public Safety	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	39	**323**	796
LoRE		**0.2**	
CoRE	221	**1835**	4525

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[17] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In Scope for purposes of risk quantification:	The risk of motor vehicle incidents or after-meter incidents, which results in significant consequences including serious injuries, fatalities and/or facility damage.
Out of Scope for purposes of risk quantification:	The risk of incidents that could affect customers and/or the public already captured in other RAMP risks, and other incidents not described as "In Scope."

16 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

17 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

Pursuant to Step 2A of the SA Decision,[18] the utility is instructed to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration data). The SDG&E Customer and Public Safety risk assessment identified two main risks: SDG&E motor vehicle risk, and SDG&E after-meter risk. The motor vehicle risk assessment primarily utilized data from the Department of Transportation (DOT), National Highway Traffic Safety Administration (NHTSA), and Federal Highway Administration (FHA). Internal subject matter expert (SME) input was also provided to assess the SDG&E after-meter risk.

Historical data from the DOT's Fatality Analysis Reporting System (FARS) was used to determine the fatal accident rate per year by vehicle type. Historical data from General Estimates System (GES) of National Automotive Sampling System (NASS) was used to calculate nonfatal incident rates per year by vehicle type. To determine fatal and nonfatal incident rates per year for SDG&E, the national average incident rate per mile, per year was applied to the vehicle miles traveled (VMT) at the company. The safety and financial consequence distributions were generated based on both FARS and GES historical data. A Monte Carlo simulation was used to yield the probabilistic safety and financial consequences for SDG&E motor vehicle risk.

Internal Company subject matter expert (SME) input was provided to estimate the safety and financial consequences of an after-meter safety incident. Based on SME input, reliability is not directly impacted by after-meter safety related incidents.

B. Sources of Input

The SA Decision[19] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Fatality Analysis Reporting System (FARS)
    - Agency: U.S. Department of Transportation

[18] *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

[19] *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- Link: https://www.nhtsa.gov/research-data/fatality-analysis-reporting-system-fars

- General Estimates System (GES) of National Automotive Sampling System (NASS):
  - Agency: U.S. Department of Transportation
  - Link: https://www.nhtsa.gov/research-data/national-automotive-sampling-system-nass
- The Economic and Societal Impact of Motor Vehicle Crashes, May 2015 (Revised)
  - Agency: U.S. Department of Transportation, National Highway Traffic Safety Administration
  - Link: https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/812013
- Shares of Highway Vehicle-Miles Traveled by Vehicle Type, 1970–2015
  - Agency: Oak Ridge National Laboratory
  - Link: https://tedb.ornl.gov/wp-content/uploads/2019/03/Edition36_Full_Doc.pdf

V. RISK MITIGATION PLAN

The SA Decision requires the utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[20] This section describes SDG&E's Risk Mitigation Plan by each selected control and mitigation for this risk, including the rationale supporting each selected control and mitigation.

As stated above, SDG&E's Customer and Public Safety risk is defined as "the risk of customer safety incidents, which results in fatality, serious injury and/or facility damage." SDG&E's Customer and Public Safety Risk Mitigation Plan, discussed below, includes both Controls that are expected to continue and Mitigations for the period of SDG&E's Test Year 2022 GRC cycle. The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time. As mentioned in the Introduction Section, many of the activities

[20] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

presented herein also help mitigate other risk areas, and many of the activities presented in the other Chapters of this 2019 RAMP Report help mitigate SDG&E's Customer and Public Safety risk. *See* Appendix A-3 to Chapter RAMP-A. These risk mitigation overlaps are also identified in the applicable activity descriptions below.

SDG&E's Customer and Public Safety risk baseline Controls that will be discussed in greater detail below include:

- Public Safety Communications
- Field and Public Safety
- First Responder Outreach and Training

SDG&E's Customer and Public Safety risk Mitigations that will be discussed in greater detail below comprise the following:

- Expansion of Utility Incident Command and First Responder Training
- Expanded Public Safety Communications

A. SDG&E-5-C1 – Public Safety Communications

SDG&E conducts public awareness efforts to enhance the safety of its customers and general public. These efforts are designed to engage with the Company's customers and the public to inform them about our shared safety responsibilities. Communication with the public promotes safety through a wide array of topics including, but not limited to, safety around Company facilities, messaging related to the Public Safety Power Shut Off (PSPS) program, and information about gas line locations and downed power lines. Without adequate communication and education programs, the public may not know how to safely dig on their property or how to keep themselves safe around company facilities that may be damaged during an event. Communication with the public also allows customers to be able to detect possible safety issues with their homes. Without adequate communications and education programs, a customer or member of the general public may not know how to identify a hazardous situation or how to prevent one.

Customer outreach, communication, and education are a few of the methods SDG&E uses to mitigate customer and public safety risk. The activities to mitigate this risk include the following:

The Public Safety Power Shut Off (PSPS) program is an element of utility wildfire mitigation plans authorized by the CPUC to address the threat of wildfire and customer/public safety, as discussed in Chapter SDG&E-1.[21] On May 30, 2019, the Commission adopted new interim guidelines for electric investor-owned utilities (IOUs) with respect to the practice of de-energization of power lines for public safety purposes (also known as Public Safety Power Shutoffs) as part of its D.19-05-042 (Guidelines). The Guidelines adopt definitions, an advance notification framework, requirements for outreach and education, and reporting requirements. The PSPS Communication plan consists of a public outreach and education campaign, implemented June through November. The campaign includes:

- Print advertising in seven languages (newspaper and magazine);
- Paid social media;
- Paid search/digital campaign;
- Bill newsletter;
- High Fire Threat District newsletter; and
- 30-minute documentary (television/broadcast).

Communications will also include notifications for Public Safety Power Shutoff events. These communications target customers, first responders, public officials and government, public safety partners, as well as the Access and Functional Needs (AFN) community. Customer notifications are made in the form of email, voice message, and/or text message. Notifications are sent:

- 24-72 hours prior to a Public Safety Power Shutoff event;
- 1-4 hours prior to a Public Safety Power Shutoff event;
- Once power is shut off;
- When patrolling for re-energization begins; and
- Once power is back on.

---

[21] *See,* RAMP Chapter SDG&E-1, Wildfires involving SDG&E Equipment (including Third Party Pole Attachments).

Public Safety campaigns focusing on informing and educating the public from the danger of downed power lines, vehicle contact with poles and the hazards associated with digging near gas lines. The campaign includes videos, TV and radio spots, newspaper ads, billboards and collateral geared toward a variety of scenarios and for use with different audiences.

Safety-related messages delivered through multiple communication channels. Communication channels include bill inserts, print media, radio, web and social media. Messages include, but are not limited to, Carbon Monoxide safety, fumigation and furnace safety.

Pipeline safety campaign, which is mandated by federal pipeline safety regulation 49 CFR, Part 192. SDG&E's campaign includes bill inserts, mailings to residential and business customers, mailings to excavators, businesses, land developers and farmers, and communications to schools and universities, public officials and emergency officials. SDG&E communications and other efforts related to third party dig-ins is further discussed in Chapters SDG&E-7 and SDG&E-8. Pipeline safety efforts provide customers with information about:

- Natural gas pipeline locations;
- What to do if you sense a leak/smell gas; and
- Messaging to direct the public to call 811 (*i.e.,* DigAlert) and other actions to take prior to digging.

B. SDG&E-5-C2 – Field and Public Safety

SDG&E Customer Services' primary goal is providing safe, reliable and efficient gas and electric service to customers, while complying with applicable federal, state, and local regulations. SDG&E has formal procedures, processes and standards it adheres to and makes accessible to field personnel so they can adequately and safely do their jobs. Until SDG&E field employees are fully trained to do their jobs adequately and safely, they cannot perform work orders on their own. SDG&E Customer Service Field representatives have access to the Company's procedures and standards through their mobile data terminal (MDT). These reference materials instruct the employee on how work should be performed, how to perform procedures safely and provide overall direction to employees. Below, are Call Center and Field activities managed by SDG&E related to safety:

Customer Care Center (CCC) Emergency Call Response – SDG&E responds to emergency calls 24 hours per day, 365 days per year from a myriad of residential, commercial, industrial and agriculture customers. Call types relative to public safety include:

- English/Spanish Emergency;
- English/Spanish Outage;
- English/Spanish Business Emergency; and
- Fire and Police Calls.

Customer Service Field (CSF) orders related to public safety include:

- Carbon Monoxide - CSF technicians respond to orders created for a customer experiencing carbon monoxide illness, a customer whose carbon monoxide alarm has sounded, or a "courtesy test" for a customer who is concerned about the possibility of their gas appliance producing carbon monoxide. Upon arrival, if carbon monoxide is detected the CSF technician will evacuate the premises, shut off the gas meter for safety and call for medical attention if necessary. A carbon monoxide investigation on all gas appliances is performed.
- High Gas Consumption Order – Smart meter technology captures daily gas consumption data. Using a newly developed algorithm we can detect a "spike" or unusual gas consumption based on historical or recent gas usage. When this occurs, a High Gas Consumption order is created for a CSF technician to investigate. Findings vary, as a customer that has simply added a new gas appliance, such as a gas pool heater, would cause a spike in gas usage; however, sometimes a gas leak on the customer's houseline or appliance is discovered (*e.g.*, appliance burner left on, fireplace or BBQ gas valve left on, but not in use).
- Fumigation - Prior to the "tenting" of a home or business CSF technicians inspect the gas riser and properly shut off and secure the gas meter to avoid gas accumulating within the tent during fumigation. Upon

completion of fumigation, a CSF technician will return to turn gas service back on and perform appliance checks on gas appliances.

- Hazardous and non-hazardous gas leaks - CSF technicians will respond to all calls of gas leaks or gas odors and perform a gas leak investigation.
- Natural Gas Appliance Testing (NGAT) or Carbon Monoxide Testing – A safety-related program for Energy Savings Assistance (ESA) Program participants. The purpose is to test in-home equipment for carbon monoxide hazards. SDG&E conducts Carbon Monoxide testing on homes weatherized through the ESA Program in accordance with the Statewide Energy Savings Assistance Program Installation Standards and the Statewide Energy Savings Assistance Program Policy and Procedures Manual. CPUC directives order SDG&E to charge the costs for the NGAT program to base rates rather than to the public purpose funds.
- Energy Diversion Investigations – Energy Diversion investigations look for unauthorized attachments (also referred to as a "bypass") that create unsafe conditions for our crews as well as public safety officers and first responders. Unauthorized attachments are not standard and violate electric code and local building ordinances. These connections present the potential for fire, electrical shock and a risk of electrocution to SDG&E service technicians, law enforcement, firefighters, city or county officials, occupants of the residence and/or community. Energy Diversion meter tampering and meter bypass investigation and remediation orders are initiated a few different ways. Reports are run regularly to identify meters that are considered "Off But Registering" (OBR), non-solar customers that are showing reverse flow, and gas meters that are registering when the associated electric meter is not. Additionally, SDG&E field employees may come across unsafe conditions created by meter tampering during the course of their regular work. Other orders are initiated through the CCC via customer notifications.

- CSF Quality Assurance (QA) Program - SDG&E field employees are trained to rectify safety hazards on customer premises. Public safety orders include carbon monoxide, fumigation, and hazardous and non-hazardous gas leaks. The QA Program is designed to verify the field employees are completing field orders according to established policy and procedures and to see that customers are receiving safe and reliable service. The program provides a snapshot of the quality of work being performed by the CSF Employees on customer premises. QA Specialists (Inspectors) take a random sampling of field orders completed by field employees and inspect the work performed on the customer premises. Inspectors record all findings of each individual order onto an inspection form. That information is then utilized to develop refresher training and to provide feedback to the CSF employees.

C. SDG&E-5-C3 – First Responder Outreach and Training

SDG&E's Emergency Management organization provides planning and guidance for responding in anticipation of, response to, or following an incident. Emergency Management effectively and efficiently supports the Company's ability to prevent, prepare for, respond to, and recover from incidents regardless of cause, size, or complexity. The overall purpose of emergency preparedness, including planning, is to safeguard the public, employees, contractors, stakeholders, reputation, and the continuation of essential business functions. Additionally, Emergency Management oversees SDG&E's emergency preparedness and response plans, standards and other compliance requirements and oversight of the testing and updating of its plans. Emergency Management works closely with SDG&E's Meteorology, Fire Coordination and Prevention, as well as operational Departments throughout the Company to see that emergency preparedness and response are safe, efficient and coordinated.

The SDG&E First Responder Outreach Program (Outreach Program) is beginning its 7th year of service to all First Responder agencies in San Diego County. The Outreach Program has expanded significantly since its inception by increasing target audiences, establishing an Operational Field and Emergency Readiness (OFER) program, and strengthening relationships with key stakeholders internally and externally. The OFER program objective is to provide targeted training and contingency planning activities for the local first responder agencies. Strategic partnerships with agency leadership allow for increased communication, awareness of gas and electric safety protocols and collaboration on mutual emergency preparedness to protect employee and public safety. Strategic planning is accomplished with the support and input of SDG&E leadership, the San Diego County Fire Chiefs' Association (SDCFCA) and the County Training Officers Section (T.O.s). The resulting Strategic Plan is continuously reviewed and revised throughout each calendar year. Since the Outreach Program's inception, nine training programs have been developed and completed. Completed training includes: First Responder (three programs), Chief Officer (two programs), Fire and SDG&E Dispatch (one program), and SDG&E Operations (three programs). The SDCFCA, their Training Officers, Dispatch leadership, and local Law Enforcement agencies continue to support the following target audiences for the First Responder Outreach Program:

- Operational First Responders including the ranks of Fire Captain, Fire Engineer, and Firefighter Paramedic;
- Chief Fire Officers including the ranks of Fire Chief, Assistant Chief, Deputy Chief, Division Chief and Battalion Chief;
- Fire and SDG&E Dispatch Personnel;
- SDG&E Natural Gas field personnel and supervisors; and
- Local Law Enforcement leadership, field and dispatch personnel.

Emergency Operations Center (EOC) First Responder Training includes incident response training and exercises. Activities include:

- Developing implementation strategies and curriculum;
- Develop exercise scenarios/materials and facilitate Incident Command exercises; and
- Manage web-based training and certifications.

First responder outreach and training addresses SDG&E's Customer and Public Safety and Wildfire risks. While it is discussed in both RAMP chapters, the costs are fully allocated in the Wildfire chapter.[22]

D. SDG&E-5-M1 – Expansion of Utility Incident Command

SDG&E's Emergency Management Department coordinates safe, effective and risk-based emergency preparedness to safely and efficiently prepare for, respond to, and recover from all threats and hazards. SDG&E responds to gas and electric emergencies as an important part of its normal business practices and has implemented and adapted a Utility Incident Command System (UICS) into those practices based on the National Incident Management System (NIMS). SDG&E utilizes a UICS structure as a framework to manage emergency incidents and events. UICS is the combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure and serves as the mechanism to direct those functions during an emergency response.

SDG&E's expansion of Utility Incident Command is designed to align all operational groups on a flexible, scalable, sustainable, and measurable scene management process that is UICS compatible, which is the standard incident management approach used nationwide by local, regional, state, and federal agencies (mandated through Presidential directive) and the utility industry. The adoption of a utility-compatible incident management approach and response structure benefits SDG&E's customers and the public through enhanced coordination with external agencies (including fire and rescue departments), use of common terminology across responding agencies, better communication, providing a manageable span of control (where no supervisor has more than approximately seven direct reports during an incident), reliance on clearly defined roles and responsibilities, and establishment of a clear chain of command. Each of these elements provides SDG&E with an opportunity to put forth an effective and efficient response – but also requires that the Company engage in significant internal and external training and collaboration.

---

22 *See id.*

The expansion of SDG&E's incident response program and strengthening of overall readiness capabilities for all hazards requires a significant increase in the number of training courses and exercises. In addition to addressing all hazards, SDG&E continues to implement UICS principals. Accordingly, resources will be required for targeted position-specific training at all levels of the organization, larger and more numerous training audiences, and more instructor time. The UICS is built on the concepts of the National Response Framework (NRF) and is compatible with the NIMS. The NRF presents the guiding principles that enable all response partners to prepare for and provide a unified national response to disasters and emergencies. It establishes a comprehensive, national, all-hazards approach to domestic incident response. The NRF defines the principles, roles, and structures that organize how we respond as a nation. In addition, the NRF:

- Describes how communities, tribes, states, the Federal government, the private sector and nongovernmental partners work together to coordinate national response;
- Describes specific authorities and best practices for managing incidents;
- Builds on NIMS, which provides a consistent template for managing incidents.

As described below, there are two parts to the program expansion; 1) SDG&E's Utility Incident Command, and 2) Operational Field and Emergency Readiness.

The Utility Incident Command serves as the primary conduit between SDG&E and the external stakeholders (*i.e.* local, county, state, and federal agencies) for coordination and communication during an emergency. To foster seamless integration with our external stakeholders, and provide mutual assistance, it is imperative that we all use the same system, which includes common terminology and position titles.

As mentioned above, the SDG&E First Responder Outreach Program is beginning its 7th year of service to all First Responder agencies in San Diego County. This Outreach Program has expanded significantly, internally and externally, since its inception, as described above, by increasing target audiences, strengthening relationships with key stakeholders, and establishing an Operational Field and Emergency Readiness (OFER) program. The OFER program objective is to provide targeted training and contingency planning activities for the local first responder agencies, as well as improved scene management and the use of the UICS for SDG&E responders. OFER is designed to be incorporated into the Safety Culture of SDG&E and to be utilized on all worksites, incidents, emergencies, crisis, and disasters where SDG&E personnel, facilities, and infrastructure are impacted. The program includes a strong Quality Assurance/Quality Improvement (QA/QI) component that will confirm the sustainability of effective incident command, control, communications, and scene safety practices.

This mitigation activity provides risk reduction benefits to SDG&E's Customer and Public Safety and Wildfire Risk Chapters. While this program is discussed in both RAMP chapters, the costs are fully allocated in the Wildfire chapter (SDG&E-1).[23]

E. SDG&E-5-M2 – Expanded Public Safety Communications

SDG&E's expanded Public Safety Communications campaigns are intended to be all encompassing of gas and electric safety messaging. Campaign categories include:

<u>Wire Down</u> - A potential Risk Scenario as described in RAMP Chapter SDG&E-4 (Electric Infrastructure Integrity) is an energized wire down event caused by third-party contact, foreign object, or failure of an electric component (*e.g.*, a connector). A wire down event involves the downing of a piece of energized overhead equipment (*e.g.*, wires or conductors). If an employee, contractor or the public comes into contact with an energized wire or in close proximity to the energized wire on the ground, the results can be fatal. The key messages of this campaign will focus on awareness and precautions pertaining to downed power lines. The target audience is our customer base and the general public within our service territory. Planned campaign tactics include:

- English language: (TV, radio, print, outdoor and digital) advertising and paid social media;
- Spanish language: (TV, radio, print and digital) advertising and paid social media; and
- Asian language: Print and digital advertising.

---

23 *See id.*

Expanded 811 Call Before you Dig - In the past, SDG&E has partnered with 811/DigAlert to promote safety messages with contractors, city and municipal workers. However, there hasn't been a strong campaign aimed at customers or the public when it comes to the potential dangers associated with digging. This campaign would target the "weekend gardener" or landscaper who doesn't think that 811 is important to them because they may not be digging that deep. Mass media advertising will help us reach our target audience. Complementary activities include special promotions with home improvement retailers such as Home Depot, Lowes and local nurseries.

Pipeline Safety – SDG&E's annual Pipeline Safety campaign provides safety information to residential and business customers. We also target excavator industry businesses with information about calling 811 before starting any digging projects. Information is provided to schools and public officials about major pipelines near their facilities and include additional safety considerations. Tactics include emails, direct mail brochures, website updates and bill inserts.

Winter Prep Safety Campaign - This annual campaign includes messaging and safety tips related to carbon monoxide safety, holiday lighting considerations, extension cord safety and cautions about overloading circuits. Tactics include mass media (TV, radio, print, outdoor and digital) as well as emails and bill inserts.

Summer Prep Safety Campaign - This annual campaign consists of messaging around power line safety, generator safety and electric safety. Tactics include mass media (TV, radio, print, outdoor and digital) as well as email, and bill inserts.

These campaigns are designed to educate and provide a deeper level of understanding to the public with respect to safe practices around gas and electric infrastructure.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the Settlement Agreement. SDG&E has not calculated a RSE for activities beyond the requirements of the Settlement Agreement but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[24] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of Tranches is presented below.

SDG&E's Customer and Public Safety program consists of communication and outreach programs aimed to reduce risk of injury or fatality to customers or the public. SDG&E grouped like activities with like risk profiles into mitigation programs. Since each of SDG&E's Customer and Public Safety risk mitigation activities has the same goal of reducing the risk of injury or fatality to the Company's customers and the public, all controls and mitigations have the same risk profile and are not further tranched.

B. Post-Mitigation/Control Analysis Results

1. SDG&E-5-C1 – Public Safety Communications

a. Description of Risk Reduction Benefits

Regular customer public safety communications reduce the risk of a Customer and Public Safety incident by raising awareness. SDG&E believes that the potential for an incident may be reduced if customers and the public are aware of how to avoid hazards. The Company provides customers with a variety of communication and educational programs so that customers can detect hazardous situations and learn how to keep themselves safe around company facilities. Communication when programs such as Public Safety Power Shut Off (PSPS) are initiated is key to determining which customers will be affected and how long. Since SDG&E is required to provide advanced notification prior to PSPS events, the Company has instituted a Communication Plan that aims to provide public outreach, educational materials and a media campaign all designed to see that the public is aware of the event.

Public safety campaigns such as the Pipeline Safety campaign provide bill inserts and mailings to customers and also the public that outline gas pipeline locations, gas leak safety and

---

[24] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

a number to call (811 DigAlert) prior to digging on properties. Other public safety campaigns undertaken by SDG&E focus on alerting the public about the danger of downed power lines, safety around company facilities, and carbon monoxide safety. The Company issues these campaigns through newspaper ads, social media, TV, radio and many other communication channels. SDG&E understands that communicating with customers is key to mitigating customer and public safety risk.

SDG&E has not performed a Risk Spend Efficiency Evaluation on SDG&E-5-C1 (Customer Communications) because the activity is not in the scope of the risk identified for Customer and Public Safety.[25] However, SDG&E raises the importance of Customer Communications here because it is important to consider the potential increase in Customer and Public safety risk if the Company stopped performing its customer communication activities to educate the public on potential safety risks.

b. Elements of the Risk Bow Tie Addressed

The Customer Communications control addresses the following elements of the risk Bow Tie: Serious injuries and/or fatalities (PC.1) and Property Damage (PC.2).

2. SDG&E-5-C2 – Field and Public Safety

a. Description of Risk Reduction Benefits

SDG&E Customer Service Field and Call Center employees are trained to perform a variety of customer related tasks utilizing formal procedures, processes and standards to adequately and safely do their jobs. SDG&E can potentially reduce the possibility of or severity of an event by responding to emergency calls 24 hours per day, 365 days per year. In 2018, 168,172 calls were attributable to emergency calls. SDG&E's Customer Service's primary goal is providing safe, reliable and efficient gas and electric service to customers, while complying with applicable federal, state and local regulations. To reduce the risk of a customer or public incident, SDG&E Field employees are trained to rectify safety hazards on customer premises. Some of these orders related to public safety include carbon monoxide, fumigation, hazardous and non-hazardous gas leaks and Natural Gas Appliance Testing (NGAT). In 2018, SDG&E

---

[25] *See* Section IV.A., above, for definition of what is "in scope" for purposes of this risk assessment.

field employees worked 40,820 fumigation orders, 2,410 Carbon Monoxide orders and 34,047 orders related to hazardous and non-hazardous gas leaks. For purposes of the RSE analysis, SDG&E reviewed its Quality Assurance program and considered the average year over year reduction in safety incidents achieved as a result of performing this activity. 1,463 Quality Assurance inspections were completed in 2018. The goal of the program is to inspect 1% of all orders worked.

For purposes of an RSE analysis, Company SMEs looked at existing controls, considered the historical improvement achieved as a result of performing these activities, and used that in considering the potential increase in safety incidents if those activities ceased to be performed. As such, the Company expects to continue to achieve higher levels of accuracy as a result of the Quality Assurance program and therefore expects to receive an additional 12% risk reduction[26] by continuing to perform these activities. Further, without performing these activities, the Company could potentially see a decrease in other programs' effectiveness, such as the ability to deploy focused employee training where needed as a result of findings from the Quality Assurance program.

b. Elements of the Risk Bowtie Addressed

The Field and Public Safety control addresses the following elements of the risk Bow Tie: Deviation from Company policy or procedure (DT.1), Inexperience or lack of training (DT.2), Serious injuries and/or fatalities (PC.1), Property Damage (PC.2) and Erosion of public confidence (PC.5).

c. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.1759**	
	CoRE	221	**1835**	4525
	Risk Score	39	**323**	796

[26] Please refer to the accompanying RSE workpapers for additional detail.

Post-Mitigation	**LoRE**	**0.1782**		
	CoRE	222	**1836**	4527
	Risk Score	40	**327**	807
	RSE	4.83	**28.24**	67.24

3. SDG&E-5-C3 – First Responder Outreach and Training

a. Description of Risk Reduction Benefits

First Responder Outreach and Training is intended to provide planning and guidance to first responders when preparing for, responding to, and following an incident. This initiative is performed through a variety of programs for first responders in their communities. The Operational Field and Emergency Readiness (OFER) program provides targeted training and planning activities for local first responders. This program allows the Company to develop strategic partnerships with local agency leadership that provide increased communication with first responders and awareness of gas and electric safety. In 2018, SDG&E trained approximately 3,600 first responders, with 44 agencies (including 18 cities within San Diego County and Tribal Fire Departments) through this outreach and training program

SDG&E's Emergency Operations Center (EOC) First Responder Training provides first responders with a curriculum of strategies and scenarios that familiarize squads with various ways to manage an incident. The program also provides responders with web-based training and certifications as well. This program has served local communities in San Diego County for seven years and has expanded significantly since inception. Since it began, nine training programs have been developed that target a variety of first responders from officers to dispatch personnel.

Emergency Management works closely with SDG&E's First Responder Programs and other departments throughout the Company to confirm that emergency preparedness and response are safe, efficient and coordinated. Emergency Management oversees the Company's emergency response and preparedness plans, standards and compliance requirements.

First Responder Outreach and Training, while not risk reducing on the front end, is important to potentially lessen the impact of an incident or event. SDG&E has not performed a

Risk Spend Efficiency Evaluation on SDG&E-5-C3 because the activity is not in the scope of this risk.[27] However, it is important to note that without this emergency event coordination and preparation, it is possible more safety incidents will occur during an incident or event.

b. Elements of the Risk Bowtie Addressed

The First Responder Outreach and Training control addresses the following elements of the risk Bow Tie: Serious injuries and/or fatalities (PC.1), Property Damage (PC.2) and Erosion of public confidence (PC.5).

4. SDG&E-5-M1 – Expansion of Utility Incident Command and First Responder Training

a. Description of Risk Reduction Benefits

The expansion of Utility Incident Command focuses on aligning all operational groups on an Incident Command System (ICS) compatible scene management process. ICS is the standard incident management approach used in the utility industry, as well as nationwide by local, regional, state, and federal government agencies. ICS is built on the concepts of the National Response Framework (NRF) and is compatible with the National Incident Management System (NIMS). NIMS provides a consistent template for managing incidents nationwide. The NRF defines principles, roles, and structures that organize how agencies unify their respond to incidents throughout the nation.

The expansion of an ICS-compatible incident management approach will see that there is a single response structure and process company-wide to manage all incidents. By utilizing ICS consistently across the organization, SDG&E's approach to coordination and communication will align with external stakeholders during emergency situations. This includes the use of common terminology and position titles. Overall, this will enhance the interaction between SDG&E and responding agencies. It is imperative that SDG&E and external stakeholders utilize the same system for seamless integration and ease of mutual assistance during emergency situations.

---

[27] *See* Section IV.A., above, for definition of what is "in scope" for purposes of this risk assessment.

The two key components of the Utility Incident Command expansion are SDG&E EOC Incident Command and OFER. Ensuring a standardized, effective, and efficient ICS-based response to incidents requires proper training to various levels of personnel via training courses and exercises targeted to position-specific personnel at all levels of the organization. The increase in training and exercises related to expand Utility Incident Command will require more instructors to both teach ICS courses, and to plan for and conduct exercises. As stated above, the Incident Command trainings and exercises administered by SDG&E are built on the concepts of the NRF and are compatible with the NIMS, both of which are recognized as nationwide response standards.

Field Integration/OFER is a program that supports strong Quality Assurance/Quality Improvement (QA/QI). It is used to confirm the sustainability of effective Incident Command practices and procedures. OFER is designed to be incorporated into the safety culture of SDG&E and will be utilized in all locations and situations where SDG&E personnel, facilities, or infrastructure are impacted.

The expansion of Utility Incident Command and First Responder Training mitigation addresses SDG&E's Customer and Public Safety, and Wildfire risks. While it is discussed in both RAMP chapters, the costs are fully allocated in the Wildfire chapter (SDG&E-1).

a. Elements of the Risk Bowtie Addressed

The Expansion of Utility Incident Command and First Responder Training mitigation address the following elements of the risk Bow Tie: Serious injuries and/or fatalities (PC.1), Property damage (PC.2) and Erosion of public confidence (PC.5).

5. SDG&E-5-M2 – Expanded Public Safety Communications

a. Description of Risk Reduction Benefits

Expanded Public Safety Communications campaigns are designed to educate the public about safety practices around gas and electric infrastructure. These campaigns aim to provide communities with a deeper understanding of appropriate safety practices to follow when encountering SDG&E's infrastructure.

SDG&E intends to expand several communication campaigns that target public safety practices around gas and electric infrastructure. The Wire Down safety campaign is focused on awareness and precautions pertaining to downed power lines. The target audience is SDG&E's customer base and the general public within the service territory.

Expansion of the 811 Call before you Dig campaign will focus on strengthening and growing messaging to customers or the public on the dangers associated with digging without calling 811 and having underground assets marked. The expanded campaign will target the "weekend gardener" or the landscaper who does not think that 811 is important to them because they may not be digging deep enough to hit an underground pipe/line. The focus of this expansion is to strengthen and broaden the campaign to customers and the public.

Expansion of annual campaigns such as the Pipeline Safety, Winter Prep Safety and Summer Prep Safety will improve public understanding and safety awareness throughout the year. The annual Pipeline Safety campaign provides infrastructure safety information to residential and business customers as well as excavators in the community. The campaign includes information on calling 811 before initiating digging projects. This campaign also provides schools and public officials with information on major pipelines near their facilities and safety considerations associated with this type of infrastructure. Winter and Summer Prep Safety Campaigns are two annual communication campaigns that provide the public with safety tips related to power line safety, generator safety, carbon monoxide safety, holiday lighting considerations, extension cord safety, and cautions about overloading circuits

The messaging of the safety campaigns will be presented through a variety of mediums. The Company intends to employ the use of radio, TV, print, email, bill inserts, direct mail brochures, outdoor and digital advertising in English, Spanish, and Asian languages.

b. Elements of the Risk Bowtie Addressed

The Expanded Public Safety Communications mitigation addresses the following elements of the risk Bow Tie: Serious injuries and/or fatalities (PC.1), Property Damage (PC.2) and Erosion of public confidence (PC.5).

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E's Risk Mitigation Plan takes into account recent trends related to Customer and Public Safety, affordability impacts, possible labor constraints and the feasibility of mitigations. SDG&E has performed a RSE analysis, in compliance with the SA Decision, but ultimate mitigation selection can be influenced by other factors including funding, labor resources, technology, planning, compliance requirements, and operational and execution considerations.

Table 6 below provides a summary of the Risk Mitigation Plan, including controls and mitigations activities, associated costs, and the RSE.

SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 6 below were estimated using assumptions provided by Company SMEs and available accounting data.

Table 6: Risk Mitigation Plan Overview[28]
(Direct 2018 $000)[29]

ID	Mitigation/Control	2018 Baseline Capital[30]	2018 Baseline O&M	2020-2022 Capital[31]	2022 O&M	Total[32]	RSE[33]
SDG&E-5-C1	Public Safety Communications	0	370	0	470 - 560	470 - 560	-
SDG&E-5-C2	Field and Public Safety	0	6,000	0	6,000 – 7,300	6,000 – 7,300	4.83 – 67.24
SDG&E-5-C3	First Responder Outreach and Training[34]	0	0	0	0	0	-

---

28 Recorded costs and forecast ranges are rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

29 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

30 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

31 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

32 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

33 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

34 Costs for this activity are presented in the Wildfire Chapter of this RAMP Report (SDG&E-1).

SDG&E-5-M1	Expansion of Utility Incident Command and First Responder Training	0	320	0	590 - 720	590 - 720	-
SDG&E-5-M2	Expanded Public Safety Communications	0	0	0	1,800 – 2,200	1,800 – 2,200	-
	TOTAL COST	**0**	**6,700**	**0**	**8,900 – 11,000**	**8,900 – 11,000**	

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

There are activities that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.*, various training). The costs associated with these internal labor activities are not captured in this chapter because SDG&E does not track labor in this manner. These activities related to the Customer and Public Safety Risk are: Employee time related to training, and employee time spent in the EOC during activation.

SDG&E is not calculating RSEs on the following activities/programs:

Table 7: Summary of RSE Exclusions

Control/Mitigation ID	Control/Mitigation Name	Reason for No RSE Calculation
SDG&E-5-C1	Public Safety Communications	Non-scoped safety activity/Mandated activity per 49 CFR § 192.616
SDG&E-5-C2	Field and Public Safety[35]	Non-scoped safety activity/Mandated activity[36]
SDG&E-5-C3	First Responder Outreach and Training	Non-scoped safety activity (costs captured in Wildfire Chapter, SDG&E-1)
SDG&E-5-M1	Expansion of Utility Incident Command and First Responder Training	Non-scoped safety activity (in Wildfire Chapter, SDG&E-1)
SDG&E-5-M2	Expanded Public Safety Communications	Non-scoped safety activity

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the Risk Mitigation Plan for the Customer and Public Safety Risk. Typically, analysis of alternatives occurs

---

35 The Quality Assurance Program, part of the Field and Public Safety control, does have an RSE calculation detailed in Section VI above.

36 *See*, Appendix B for listing of Field and Public Safety compliance mandates.

when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SDG&E-5-A1 – Post-training Follow-up Field Evaluation

SDG&E considered an alternative that would provide new field service technicians with a follow up field evaluation six months after being released from formal training. This evaluation would determine whether these new employees continue to follow the safety policies and procedures established during their formalized training. Any deficiencies in an employee's performance would be addressed on an individual basis and follow up training would be scheduled to remediate any issues.

This alternative was not implemented because employees currently participate in annual reviews of safety- and risk-related policies and procedures (*e.g.*, Gas Standards, monthly defensive driving training, ergonomic training, bi-weekly safety meetings, etc.). SDG&E employees attend week-long compliance/refresher training that covers pertinent policies, addresses Field QA findings and reviews recent incidents to help mitigate risk. At SDG&E, there is also no set time period to start QA inspections on new employees. When issues are found they are coached by the direct supervisor, which can lead to field rides by the Supervisor, Appliance Mechanic, Field Instructor, Instructor or QA Inspector. Expanding the scope of training or reducing the period between policy reviews across the board would require additional resources and increase costs yet were not expected to yield significant benefits.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.1759**	
	CoRE	221	**1835**	4525
	Risk Score	39	**323**	796
Post-Mitigation	LoRE		**0.1759**	
	CoRE	221	**1834.8**	4525
	Risk Score	39	**322.71**	796
	RSE	0.13	**1.42**	3.27

B. SDG&E-5-A2 – Modernization of CSF Training Materials

SDG&E considered modernizing CSF training materials to include development of additional online training modules, video production, Power Point presentations, Captivate (CBT) training modules and creation of modernized testing materials. Currently, SDG&E employs CSF policy manuals coupled with training workbooks designed to teach employees how to perform different jobs in accordance with the policy manuals. In general, CSF policies provide guidance on "what to do" in most situations, but the training materials explain "how to do" the job in those situations and provides process detail to effectuate compliance with the policy. This approach allows employees to do their jobs safely and maintain compliance. SDG&E considered updating its training materials to leverage newer technology to improve on training efficiency and effectiveness. Policy updates, process changes, new programs and training module improvements require continuous review, as these areas are dynamic.

Because policies and best practices change regularly, converting the training materials and updating on an ongoing basis is not a realistic option due to resource and cost constraints. For example, it would be necessary to pull existing trainers and instructors out of the classroom and field for re-training, and continuously employ instructional designers in addition to the ongoing expense for training module updates. After research and consideration, SDG&E has chosen to review and modernize its training materials and technology as changes are warranted.

1. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE	0.1759		
	CoRE	221	**1835**	4525
	Risk Score	39	**323**	796
Post-Mitigation	LoRE	0.1759		
	CoRE	221	**1834.8**	4525
	Risk Score	39	**322.71**	796
	RSE	0.03	**0.30**	0.68

Table 8: Alternative Mitigation Summary
(Direct 2018 $000)[37]

ID	Mitigation	2020-2022 Capital	2022 O&M	Total[38]	RSE[39]
SDG&E-5-A1	Post-training Follow-up Field Evaluation	0	24 – 30	24 – 30	0.13 – 3.27
SDG&E-5-A2	Modernization of CSF Training Materials	0	110 - 140	110 - 140	0.03– 0.68

37 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

38 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

39 The RSE ranges are further discussed in Chapter RAMP-C and Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF THE RISK BOW TIE ADDRESSED

ID	Control Name	Element of the Risk Bow Tie Addressed
SDG&E-5-C1	Public Safety Communications	PC.1, PC.2
SDG&E-5-C2	Field and Public Safety	DT.1, DT.2, PC.1, PC.2, PC.5
SDG&E-5-C3	First Responder Outreach and Training	PC.1, PC.2, PC.5
SDG&E-5-M1	Expansion of Utility Incident Command	PC.1, PC.2, PC.5
SDG&E-5-M2	Expanded Public Safety Communications	PC.1, PC.2, PC.5

SDGE
A Sempra Energy utility

APPENDIX B: FIELD AND PUBLIC SAFETY COMPLIANCE MANDATES

Hazardous Gas Leaks:

- California Public Utilities Code, Division 1, Part 1, Chapter 2.2, Section 328.1 A & C
- CPUC Plan, Code: 961 [2. Natural Gas Pipeline Safety Act of 2011], D6
- CPUC Plan, Code: 963 [2. Natural Gas Pipeline Safety Act of 2011] A-C
- CPUC, General Order 58-A, section 22 b & c
- CFR Title 49 Part 192.605(b)(11) Procedural manual for operations, maintenance, and emergencies [L]
- CFR Title 49, Part 192.615 section (a)(3, 5, and 7)

Non-Hazardous Gas Leaks:

- CPUC Plan, Code: 961 [2. Natural Gas Pipeline Safety Act of 2011], D6
- CPUC Plan, Code: 963 [2. Natural Gas Pipeline Safety Act of 2011] A-C
- CPUC, General Order 58-A, section 22 b & c
- CFR Title 49 Part 192.605(b)(11) Procedural manual for operations, maintenance, and emergencies [L]
- CFR Title 49, Part 192.615 section (a)(3, 5, and 7)

Fumigation Orders:

- CPUC Plan, Code: 963 [2. Natural Gas Pipeline Safety Act of 2011] A-C
- CPUC Tariff Rule 9, Section K
- Advice Letter 3210, Establishment of the Fumigation Turn-Off/Turn-On Service Memorandum Account
- CFR Title 49, Subpart N - Operator Qualifications, section 192.801

CO Testing:

- CPUC Plan, Code: 963 [2. Natural Gas Pipeline Safety Act of 2011] A-C
- CPUC, General Order 58-A, section 22 b & c

NGAT:

- CPUC Plan, Code: 963 [2. Natural Gas Pipeline Safety Act of 2011] A-C
- California Public Utilities Code, Division 1, Part 2, Chapter 6, Section 2790
- California Public Utilities Code, Division 1, Part 1, Chapter 4, Article 13, Section 922
- CEC Building Energy Efficiency Standards, Title 24, Part 6
- CEC Appliance Efficiency Standards, Title 20

Risk Assessment Mitigation Phase

(Chapter SDG&E-6)

Medium Pressure Gas Pipeline Incident (Excluding Dig-in)

November 27, 2019

TABLE OF CONTENTS

Risk: Medium Pressure Gas Pipeline Incident

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas and Electric Company's (SDG&E or Company) Medium Pressure Gas Pipeline Incident risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout the 2019 RAMP Report, activities are delineated between controls and mitigations, which is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See* D.18-12-014 at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Medium Pressure Gas Pipeline Incident risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission Staff and stakeholder discussions.

---

3 *Id.* at 16.

4 *Id.* at 17.

SDG&E and Southern California Gas Company (SoCalGas), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' gas pipeline incident related chapters.[5]

A. Risk Definition

For purposes of this RAMP Report, the Medium Pressure Gas Pipeline Incident risk is the risk of damage, caused by a medium pressure pipeline[6] event, which results in serious injuries or fatalities. This risk concerns a gas public safety event on a medium-pressure distribution plastic or steel pipeline and/or its appurtenances (*e.g.*, valves, meters, regulators, risers).

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[7] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger & Potential Consequence
DT.1	Corrosion
DT.2	Natural forces (natural disasters, fires, earthquakes)
DT.3	Other outside force damage (excluding dig-in)
DT.4	Pipe, weld or joint failure
DT.5	Equipment failure

5 The other gas pipeline incident related chapters in the 2019 RAMP Report include: SCG-5 – High Pressure Gas Pipeline Incident; SCG-1 – Medium Pressure Gas Pipeline Incident; and SDG&E-8 – High Pressure Gas Pipeline Incident.

6 Maximum Allowable Operating Pressure (MAOP) at or lower than 60 psig.

7 D.18-12-014 at Attachment A, A-11 (Bow Tie).

DT.6	Incorrect operations
DT.7	Incorrect /inadequate asset records
PC.1	Serious injuries and/or fatalities
PC.2	Property damage
PC.3	Adverse litigation
PC.4	Penalties and Fines
PC.5	Erosion of public confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[8] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SDG&E-6-C1	Cathodic Protection
SDG&E-6-C2	Assessment of Buried Piping in Vaults
SDG&E-6-C3	Regulator & Valve Inspection and Maintenance
SDG&E-6-C4	Plastic Pipe Replacement
SDG&E-6-C5	Leak Repair
SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol.
SDG&E-6-C7	Utility Conflict Review (Right of Way)
SDG&E-6-C8	Meter Inspection and Maintenance

SDG&E will continue the 2018 controls identified above. Additional activities are being forecasted within the existing controls for Cathodic Protection and Plastic Pipe replacement and SDG&E is also projecting to increase annual activity levels within existing controls. SDG&E also forecasts additional projects and/or programs (*i.e.,* mitigations) as follows:

---

8 *Id.* at Attachment A, A-11 (Definition of Risk Events and Tranches).

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-6-M1-T1	Early Vintage Program (Pipeline): Early Vintage Threaded Main Replacement
SDG&E-6-M1-T2	Early Vintage Program (Pipeline): Early Vintage Steel Replacement
SDG&E-6-M1-T3	Early Vintage Program (Pipeline): Oil Drip Removal
SDG&E-6-M2-T1	Early Vintage Program (Fittings): Dresser Mechanical Coupling Removal
SDG&E-6-M2-T2	Early Vintage Program (Fittings): High/Medium Valve Separation Removal

Finally, pursuant to the SA Decision,[9] SDG&E presents in Section VIII alternatives to the described mitigation plan for this risk and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VII.

II. RISK OVERVIEW

Typically, medium-pressure distribution systems use a series of mains (pipes with larger diameter) to feed service lines, regulator stations, meters and other appurtenance piping. Service lines are smaller diameter pipes which feed customer homes, businesses, and some commercial applications. Medium-pressure pipelines are made of steel or plastic material.

For safety and compliance, Title 49 of the CFR 192, General Order (GO) 58, and GO 112 are the leading sources of requirements for SDG&E's medium-pressure pipelines (among other legal and regulatory provisions). 49 CFR 192 prescribes safety requirements for pipeline facilities and the transportation of gas at the federal level. GO 112 and GO 58 complement and enhance the requirements of 49 CFR 192 at a state level.

With regard to medium pressure pipelines, SDG&E currently operates almost 8,000 miles of medium pressure main with approximately 3,200 miles being steel and approximately 4,500 being plastic. These medium-pressure pipelines serve over 3.6 million SDG&E consumers.

---

9 *Id.* at 34.

Table 4: Medium-Pressure Pipelines

Medium Pressure Pipelines	SDG&E Mains	SDG&E Services
Miles of Steel	3258	2622
Miles of Plastic	4596	3770
Total Miles Medium Pressure Pipelines	7881	6392

Various causes and events can lead to medium pressure pipeline incidents. Drivers can range from natural forces (such as natural disasters, fires, earthquakes), improper installation techniques, material defects, aging/environmental factors such as corrosion and material fatigue, improper operations, and inadequate maintenance of the pipeline infrastructure. For the purposes of this chapter, the Medium-Pressure Pipeline Incident risk focuses on risk events that result in serious injuries or fatalities.

SDG&E notes that when the loss of gas cannot be resolved by lubing, tightening or adjusting, it is defined as a "leak." A leak in and of itself may cause little-to-no risk of serious injury or fatality. Risk to the public and employees can increase when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate into a confined space. The safety concern of the leak is addressed by SDG&E's leak indication prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in American Society of Mechanical Engineering B31.8S.[10]

Additionally, although not included in this RAMP filing, SDG&E is currently in the very preliminary stages of organizing and modeling a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association (CEPA) and

---

10 American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes.

the Pipeline Research Council International (PRCI). The FIMP is not intended to duplicate any systems, processes, or information that may already exist, but rather to supplement the already existing programs to enhance the safety and integrity of the integrated gas pipeline system.[11] FIMP will be a documented program, specific to the facilities portion of a pipeline system,[12] that identifies the practices used by the operator for purposes of "safe, environmentally responsible, and reliable service."[13] While SDG&E is currently in the preliminary stages of organizing and modeling a FIMP approach based on the principles of CEPA, FIMP is anticipated to be included in the next GRC. Although this concept of an overarching program is still maturing in the industry, SDG&E's intention of a FIMP is to better identify and reduce risks of facility assets, extend the life of assets, and achieve operational excellence, in alignment with both the principles of RAMP and the Company's existing Transmission and Distribution, Integrity Management Programs (TIMP, DIMP respectively).[14] Consistent with the SA Decision, a supplemental analysis will be conducted in the GRC for FIMP if it ultimately meets the criteria for inclusion in that proceeding.

III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Medium Pressure Gas Pipeline Incident risk.

---

11 SDG&E notes that there are certain facilities management systems and processes in place, for example Pipeline Research Council International (PRCI) – Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718.

12 "Pipeline system" is defined by Pipeline Research Council International (PRCI) - Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718 as "*Pipeline System is comprised of pipelines, stations, and other facilities required for the measurement, processing, gathering, transportations, and distribution of oil or gas industry fluids*."

13 Canadian Energy Pipeline Association (CEPA), Facilities Integrity Management Program, Recommended Practice, 1st Edition (May 2013) at 7-8.

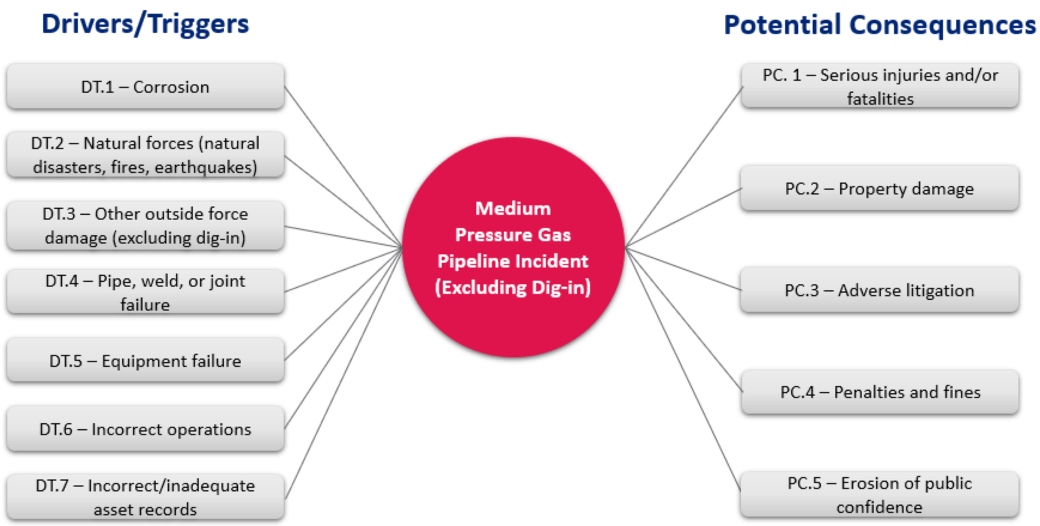
14 Based on industry definitions, there are a variety of types of facilities; facilities are highly complex; a variety of equipment/asset types exist within facilities; and in this context facilities are not considered building structures.

15 D.18-12-014 at 33 and Attachment A, A-11 (Bow Tie).

A. Risk Bow Tie

The risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[16] directs the utilities to endeavor to identify all asset groups or systems subject to the risk.

The Natural Gas Pipeline Distribution System consists of SDG&E's medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and its appurtenances *(e.g.*, meters, regulators, risers). As discussed in RAMP-G, the tracking of costs by SDG&E is not logically disaggregated by high/medium pressure, and therefore costs with some controls for high pressure assets are captured within this chapter.

[16] *Id.* at Attachment A, A-11 (Definition of Risk Events and Tranches).

SDG&E's Medium Pressure Gas Pipeline Incident risk impacts all of SDG&E's natural gas infrastructure and assets in the medium pressure pipeline system. The medium pressure pipeline system is comprised of plastic and steel pipelines and its appurtenances (*e.g.*, valves, meters, regulators, risers) operating at or less than 60 psig.[17] The large size of the system means a high volume of related appurtenances for example the system includes more than 892 thousand meters and approximately 500 regulator stations to distribute and regulate pressure.

C. Risk Event Associated with the Risk

The SA Decision[18] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the risk event (center of the bow tie) is a pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[19]

The SA Decision[20] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Medium Pressure Gas Pipeline Incident, SDG&E identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – Corrosion:** External corrosion is a naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[21] External corrosion occurs to the outside of a pipe. Internal corrosion is the deterioration of metal that results from an electrochemical

[17] Due to cost tracking limitations, the cost reflects a small percentage of miles of high-pressure pipelines maintained by Distribution Operations.

[18] D.18-12-014 at Attachment A, A-11 (Bow Tie).

[19] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[20] D.18-12-014 at Attachment A, A-11 (Bow Tie).

[21] L.S. Van Delinder, *Corrosion Basics, An Introduction* (1984); *see also* U.S. Department of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

reaction with its immediate surroundings. This reaction causes the iron in the steel pipe or other pipeline appurtenances to oxidize (rust). Internal corrosion results in metal loss in the inside of the pipe. Over time and if left unmitigated, corrosion can cause the steel to lose its strength and possibly render it unable to contain the fluid in the pipeline at its operating pressure. The loss of material from corrosion can eventually result in "pinhole" leakage, or a crack, split, or rupture of the pipeline unless the corrosion is repaired, the affected pipe section is replaced, or the operating pressure of the pipeline is reduced.[22] In pipelines, corrosion can occur internally and/or externally, both potentially resulting in a pipeline incident; therefore, will be referred to as "corrosion" in the remainder of this chapter, unless otherwise needed.

- **DT.2 – Natural forces (natural disasters, fires, earthquakes):** Attributable to causes not involving **humans**, but includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, wildfires and high winds.
- **DT.3 – Other outside force damage (excluding dig-in):** Attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck or motorized equipment not engaged in excavation, etc.
- **DT.4 – Pipe, weld, or joint failure:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, improper construction or fabrication or in-service stresses such as vibration, fatigue and environmental cracking.
- **DT.5 – Equipment failure:** Similar to DT.4, but unrelated to pipe (main and services). These failures are attributable to the malfunction of a

---

22 *Id.*

component including, but not limited to, regulators, valves, meters, flanges, gaskets, collars, and couples. This driver/trigger is specific to the material properties related to the manufacturing process or post installation of the equipment.

- **DT.6 – Incorrect operations**: May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **D.T7 – Incorrect /inadequate asset records:** The use of inaccurate or incomplete information that could result in the failure to: (1) construct, operate, and maintain SDG&E's pipeline system safely and prudently; or, (2) to satisfy regulatory compliance requirements.

E. Potential Consequences

If one of the drivers listed above were to result in an incident, the potential consequences, in a reasonable worst-case scenario, could include:

PC.1 – Serious injuries and/or fatalities;
PC.2 – Property damage;
PC.3 – Adverse litigation;
PC.4 – Penalties and fines; and
PC.5 – Erosion of public confidence.

These potential consequences were used in the scoring of the Medium Pressure Gas Pipeline Incident risk during the development of SDG&E's 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION FRAMEWORK

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[23] including enhancements to D.16-08-018.[24] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how

[23] D.18-12-014 at Attachment A.

[24] *Id.* at 2-3.

the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 5: Pre-Mitigation Analysis Risk Quantification Scores[25]

Medium Pressure Gas Pipeline Incident (Excluding Dig-in)	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	47	**252**	594
LoRE		**101**	
CoRE	0.5	**2.5**	5.9

F. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[26] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

In Scope for purposes of risk quantification:	The risk of damage, caused by a medium pressure pipeline (maximum allowable operating pressure - MAOP at or lower than 60 psig) failure event, which results in consequences such as injuries or fatalities or outages.
Out of Scope for purposes of risk quantification:	The risk of damage caused by a non-medium-pressure pipeline failure event or third-party dig-ins which results in consequences such as injuries or fatalities or outages.

25 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

26 D.18-12-014 at Attachment A, A-11 (Calculation of Risk).

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results, available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration (PHMSA) data).[27]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SDG&E, the national average incident rate per mile per year was applied to the medium-pressure pipeline miles at SDG&E.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA medium-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

G. Sources of Input

The SA Decision[28] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
    - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
    - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Annual Report Mileage for Gas Distribution Systems

---

27 *Id.* at Attachment A, A-8 (Identification of Potential Consequences of Risk Event).

28 *Id.* at Attachment A, A-8 (Identification of the Frequency of the Risk Event).

- Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
- Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems

- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SDG&E Medium-Pressure Pipeline Miles are 2017 Internal SME Data
- Gas Industry Sales Customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SDG&E End User Natural Gas Customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
  - Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[29]

---

[29] *Id.* at Attachment A, A-14 (Mitigation Strategy Presentation in the RAMP and GRC).

This section describes SDG&E's Risk Mitigation Plan by each selected mitigation and control for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, the Medium Pressure Gas Pipeline Incident risk is the risk of damage, caused by a medium pressure pipeline event, which results in serious injuries or fatalities. The Risk Mitigation Plan includes both controls that are expected to continue and projected mitigations for the period of SDG&E's Test Year 2022 General Rate Case (GRC) cycle. The controls are those activities that were in place as of 2018, most of which are compliance driven and have been implemented over decades plus the addition of the Distribution Integrity Management Program (DIMP) that has been developed over recent years, to address this risk. SDG&E's mitigation plan for this risk consists of controls based on 42 CFR Part 192, GO 58, GO 112-F and forecasted enhancements within existing controls. Overall the compliance requirements are set forth within the regulations (although considered minimum requirements.) The compliance requirements are robust in that they provide prescriptive preventative and maintenance guidance for the medium pressure assets. In addition, the DIMP regulations have allowed operators to identify risks specific to their system and address them through additional controls and mitigations.

For this RAMP chapter, the makeup of the portfolio of controls is a combination of compliance requirements and additional programs implemented by DIMP within the last 7 years. The DIMP is continually evaluating the system threats and risk to determine if additional mitigations are appropriate. The threat and risk evaluation leverages leak repair, incident data and SME input to evaluate and rank risk. As programs are developed, available data sets are leveraged to develop specific risk ranking for each, which allows higher priority remediations to be completed first. For example, the Distribution Risk Evaluation and Monitoring System (DREAMS) steel replacement programs utilize leak rates, condition of the pipe, soil and other factors to prioritize medium pressure segments for replacement. Another example is the introduction of the Damage Program Analyst specifically covered within the Third Party Dig-In on a Medium Pressure Pipeline Chapter SDG&E-7. The incremental request within existing controls for Cathodic Protection and Meter and Regulations[30] are the first steps to evaluating the need for larger programs and further analysis will aid in the overall prioritization given the size of the system.

Other programs and activities also mitigate the Medium Pressure Gas Pipeline Incident risk, but they are not included in this Risk Mitigation Plan. For example, the Mobilehome Park Utility Upgrade Program (MHP) is converting master-metered/sub-metered natural gas and/or electric services to direct utility services in mobile home parks and manufactured housing communities to improve the safety and reliability of service for residents of mobile home parks currently served by master-metered gas systems. The MHP is not included in this mitigation plan because MHP costs are not anticipated to be forecasted in SDG&E's next GRC.[31] Another example is SDG&E's methane emissions reduction activities in compliance with Senate Bill (SB) 1371 and the resulting Gas Leak Abatement OIR (R.15-01-008). In addition to the federally mandated leak survey requirements described in the Pipeline Monitoring Control (SDG&E-6-C6) below, SDG&E proposed transitioning pre-1986 plastic to annual survey as part of the GRC to an annual survey per the SB 1371 proceeding. SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code section 961(d) and 49 CFR § 192.703(c). SDG&E has been an active participant in the rulemaking and has provided comments as well as met the reporting requirements set forth under SB 1371. SDG&E' first Leak Abatement Compliance Plan and accompanying Advice Letter were approved in 2018 and the Plan is being implemented by the Emissions Strategy Project Management Organization to implement 26 Mandatory Best Practices. Although the focus of SB 1371 activities is to reduce methane emissions, the activities may result in collateral safety benefits as a reduction in the number of leaks reduces the potential opportunity for ignition. However, the risk reduction analysis and the costs tied to the implementation of SB 1371 are not reflected in the Mitigation Plan for this chapter because the

---

30 Continued incremental request because 2019 GRC requested funding to increase regulator replacement programs

31 The Mobile Home Park Conversion Program is a pilot program authorized by and discussed in D.14-03-021 and Resolutions E-4878 (September 28, 2017) and E-4958 (March 14, 2019).

intent of SB 1371 best management practice activities is to reduce methane emissions (and thus it is not primarily focused on addressing safety risk).

A. SDG&E-6-C1: Cathodic Protection

Corrosion is a natural process that can deteriorate steel assets and potentially lead to leaks or damage. If a leak migrates to a confined space and an ignition source is introduced, there is the potential for injuries. Although the SDG&E operations groups immediately respond to these leak situations, they have the potential to lead to a pipeline incident. Cathodic Protection (CP), coating and monitoring can protect and extend the life of a steel asset by mitigating corrosion. The application of a Cathodic Protection current is necessary to overcome local corrosion currents along the pipeline, that left unabated would result in localized corrosion at anodic sites. Cathodic Protection can be achieved by the installation of sacrificial anodes or impressed current systems.[32]

The directives prescribed by 49 CFR 192 Subpart I, include the monitoring of CP areas, remediation of CP areas that are out of tolerance,[33] and preventative installations to avoid out of tolerance areas. The following summarizes the required intervals for completing these preventative measures as prescribed in 49 CFR § 192.465 External Corrosion Control (Monitoring):

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463. However, if tests at those intervals are impractical for

32 SDG&E utilizes both impressed current and magnesium anode (galvanic) systems to provide CP to existing pipelines. Impressed current systems utilize a rectifier for the generation of the direct current. Both systems utilize sacrificial anodes as a primary component in the system. Anodes are installed in wells drilled into the surrounding soil by third-party drilling contractors. Each protected pipe segment requires multiple anodes, collectively referred to as an "anode bed." The number of anodes needed to achieve the desired level of protection and the average life of the anode bed can vary based on pipeline length, coating effectiveness, soil conditions and interference that may occur on the system.

33 Out of tolerance areas are defined as areas where CP measures are not efficiently mitigating the effect of the corrosive environment on steel assets.

separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

- Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 1/2 months, to insure that it is operating.[34]

SDG&E plans to continue with work according to this schedule.

This incremental work activity supports the safety and integrity of the system and mitigates risks defined in this RAMP chapter.

B. SDG&E-6-C2: Assessment of Buried Piping in Vaults

This control is for the replacement of piping located in underground vaults.[35] SDG&E has a number of valves that are surrounded by a concrete vault to provide access to the valve for emergency operations. Any pipe segment, fitting, or valve exposed within a below grade vault is at risk for accelerated atmospheric corrosion due to the potential for water accumulation, pipe coating failure, and decreased cathodic protection effectiveness as these components within the vault are not buried and are exposed to the atmosphere. This RAMP incremental addition follows the review of existing work orders determining the locations of all vaults containing medium and high-pressure facilities. Once all vaults with exposed valves are identified, the valve will be replaced with a valve appropriate for buried service, and the vault removed and backfilled so that the valve will be protected by cathodic protection. The valve would continue to be accessible so that it could be used for emergency isolation. It is estimated that approximately 50 locations will require replacement. SDG&E will assess the coating and the

---

34 49 CFR § 192.465(a) and (b).

35 Vaults are rooms that allow for access to piping and piping components.

condition of the above-ground and below-ground facilities within the vaults and prioritize for complete replacement.

C. SDG&E-6-C3: Regulator & Valve Inspection and Maintenance

This control is for inspections and maintenance to regulators. Regulator stations reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure used on the distribution pipeline system. A failure of a regulator station due to mechanical failure, corrosion, contamination or other cause could result in over-pressurization of the gas distribution system, which may compromise the integrity of medium-pressure pipelines and/or jeopardize public safety as evident by recent over-pressure events in the industry.

Regulator stations are critical control elements in the gas distribution system. 49 CFR § 192.739 requires inspections/tests to be conducted done annually, not to exceed 15 months to maintain these devices in good mechanical condition. Functional tests of regulator stations are performed as part of inspections. The pressure checks are done to verify that the station's pressure protection devices perform as designed. If a station does not perform properly, internal maintenance and inspections are conducted. This consists of disassembling the regulator devices and inspecting the internal components for worn or damaged parts. The regulator is cleaned and inspected for corrosion and any faulty parts are replaced.

As regulator stations age, their parts and equipment can begin to wear, malfunction, and become harder to disassemble, increasing maintenance requirements. Modern regulator stations are beginning to be designed with dual-run feeds to maintain continued safe and reliable operation of the station in the event of a failure within either of the two runs. Annual maintenance and inspections are used to record the condition of each station and identify items that require immediate and long-term action. The overall inspection of the station is leveraged to prioritize future regulator station replacement projects. The assessment includes evaluation of the design, condition of the equipment, valves and vaults, and exposure to other outside forces including flooding and traffic conditions.

SDG&E's operating and maintenance practices allow stations to exceed their useful lives. However, it is prudent to proactively replace regulator stations prior to the end of their design life in order to reduce the overall system risk. This risk reduction is achieved through improved station design of dual-run regulators which will reduce the risk of over-pressure and the stations location can be evaluated to reduce the risk of vehicular damage (outside force) or vandalism. SDG&E operates and maintains approximately 500 regulator stations, of which, on average, two to three stations are replaced or added to the system each year. The average life expectancy of a regulator station is approximately 35 years. SDG&E will evaluate a replacement plan of district regulator stations (DRS) across the operating region. Once developed, this regulator station replacement plan will be used as an example of addressing SDG&E's aging infrastructure and will be used as a model to review other facilities and equipment in a similar fashion. The following summarizes the requirements for completing these preventative measures as prescribed within then 49 CFR § 192.739 Pressure limiting and regulating stations: Inspection and testing:

a) Each pressure limiting station, relief device (except rupture discs), and pressure months, but at least once each calendar year, to inspections and tests to determine that it is—

(1) In good mechanical condition;

(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of § 192.201(a); and

(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

Valve Maintenance allows the opportunity to validate that the valves within the system operate at optimum effectiveness which enhances public safety by providing SDG&E with the ability to control the pressure and flow of gas in the system. The maintenance activities may include flushing, lubrication, parts replacement, cleaning and testing of operability. Valves are installed for control of pressure and flow of gas. Their location and purpose determine their criticality: fire valves at regulator stations isolate the high- and medium-pressure systems; emergency valves isolate segments of pipelines in case of pipe damage or for operational purposes; and isolation valves segment portions of the system in the event of a widespread emergency, such as an earthquake and reduce the impact of resulting pipeline damage. A valve that is operating at its optimum effectiveness means that, for example, in the case of an earthquake or fire where an area needs to be isolated to reduce the risk of incident, these valves will operate as intended and fully isolate the area. A second example, which happens more frequently, when third-party damage occurs, these valves can be operated to allow for a safe environment to complete the repairs and minimize the risk of furthering the incident. The following summarizes the requirements for completing these preventative measures as prescribed within the CFR § 192.747:

> (a) Each valve, the use of which may be necessary for the safe operation of a distribution system, must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.
>
> (b) Each operator must take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve.

D. SDG&E-6-C4: Plastic Pipe Replacement

The Vintage Integrity Plastic Plan (VIPP) falls within the umbrella of the Distribution Risk Evaluation and Monitoring System. Plastic pipe manufactured and used for gas service from the 1960s through the early 1980s (1,578 miles) exhibit brittle-like cracking characteristic that could cause a leak to grow and release additional natural gas than would normally be released, increasing the risk of natural gas gathering and igniting causing injuries and/or fatalities. Given the potential for a higher release of gas, the leak survey frequency has been increased to yearly versus every five years for plastic pipelines within this vintage. The initial focus of the VIPP is early vintage plastic manufactured pre-1973. This vintage of plastic exhibits the brittle-like cracking characteristics discussed, but also exhibits a Low Ductile Inner Wall (LDIW) issue that further exacerbates the brittle-like cracking issues since it expedites crack initiation when external loads are applied. This issue in the manufacturing practice has been the focus of earlier notices as issued by the manufacturer DuPont and PHMSA. Therefore, the focus will be a wholesale replacement of pre-1973 plastic pipe with a priority given to poor performing segments by utilizing a relative risk model and dynamic segmentation. The secondary focus will be to leverage the same relative risk model and dynamic segmentation to continue to focus on the replacement of poor performing early vintage plastic for all pre-1986 plastic pipe. SDG&E is on target to replace the forecasted 19 miles of mains and associated services for replacement above and beyond routine replacements. As SDG&E's infrastructure continues to age and more leak data is accumulated through annual inspections, SDG&E anticipates continuing to increase the level of replacement over the next 6-8 years while monitoring performance to continually review the benefits and risk reduction accomplished through VIPP through indicators such as leak repair and incident rates related to early vintage plastic.

E. SDG&E-6-C5: Leak Repair

SDG&E proactively surveys its gas distribution system for leakage at frequencies determined based on the pipe material involved, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities as prescribed within CFR § 192.723. A routine leak survey consists of surveys at intervals of one, three, or five years of steel mains and plastic at intervals of five years. The frequency of this survey is determined by the pipe material involved. Annual surveys are scheduled in business districts, and near public service establishments, such as schools, churches, hospitals and pre-1986 plastic (Aldyl-A). Three-year survey cycles are used for all cathodically unprotected mains and services. Five-year survey cycles are typically used for plastic and cathodically protected steel mains and services installed in residential areas. The results of leak surveys feed into risk models for pipeline replacement.

If a leak is found during a survey of the gas distribution system, SDG&E takes steps to either remediate or monitor the situation depending on the type of leak classification. A leak will be remediated immediately if there is a hazardous condition. If the leak does not create a hazardous situation, SDG&E will monitor the leak. SDG&E has shortened the prescribed timeframe for which leaks will be monitored and scheduled for remediation. The leak survey program has accelerated due to the increased footage for leak surveys, which requires more leak survey activities. SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities consistent with Public Utilities Code section 961(d) and 49 CFR § 192.703(c). SDG&E has been an active participant in the rulemaking and has provided comments as well as met the reporting requirements set forth under SB 1371. SDG&E's first Leak Abatement Compliance Plan and accompanying Advice Letter were approved in 2018 and the Plan is being implemented across by the Emissions Strategy Project Management Organization to implement 26 Mandatory Best Practices. This will result in collateral safety benefits. However, the risk reduction analysis and the costs tied to the implementation of SB 1371 are not included as part of this control.

F. SDG&E-6-C6: Pipeline Monitoring (Leak Mitigation, Bridge & Span, Unstable Earth and Pipeline Patrol)

SDG&E conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include pipeline patrols, leak surveys, bridge and span inspections, and unstable earth inspections. These inspections are critical since they are intended to observe assets over time to determine if abnormal conditions exist prior to becoming a concern. For example, a span that no longer is coated appropriately due to recent weather conditions can be identified for re-coating before corrosion begins that could lead to a leak. The leak survey monitoring identifies leaks that require repair.

The monitoring and inspections must follow certain prescribed processes included in the Code of Federal Regulations.[36]

G. SDG&E-6-C7: Utility Conflict Review (Right of Way)

The Land and Right-of-Way group is responsible for managing the necessary property rights that allow for the access, operation, and maintenance of our pipeline infrastructure on public and private properties. Right of way (ROW) access is critical for the overall general safety of employees and the public and includes span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and right-of-way maintenance. Maintenance of access roads is critical to allow pipelines to be accessed in a timely manner, minimizing third party pipeline damages and prevention of wildfire damages. The costs associated with the ROW in this RAMP report refer to the O&M activities required to maintain access to Company assets. These costs do not include costs related to the acquisition of ROW space.

---

[36] 49 CFR § 192.721.

H. SDG&E-6-C8: Meter Inspection and Maintenance

The Meter Set Assemblies (MSA) reduce the pressure of natural gas and measure the volume of natural gas delivered to the customer. General Order 58-A requires that meters, regulators, and other components be maintained, repaired, and tested periodically to meet customers' capacity requirements, measure gas volume accurately and deliver natural gas at an adequate pressure for the houseline and home appliances. Additionally, if MSAs are housed in vaults, the vaults must be inspected and repaired, if necessary, to protect the MSA. Should the regulators fail a household could potentially see a much higher pressure of natural gas and may lead to an incident. Scheduled inspections of meter set assemblies proactively target the risk of equipment failures, corrosion, and outside force before operation and safety issues arise.

As required by 49 CFR § 192.481, above ground piping facilities must be inspected for atmospheric corrosion no less than once every three calendar years and at intervals not to exceed 39 months.

I. SDG&E-6-M1: Early Vintage Program (Pipeline)

The Early Vintage Program mitigates risk on early vintage pipelines that were installed using construction practices that are no longer considered best practices. The determination of where and when to implement mitigation measures is based on pipe attributes, operational conditions, and potential impacts on populations in the event of an incident. The Early Vintage Program proactively identifies the risk factors for remediation before operational and safety issues arise. As these programs continue to be evaluated, activity may vary between the tranches. SDG&E's Early Vintage Program (Pipeline) consists of the following elements: Early Vintage Threaded Main Replacement, Early Vintage Steel Replacement, Oil Drip Removal, Leak History Replacement. Each control is further described below:

1. SDG&E-6-M1-T1: Early Vintage Threaded Main Replacement.

Prior to 1933, piping in the gas distribution system was joined by treaded couplings. This project aims to proactively remove a total of 152 miles of threaded main pipe over a 10-year period as well as associated services (approx. 153 miles of services have been identified). This is approximately a10-year program which on average would require 15 miles of pipe per year, however mileage can vary slightly from year-to-year. Threaded pipe has a greater susceptibility to leaks at the joint connections and higher potential for joint failure during a seismic event.

2. SDG&E-6-M1-T2: Early Vintage Steel Replacement.

The Early Vintage Steel Replacement Program focuses on the replacement of poor performing steel. In early vintage steel mains, cold tar asphaltic wrap was used as the first layer of corrosion protection. Over time, the early generation pipe wrap degrades and disbonds from the pipe, causing any cathodic protection current to leave the pipe around the disbonded coating thereby not providing adequate protection. Ultimately, this lack of corrosion protection will lead to increased leakage. In 2019, SDG&E is targeting replacement of 7.4 miles. SDG&E anticipates continuing this program while monitoring performance to continually review the benefits and risk reduction accomplished through Early Vintage Steel Replacement through indicators such as leak repair and incident rates related to steel pipeline.

3. SDG&E-6-M1-T3: Early Vintage Oil Drip Removal.

Pipeline oil drips were installed in low point high volume areas of the system to collect and purge unwanted liquids from the main. These systems were installed in the early days in the downtown areas when coal gasification was used and liquids were traditionally found in the system. Since liquids are no longer an issue for the SDG&E pipeline system, oil drips are obsolete. The buried oil drip piping facilities are at risk of excavation damage as their location and configuration historically were not captured with enough detail to identify them with precision on facility maps. These facilities often were symbolized by a “teardrop” on the maps. Because the feature lengths and attributes were not mapped in detail, it has led to difficulties in marking out as part of locate and mark requests. In recent history, a facility was damaged and caused an uncontrollable release of gas until the pipeline could be shut down. This incident caused a major freeway that serves Southern San Diego County to be shut down for safety. Gas Distribution has gathered partial historical oil drip location data and for 176 sites and marked the approximate location of these facilities in GIS; however, this effort needs additional validation. This capital project will follow the review of 44 work orders and field validation of above ground and buried oil drip lines and containers. Additionally, this capital expenditure will be associated with an estimated 120 oil drip lines and containers that are no longer necessary and will be removed from the system thus improving the safety and reliability of the system.

J. SDG&E-6-M2: Early Vintage Program (Fitting)

The Early Vintage Program mitigates risk on early vintage fitting. The determination of where and when to implement mitigation measures is based on fitting attributes, operational conditions, and impact on populations in the event of an incident. The Early Vintage Program proactively identifies the risk factors for remediation before operational and safety issues arise. SDG&E's Early Vintage Program (Fitting) consists of Dresser Mechanical Coupling Removal and High/Medium Valve Separation Removal. Each mitigation is further described below:

1. SDG&E-6-M2-T1: Dresser Mechanical Coupling Removal.

The Dresser mechanical coupling joins two pipes together without the need for welding. This type of coupling cannot resist lateral movement, and over time the rubber pressure containing seal degrades. The Early Vintage Program (Fitting) consists of evaluating locations where Dresser mechanical couplings exist, excavating, removing approximately 100 Dresser mechanical couplings, and welding pipes back together. Dresser mechanical couplings require lateral support and are not as strong as modern mechanical coupling which have a rubber mechanical seal. In the event of land movement, pipe separation/rupture may occur and create an incident. These types of incidents are low frequency, but potentially high consequence events because the Dresser mechanical couplings are primarily located in high population density areas. They exist in both the medium and high-pressure systems.

2. SDG&E-6-M2-T2: High/Medium Valve Separation Removal.

SDG&E has identified 130 valves which separate high-pressure from medium-pressure systems. These valves are permanently locked out and tagged out in the closed position to serve as a physical barrier between high pressure and medium pressure. This condition is a result of a MAOP uprating of a pipeline which was previously interconnected to a distribution system and operated at a lower MAOP. Simply closing and locking the valve between high- and medium pressure systems is no longer an acceptable practice as there is inherent risk should the valve be operated in error, operated in an act of sabotage, or the valve leak pressure downstream to the lower MAOP system potentially causing an overpressure condition of the downstream system.

This project will verify valve locations in the field, excavate, and remove the closed and locked valves currently connecting high-pressure piping to medium-pressure piping thus improving the safety and reliability of the system.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Unless otherwise specified, all elements of the bow tie concerning Potential Consequences are assumed to be addressed by the below mentioned controls or mitigations. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[37] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. Risk reduction from mitigations and RSEs are determined at the tranche level. For purposes of the risk analysis, each tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of tranches is presented below.

SDG&E's comprehensive integrity and maintenance programs consist of policies, programs, and efforts designed to reduce the probability of a pipeline incident. The extensive activities SDG&E performs to mitigate pipeline risks have been grouped into the controls presented herein based on the similarity of their risk profiles.

SDG&E does differentiate some programs by asset type (*e.g.*, steel vs. plastic); however, as discussed in RAMP-G, costs are not tracked at a level of detail to allow for the logical disaggregation of assets or systems at a more granular level than the controls described in the mitigation plan.

Outside of the aforementioned groups, The Early Vintage Program has a logical disaggregation for activities as listed in the Summary of Risk Mitigation Plan and was tranched.

---

[37] D.18-12-014 at Attachment A, A-11 (Definition of Risk Events and Tranches).

The Early Vintage Program focuses on assets, pipelines and fittings, and of those assets, specific groups are targeted for remediation and tranched accordingly:

Table 6: Summary of Tranches

ID	Mitigation	Tranche	Tranche ID
SDG&E-6-M1	Early Vintage Program (Pipeline)	Early Vintage Threaded Main Replacement	SDG&E-6-M1-T1
		Early Vintage Steel Replacement	SDG&E-6-M1-T2
		Oil Drip Removal	SDG&E-6-M1-T3
SDG&E-6-M2	Early Vintage Program (Fittings)	Dresser Mechanical Coupling Removal	SDG&E-6-M2-T1
		High/Medium Valve Separation Removal	SDG&E-6-M2-T2

B. Post-Mitigation/Control Analysis Results

As described in RAMP-D and Section 4 above, SDG&E utilized both internal data/modeling as well as PHMSA data to build RSEs for the pipeline incident risk areas. In the determination of inputs for the RSE calculations, SMEs were heavily utilized to confirm and provide data to perform the RSE calculations. Such input included the effectiveness of each control. The effectiveness percentages shown below are the results of discussions with SMEs whose knowledge of the control heavily dictated the values selected.

The below sections detail the Risk Reduction Benefits of each control/mitigation as well as specifically outline the data used in conjunction with said SME input to develop the RSE values.

1. SDG&E-6-C1: Cathodic Protection (CP)

a. Qualitative Description of Risk Reduction Benefits

A steel pipeline can corrode externally and experience a degradation process that can lead to a structural incident. Corrosion control activities, like CP, are meant to manage or arrest structural changes. CP is a method to mitigate external corrosion on steel pipelines thereby extending the life of a steel asset. The activities associated with CP include installation, monitoring, and remediation. SDG&E has installed CP on all of its 3,571 miles of steel gas mains and all of its 266,806 gas services. Given the mandated requirement to continuously monitor and evaluate the CP areas, the management of this control is cyclical in nature. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

CP reduces safety risks by controlling pipeline corrosion rates thus reducing the frequency of corrosion-related incidents. Minimizing corrosion has the additional benefits of reducing reconstruction costs from pipeline incidents, reducing risk to property, and the potential benefit of improved service reliability. SDG&E exceeds the minimum safety requirements for CP prescribed by 49 CFR 191 Subpart I, which includes monitoring of CP areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance.

b. Elements of the Bow Tie Addressed

Cathodic protection addresses the following elements of the bow tie:

i. [DT.1] – Corrosion

***ii. [DT.4] – Pipe, weld, or* joint failure**

c. RSE Inputs and Basis

Scope	The cathodically protected distribution system running at a pressure of 60 psi or lower.
Effectiveness	Per internal SME assessment, we assume 95% effectiveness. Based on SME analysis, vintage steel segments that are being replaced are 13.2 times more likely to have an incident occur than modern plastic pipe over a lifecycle. We assume a similar deterioration proportion were cathodic protection discontinued.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 41 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 1 out of the 41 SoCalGas and SDG&E incident samples were corrosion-related events (2%). Using these assumptions, this control tranche could improve safety risk by up to 31% of the current residual risk. **Reliability:** Using these assumptions, this control tranche could improve reliability risk by up to 31% of the current residual risk. **Financial:** Using these assumptions, this control tranche could improve financial risk by up to 31% of the current residual risk.

SDGE
A Sempra Energy utility

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**131.89**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	60.81	**328.78**	775.40
	RSE	0.77	**4.16**	9.81

2. **SDG&E-6-C2: Assessment of Buried Piping in Vaults**

a. **Qualitative Description of Risk Reduction Benefits**

SDG&E has pipeline buried in vaults that may be corroded by above ground facilities and pitting of below ground piping. This activity will identify the locations vaults containing medium and high-pressure facilities and remediate locations where corrosion is found.

Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group. The assessment and remediation of buried piping in vaults is preventative in nature and is intended to reduce or eliminate conditions that might lead to an incident. These activities increase public and employee safety by mitigating various risk sources, primarily corrosion and degradation of equipment.

b. **Elements of the Bow Tie Addressed**

Assessing buried piping in vaults addresses the following elements of the bow tie:

i. [DT.1] – Corrosion

ii. [DT.2] – Natural forces

iii. [DT.3] – Outside Forces

iv. [DT.4] – Pipe, weld, or joint failure

c. RSE Inputs and Basis

Scope	There are 289 vaults that will be assessed and repaired, if necessary.
Effectiveness	Per internal SME assessment, the effectiveness of these activities is 95%. It is also assumed that all vaults have the same level of risk.
Risk Reduction	**Safety**: According to PHMSA data, 2 out of 426 significant events were associated with vaults at the national level. Using these assumptions, this control tranche could improve safety risk by up to 0.3%. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 0.3%. **Financial**: Using these assumptions, this control tranche could improve financial risk by up to 0.3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	**LoRE**		**101.33**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.72	**252.61**	595.75
	RSE	0.15	**0.81**	1.91

3. SDG&E-6-C3: Regulator & Valve Inspection and Maintenance

a. Qualitative Description of Risk Reduction Benefits

Regulator stations reduce the pressure of gas entering the distribution system from high-pressure pipelines to provide a lower pressure used on the distribution pipeline system. A failure of a regulator station due to mechanical failure, corrosion, contamination, or other cause could result in over-pressurization of the gas distribution system, which may compromise the integrity of medium-pressure pipelines and/or jeopardize public safety. Regulator maintenance activities are cyclical in nature and are conducted in accordance with 49 CFR § 192 Subpart M which require the annual inspection and maintenance of all of the approximately 500 regulator stations operated by SDG&E in order to maintain these devices in good mechanical condition.

Regulator maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent equipment issues. In addition to addressing emerging issues, regulator maintenance activities provide an opportunity for SDG&E to identify equipment that is at risk of deterioration in the future and procure equipment to address said equipment during the next inspection cycle. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

Regulator maintenance increases public and employee safety by mitigating various risk sources, including corrosion and degradation (for example). When a regulator station is replaced as part of regulator maintenance, there are additional benefits that improve safety and reliability. The design of new regulator stations includes dual-run feeds which provide redundancy, and there is a financial benefit with the installation of new regulator stations due to ease of maintenance. Modern regulator stations have more monitoring points that feed into the Distribution Operations Control Center (DOCC)[38] which improves response time in the event of an incident. Additionally, when maintenance is required, parts are more readily available compared to older model regulator stations. Minimizing safety threats also provides additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

Valves provide the ability to control the pressure and flow of gas in SDG&E's system. Valves are controlled locally or remotely from a central control system. Valve inspections and maintenance validate that the valves within the system operate at optimum effectiveness by detecting and addressing emerging equipment issues. Valve inspections and maintenance are conducted in accordance with 49 CFR § 192 Subpart M, which require that each valve must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. Given the mandated requirement to complete valve inspections and maintenance, the

[38] The DOCC is not included in the SDG&E Medium Pressure Incident Chapter. The forecasted capital costs (and Control description) have been included in the SoCalGas Medium Pressure Incident Chapter because it is anticipated to be a SoCalGas owned asset that will also be used by SDG&E. Costs will get allocated to SDG&E through the Shared Asset Billing process.

management of this control is cyclical in nature. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

Valves that are operating at optimum effectiveness enhance public safety by providing SDG&E with the ability to control the pressure and flow of gas in the system. Valve inspections and maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident. Valve inspections and maintenance increase public and employee safety by mitigating various risk sources, primarily corrosion and degradation. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Regulator and Valve Inspection and Maintenance addresses the following elements of the bow tie:

i. [DT.1] – Corrosion

ii. [DT.2] – Natural forces

iii. [DT.3] – Outside Forces

iv. [DT.5] – Equipment Failure

v. [DT.6] – Incorrect Operations

4. SDG&E-6-C4: Plastic Pipe Replacement

a. Qualitative Description of Risk Reduction Benefits

The Vintage Integrity Plastic Plan (VIPP) falls within the umbrella of the Distribution Risk Evaluation and Monitoring System. SDG&E utilizes a relative risk model in order to rank and prioritize the risk for plastic pipeline. Starting in 2019, SDG&E plans to target 46 miles of mains and associated services for replacement above and beyond routine replacements in accordance with DIMP regulations for the replacement of vintage plastic as part of the Vintage Integrity Plastic Plan (VIPP). VIPP is conducted in accordance with 49 CFR Part 192. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

Significant reductions in safety risks are achieved with the replacement of vintage plastic (and steel pipeline with new plastic pipe). Newly installed plastic pipe has a very low leak rate and is not subject to corrosion. A newly installed pipeline has a lower residual risk level and its risk rises on a different path than that of vintage pipe. The difference in deterioration paths is the performance benefit derived from reconstruction. This directly translates into a decrease in safety risk. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability over time.

b. Elements of the Bow Tie Addressed

The Plastic Pipe Replacement program addresses the following elements of the bow tie:

i. [DT.2] – Natural forces

ii. [DT.3] – Outside Forces

iii. [DT.4] – Pipe, weld, or joint failure

iv. [DT.5] – Equipment Failure

v. [DT.6] – Incorrect Operations

c. RSE Inputs and Basis

Scope	SDG&E will be replacing 73 miles of vintage plastic pipe out of 1,239 miles (6%).
Effectiveness	Per internal SME assessment, we assume 100% effectiveness because the failure rate of modern PE plastic pipe is very low. Based on SME analysis, the plastic segments being replaced are 12.5 times more likely for an incident to occur than modern plastic pipe over a lifecycle.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 18 out of 426 nationwide significant events were associated with plastic Aldyl-A pipe. Using these assumptions, this mitigation could improve safety risk by up to 3%. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 3%. **Financial**: Using these assumptions, this control tranche could improve financial risk by up to 3%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**104.14**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	48.02	**259.61**	612.26
	RSE	0.24	**1.28**	3.03

5. SDG&E-6-C5: Leak Repair

a. Qualitative Description of Risk Reduction Benefits

SDG&E proactively surveys its gas distribution system for leakage at frequencies determined based on the pipe material involved, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities as prescribed within CFR § 192.723. Leak repair activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent issues. Leak repairs increase public and employee safety by mitigating various risk sources. Safety risks are proactively reduced on a regular basis as result of the continual, ongoing nature of leak repair activities. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

The Leak Repair program addresses the following elements of the bow tie:

- ***i. [DT.1] – Corrosion***
- ***ii. [DT.2] – Natural forces***
- ***iii. [DT.3] – Outside Forces***
- ***iv. [DT.5] – Equipment Failure***

6. SDG&E -6-C6: Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol

a. Qualitative Description of Risk Reduction Benefits

SDG&E conducts pipeline monitoring and inspection activities to proactively target risk factors before operation and safety issues arise. These monitoring activities include bridge and span inspections, unstable earth inspections, pipeline patrols, and leak surveys. These inspections are critical since they are intended to observe assets over time to determine if abnormal conditions exist prior to becoming a concern. For example, a span that no longer is coated appropriately due to recent weather conditions can be identified for re-coating before corrosion begins that could lead to a leak. The leak survey monitoring identifies leaks that require repair.

SDG&E will conduct pipeline monitoring and inspections to proactively target risk factors before operational and safety issues arise. Pipeline monitoring activities include bridge and span inspections, unstable earth inspections, pipeline patrols, and leak surveys. Distribution pipeline spans, pipe supported on bridges, aboveground (or jacketed) pipelines, and all other exposed pipeline (as installed) are inspected for atmospheric corrosion or abnormal conditions: Onshore, at least once every 2 calendar years, but with intervals not exceeding 27 months. Offshore, at least once each calendar year, but with intervals not exceeding 15 months. SDG&E will proactively survey its gas distribution system for leakage at frequencies determined based on the pipe material involved, the operating pressure, whether the pipe is under cathodic protection, and the proximity of the pipe to various population densities as prescribed within CFR § 192.723. Distribution Operations will manage the implementation of the work associated with this control with engineering oversight.

Pipeline monitoring activities are preventative in nature and should reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent issues. Pipeline monitoring activities should increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. Safety risks will be proactively reduced on a regular basis as result of the continual, ongoing nature of pipeline monitoring activities. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Pipeline Monitoring addresses the following elements of the bow tie:

i. [DT.1] – Corrosion

ii. [DT.2] – Natural forces

iii. [DT.3] – Outside Forces

iv. [DT.5] – Equipment Failure

7. SDG&E-6-C7: Utility Conflict Review (Right of Way)

a. Qualitative Description of Risk Reduction Benefits

Utility Conflict Review (Right of Way) includes managing property rights that allow for the access, operation, and maintenance of SDG&E's pipeline infrastructure on public and private properties, as well as the maintenance of access roads to allow pipelines to be accessed in a timely manner. Gas Engineering and the Land and Right-of-Way group manage the implementation of the work associated with this control.

Utility Conflict Review (Right of Way) activities are preventative in nature and are intended to increase pipeline visibility and accessibility through vegetation and land management surrounding the immediate vicinity of SDG&E's pipelines. This allows pipelines to be accessed in a timely manner in this event of an incident which then may minimize third-party pipeline damages and reduce wildfire damage. This control increases the public and employee safety and reduces the risk of property damage when an incident does occur.

b. Elements of the Bow Tie Addressed

Right of Way addresses the following elements of the bow tie:

i. [DT.2] – Natural forces

ii. [DT.3] – Outside forces

8. SDG&E-6-C8: Meter Inspection and Maintenance

a. Qualitative Description of Risk Reduction Benefits

The medium and large customers MSAs require routine maintenance of the meters, regulators, and other components to meet customers' capacity requirements and to measure gas volume accurately. MSA inspection and maintenance activities are conducted in accordance with General Order 58-A which requires routine maintenance on medium and large MSAs. Given the mandated requirement to conduct MSA inspections and maintenance, the management of this control is cyclical in nature.

MSA inspection and maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by detecting and addressing emergent equipment issues. In addition to addressing emergent issues, MSA inspection and maintenance activities provide an opportunity for SDG&E to identify equipment that is at risk of deterioration in the future and procure equipment to remediate or replace that equipment during the next inspection cycle. Distribution Operations manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

MSA inspection and maintenance activities increase public and employee safety by mitigating various risk sources, including corrosion and degradation, for example. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Meter Inspection and Maintenance addresses the following elements of the bow tie:

i. ***[DT.1] – Corrosion***

ii. ***[DT.2] – Natural forces***

iii. ***[DT.3] – Outside Forces***

iv. ***[DT.5] – Equipment Failure***

v. ***[DT.6] – Incorrect Operations***

9. SDG&E-6-M1: Early Vintage Program (Pipeline)

a. Qualitative Description of Risk Reduction Benefits

SDG&E's Early Vintage Program (Pipeline) consists of Early Vintage Threaded Main Replacement, Early Vintage Steel Replacement, Oil Drip Removal, Leak History Replacement. The Early Vintage Program increases public safety by mitigating risk associated with early vintage equipment before operational and safety issues arise. The risk reduction associated with each mitigation tranche is further described below:

i. SDG&E-6-M1-T1: Early Vintage Threaded Main Replacement:

There is a reduction in safety risks with the replacement of early vintage threaded mains. Eliminating this classification of pipe and replacing it with state-of-the-art polyethylene pipe, the threat of corrosion and threaded joint failure will be eliminated. Polyethylene pipe also is also much more flexible and therefore less susceptible to failure during a seismic event. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability over time.

ii. SDG&E-6-M1-T2: Early Vintage Steel Replacement:

Significant reductions in safety risks are achieved with the replacement of vintage steel pipeline with new plastic pipe. Newly installed plastic pipe has a very low leak rate and is not subject to corrosion. A newly installed pipeline has a lower residual risk level and its risk rises on a different path than that of vintage pipe. The difference in deterioration paths is the performance benefit derived from reconstruction. This directly translates into a decrease in safety risk. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability over time.

iii. SDG&E-6-M1-T3: Early Vintage Oil Drip Removal:

The removal of the oil drip facilities will eliminate any threat that they may be damaged due to the inability to properly locate and mark these features. The ones that will remain in service will have detailed dimensioning of the pipeline features put into the GIS system in which the Locators rely on to accurately mark-out. This will eliminate future pipeline damage events.

b. **Elements of the Bow Tie Addressed**

The Early Vintage Program (Pipeline) addresses the following elements of the bow tie:

i. ***[DT.1] – Corrosion***

ii. ***[DT.2] – Natural forces***

iii. ***[DT.3] – Outside Forces***

iv. ***[DT.4] – Pipe, weld, or joint failure***

c. **RSE Inputs and Basis**

i. **SDG&E-6-M1-T1: Early Vintage Threaded Main Replacement**

Scope	45 miles of threaded main that will be replaced as part of the Early Vintage Program (Pipeline).
Effectiveness	Per internal SME assessment, we assume 100% effectiveness because failure rate of replacement PE plastic pipe is very low. Based on SME analysis, steel segments that are being replaced are 13.2 times more likely for an incident to occur than modern plastic pipe over a lifecycle.
Risk Reduction	**Safety**: 1 out of 41 SoCalGas and SDG&E incidents are associated with steel mains. Based on PHMSA data assessment, 55% of the risk is attributed to early vintage steel, 17.6% to threaded main, and the rest to other pipe types. Using these assumptions, this mitigation tranche could improve safety risk by up to 2%. **Reliability**: Using these assumptions, this mitigation tranche could improve reliability risk by up to 2%. **Financial**: Using these assumptions, this mitigation tranche could improve financial risk by up to 2%.

ii. **SDG&E-6-M1-T2: Early Vintage Steel Replacement**

Scope	90 miles of early vintage steel will be replaced as part of the Early Vintage Program (Pipeline).
Effectiveness	Per internal SME assessment, we assume 100% effectiveness because the failure rate of replacement PE plastic pipe is very low. Based on SME analysis, steel segments that are being replaced are 13.2 times more likely for an incident to occur than modern plastic pipe over a lifecycle.
Risk Reduction	**Safety**: 1 out of 41 SoCalGas and SDG&E incidents are associated with steel mains. Based on PHMSA data assessment, 55% of the risk is attributed to early vintage steel, 17.6% to threaded mains, and the rest to

	other pipe types. Using these assumptions, this mitigation tranche could improve safety risk by up to 8%. **Reliability**: Using these assumptions, this mitigation tranche could improve reliability risk by up to 8%. **Financial**: Using these assumptions, this mitigation tranche could improve financial risk by up to 8%.

iii. SDG&E-6-M1-T3: Early Vintage Oil Drip Removal

Scope	107 locations will be verified and assessed for oil drip piping removal as part of the Early Vintage Program (Pipeline).
Effectiveness	Per internal SME assessment, the effectiveness of these activities is 90%.
Risk Reduction	**Safety**: The 2 recorded oil drip piping events out of 43 incidents were not significant, so their consequence is deflated by 50%. Using these assumptions, this mitigation could improve safety risk by up to 2%. **Reliability**: Using these assumptions, this mitigation tranche could improve reliability risk by up to 2%. **Financial**: Using these assumptions, this mitigation tranche could improve financial risk by up to 2%.

d. Summary of Results

i. SDG&E-6-M1-T1: Early Vintage Threaded Main Replacement

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	**LoRE**		**98.94**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	45.62	**246.63**	581.65
	RSE	1.20	**6.51**	15.35

ii. SDG&E-6-M1-T2: Early Vintage Steel Replacement

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**93.37**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	43.05	**232.76**	548.94
	RSE	5.09	**27.53**	64.92

iii. SDG&E-6-M1-T3: Early Vintage Oil Drip Removal

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**98.89**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	45.60	**246.51**	581.36
	RSE	0.98	**5.28**	12.46

10. SDG&E-6-M2: Early Vintage Program (Fitting)

a. Qualitative Description of Risk Reduction Benefits

SDG&E's Early Vintage Program (Fitting) consists of: Dresser Mechanical Coupling Removal and High/Medium Valve Separation Removal. The Early Vintage Program increases public safety by mitigating risk associated with early vintage equipment before operational and safety issues arise. The risk reduction associated with each mitigation tranche is further described below:

i. SDG&E-6-M2-T1: Dresser Mechanical Coupling Removal

The Early Vintage Program (Fittings) consists of evaluating locations where Dresser mechanical couplings exist, excavating, removing the Dresser mechanical couplings, and welding pipes back together to reduce the risk of pipe separation and rupture in the event of a land movement. Distribution Operations manages the implementation of the work associated with this mitigation with engineering oversight from the Pipeline Integrity group. The pace of the work associated with this program relies on the ability of SDG&E to procure permits in a timely manner.

The Early Vintage Program (Fittings) is preventative in nature and is intended to eliminate conditions that might lead to an incident. This program reduces the frequency of gas leak incidents and eliminates the possibility of a pipeline fitted with a Dresser mechanical coupling rupturing as a result of land movement from seismic activity or third-party construction activity near the pipeline, for example. Minimizing safety threats has the additional benefits of reducing risk to property and the potential benefit of improved service reliability.

ii. SDG&E-6-M2-T2: High/Medium Valve Separation Removal

There is a reduction in safety risks with high/medium valve separation removal. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability over time.

b. Elements of the Bow Tie Addressed

The Early Vintage Program (Fitting) addresses the following elements of the bow tie:

i. [DT.1] – Corrosion

ii. [DT.2] – Natural forces

iii. [DT.3] – Outside Forces

iv. [DT.5] – Equipment Failure

c. RSE Inputs and Basis

i. SDG&E-6-M2-T1: Dresser Mechanical Coupling Removal

Scope	60 locations will be addressed as part of the Early Vintage Program (Fitting)
Effectiveness	Per internal SME assessment, the assumed effectiveness is 75%.

Risk Reduction	**Safety**: 2 significant events out of 426 events at the national level are associated with Dresser mechanical couplings. Using these assumptions, this mitigation tranche could improve safety risk by up to 0.1%. **Reliability**: Using these assumptions, this mitigation tranche could improve reliability risk by up to 0.1%. **Financial**: Using these assumptions, this mitigation tranche could improve financial risk by up to 0.1%.

ii. SDG&E-6-M2-T2: High/Medium Valve Separation Removal

Scope	Removal of valves at 130 interfaces.
Effectiveness	Per SME estimate, we assume 100% effectiveness. These removals eliminate the threat of bringing higher pressure gas into lower pressure systems.
Risk Reduction	**Safety**: nationwide, 2 out of a sample of 765 significant incidents can be attributed to valves based on data reported to PHMSA since year 2010. For analysis purposes, this risk is split evenly between reliability causes and inadvertent openings. Using these assumptions, this mitigation could improve safety risk by up to 0.1%. **Reliability:** Using these assumptions, this mitigation could improve safety risk by up to 0.1%. **Financial:** Using these assumptions, this mitigation could improve safety risk by up to 0.1%.

d. Summary of Results

i. SDG&E-6-M2-T1: Dresser Mechanical Coupling Removal

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**100.88**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.52	**251.49**	593.10
	RSE	0.05	**0.28**	0.65

ii. SDG&E-6-M2-T2: High/Medium Valve Separation Removal

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**100.87**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.51	**251.45**	593.01
	RSE	0.45	**2.45**	5.77

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

As discussed, the existing controls outlined within this Chapter will continue and certain controls will increase in scope or at an accelerated pace. However, as a diligent operator the controls will be monitored to determine if any adjustments are needed during the implementation period. The programs could be influenced as additional information is gathered or understanding of risk and controls relationship changes. Should controls need to change, consideration will be given to available technology, labor resources, planning and construction lead time, compliance requirements, and operational and execution considerations.

The table below provides a summary of the Risk Mitigation Plan, including controls and forecasted mitigation activities, associated costs, the RSEs by tranche. SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in the table were estimated using assumptions provided by SMEs and available accounting data.

Table 7: Risk Mitigation Plan Overview[39]
(Direct 2018 $000)[40]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-6-C1	Cathodic Protection	T1	12,000	1,600	11,000 – 15,000	1,400 – 1,800	12,000 – 17,000	0.77 – 9.81
SDG&E-6-C2	Assessment of Buried Piping in Vaults	T1	0	0	21,000 – 27,000	0	21,000 – 27,000	0.15 – 1.91
SDG&E-6-C3	Regulator & Valve Inspection and Maintenance	T1	0	1,600	0	1,400 – 1,800	1,400 – 1,800	-
SDG&E-6-C4	Plastic Pipe Replacement	T1	34,000	0	150,000 – 200,000	0	150,000 – 200,000	0.24 – 3.03
SDG&E-6-C5	Leak Repair	T1	7,500	1,200	21,000 – 26,000	1,100 – 1,400	22,000 – 27,000	-
SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth	T1	0	2,100	0	1,800 – 2,300	1,800 – 2,300	-

39 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

40 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

41 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

42 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

43 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

44 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

	Inspections, Pipeline Patrol.							
SDG&E-6-C7	Utility Conflict Review (Right of Way)	T1	570	51	1,100 – 1,400	58 - 74	1,200 – 1,500	-
SDG&E-6-C8	Meter Inspection & Maintenance	T1	0	110	0	170-220	170-220	-
SDG&E-6-M1	Early Vintage Program (Pipeline) - Threaded Main Replacement	T1	0	0	20,000-25,000	0	20,000-25,000	1.20 – 15.35
SDG&E-6-M1	Early Vintage Program (Pipeline) - Steel Replacement	T2	1,500	0	17,000 – 22,000	0	17,000 – 22,000	5.09 – 64.92
SDG&E-6-M1	Early Vintage Program (Pipeline) - Oil Drip Removal	T3	0	0	25,000 – 32,000	0	25,000 – 32,000	0.98 – 12.46
SDG&E-6-M2	Early Vintage Program (Fittings) - Dresser Mechanical Coupling Removal	T1	0	0	21,000 – 27,000	0	21,000 – 27,000	0.05 – 0.65
SDG&E-6-M2	Early Vintage Program (Fittings) - High/Medium Valve Separation Removal	T2	0	0	3,200 – 4,000	0	3,200 – 4,000	0.45 – 5.77
TOTAL COST			**56,000**	**6,700**	**290,000 – 380,000**	**5,900 – 7,600**	**300,000 – 390,000**	-

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 8: Summary of RSE Exclusions

Control ID	Control Name	Reason for No RSE Calculation
SDG&E-6-C3	Regulator & Valve Inspection and Maintenance	Mandated activity per 49 CFR 192 Subpart H
SDG&E-6-C5	Leak Repair	Mandated activity per 49 CFR § 192.720 and § 192.723
SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol	Mandated activity per 49 CFR § 192.705, § 192.722, § 192.723 and § 192.935
SDG&E-6-C7	Utility Conflict Review (Right of Way)	Mandated activity per 49 CFR 192 § 192.705
SDG&E-6-C8	Meter Inspection & Maintenance	Mandated activity per 49 CFR 192 Subpart H

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the described mitigations for the Medium Pressure Gas Pipeline Incident risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, including but not limited to operational, compliance and resource constraints.

A. SDG&E-6-A1 – Assessment and Replacement of 10-year Cycle Cathodically Protected Services (CP10s)

SDG&E considered replacing the 58,083 CP10 service rather than continuing to monitor, inspect and maintain them on ten-year cycle. CP10 services are separately protected service lines that are surveyed on a sampling basis where at least 10% of system inventory are sampled each year, so that the entire system is tested in a 10-year period. However, due to the number of CP10 services in the system, a program targeting complete replacement of CP10 services would exceed $350 million and likely take many decades to complete. As complete replacement is not feasible, further evaluation of CP10 services is required to evaluate and quantify the risk reduction benefits, potentially developing a risk based targeted in replacement program. In the interim CP10s will be replaced based on performance history and current protection levels.

1. RSE Inputs and Basis

Scope	Per SME input, scope is 2.8% or a replacement of 150 units out of 5,400.
Effectiveness	Per internal SME assessment, the effectiveness of this mitigation is 95%.
Risk Reduction	Based on historical information reported to PHMSA, risk addressed is 2%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.1%.

2. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**100.93**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.54	**251.61**	593.40
	RSE	0.51	**2.75**	6.49

B. SDG&E-6-A2 - Soil Sampling Program

SDG&E considered expanding its collection of soil property information. SDG&E collects soil properties (rocky, clay, sandy) during excavations and repairs along its pipelines. These soil properties are an element within the relative risk models used for prioritization process of the vintage replacement program for plastic. Expanding the collection of soil properties beyond leak repair excavations may allow SDG&E to further refine its replacement efforts. The cost estimate of sampling the 5,907 miles of distribution pipe is $12.2 million; on average, 14 samples per day will be tested at intervals of 2 samples per mile. SDG&E has not initiated an expanded soil sampling program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature for the corrosion threat the benefit of additional information can be better understood. In the interim SDG&E will be researching available data sets and determining the benefit of additional granularity.

1. RSE Inputs and Basis

Scope	Assuming 100% of soil would be sampled, as a one-time effort: once the soil is sampled, it does not need to be resampled.
Effectiveness	Per internal SME assessment, effectiveness of having additional data for making better pipe replacement decisions will be minimal, at 1%.[45]
Risk Reduction	Per SME guidance, risk addressed is 17%, same as the SDG&E plastic DREAMS program. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.2%.

2. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**101**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.57	**251.78**	593.78
Post-Mitigation	LoRE		**100.83**	
	CoRE	0.46	**2.49**	5.88
	Risk Score	46.49	**251.35**	592.77
	RSE	0.01	**0.03**	0.08

45 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

Table 9: Alternative Mitigation Summary
(Direct 2018 $000)[46]

ID	Mitigation	2020-2022 Capital[47]	2022 O&M	Total[48]	RSE[49]
SDG&E-6-A1	Assessment and Replacement of 10-year Cycle Cathodically Protected Services (CP10s)	1,500 – 2,000	0	1,500 – 2,000	0.51 – 6.49
SDG&E-6-A2	Soil Sampling Program	0	2,200 – 2,900	2,200 – 2,900	0.01 – 0.08

46 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

47 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

48 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

49 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control / Mitigation Name	Elements of the Risk Bow Tie Addressed
SDG&E-6-C1	Cathodic Protection	DT.1, DT.4
SDG&E-6-C2	Assessment of Buried Piping in Vaults	DT.1, DT.2, DT.3, DT.4
SDG&E-6-C3	Regulator & Valve Inspection and Maintenance	DT.1, DT.2, DT.3, DT.5, DT.6
SDG&E-6-C4	Plastic Pipe Replacement	DT.1, DT.2, DT.3, DT.4, DT.5, DT.7
SDG&E-6-C5	Leak Repair	DT.1, DT.2, DT.3, DT.5
SDG&E-6-C6	Pipeline Monitoring: Leak Mitigation, Bridge & Span Inspections, Unstable Earth Inspections, Pipeline Patrol.	DT.1, DT.2, DT.3, DT.5
SDG&E-6-C7	Utility Conflict Review (Right of Way)	DT.2, DT.3
SDG&E-6-C8	Meter Inspection and Maintenance	DT.1, DT.2, DT.3, DT.5, DT.6
SDG&E-6-M1-T1	Early Vintage Program (Pipeline): Early Vintage Threaded Main Replacement	DT.1, DT.2, DT.3, DT.4
SDG&E-6-M1-T2	Early Vintage Program (Pipeline): Early Vintage Steel Replacement	DT.1, DT.2, DT.3, DT.4
SDG&E-6-M1-T3	Early Vintage Program (Pipeline): Oil Drip Removal	DT.1, DT.2, DT.3, DT.4
SDG&E-6-M2-T1	Early Vintage Program (Fittings): Dresser Mechanical Coupling Removal	DT.1, DT.2, DT.3, DT.5
SDG&E-6-M2-T2	Early Vintage Program (Fittings): High/Medium Valve Separation Removal	DT.1, DT.2, DT.3, DT.5

Risk Assessment Mitigation Phase

(Chapter SDG&E-7)

Third Party Dig-in on a Medium Pressure Pipeline

November 27, 2019

TABLE OF CONTENTS

Risk: Third Party Dig-in on a Medium Pressure Pipeline

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas & Electric Company's (SDG&E or Company) Third Party Dig-in on a Medium Pressure Pipeline risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in the 2019 RAMP Report are those costs which SDG&E anticipates requesting recovery for in the Test Year (TY) 2022 GRC. The information presented in the 2019 RAMP Report will be refined with supporting testimony and integrated into the TY 2022 GRC.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. The 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and are within the scope of the analysis required in this RAMP Report. Throughout the 2019 RAMP Report activities are delineated between controls and mitigations, consistent with the definitions adopted in the 2018 S-MAP Revised Lexicon per D.18-12-014. A "Control" is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC).

defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Third Party Dig-in on a Medium Pressure Pipeline risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are non-GRC jurisdictional and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order (GO). Activities with no RSE score presented in this RAMP Report are identified in Section VII below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable Control/Mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

SDG&E and the Southern California Gas Company (SoCalGas), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SDG&E and SoCalGas territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' third party dig-in related chapters.[3]

A. Risk Definition

For purposes of this TY 2022 RAMP Report, the Third Party Dig-in on a Medium Pressure Pipeline risk is defined as a dig-in on a medium pressure pipeline [Maximum Allowable Operating Pressure (MAOP), at or lower than 60 pounds per square inch gauge (psig)] caused by third party activities which results in significant consequences including serious injuries and/or fatalities.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each Control and Mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the Control or Mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequence
DT.1	Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation
DT.2	Locator error contributing to the incorrect marking of underground gas structures
DT.3	Hand excavation is not performed in the vicinity of located gas pipelines
DT.4	Company does not respond to 811 requests in required timeframe
DT.5	Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark
PC.1	Serious Injuries and/or Fatalities
PC.2	Property Damage
PC.3	Prolonged Outages
PC.4	Penalties and Fines
PC.5	Adverse Litigation

3 The other third party dig-in related chapters in the 2019 RAMP Report include: SCG-6 – Third Party Dig-in on a Medium Pressure Pipeline; SCG-7 – Third Party Dig-in on a High Pressure Pipeline; and SDG&E-9 – Third Party Dig-in on a High-Pressure Pipeline.

4 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

ID	Description of Driver/Trigger and Potential Consequence
PC.6	Erosion of Public Confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SDG&E has performed a detailed pre- and post-mitigation analysis of Controls and Mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline Controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

Control ID	Control Name
SDG&E-7-C1	Locate and Mark Training
SDG&E-7-C2	Locate and Mark Activities
SDG&E-7-C3	Locate and Mark Annual Refresher Training and Competency Program
SDG&E-7-C4	Locate and Mark Operator Qualification
SDG&E-7-C5	Locate and Mark Quality Assurance Program
SDG&E-7-C6	Damage Prevention Analyst Program
SDG&E-7-C7	Prevention and Improvements-Refreshed Laptops
SDG&E-7-C8	Public Awareness Compliance
SDG&E-7-C9	Increase Reporting of Unsafe Excavation
SDG&E-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board
SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates
SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance
SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program
SDG&E-7-C14	Locating Equipment
SDG&E-7-C15	Remain Active Members of the 811 California One-Call Centers

SDG&E will continue the baseline Controls identified above and describes additional projects and/or programs (*i.e.*, Mitigations) as follows:

---

5 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-7-M1	Automate Third Party Excavation Incident Reporting
SDG&E-7-M2	Establish a program to address the area of continual excavation
SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator
SDG&E-7-M4	Utilize electronic positive response
SDG&E-7-M5	Enhance process to utilize and leverage emerging excavation technology to help with difficult locates
SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring
SDG&E-7-M7	Leverage data gathered by locating equipment
SDG&E-7-M8	Install warning mesh above buried company facilities

Finally, pursuant to the SA Decision,[6] SDG&E considered alternatives to the mitigations for the Third Party Dig-in on a Medium Pressure Pipeline Risk and summarizes the reasons that the alternatives were not included into the mitigation plans in Section VIII.

II. RISK OVERVIEW

Excavation damage, or dig-ins, to medium pressure underground gas infrastructure has been a risk to SDG&E for as long as pipe has been buried underground. This risk is not a risk unique to the Company. Third-party dig-ins are a common national problem for all industries and utilities with buried infrastructure. These "third-party" excavation activities can vary widely based on project scope and size. Examples can include a homeowner doing landscaping work, a plumber repairing a sewer line, or a city upgrading its aging municipal water or sewer systems.

Third-party excavation damage can range from minor scratches or dents, to ruptures with an uncontrolled release of natural gas. The release of natural gas may not just occur at the time of the damage. A leak or rupture may also occur after the infrastructure has sustained more minor damage, but then becomes weakened over time. Once damaged, the responsible party may not report non-gas release damages, bypassing the efforts of the Company to assess and make the appropriate repairs before a weakening of the pipe occurs.

---

6 *Id.* at 33.

Serious consequences may result if an event occurs because of this risk. For example, if a leak or rupture occurs, an ignition of the released gas could lead to an explosion, fire or both. The nearby public could be seriously injured, and property damage can be extensive.

Federal and state agencies have responded to the third party dig-ins risk by adopting numerous regulations and industry standards[7] and have promoted other efforts[8] to help prevent third-party dig-ins. For example, the Department of Transportation (DOT) sponsored the "Common Ground Study", completed in 1999. The "Common Ground Study" then led to the creation of the Common Ground Alliance (CGA), a member-driven association of 1,700 individuals, organizations, and sponsors in every facet of the underground utility industry. With industry-wide support, CGA created a comprehensive consensus document that details the best practices addressing every stake-holder groups' activity in promoting safe excavation and preventing dig-in damages.

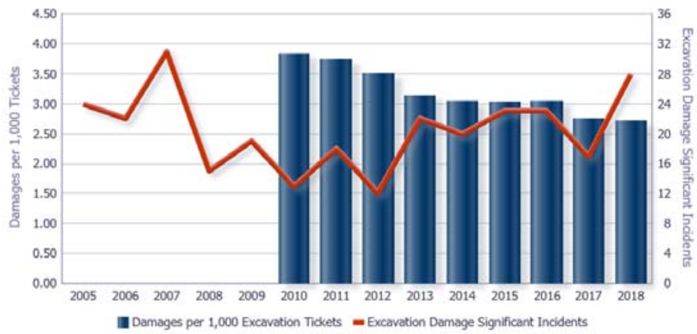
While these efforts are important and commendable, and the number of dig-ins per 1,000 excavation tickets has been trending down (Figure 1), the numbers still remain high. Figure 1 represents trends for third party dig-ins on distribution lines. Similar data is not available for transmission lines since transmission incidents caused by excavation are not common enough to trend. Thus, the Pipeline and Hazardous Materials Safety Administration (PHMSA) collects ticket totals in annual reports for distribution facilities but does not collect ticket information for transmission facilities.

---

7 49 Code of Federal Regulations (CFR) § 192, *et al.*; *id.* at § 196; Cal. Govt. Code § 4216, General Order (GO) 112-F; American Petroleum Institute (API) Recommended Practice (RP) 1162.

8 Common Ground Alliance (CGA), Best Practices Guide (March 2019), available at https://commongroundalliance.com/best-practices-guide.

Figure 1: Excavation Tickets & Incidents[9]



Under California State Law,[10] a third-party planning excavation work is required to contact the Regional Notification Center for their area, also known as 811 or Underground Service Alert (USA), at least two (2) full working days prior to the start of their construction excavation activities, not including the day of the notification. Eight-One-One (811) is the national phone number designated by the Federal Communications Commission (FCC), that connects homeowners who plan to dig with professionals through a local call center. California has two Regional Notification Centers, DigAlert and USA North, that split California at the Los Angeles /Kern county and Santa Barbara/San Luis Obispo county lines; USA North serves all counties north of the county lines and DigAlert serves all counties south of the county lines. DigAlert and USA North will be referenced as 811 USA for the remainder of this chapter. Once a third-party makes the contact, the Regional Notification Center will issue a USA Ticket notifying local utilities and other operators of the location and areas to be inspected for potential conflicts of underground infrastructure with the pending excavation work. Operators are required to provide a positive response to indicate that there are no facilities in conflict or mark their underground facilities via aboveground identifiers (e.g. paint, chalk, flags, whiskers) to designate where underground utilities are positioned, thus enabling third parties, like contractors and homeowners, to know where these substructures are located. The law also requires third-

---

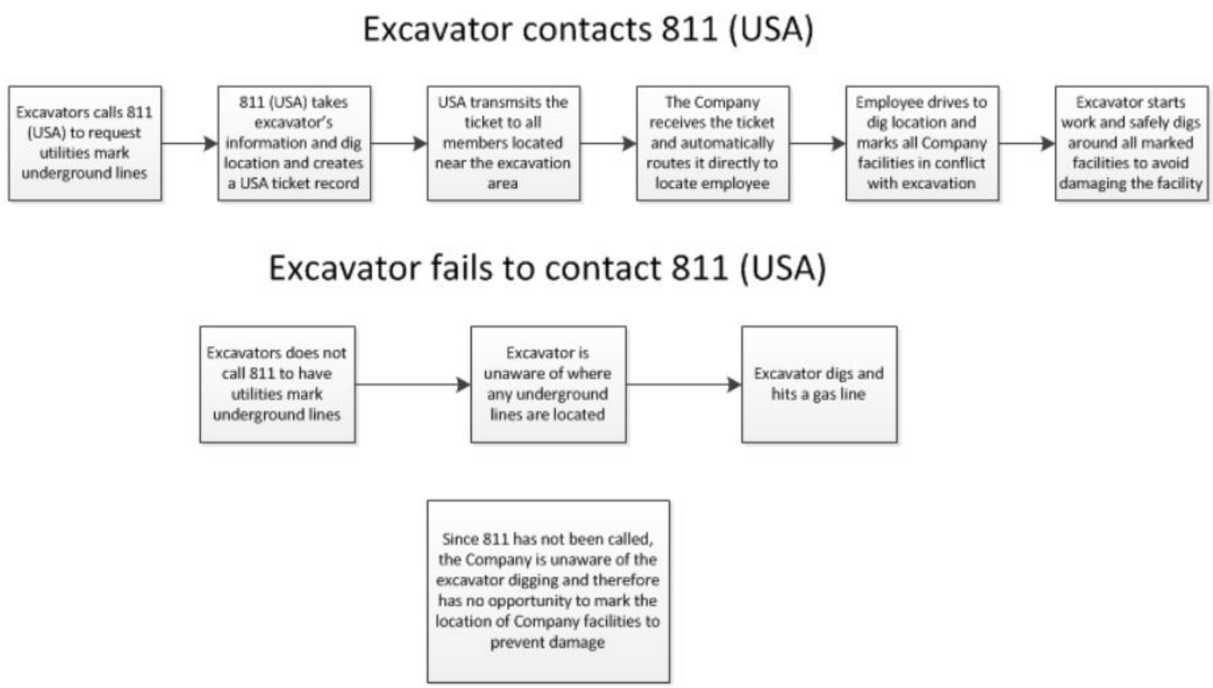
9 *See* United States Department of Transportation, *National Pipeline Performance Measures, available at* https://www.phmsa.dot.gov/data-and-statistics/pipeline/national-pipeline-performance-measures/.

10 Cal. Govt. Code § 4216.2(b).

party excavators to use careful, manual (hand digging) methods to expose substructures prior to using mechanical excavation tools.

Figure 2 below illustrates the sequence of events that may occur when a third-party contacts 811 USA prior to conducting excavation work and, in contrast, the sequence that may occur when they do not.

Figure 2: Excavation Contact Process Flow



As can be seen from the above flow charts, while there may be more steps when a third party calls 811 USA prior to commencing the excavation work, it is more likely to result in a positive outcome compared to when a call is not made. Having third-parties call 811 USA before digging is critical and can significantly reduce the likelihood of a potential event if the correct processes are followed.

SDG&E managed nearly 130,000 811 USA tickets and reported over 300 dig-in excavation damages in 2018. Further analysis of the reported damage incidents shows that 50% were due to a lack of notification to 811 USA for a locate and mark ticket and another nearly

36% were due to insufficient excavation practices even after the excavator called 811 USA and underground facilities were marked.[11]

In addition to direct involvement with excavators and 811 USA, SDG&E engages in promoting safe digging practices through its Public Awareness Program[12] and corporate safety messaging through stakeholder outreach. The message is presented by way of multi-formatted educational materials through mail, email, social media, television, radio, events, and association sponsorships. This Control is further described in Section V.

III. RISK ASSESSMENT

In accordance with the SA Decision,[13] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Third Party Dig-in on a Medium Pressure Pipeline risk.

A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers/triggers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

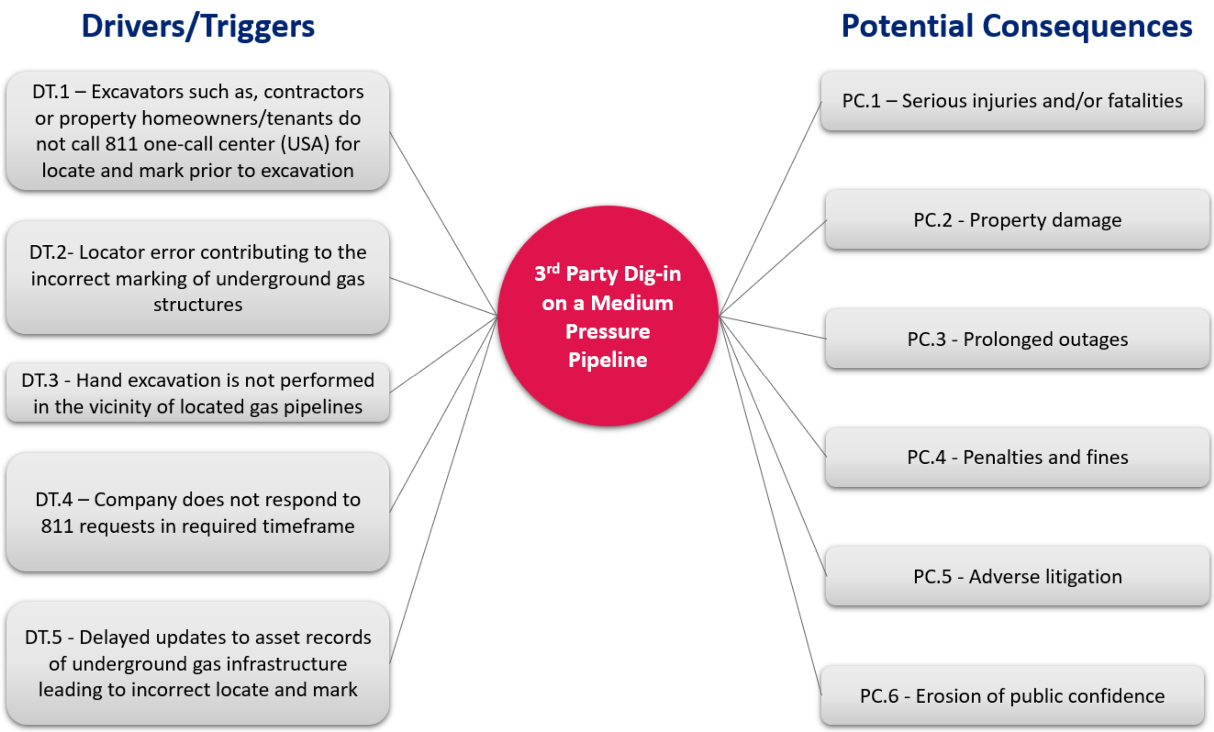
---

[11] Common Ground Alliance, *CGA Released 2018 Damage Information Reporting Tool (DIRT) Report*, *available at* https://commongroundalliance.com/DIRT.

[12] API 1162.

[13] D.18-12-014 at 33 and Attachment A, A-11 (“Bow Tie”).

Figure 3: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision directs the utilities to endeavor to identify all asset groups or systems subject to the risk. These assets primarily include the Natural Gas Pipeline Distribution System. SDG&E's medium and high-pressure distribution pipeline system is comprised of plastic and steel medium and high pressure pipelines and appurtenances (*e.g.*, meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines by definition; however, these assets are operated by Distribution Operations.

C. Risk Event Associated with the Risk

The SA Decision[14] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the risk event (center of the bow tie) is

[14] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

a third party dig-in on a medium pressure pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. The Risk Scenario (*i.e.*, a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency) is assessed for SDG&E' 2018 Enterprise Risk Registry. This scenario does not necessarily address all Drivers/Triggers and Potential Consequences and does not reflect actual or threatened conditions.

D. Potential Drivers/Triggers[15] of Risk Event

When performing the risk assessment for Third Party Dig-in on a Medium Pressure Pipeline, SDG&E identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT.1 – Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation:** Despite the creation of Regional Notification Centers to inform and allow excavators to have underground infrastructure located and marked, and advertising campaigns alerting the excavator of the need to do so, incidents still occur where excavations are conducted without first calling 811 USA. In fact, third party failure to contact the Regional Notification Center prior to excavating is the leading contributor of damages to Company pipelines. Third parties can damage or rupture underground pipelines and potentially cause property damage, injuries, or even death if gas lines are not properly marked before excavation activities begin. Without receiving an 811 USA ticket, the Company has no opportunity to mark its facility within the area of excavation.
- **DT.2 – Locator error contributing to the incorrect marking of underground gas structures:** The Company or Company Contractors in some cases, inaccurately mark facilities due to incorrect operations, such as mapping/data inaccuracies, equipment signal interference, and human error. When this happens, third parties are not provided with accurate knowledge of underground

[15] An indication that a risk could occur. It does not reflect actual or threatened conditions.

structures in the vicinity of their excavations and the risk of damaging or rupturing gas pipelines increases.

- **DT.3 – Hand excavation is not performed in the vicinity of located gas pipelines:** Before using any power operated excavation equipment or boring equipment, the excavator is required to hand expose, using "Hand Tools," [16] to the point of no conflict 24 inches on either side of the Medium-Pressure Gas Pipeline to determine the exact location of these structures. If excavators do not use care when digging near natural gas pipelines they put themselves and others at risk for injuries.
- **DT.4 – Company does not respond to 811 requests in required timeframe:** Company may fail to respond to 811 USA requests within the 'legal excavation start date and time' [17] (within two working days of notification, excluding weekends and state holidays, not including the date of notification, or before the start of the excavation work, whichever is later, or at a time mutually agreeable to the operator and the excavator). This may happen because of human error, poor communication, or system failures. In these cases, the third party may not know that the locate and mark activity was not performed and may wrongly assume that not seeing any marking at their excavation site indicates there is no gas infrastructure nearby. Without the marked gas infrastructure, third parties may damage or rupture the infrastructure if they are performing excavation activities near pipelines.
- **DT.5 – Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark:** The Company may fail to supply the necessary information in a timely manner to update permanent mapping records necessary to meet federal, state, and local regulations, as well as corporate needs. This could result in underground infrastructure being incorrectly marked, which

[16] Cal. Govt. Code § 4216(i).

[17] *Id.* at § 4216(l).

could lead to third party damage if the excavator does not have the correct information on infrastructure location. In addition, in the event in which a pipeline is damaged, obsolete maps could cause delays in performing the necessary repairs.

E. Potential Consequences of Risk Event

If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[18] and/or fatalities;
- Property damage;
- Prolonged outages;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of SDG&E's Third Party Dig-in on a Medium Pressure Pipeline Risk that occurred during the development of SDG&E's 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP, including enhancements to the Interim Decision 16-08-018. SDG&E has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

[18] As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." *See* 8 CCR § 330(h).

Table 4: Risk Quantification Scores[19]

Third Party Dig-in on a Medium Pressure Pipeline	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	125	**172**	250
LoRE		**338**	
CoRE	0.4	**0.5**	0.7

A. Risk Scope & Methodology

The SA Decision requires a pre- and post- mitigation risk calculation.[20] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification	The risk of a dig-in on a medium pressure pipeline (MAOP at or lower than 60 psig) caused by third party activities, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification	The risk of pipeline event unrelated to a third party dig-in on a medium-pressure pipeline (MAOP at or lower than 60 psig) which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision , the utility is instructed to use actual results, available and appropriate data (*e.g.*, PHMSA data).[21]

19 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score"), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

20 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

21 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SDG&E, the national average incident rate per mile per year was applied to the medium-pressure pipeline miles at SDG&E.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA medium-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

B. Sources of Input

The SA Decision[22] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Annual Report mileage for Gas Distribution Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: PHMSA
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

[22] *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- SDG&E medium-pressure pipeline miles
  - o 2017 internal SME data
- Gas industry sales customers
  - o Agency: AGA (2016Y)
  - o Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SDG&E end user natural gas customers
  - o Source: SNL (2016Y, from the FERC Form 2/2-F, 3/3-A or EIA 176)
  - o Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[23] This section describes SDG&E' Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SDG&E' Third Party Dig-in on a Medium Pressure Pipeline Risk involves impact to gas infrastructure arising from third party dig-ins resulting in significant consequences including serious injuries and/or fatalities. The Risk Mitigation Plan discussed below includes both Controls that are expected to continue and Mitigations for the period of SDG&E' Test Year 2022 GRC cycle. The Controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SDG&E-7-C1 – Locate and Mark Training

This program provides employees with the training to perform activities associated with locate and mark. Adequately preparing employees by offering educational opportunities and

---

23 *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

resources gives them the knowledge to implement governmental and Company policies and procedures in a safe manner. This, in turn, helps SDG&E operate and maintain its system as well as protect employees, contractors, and the public from the threat of an event attributable to this risk.

Locate and Mark Training consists of approximately seven days of classroom and hands-on training at a centralized training facility, as well as eLearning. SDG&E will continue to implement a competency based training program that will encompass training designed for third-party dig-ins policy and procedural changes. A competency based online/video training module system enhances SDG&E's ability to incorporate new policies and increases learning at a faster pace. This system uses a comprehensive, multimedia, competency-based training approach which will include self-paced, individualized, modular instruction, eLearning, just-in-time training, structured on-the-job training and mentoring. This is a mandated activity in order to comply with Operator Qualification requirements and to provide the basic knowledge necessary to satisfactorily perform this critical task. The training schedule is dependent on annual demand, but occurs, on average, about every two months.

The training provides the participating employees several key components of locating, enabling them to locate and mark the below ground facilities accurately and in the appropriate time frame. The marked facilities provide the excavator with approximate locations of where the gas lines exist in the work area which enables the excavator to either avoid the areas or dig with hand tools so underground substructures are not accidentally damaged by the excavation work.

B. SDG&E-7-C2 – Locate and Mark Activities

This Locate and Mark Activity includes three efforts: (1) Locate and Mark, (2) Pipeline Observation (stand-by), and (3) Staff Support. Verifying that SDG&E is executing such tasks safely can reduce the potential of an event occurring.

The first activity is Locate and Mark, which is the actual work performed by SDG&E gas operations which is required to respond to over 130,000 811 USA notifications per year.[24] To do this activity, SDG&E's locators travel to the job site and locate and mark any and all company

---

[24] Represents 811 USA notifications for SDG&E's distribution and transmission system.

operated pipelines in the delineated work area. Understanding the physical location of the pipeline allows the third-party to avoid that area or carefully perform the excavation work to avoid contact with the pipeline. This activity is mandated by both State[25] and Federal law.[26] This Control activity also includes all aspects necessary to performing the mandated locate and mark activities, including locators, vehicles, tools, Mobile Data Terminals (MDTs), Geographical Information System (GIS)-related costs, ticket routing systems, locating materials, fees to Regional Notification Centers, and quality assurance.

The second Locate and Mark activity is Pipeline Observation (stand-by). In accordance with Title 49 Code of Federal Regulation, section 192.935, Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. This activity occurs daily in both Distribution and Transmission operations. The purpose of this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having another pair of qualified eyes observing the work being done. This is a best practice in the gas industry and is critical to the safety of employees, contractors and the public.

The third activity is staff support. Support staff consists of employees who are responsible for developing and maintaining policies, processes, and procedures that guide and direct locators in properly performing their assigned tasks in compliance with Federal and State regulations. Staff is engaged daily in supporting operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, and providing refresher training as requested. This is a critical activity that allows the Company to meet or exceed State and Federal requirements and align with industry best practices when applicable.

C. SDG&E-7-C3 – Locate and Mark Annual Refresher Training & Competency Program

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards

---

25 Cal. Govt. Code § 4216.

26 49 CFR § 192.614.

with the locate and mark workforce. All employees are required to pass the refresher training in order to continue locate and mark activities. This refresher training involves all aspects of the Locate and Mark procedures to allow personnel to be able to successfully receive a ticket and provide a proper positive response. Similar to the Locate and Mark training mentioned above, refresher training will also be an interactive eLearning course, which potentially will consist of on-the-job training and mentoring. This is a mandated activity in order to comply with regulations and code requirements and to provide employees with the basic knowledge to satisfactorily perform this critical task.[27]

D. SDG&E-7-C4 – Locate and Mark Operator Qualification

Locate and Mark Operator Qualification (OQ) training is an enhanced training which requires pipeline operators to document that certain employees have been adequately trained to recognize and react to abnormal operating conditions that may occur while performing specific tasks. It provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. The training demonstrates an employee's knowledge and competency to perform locate and mark activities and is mandated by PHMSA.[28] Employing resources that are formally trained to be aware and react to unusual pipeline conditions allows SDG&E to potentially protect against an adverse event before its occurrence. Locators are qualified at the end of training and then every five years. This certification is an industry standard qualification program.

E. SDG&E-7-C5 – Locate and Mark Quality Assurance Program

The Locate and Mark quality assurance audit program reviews work activity to determine whether proper processes and procedures are being met. This includes, but is not limited to, employee qualification, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and mark activities, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations.

---

[27] *See* Cal. Govt. Code § 4216.

[28] 49 CFR §§ 192.801 - 192.809.

SDG&E has developed guidelines for quality assessments of locate and mark activities. The Gas Compliance Quality Management (GCQM) team conducts the re-occurring assessments of all districts (or bases) in order to provide an independent check of processes and to verify that applicable documentation is accurate and complete. The assessments include equipment testing, documentation reviews, field checks, and operator qualification reviews. After the assessment is complete, the GCQM will review findings with base management and gas distribution operations. Base management acknowledges the final report and develops plans for corrective actions, which are provided to GCQM. Findings are tracked, recorded, and monitored by base supervision.

Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

F. SDG&E-7-C6 - Damage Prevention Analyst

SDG&E Damage Prevention Analysts work to reduce the number of third-party excavation incidents in cities and jurisdictions with the highest number of reported occurrences by addressing the contractors and excavators operating in these jurisdictions. The intent of the SDG&E Damage Prevention Analyst program is to promote safe excavation practices and reduce the number of excavation damages. An important method of achieving this goal is to build and foster positive relationships with the excavator community through visibility, communication, and safe excavation education. Through this effort the desire is also for these employees to be viewed as a resource for contractors and to help overcome obstacles when excavating in the vicinity of underground SDG&E infrastructure. To achieve these objectives, the Analysts are equipped with the current 811 USA ticket information and GIS/mapping information for the local pipe network. Analysts also regularly partner with SDG&E's operating district personnel if additional infrastructure location information is needed.

The Damage Prevention Analysts prioritize their daily job site visits with the aid of a ticket prioritization software. Certain construction jobs may be more prone to excavation damage than others due to specific 811 USA ticket attributes and local environmental conditions. Eight-One-One ticket prioritization utilizes historical damage information as well as geographic, environmental, and other publicly available information. The software then weighs the pertinent attributes and performs calculations using complex algorithms to identify excavation sites that may be more susceptible to third party damages. This prioritization allows for the Company to take appropriate and timely measures to avoid damages such as making an extra phone call or email to the excavator or scheduling a pre-excavation site meeting to discuss the project in detail.

The Damage Prevention Analysts routinely visit active construction sites with known 811 USA tickets in their jurisdiction but will also look out for other active construction sites that do not appear on their 811 USA ticket listing. The purpose for visiting the latter is to make positive contact with the excavator and determine whether the supervision and workers at those projects have followed the safe digging practices. If not, the Analyst explains the safety risks, law violations and potential ramifications, and asks the excavator to stop their job and contact 811 USA to get the proper underground markings. These interactions have been very successful in getting the excavator to halt further excavation work until 811 USA contact was established. The most common reason for "Stopping-The-Job" was due to the excavator not having an 811 USA ticket. In addition, some were due to unsafe excavation practices.

The Damage Prevention Analysts also visit with local municipality personnel to discuss the importance of safe excavation with the Planning and Permitting departments. Gaining a safe-excavation partnership with the entities that approve, permit, and inspect excavation work is seen as an integral part of the Damage Prevention Analyst Program. During the interactions with City officials, the Analysts offer to present educational information regarding the Dig Safe laws and practices to interested parties.

Another key activity that falls within the Damage Prevention Analyst job responsibilities is responding to dig-in damages. Their role is to support the Operations response team through accurate documentation of the incident and collecting all relevant information to enable accurate regulatory reporting, damage-cause trending, and appropriate cost recovery where warranted. This data is used by the Damage Prevention Strategy and Distribution Integrity Management Program teams to evaluate and trend the causes of excavation damage and pursue the appropriate mitigation activities.

G. SDG&E-7-C7 – Prevention and Improvements – Refreshed Laptops

Locate and Mark laptops and software are utilized by SDG&E to comply with the requirements of state and federal regulations.[29] SDG&E provides locate and mark technicians rugged laptops called Mobile Data Terminals (MDTs) containing KorMobile© Ticket Management Software to respond to 811 USA tickets in real-time. Using obsolete technology increases wait times, contributes to data communication failure, and increases the likelihood of not responding to an 811 USA ticket requests in the required timeframe.

SDG&E has a service territory that covers about 4,100 square miles, from San Diego to southern Orange counties. The service territory covers 2 counties, and 25 communities. Providing durable refreshed laptops increases efficiency and the ability to work in a rugged outdoor setting. Increasing the processor speed and extending the battery life also allows for prolonged working hours. The refreshed laptops contain a detachable screen with a built in camera allowing the on-site technician to photograph the surroundings and the excavating equipment associated with an 811 USA ticket. A 4G LTE Advanced multi carrier mobile broadband facilitates the response to 811 USA tickets in real-time.

H. SDG&E-7-C8 – Public Awareness Compliance

It is important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks and private property – sometimes just inches below the surface. Hitting one of these pipelines while digging, planting or doing demolition work can cause serious injury, property damage, and/or loss of utility service.

Under Title 49 Code of Federal Regulation, section 192.616, SDG&E is required to educate the public, appropriate government organizations, and persons engaged in excavation related activities (1) about the use of a one-call notification system (811 USA) prior to excavation, (2) other damage prevention activities, (3) possible hazards associated with the unintended release from a gas pipeline facility, (4) physical indications of a natural gas release, (5) steps to be taken in the event of a gas pipeline release, and (6) procedures for reporting such

[29] 49 CFR § 192.614; Cal. Govt. Code § 4216.

an event. In addition to undertaking actions to meet the minimum requirements of section 192.616, SDG&E participates, promotes, and contributes to other public awareness and excavation improvement programs. To promote public awareness of the 811 USA program SDG&E utilizes various communication methods such as utilized bill inserts, media campaigns, damage prevention industry memberships, sponsorships, radio advertising, internet advertising, billboard advertising, and safety meetings. The four types of audiences identified in section 192.616 are the affected public, emergency officials, local public officials, and excavators. These types of audiences make up the four tranches further described below in Section VI.

I. SDG&E-7-C9 – Increase Reporting of Unsafe Excavation

Senate Bill (SB) 661 modified existing California Government Code section 4126 by establishing the California Underground Facilities Safe Excavation Board (Dig Safe Board). SDG&E has two groups involved in identifying excavators who frequently utilize unsafe practices and reporting those contactors to the appropriate state board. The Damage Prevention Strategies team informs Dig Safe Board investigators about unsafe practices SDG&E witnesses in the field. The Claims Recovery team reports incidents to the Contractor State Licensing Board (CSLB) when it becomes aware of them through its involvement with insurance and financial considerations as a result of incidents. The Dig Safe Board is developing regulations related to reporting and SDG&E plans to implement any new requirements.

J. SDG&E-7-C10 – Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board

SDG&E continues to actively participate in regulatory proceedings that will support the effectiveness of federal and state safe digging laws through legislation and enforcement of sanctions and penalties. Sanctions and penalties should be enforced against parties not following the well-established rules requiring third parties to call 811 USA to have pipelines marked prior to excavation. SDG&E supported California State Senate Bill SB 661, which modified California Government Code, section 4216, establishing the Dig Safe Board, by providing proposed language to increase protection of underground substructures..

In addition, SDG&E participates at board meetings of the Dig Safe Board, which was created by the Dig Safe Act of 2016 and is included in California's Government Code section

4216.12, Safe Digging law. The Dig Safe Board's charter is to coordinate education and outreach activities that encourage safe excavation practice; develop standards that support safe excavation practices; investigate possible violations of section 4216; and enforce section 4216 to the extent of granted authority.

Company involvement and participation at Dig Safe Board meetings and workshops help foster a positive working relationship with all stakeholders. These meetings and workshops provide the opportunity to raise the issues and concerns facing the Natural Gas industry and issues in regard to excavation damage prevention.

K. SDG&E-7-C11 – Public Awareness - Meet with Cities with Highest Damage Rates

SDG&E Damage Prevention Analysts work to reduce the number of third party excavation incidents in cities and jurisdictions with the highest number of reported occurrences. To achieve this objective, they partner with SDG&E' operating districts management and represented personnel to identify and meet with city officials with functions and responsibilities related to construction and excavation activities in their respective jurisdictions. This effort provides outreach and education to these officials on the proper 811 USA process and safe digging techniques. The officials can then pass those requirements on to the contractors operating in their cities as permits are granted or city inspectors visit job sites.

Cities have many resources and avenues for promoting and executing excavation safety within their communities. All planned work requiring a permit must start at the planning and permits department. Cities thus often have the first opportunity to educate applicants about excavation safety by providing 811 USA literature. On-site City inspectors could also potentially be tasked with patrolling and enforcing California Government Code section 4216 compliance as part of their daily work. City inspectors hold the authority to stop any job that violates code. Cities may also consider preventing excavators from working in their boundaries if the excavator is known to cause frequent excavation violations.

L. SDG&E-7-C12 – Public Awareness - Remain Active Members of the California Regional Common Ground Alliance

The California Regional Common Ground Alliance (CARCGA) is a group of California-based stakeholders who are impacted by excavation activities. CARCGA is the regional group within the Common Ground Alliance (CGA). The CGA works with its membership to establish best practices for the 811 USA One-Call Centers, underground facility owners, excavators, locators, project owners, and designers. Through its Damage Prevention Strategies function, SDG&E participates with CARCGA members to inform CGA objectives from a regional perspective.

M. SDG&E-7-C13 – Continue to Participate in the Gold Shovel Standard Program

SDG&E requires construction contractors doing work on its behalf to participate in the Gold Shovel program. The program certifies an excavator's policies and procedures against the Gold Shovel Standard, a set of excavator training procedures designed to protect underground facilities. The Gold Shovel standard also publishes a rating which is an ongoing measure of an excavator's digging-safety-worthiness. This requirement serves to incentivize construction contractors to follow safe excavation laws and practices. The Gold Shovel Standard (GSS) is a nonprofit organization committed to improving workforce and public safety and the integrity of buried infrastructure. GSS believes that greater transparency in all aspects of damage prevention among buried-asset operators, locators, and excavators is essential to drive continuous improvement, and vital to increasing safe working conditions and communities. Certifying excavators who participate in the Gold Shovel Program complies with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

N. SDG&E-7-C14 – Locating Equipment

SDG&E utilizes locating equipment, updated GIS maps, and/or excavating (daylighting) to verify the physical locations of underground infrastructure. Part of this process involves uploading scanned construction drawings temporarily until the job is posted officially to GIS. SDG&E continues to remain compliant with codes and regulations and follow industry best practices and company policies and procedures as they apply to the safe and effective locating and marking of underground facilities. This Control includes written and accessible procedures, availability of proper equipment, and access to required information to enable personnel to successfully perform their duties. Locating equipment is utilized to comply with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

O. SDG&E-7-C15 – Remain Active Members of the 811 California One-Call Centers

Title 49 Code of Federal Regulations, section192.614 and California Government Code, section 4216 require natural gas utilities to remain members and actively participate in the activities of 811 USA local one-call centers. Excavators are required to notify the 811 USA one call centers of their intent to dig. Owners of underground facilities in close proximity to the dig site are required to provide a positive response with the location of their facilities that may be in conflict with the excavation and also to provide any other efforts that may be required to protect the integrity of their underground facilities. The members of the one-call centers actively meet to make the 811 USA process easier for excavators while also exploring ways to make the service more accessible on a variety of platforms. They also work to promote the safe digging message through various avenues.

The Controls addressed above will continue to be performed. The Company's Mitigations, addressed below, aim to further reduce the frequency of third party dig-Ins.

P. SDG&E-7-M1 – Automate Third Party Excavation Incident Reporting

Timely and accurate reporting of excavation incidents is a critical component of the continual improvement process. Enhancing the data collection of incidents helps measure the performance of adhering to compliance reporting obligations, and also assists the Company in filing various regulatory reports. The reporting system is the basis for excavation incident analysis and is used to understand the Company's opportunities for internal improvement for locate and mark activities. Through this analysis of excavation incidents, SDG&E can further understand the internal and external leading causes of dig-ins, trend incident locations, trend frequency of damages caused by individual excavators, trend which facilities are damaged the most, and stay informed about the most common damaging excavation equipment.

Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SDG&E is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors. SDG&E is also actively enhancing its ability to improve data capture, data validation, and automated escalations. New Third Party Excavation Incident Reporting systems will provide accessibility and efficiency across multiple platforms reducing reporting and notification times by automating the reporting process. The upgraded reporting system efficiently analyzes accurate incident data and provides course corrections as locate and mark trends are identified.

Q. SDG&E-7-M2 – Establish a Program to Address Areas of Continual Excavation

Generally, a typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[30] Agricultural excavators who perform repetitive excavations prefer 811 USA Tickets that are valid for longer periods of time. Requiring 811 USA notifications every 28 days could discourage participation in the 811 USA process by agricultural excavators, who may find it too burdensome to renew a ticket. These situations are typically in flood control channels and agricultural fields where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement[31] to develop a process that would allow for certain agreements for continual excavation, called ACE tickets. In flood control and agricultural situations, SDG&E will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement.

---

30 Although USA tickets are valid for 28 days from the date of issuance, if work continues beyond 28 days, the excavator may renew the ticket per Cal. Govt. Code § 4216.2(e).

31 California Senate Bill (SB) 661 modified Cal. Govt. Code § 4216, establishing an Area of Continual Excavation (ACE) Ticket.

Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. The Dig Safe Board has drafted regulations[32] requiring operators to address ACE tickets by completing newly developed forms, conducting onsite meetings, potentially excavating the facility, and providing additional records. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators.

R. SDG&E-7-M3 – Recording Photographs for Each Locate and Mark Ticket Visited by Locator

Under this mitigation, locators will take photographs of the areas located and marked and the areas the excavators delineated either using white paint or other approved marking methods for each ticket they complete. The pictures taken by the locators will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Pictures will also mitigate potential disputes between excavators and SDG&E by providing visual confirmation of the location marks at the time the ticket was located and marked. The photographs will include a digital time stamp and geographical identification metadata.

S. SDG&E-7-M4 – Utilize Electronic Positive Response

SDG&E will utilize an electronic positive response system (EPS) which informs an excavator once a locate and mark activity is completed for the excavator's 811 USA ticket. For example, if the locator marks the jobsite, the excavator will be notified on their USA ticket that the company has completed markings at the ticket location. EPS gives excavators and the company a shared record of locate and mark activity completed by the locator. This will help excavators by providing them with the appropriate documented communication before they dig. Enhancing electronic positive response will be used to measure the performance of adhering to Title 49 Code of Federal Regulations, section 192.614.

---

[32] Dig Safe Board, Resolution No. 19-07-01, *available at* https://digsafe.fire.ca.gov/media/2197/resolution-19-07-01.pdf.

T. SDG&E-7-M5 – Enhance Process to Utilize and Leverage Emerging Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SDG&E will work with the requesting contractor to help fulfill their request without creating an unsafe situation. More specifically, SDG&E will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Vacuum excavation is recognized by the damage prevention industry as the safest excavation method that can be used today because the water and air used for excavation is adjustable, preventing damage to pipe and coatings. The Company plans to enhance its excavation practices by using hydro vacuum excavation technology which is typically installed onto a truck or portable trailer and allows the excavator to perform a keyhole excavation process, when applicable. Generally, a keyhole excavation process is utilized to excavate targeted areas.

Hydro vacuum excavation uses water at a high pressure to loosen the soil, this allows for precise excavation and vacuuming of the material. The use of water at a high pressure reduces the soil's cohesiveness thus helping to break the soil and suction easily. Dirt is stored in a debris tank, keeping the work area cleaner and avoiding the creation of dirt spoils. Hydro vacuum excavation is less invasive compared to other traditional methods of excavation. The benefits of hydro vacuum excavation include a reduced likelihood of causing third party damages, faster and precise excavations, and it also requires less manpower compared to conventional excavations.

The keyhole excavation process cost-effectively and safely exposes underground infrastructure to allow operators to perform repairs and maintenance without resorting to more costly and disruptive conventional excavation methods. The keyhole excavation process consists of performing work on the surface with smaller excavations, which can be performed on paved or non-paved areas. Pavement removal can be accomplished often by saw cutting and coring. The size of the pavement opening is determined upon the scope of the task at hand. The normal process utilizing keyhole excavation involves coring, vacuum excavation, construction and maintenance activities, and finally backfill and pavement restoration.

The Company will enhance its processes to utilize this excavation technology to facilitate hard to locate facilities.

U. SDG&E-7-M6 – Promote Process and System Improvements in USA Ticket Routing and Monitoring

As part of continuous improvement efforts, an assessment of the current state of the 811 USA one-call ticket routing and monitoring process is underway. The intent of this effort is to query system users and managers on potential improvements that would provide benefits to the process. The software vendor, Korterra, has been engaged to provide software solutions for identified system enhancements that will allow for more streamlined data collection, better documentation capture capability, and more detailed reports for process supervision.

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulations, section 192.614.

These new tools will give the company the ability to better manage the 811 USA ticket load across the company. The tools and enhancements entail workflows requiring locators to input specific data into dedicated fields detailing mutual agreements. These fields will enable reporting for all mutual agreements giving SDG&E additional measures for ticket compliance. Other tools include automated notifications in the form of emails and/or texts for management when tickets are approaching the mutual agreement due dates. This will trigger follow up action to address tickets on time. This mitigation will include the resources that support the enhanced data collection and field management of ticket efforts and will also support 811 USA ticket prioritization. These resources are needed to manage data, perform analytics on the new volume of data and to identify system enhancements.

V. SDG&E-7-M7 – Leverage Data Gathered by Locating Equipment

SDG&E uses locating equipment that automatically captures GPS coordinates as the locator performs their locating activities. The GPS data may also be manually recorded when the locator pushes a designated button on the equipment console. The equipment's GPS data is downloaded through a physical connection with a terminal allowing the data to be saved then transmitted to the GIS group. Future enhancements may include the ability to wirelessly transmit the GPS data. The GPS data can then be used in GIS to compare real world locating data with GIS mapping data to evaluate discrepancies and potentially catch mapping errors or locating errors thereby increasing the accuracy of the locating activity. Correcting mapping errors or omissions using this data may potentially reduce damages caused by mapping issues. Leveraging data gathered by locating equipment improves adherence to Title 49 Code of Federal Regulations, section 192.614.

W. SDG&E-7-M8– Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)

Plastic underground warning mesh is a high strength polypropylene mesh and is designed to alert excavators of the presence of buried utilities. It is typically installed at a minimum of 18 inches above the buried facility which provides the excavator awareness of a buried pipeline below. If an excavator was not expecting buried facilities in their excavation the mesh serves to alert them, identifies the presence of a gas line, and directs them to contact 811 USA before proceeding so that proper precautions can be implemented before further excavation. Providing this type of warning before excavating further into an underground gas facility substantially reduces the risk of third party damage and the associated consequences. SDG&E installs warning mesh during new pipeline installations. Warning mesh installation applies to high pressure pipelines (MAOP > 60 psig) and medium pressure pipelines (MAOP ≤ 60 psig).

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the SA Decision. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[33] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from Controls and Mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E' rationale for the determination of Tranches is presented below.

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing the risk of injuries or fatalities to the public, employees, and contractors. Given the vast number of activities SDG&E performs to mitigate the Third Party Dig-in on a Medium Pressure Pipeline risk, SDG&E grouped like activities with like risk profiles into mitigation programs.

Table 6: Summary of Tranches

ID	Mitigation/Control	Tranche	Tranche ID
SDG&E-7-C9	Public Awareness	External Education - The Affected Public	SDG&E-7-C8-T1
		External Education - Emergency Officials	SDG&E-7-C8-T2
		External Education - Local Public Officials	SDG&E-7-C8-T3
		External Education - Excavators	SDG&E-7-C8-T4

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SDG&E utilized historical gas dig-in results year-over-year to calculate an overall risk reduction benefit of performing these activities.[34] SDG&E then looked at existing/continuing programs (*i.e.*, Controls), with the expectation of observing similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SDG&E also accounted for the risk increase that would occur over time if the risk

---

33 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

34 *Id.* at Attachment A, A-5 ("MAVF Principle 4 – Risk Assessment").

reduction activities were reduced or cancelled. For new and/or incremental mitigations, SDG&E expects to achieve further risk reduction. The specific risk reduction benefit percentages used for each identified Control/Mitigation is included under each of the program headings below.

1. SDG&E-7-C1 – Locate and Mark Training

A single tranche is appropriate for this program because SDG&E has an obligation to provide Locate and Mark Training for all Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Training has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and mark training provides participating employees with the necessary knowledge and capabilities to locate and mark the below ground gas facilities accurately and in the appropriate time frame. At SDG&E, Locators have the responsibility to locate and mark gas facilities in response to an excavation request. Gas Operations Training and Development provides each Locator with the initial in-depth locate and mark training upon being newly assigned to a Locator position. Overall training is about an 8 week course with locate and mark training comprising about one week of that time. In 2019, SDG&E's Gas Operations Training and Development function is forecasting to provide Locate and Mark Training to about 12 Locators.

It is necessary to have a trained workforce to accurately locate and mark gas infrastructure to provide the necessary information for a third-party excavator to perform their work as safely as possible. Marked facilities provide the excavator with approximate locations of where the gas facilities exist within the delineated work area. Awareness of underground gas facilities allows the excavator to either avoid the areas or carefully dig with hand tools to prevent damage caused by the excavation work. Since a vast majority of the utility's assets are buried below ground it is imperative that proper action is taken to reduce the risk of accidental damage to these facilities by accurately communicating the locations to the excavators. Without a highly skilled and trained locate and mark workforce, excavators would have little knowledge and confidence of gas line locations which could lead to third party excavation damage. By improving knowledge and competency through training, locate and mark accuracy will increase, and the number of mismarks should be reduced, leading to a decrease in the risk of third party excavation damage. Additionally, this training provides the workforce with the necessary understanding of not only the requirements for accurate locating and marking but also the importance of two-way communication with an excavator, thorough job documentation and timeliness of locate and mark completion.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C1 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

2. SDG&E-7-C2 – Locate and Mark Activities

A single tranche is appropriate for this program because SDG&E has an obligation to perform Locate and Mark Activities across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and California Government Code, section 4216. Therefore, Locate and Mark Activities has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Activities are to prevent damage to gas infrastructure caused by third party excavators. They consist of three distinct activities:

(1) locating and marking underground gas facilities before excavation occurs,

(2) observing (stand-by) pipeline excavation activities; and

(3) providing staff support for compliance and improvement.

The first of these activities, locating and marking, refers to the actual physical act of locating and marking of underground facilities. In 2018, SDG&E Gas Field Operations fulfilled approximate 130,000 locate and mark requests, with nearly all being classified as medium pressure. By providing a visual indication of the location of underground facilities, the excavator has the necessary information to proceed with their activities in a safe and controlled manner. The second locate and mark activity is Pipeline Observation (stand-by) in specific required situations. Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. The purpose of this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having a dedicated employee representing the operator who is specifically there to maintain the integrity of the gas pipeline. The third activity involves staffing to provide daily support in operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, providing refresher training as requested, and tracking and trending locate and mark data to proactively identify areas for improvement. This is a critical risk reduction activity that directly supports the field locator personnel in their daily activities and leads to more accurate and timely responses to locate and mark tickets.

Locating and marking underground gas infrastructure provides the excavator with the information necessary to avoid hitting or damaging gas facilities. This is done by understanding what type of facilities are underground and the approximate location. Once the facility is marked, the excavator can take the necessary steps to work around the gas pipe and/or use the appropriate excavation techniques. Third party excavation damage can result in an immediate gas leak or explosion, or it can create a situation where a leak or explosion could develop in the future. The activity also must be completed in a required timeframe. Performing an accurate and timely locate and mark activity helps to reduce serious injuries and/or fatalities, property damage, prolonged outages, penalties and fines, and adverse litigation.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C2 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

3. SDG&E-7-C3 – Locate and Mark Annual Refresher Training & Competency Program

A single tranche is appropriate for this program because SDG&E has an obligation to provide a Locate and Mark Annual Refresher Training & Competency program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Annual Refresher Training & Competency Program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to continue locate and mark activities.

The Locate and Mark Refresher Training and Competency program reinforces several key components of locate and mark. By reviewing the gas standards on an annual basis, employees performing locate and mark activities are provided an opportunity to review expected procedures, learn changes in procedures, and obtain clarification. Without an opportunity to refresh their understanding, the locate and mark workforce might not be up to date on the latest procedure, requirement, or technology. Refresher training enables trained personnel to perform their duties with greater accuracy and efficiency, and it increases trained personnel’s ability to adopt to new technologies and methods. Marking facilities accurately provides the excavator and public with greater safety assurance. It enables the excavator to either avoid the delineated areas or dig with hand tools to avoid damage that could result in an immediate or future incident.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C3 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

4. SDG&E-7-C4 – Locate and Mark Operator Qualification Program

A single tranche is appropriate for this program because SDG&E has an obligation of providing a Locate and Mark Operator Qualification program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Operator Qualification program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and Mark Operator Qualification (OQ) training demonstrates an employee's knowledge and competency to perform specific locate and mark activities that allow the employee to recognize and react to abnormal operating conditions that could occur, such as fire over the pipeline, the smell of gas, and dirt blowing from the ground. Locate and Mark Operator Qualification is administered by the Operator Qualification – Gas System Integrity function at

SDG&E and OQ certification is required every five years. This training is mandated by PHMSA.[35]

Employing resources that are formally trained and Operator Qualified to perform Locate and Mark functions demonstrates both procedural knowledge and field implementation of the necessary tasks required to successfully perform these functions. Maintaining this level of prepared and qualified workforce allows SDG&E to meet its regulatory requirements and the demands of the excavator community and helps provide for a safe excavation environment.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C4 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E -7-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

5. SDG&E-7-C5 – Locate and Mark Quality Assurance Program

A single tranche is appropriate for this program because SDG&E has an obligation to perform quality assurance activities for Locators across its entire service territory. Therefore, Locate and Mark Quality Assurance program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Quality Assurance Program is to verify that proper processes and procedures are being followed and implemented by the locate and mark workforce and to correct those instances where processes and procedures are not being followed.

---

35 49 CFR §§ 192.801 - 192.809.

SDG&E's Pipeline Safety and Compliance function visits every district at least once per year and performs 4 audits per day. During these visits, they evaluate employee qualifications, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and markings, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations, for example. Feedback on a quality assurance audit is provided to each local supervisor who is responsible to follow-up with individuals or crews needing further or refresher training.

The Locate and Mark QA Program provides a variety of benefits to reducing the number of and potential for damage to gas infrastructure by a third party. By evaluating locate and mark activities that have been completed or are being performed, SDG&E can address gaps in performance with additional training or updating of company documentation or recordation of assets. Locate and mark workforce errors can result in an incorrect mark and locate or one that is not done within the required timeframe. Additionally, the QA review can highlight errors in the timely and/or accurate documentation of utility assets, which, if not corrected, could result in an incorrect locate and mark. Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

b. Elements of the Bow Tie Addressed

SDG&E-7-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of activities in the program would benefit from this mitigation.
Effectiveness	Assuming 5% effectiveness as QA program has above-marginal impact on reducing mismarks.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.5070**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.64	**172.49**	250.57
	RSE	5.22	**7.16**	10.41

6. SDG&E-7-C6 – Damage Prevention Analyst Program

The Damage Prevention Analyst Program works to reduce the number of third-party damage to gas facilities by identifying at risk excavating contractors and educating them on proper 811 USA process and safe digging techniques. Therefore, any excavating contractors at risk that are identified by the damage prevention analysts pose the same safety risk and a single tranche is appropriate for this program.

a. Description of Risk Reduction Benefits

The Damage Prevention Analyst Program works to reduce the number of third party damages to gas facilities by identifying contractors at risk of causing dig-in damages and educating them on proper 811 USA one-call and safe digging techniques. Through the Damage Prevention Strategies function, Damage Prevention Analysts focus on the districts with the greatest number of reported incidents, by driving to and physically inspecting excavation projects with 811 USA ticket requests. The Analysts will also stop at other construction projects to investigate whether proper 811 USA one-call and digging techniques are being used. In cases where the Analysts find an offense, they will stop the job and provide education to the contractor on the correct safe digging practices and procedures.

The benefits of the Damage Prevention Analyst function are threefold. First, it enables SDG&E to stop a job before an incident occurs if no underground markings are present or the excavator is not practicing safe digging techniques. Second, it provides an opportunity to educate contractors on their requirements before digging or when digging around gas facilities before damage is done. This education has far-reaching benefits as the contractor will perform future projects in other districts not currently part of the program, and the education could be applied to those future projects. Third, it creates a list of contractors who might be repeat offenders or of site characteristics to improve prioritization of future construction site inspections.

b. Elements of the Bow Tie Addressed

SDG&E-7-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation, DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence

c. RSE Inputs and Basis

Scope	Damage Prevention Analyst program focuses on 100% of the excavation tickets through risk assessment.
Effectiveness	The effectiveness is assumed at 25% as analysts prioritize work, support training, stop unsafe jobs, support all districts, etc.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 9%.

d. Summary of Results

		Low Alternative	**Single Point**	**High Alternative**
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**368.7690**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	136.87	**187.91**	272.97
	RSE	92.03	**126.35**	183.55

7. SDG&E-7-C7 – Prevention & Improvements- Refreshed Laptops

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and efficiently provide correct information helps with accurately locating underground infrastructure. Laptops with the applicable Software are deployed across SDG&E' territory. SDG&E has a service territory that covers about 4,100 square miles, from San Diego to southern Orange counties. The service territory covers 2 counties, and 25 communities. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The workforce that performs the locate and mark activities relies on laptops, USA tickets, asset mapping, records data, and software. Using laptops in an outdoor setting, and often in construction areas, can reduce life expectancy due to the harsh environment. Therefore, SDG&E provides its workforce with ruggedized laptops that are designed to better withstand their operating environment. Additionally, as software and data are updated, and new features are added, new laptops with advanced capabilities are required so that all information can be provided to the locate and mark workforce and data can be updated. Approximately 40 laptops are replaced every 4 years.

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and provide the right information in a timely manner helps with locating infrastructure correctly in a timely manner and using updated company maps and asset records. Updated ruggedized laptops contain a longer battery life and are able to run the required software faster and more efficiently. Updated hardware and software increase the effectiveness of performing locate and mark. The ruggedized laptops also have the ability to take a picture of the surroundings conditions of the excavation site to update mapping information for improved asset and mapping information. All features of the refreshed laptops work to reduce the number of errors that might occur in locating gas infrastructure through improved data and could be used to support the development of improved safe-digging procedures.

b. Elements of the Bow Tie Addressed

SDG&E-7-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of laptops will be refreshed.
Effectiveness	Assuming negligible improvement in effectiveness (0.25%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.09%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.3077**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.57	**172.39**	250.43
	RSE	0.31	**0.43**	0.63

8. SDG&E-7-C8 – Public Awareness Compliance

For the purposes of an RSE analysis, SDG&E separated Public Awareness into four tranches. Each of the four tranches reduces the likelihood of third party damage differently according to the RSEs.

Title 49 Code of Federal Regulation, section 192.616 requires utilities/natural gas providers to include efforts to educate the public, appropriate government organizations, and persons engaged in excavation related activities. The four types of groups identified in section192.616[36] are the affected public, emergency officials, local public officials, and excavators. Thus SDG&E-6-C8 – Public Awareness has been tranched to match the four groups identified in section 192.616.

Periodically SDG&E participates in Distribution Public Awareness Council (DPAC) Benchmark studies to collect and compare membership data related to the effectiveness of public awareness and community safety outreach programs managed by gas utilities. There is a clear distinction between the general level of awareness between the affected public, emergency officials, local public officials, and excavators. In order to address this gap and reduce third party damage, targeted messaging campaigns are performed for each subgroup to increase overall awareness and education. Emergency officials and local public officials are often met with in person to discuss municipal third party damage trends. The public and excavators are further informed of 811 USA and safe digging practices using bill inserts, media campaigns, SDG&E damage prevention analysts, radio advertising, internet advertising, billboard advertising, and safety meetings. Public Awareness is mandated pursuant to section 192.616 and its purpose is to develop and implement a continuing public education program focused on use of the 811 USA one-call notification system, hazards associated with the unintended release of gas, physical indications that an unintended release of gas has occurred, steps that should be taken to protect public safety in the event of gas release, and procedures for reporting unintended releases of gas. A summary of SDG&E's 2018 public awareness activities is shown in the table below.

---

[36] 49 CFR § 192.616 (emphasis added):

(d) The **operator's** program must specifically include provisions to educate the public, appropriate government organizations, and **persons** engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a **gas pipeline facility**;

(3) Physical indications that such a release **may** have occurred;

(4) Steps that should be taken for public safety in the event of a **gas pipeline** release; and

(5) Procedures for reporting such an event.

Table 7: Summary of SDG&E's 2018 Public Awareness Activities

	Mailers	Email messages	Public Service Announcements (2019)	811 Unique Page views (2019 data)
Excavators	29,000	6,500	1	Over 15,000 page views CYTD for the gas safety-related pages on SDG&E.com
Public Officials	189,000	220	0	
Affected Public	550,000 customers and 175,000 live/work near high pressure	630,000	1	
Emergency Officials	339,000	4	0	

A comprehensive public awareness program works to reduce the number of gas incidents by educating the general public on the indication of a gas leak and what to do if they do identify the potential for one. This allows first responders and SDG&E to respond in a timely manner to avoid a gas incident or minimize its impact. More specifically, the Public Awareness Program works to reduce the number of potential gas incidents due to third party excavation activities. Third parties refer to a broader group than just excavators, it can also include "do it yourself" home and business owners. By providing information about the 811 USA one-call process and safe digging practices to these audiences, SDG&E can increase the number of locates performed by the gas utility and potentially reduce the number of incidents of damage to gas infrastructure.

9. SDG&E-7-C8-T1 – Public Awareness Compliance - The Affected Public

a. Description of Risk Reduction Benefits

Unsafe digging from construction and landscaping activities resulted in almost 400 natural gas leaks in San Diego and southern Orange counties in 2019. Work as simple as installing a mailbox or adding landscaping could result in damage to a gas line. In observance of National Safe Digging Day, SDG&E joined energy companies across America to highlight the importance of calling 811 USA to have underground utility lines marked before digging. SDG&E promotes the awareness of the importance of calling 811 USA before digging underground utilizing various communication methods to reach the public such as bill inserts, media campaigns, radio advertising, internet advertising and billboard advertising. Homeowners should call 811 USA, or submit a request at Call811.com, at least two business days prior to digging. SDG&E will then mark the location of buried gas lines free of charge. It typically takes only 24–48 hours to complete a request to mark underground utility lines.

b. Elements of the Bow Tie Addressed

SDG&E-7-C8-T1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The affected public tranche of public awareness is assumed to impact 50% of the risk.
Effectiveness	Per SME input, effectiveness is marginal (1%). More effective than targeting local public and emergency officials, but less effective than excavators.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 97% of the causes (97% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**339.6393**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	126.06	**173.07**	251.41
	RSE	1.32	**1.81**	2.63

10. SDG&E -7-C8-T2 – Public Awareness Compliance - Emergency Officials

a. Description of Risk Reduction Benefits

Third party damages can result in a wide-range of inconveniences to the public including service outages and closed streets and places a strain on emergency officials. SDG&E coordinates liaison activities with Fire, Law Enforcement, Dispatch Centers, and other Cooperating Agencies to comply with the requirements of Title 49 Code of Federal Regulations, sections 192,192.615 and 192.616(e). There are significant benefits to creating strategic partnerships and promoting awareness with emergency officials. Communication and coordination are improved when it matters most. Public Awareness for Emergency Officials reduces the likelihood of third party damages and improves coordination during any kind of natural gas emergency.

b. Elements of the Bow Tie Addressed

SDG&E-7-C8-T2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines,

PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The emergency official's tranche of public awareness is assumed to impact 5% of the risk.
Effectiveness	Emergency officials can help with all excavation cause codes and are assumed to have the same effectiveness as the Affected Public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 28% of the causes (28% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.0473**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.47	**172.26**	250.23
	RSE	0.39	**0.53**	0.77

11. SDG&E -7-C8-T3 – Public Awareness Compliance - Local Public Officials

a. Description of Risk Reduction Benefits

Working directly with city officials involved in construction activities within their jurisdictions helps to educate external personnel to support SDG&E's enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. This interaction can involve several efforts. First is educating city personnel on the specific requirements of the California safe excavation laws. Second is helping officials to understand their role in helping to enforce the laws by promoting the use of 811 USA for excavation tickets through their project review and permitting activities as well as the field inspections their employees perform. Third is to explain the city's potential cost savings from avoiding their emergency personnel from having to respond to a blowing gas emergency due to non-compliant excavation damage. City officials can help avoid unnecessary emergency response if they promote safe excavation practices during their routine daily planning and permitting work. The following outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616 (d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SDG&E-7-C8-T3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The local public official's tranche of public awareness is assumed to impact 15% of the risk.
Effectiveness	Minimal impact since they're not the excavators; assuming 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 56% of the causes (56% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	LoRE		**338.2839**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.56	**172.38**	250.41
	RSE	0.76	**1.05**	1.52

12. SDG&E -7-C8-T4 – Public Awareness Compliance - Excavators

a. Description of Risk Reduction Benefits

Excavator awareness of 811 USA is very important. According to the Common Ground Alliance (CGA) Damage Information Reporting Tool (DIRT) Report, an underground utility line is damaged every six minutes in the United States because someone decided to dig but did not call 811 USA. Less than 1% of excavations cause damages in instances where excavators simply provide proper notice to 811 USA one-call before excavating. Promoting awareness of 811 USA amongst excavators can significantly reduce the number of unintended third party damages. Trenching, drilling, road work, building a deck, and installing landscaping are all examples of digging projects that necessitate a call to 811 USA before starting. Unreported damage, where gas lines are nicked or hit, can also lead to corrosion that can cause problems months or even years later. Contacting 811 USA before starting any project involving digging is the best way to avoid damage to underground utilities. Excavator outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616(d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SDG&E-7-C8-T4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (811 USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The excavator's tranche of public awareness is assumed to impact 30% of the risk.
Effectiveness	Public awareness campaigns for excavators are expected to be more effective than for other diggers, and the effectiveness is set to a higher number of 3%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 97% of the causes (97% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.9%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**340.9507**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	126.55	**173.74**	252.38
	RSE	3.96	**5.43**	7.89

13. SDG&E-7-C9 – Increase Reporting of Unsafe Excavation

The purpose of Increased Reporting of Unsafe Excavation is to identify and report excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or State Licensing Board (CSLB). Reporting of unsafe excavation is applicable to the entire SDG&E territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of Increased Reporting of Unsafe Excavation is to consolidate and formalize the Company's internal procedures for identifying and reporting excavators who frequently utilize unsafe excavation practices and to report those contractors to the California Dig Safe Board and/or State Licensing Board (CSLB). This includes consolidating the efforts of the Damage Prevention Strategies Team with the Claims Recovery Team. Both internal groups engage in excavator education and outreach efforts on safe digging practices. The consolidation of efforts-includes a consistent methodology for identifying targeted excavators. Education and outreach efforts provides the excavators understanding of the implications of unsafe excavation practices.

By combining the information from two functions within SDG&E, this program provides a more complete effort to achieve the benefits of reducing third party damages. First, it provides the names of unsafe excavators to the appropriate state boards to support the state's objectives. Second, it provides an opportunity for the excavators to be educated and informed on their obligations, such as the contractor's requirement to call 811 USA prior to any excavation activity and to perform hand excavation in the vicinity of gas pipelines. With a better informed contracting community, who follow the appropriate procedures, the number of excavation activities around gas infrastructure without location marks or without following the correct excavation procedures should decrease. The number of resulting incidents from these contractors should also decrease.

b. Elements of the Bow Tie Addressed

SDG&E-7-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation

DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that of excavators that are causing issues less than 1% are reported.
Effectiveness	Once the process is established, an increase in excavator notifications of 30% has been observed.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 27% of the causes (27% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.1%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.2738**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.55	**172.37**	250.40
	RSE	1.68	**2.31**	3.35

14. SDG&E-7-C10 – Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board

The purpose of securing greater enforcement through Legislation and the Dig Safe Board is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the Dig Safe Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SDG&E actively participates in the California Underground Safe Excavation Board (Dig Safe Board) to provide input and education from the natural gas utility perspective. The purpose of this participation is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority.

Through its involvement in board meetings and workshops and collaborating to achieve common objectives related to damage prevention, SDG&E fosters a positive and stronger working relationship with all stakeholders. By playing an active role in developing and enforcing utility and contractor requirements, a more complete education and cooperative environment can be achieved among all stakeholders. The Dig Safe Board provides a way in which effective safe excavation requirements can be cooperatively developed and disseminated to reduce third party damages.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C10 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C10 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 –

Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

15. SDG&E-7-C11 – Public Awareness - Meet with Cities with Highest Damage Rates

The activities associated with this program include providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. Public awareness, meeting with cities with the highest damage rates is applicable to all cities across SDG&E' territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of meeting with cities with the highest damage rates is to reduce the number of third party excavation incidents by providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. More specifically, using its Damage Prevention Analyst function, SDG&E will meet with leaders in all of the approximately 19 municipalities in its service territory. Priority is given to the cities with the highest number of excavation incidents.

The Damage Prevention Analysts will meet with the permitting, inspection, and/or other pertinent officials within the municipalities to develop a strong working relationship to reduce third party damages. Concepts are discussed, such as asking the city inspectors to also look for proper utility markings, stop the job, or incorporate 811 USA literature with the permit application.

Working directly with the city officials involved in construction activities within their jurisdictions helps to develop an extended education and enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. It also creates an additional opportunity to identify poor practices and the offending excavators so that education on contacting 811 USA prior to digging and on utilizing proper excavation techniques can be provided before any digging or damage has occurred. As excavators operate in multiple jurisdictions, any education of a contractor that occurs in one city can also be applied to the contractor's future jobs in other jurisdictions. Finally, as the number of excavation incidents decreases, the demands on local first responders will also decrease.

b. Elements of the Bow Tie Addressed

SDG&E-7-C11 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Meeting with the top 3% of cities (7 cities out of 240 total).
Effectiveness	Minimal impact since they are not the excavators. Assuming same effectiveness as public awareness for the affected public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 89% of the causes (89% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	**Single Point**	**High Alternative**
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.0877**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.49	**172.28**	250.26
	RSE	0.71	**0.98**	1.42

16. SDG&E-7-C12 – Public Awareness - Remain Active Members of the California Regional Common Ground Alliance

The purpose of remaining active members of the California Regional Common Ground Alliance (CARGA) is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the California State Digging Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SDG&E is an active member in the CARGA through its Damage Prevention Strategies function. CARGA is the regional organization associated with the Common Ground Alliance (CGA). The CGA is an underground utility industry association, across North America, whose mission is to prevent damage to underground infrastructure and to protect those who live and work near these assets through the shared responsibilities of stakeholders. CGA helps to develop best practices among industry stakeholders in all aspects of the safe excavation practices of underground infrastructure.

By participating in CARGA, SDG&E is able to play a role in developing best practices with other regional membership, to inform and help develop best practices on the national level, highlight localized issues that need to be addressed, and interact with contractors and other utilities to create safer excavation techniques and requirements. By working with all members of the underground industry, both locally and nationally, SDG&E not only helps to develop best practices but is also informed of other best practices in the industry which will help to improve utility and contractor implementation of safe digging techniques and procedures.

b. Elements of the Bow Tie Addressed

SDG&E-7-C12 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate is 50% as not all policies are affected.
Effectiveness	Maybe once every decade there is a practice that can be improved; however, improvement is marginal (0.05%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 100% of the causes (100% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**338.0845**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.48	**172.27**	250.26
	RSE	0.38	**0.53**	0.77

17. SDG&E-7-C13 - Continue to Participate in the Gold Shovel Standard Program

The Gold Shovel Standard (GSS) Program utilizes an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. This program is applicable to all third party contractors working for SDG&E.

All third party damages caused by contractors working for SDG&E poses the same safety risk. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The Gold Shovel Standard (GSS) Program is an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. The GSS provides positive reinforcement and reviews contractor's excavation performance. SDG&E requires all of its contractors to participate in the Gold Shovel Program.

The GSS provides positive guidance to underground contractors, aligning their excavation practices against established safe digging practices and procedures. It helps to educate contractors on expected industry excavation standards and identify and address gaps in their processes. SDG&E requires contractors who perform excavation on behalf of SDG&E to be GSS certified. GSS serves as an additional quality check for its contractors. Actively supporting the Gold Shovel Standard Program helps to improve excavation contractors use of the 811 USA one-call requirement and to improve their safe digging techniques, such as hand-digging when near gas pipelines.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C13 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C13 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

18. SDG&E-7-C14 – Locating Equipment

SDG&E provides the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure, as mandated by Title 49 Code of

Federal Regulation, section 192.614 and California Government Code, section 4216. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Locating Equipment Program is to utilize technology to standardize locating procedures and to provide the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure. The Locating Equipment program will provide the locate and mark workforce with standardized and compliant location devices and tools that are equipped with 811 USA ticket, asset records, and mapping information. Equipment will be provided to the workforce as part of the normal replacement cycle.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Finally, providing standardized equipment allows for consistent training and field use for the equipment across all operating districts for improved locate accuracy by the workforce.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C14 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-6-C14 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

19. SDG&E-7-C15 – Remain Active Members of the 811 California One-Call Centers

The California 811 USA One-Call Centers serve as the communication conduit between SDG&E and excavators. SDG&E is an active member of both Dig Alert and USA North. Dig Alert's territory includes nine Southern California Counties: Imperial, Inyo, Los Angeles, Orange, San Bernardino, San Diego, Santa Barbara, Riverside and Ventura. USA North covers fifty Northern California Counties. SDG&E is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to remain an active member of the California One-Call Centers. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The California 811 USA One-Call Centers serve as the communication conduit between SDG&E and excavators to support safe digging practices. Excavators contact the one-call centers with their intent to excavate in a specific location. This information is made available to the owners and operators of underground infrastructure to provide location information before excavation occurs. SDG&E is an active member of local one-call centers. In calendar year 2018, SDG&E responded to approximately 130,000 requests for locate and mark activities of its distribution system through the local one-call centers, nearly all distribution pipe is considered as medium pressure.

As a member of the 811 USA one-call centers, SDG&E actively works with other industry stakeholders toward simplifying the process, improving its accessibility, and educating safe digging practices. The California one-call centers play a critical role in safe excavation practices and reducing the number of third party damages. The call centers provide a single source for all excavators to contact as well as a source for utilities, simplifying the communication process between many contractors and the various utilities, many of which are not known by the contractors. The one-call process also allows this communication process to take place before digging occurs, so that utilities can correctly locate and mark their facilities within an expected timeframe. Excavating with these marks, allows the contractors to practice safe digging techniques, minimizing the potential of hitting or damaging gas piping as they complete their work.

SDG&E has not performed an RSE Evaluation on SDG&E-7-C15 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-7-C15 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

20. SDG&E-7-M1 – Automate Third Party Excavation Incident Reporting

Automating Third Party Excavation incident reporting into one system will centralize the reporting and data analysis. This will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. SDG&E is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to collect data on third Party Excavation Incidents. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

Automating third party excavation incident reporting will be the result of an effort to consolidate and simplify the data collection process involved in investigating a gas incident. Field supervisors complete the investigations of gas incidents. Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SDG&E is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors.

Standardizing data collection into one system will centralize reporting and data analysis will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. This will facilitate improvements in SDG&E's accuracy and timeliness in locating and marking its infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-7-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Marginal improvement is expected (0.5%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20

Post-Mitigation	**LoRE**		**337.9805**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.22**	250.18
	RSE	0.00	**0.00**	0.01

21. SDG&E-7-M2 – Establish a Program to Address Area of Continual Excavation

SB 661 modified California Government Code, section 4216 establishing an ACE Ticket. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators. Starting in July 2020, excavators working on agricultural and flood control lands may obtain an Area Continual Excavation (ACE) ticket. This ticket is applicable to areas within SDG&E's territory. All excavations performed with the use of an ACE ticket poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Generally, a typical USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[37] These situations are typically in flood control channels and agricultural field where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement to develop a process that would allow for certain agreements for continual excavation. In flood control and agricultural situations, SDG&E will meet with the landowner and develop an annual agreement that will allow for safe continual excavation activity within the parameters of the agreement.

Having to continually renew an 811 USA ticket may discourage some excavators from using the 811 USA process. This program will reduce dig-in risk as it will encourage landowners to use the one-call process before excavating and reduce the need to continually call every time digging needs to occur in the same area over the one-year timeframe of the ticket. By informing the 811 USA one-call center, and then the utility, the landowner can be made aware of

[37] Although USA tickets are valid for 28 days from the date of issuance. If work continues beyond 28 days, the excavator may renew the ticket per California Government Code, § 4216.2(e).

gas infrastructure in the area and develop an agreed-upon process to employ safe-digging techniques within the parameters established in the ACE ticket. Additionally, this process will assist the utility in accurately and timely marking the facilities as they will not have to make multiple, repeat visits to the same excavation site. By providing a mechanism to reduce effort for both the landowner and the utility, and providing the location of gas infrastructure to the landowner, the use of safe-digging practices should increase, and the amount of infrastructure damage should decrease.

b. Elements of the Bow Tie Addressed

SDG&E-7-M2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	For assessment purposes, SMEs consider farmers to be equivalent to excavators fielding heavy machinery. The proportion of farmers to heavy machinery excavators is assumed to be 1 to 200, hence a scope of 0.5%.
Effectiveness	Effectiveness assumed to be high (90%) as the percentage of the targeted people (farmers) are likely to follow procedure and prevent a dig-in once aware of the situation.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74

	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**337.3842**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.22	**171.92**	249.74
	RSE	71.84	**98.63**	143.27

22. SDG&E-7-M3 – Recording Photographs for Each Locate and Mark Ticket Visited by Locator

Recording photographs for each locate and mark ticket visited by locator is planned for all SDG&E's above and belowground facilities within its entire service territory. These pictures will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of recording photographs of each locate and mark ticket is to improve the accuracy of the locating activity and to inform process improvements based on investigations of gas incidents and quality assurance audits. By having a record of the locate marks, SDG&E will be able to better perform root cause analyses of QA activities and investigations into gas incidents. These photographs could show incorrect markings, which would result in improved training, or they could show incorrect mapping and asset data, which could result in improved utility data. The benefits of this Mitigation is its role in improving future locate and mark accuracy to avoid damage to gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-6-M3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets will have associated photographs.
Effectiveness	The effectiveness is marginal in nature and considered to be 1% as the impact is only on lessons learned.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**337.8990**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.42	**172.18**	250.12
	RSE	0.14	**0.19**	0.28

23. SDG&E-7-M4 – Utilize Electronic Positive Response

Electronic positive response is an electronic response provided to the regional notification center (DigAlert and USA North) that informs the excavator, prior to their excavation date, if the facility has been marked or if there is no conflict with the proposed excavation. Utilizing electronic positive response is applicable to all areas within SDG&E's territory. All excavations utilizing electronic positive response pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

SDG&E is required to locate and mark its underground infrastructure within two days of receiving a locate and mark ticket request. Implementing a positive response feature with the regional notification centers, such as USA North and DigAlert, improves communication between SDG&E and excavating contractors. The system will inform the contractor that the utility has completed their task or, alternatively, will inform them if no gas infrastructure is in conflict with their excavation activities. This effort also provides a means to communicate stand-by requirements or if the locate task was not able to be completed due to weather or accessibility issues.

This program requires participation from contractors and SDG&E. It will avoid the potential of damage to gas infrastructure due to miscommunication between the contractors and SDG&E. This is especially important in situations where the utility was not able to provide markings within the required timeframe, but the contractor assumes no markings means no gas infrastructure. When there are no markings, the contractor may not employ safe digging procedures resulting in a hit to gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-7-M4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of tickets will have electronic positive response available.
Effectiveness	This mitigation improves communication but has a marginal impact on excavator behavior, therefore the effectiveness is assumed to be 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	LoRE		**337.9082**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.42	**172.19**	250.13
	RSE	0.07	**0.10**	0.14

24. SDG&E-7-M5 – Enhance Process Leverage Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

Vacuum excavation technology is an example of a hydro excavation tool that can be deployed to find the location of buried company facilities when a locator is not getting an indication of where the facility is located. Technology such as this has proven itself in the damage prevention industry as a safe alternative to hand tools to prevent damage when unknown buried facilities are encountered. Vacuum excavation is utilized on an as-needed, case-by-case basis during Locate and Mark activities or in a more programmatic way by first identifying areas that are known to be hard to locate. Vacuum excavation is applicable to all areas within SDG&E's territory. All excavations utilizing vacuum excavation technology pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SDG&E will work with the requesting contractor to help fulfill their request without creating an unsafe situation. SDG&E will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging techniques. These alternatives include: stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Using locating tools that can provide the actual location of gas infrastructure by safely exposing the pipe will provide the most accurate location of the gas infrastructure. With this knowledge, the contractor is aware of when to employ safe digging techniques and company records can be updated with the actual piping location. Both of these benefits will work toward reducing the potential for damage to underground piping for the current project and future projects.

b. Elements of the Bow Tie Addressed

SDG&E-7-M5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, DT.6 - Incorrect /inadequate information in existing asset records leading to incorrect locate and mark , PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 15% of targeted locations will be assisted with emerging excavation technology.
Effectiveness	Effectiveness is high and assumed to be 95%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74

	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**336.4294**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	124.87	**171.43**	249.03
	RSE	0.36	**0.49**	0.71

25. SDG&E-7-M6 – Promote Process and System Improvements in 811 USA Ticket Routing and Monitoring

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

As part of continuous improvement, an assessment of the current state of the 811 USA one-call ticket routing and monitoring is underway. The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to provide increased abilities to monitor and manage locate and mark ticket requests and to evaluate and measure performance on meeting timing commitments. In calendar year 2018, SDG&E fulfilled approximately 130,000 USA ticket requests from excavators for its distribution system, nearly all distribution pipe is considered to be medium pressure.

SDG&E has a time requirement to fulfill locate and mark ticket requests. If these time requirements are not met, contractors might assume that no marks mean there are no underground facilities in conflict with their project, and they might start their excavation processes. If this occurs, contractors could hit and damage underground gas infrastructure due to the lack of surface markings. By providing enhanced capabilities to monitor and manage ticket request workload, SDG&E will have the potential to be better able to prioritize ticket requests, assign crews, and balance workload among the locate and mark crews. Additionally, the data capture and reporting enhancements can improve SDG&E's ability to monitor its own processes and identify process improvements. These enhancements work toward improving SDG&E's performance in meeting the locate and mark timeframe, thereby reducing the potential of contractors digging without knowledge of underground gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-7-M7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Improvement of up to 15%. This mitigation is closely tied to the Damage Prevention Analysts program.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20

Post-Mitigation	**LoRE**		**337.4140**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.24	**171.93**	249.76
	RSE	1.03	**1.41**	2.05

26. SDG&E-7-M7 – Leverage Data Gathered by Locating Equipment

The current locating equipment has the capability of recording all information from a locate. This information could be used to assess the quality of each locate and the relative accuracy of pipe location in the GIS system. By having a quality measurement for each locate the company can further determine areas that need improvement. The data gathered by leveraging locating equipment will be used to evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Leveraging Data Gathered by Locating Equipment Program is to utilize technology to improve the speed with which SDG&E mapping and asset records are updated and improve the accuracy of the resulting locate and mark activities. It provides the locate and mark workforce with the tools and technology to facilitate the ability to update Company records by capturing location coordinates found in the field, which can then be used to evaluate against existing company records to identify any mapping, records, or locating errors.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Using equipment with the latest technology assists in locating the infrastructure more accurately by providing specific location coordinates to the company's GIS system for updated records. Accurate mapping and company records on its facilities improves the accuracy of future locate and mark activities thereby providing excavators with an improved vision of underground piping.

b. Elements of the Bow Tie Addressed

SDG&E-7-M7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.5 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	A 25% scope is used as a middle ground (between 13% for damages on mains and 40% for damages from backhoes).
Effectiveness	Assume marginal effectiveness of 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.003%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**337.9999**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
	RSE	0.00233	**0.00320**	0.00465

27. SDG&E-7-M8 – Install Warning Mesh Above Buried Company Facilities (Open Trench New Facilities Only)

Warning mesh is a mitigation against those excavators that do not adhere to the 811 USA excavation safety notification requirement. Approximately 50% of company damages are caused by excavators not contacting 811 USA before they dig. Warning mesh would be installed when any new open trench company facility is installed before backfilling. This program is applicable to all SDG&E open trench buried new company facilities. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The purpose of installing warning mesh above underground gas pipelines is to provide a visual warning to excavators who have not called 811 USA of the existence of gas infrastructure. Warning mesh will be installed in all open trench applications in new construction.

The warning mesh is a visual indicator that can be exposed before the excavator damages the underlying gas infrastructure and can help to address other shortcomings in the mark and locate and safe digging process by both the utility and the excavator. It can serve as a reminder to the excavator to apply hand-digging techniques, it can act as a correction for inaccurate surface locate markings, and it could serve as a warning to an excavator who did not call to have underground facilities marked.

b. Elements of the Bow Tie Addressed

SDG&E-6-M8 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Used mesh procured with the proposed funding to arrive at the scope percentage (0.3%).
Effectiveness	Assuming 50% effectiveness since large machines can still cause damage.

Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.05%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	LoRE		**337.8163**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.38	**172.14**	250.06
	RSE	30.42	**41.77**	60.67

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E evaluated the constraints and challenges for the Risk Mitigation Plan. Third Party Excavation Damage continues to be a difficult risk to manage due to several factors. However, according to the CGA, if an 811 USA ticket is requested there is an over a 99%[38] chance that there will not be damage to one of SDG&E' pipelines. One of the primary challenges faced in minimizing this risk is the actions by third party contractors and the failure to request 811 USA tickets. The requesting of a ticket allows SDG&E to locate and mark the natural gas underground facilities within the delineated area. SDG&E experiences a majority of the damages under this risk on small plastic lines within private property. When homeowners

38 Common Ground Alliance, *Common Ground Alliance's 2014 DIRT Report Confirms Importance of Calling 811 Before Digging for Fifth Consecutive Year* (August 11, 2015), *available at* https://commongroundalliance.com/sites/default/files/press_release_pdfs/2014%20DIRT%20Report%20Press%20Release%20FINAL.pdf.

excavate and perform work that does not require a work permit (sprinklers, landscaping, etc.) there is no requirement by state law to request an 811 USA ticket. In addition, both licensed and unlicensed, inexperienced, or negligent contractors doing work for homeowners may not pull a work permit nor consider the activities they are performing as excavation in nature (installing a fence, electrical ground rods, pouring a driveway, etc.). Another source of damage is due to excavators who do not practice safe excavation procedures even when they have a valid 811 USA ticket. Affecting positive behavioral changes to these stakeholder groups remains a significant challenge to driving down third party excavation damages. To remain a leader in damage prevention, new technologies and strategies must continue to be evaluated to determine how they complement the existing portfolio of mitigation measures.

Below ground utility infrastructure can be challenging to locate. It requires a trained and seasoned workforce, use of sophisticated electronic equipment, and access and use of online GIS, mapping, and historical installation information to accurately identify locations. Throughout the years, due to growth and modernization, the density of underground utilities within rights-of-way has increased significantly. This in turn can lead to increased difficulty in locating individual facilities due to locating signal interference from adjacent infrastructure. Techniques learned over the years by seasoned locators are invaluable when faced with hard to locate areas.

Additionally, implementing, operating and maintaining a mitigation such as an 811 USA ticket risk assessment tool assumes that the algorithm will properly identify the riskiest evacuations and operators. The Company has to rely on legacy software programs and frequently perform updates to it in order to maintain the 811 USA ticket risk assessment tool. Computer hardware improvements increase the performance of the software and allow the Locate and Mark Technician to collect additional data and photographic documentation of the site with utility markings. Additional challenges on the locate and mark program are the occasions when tickets fail to be transmitted through the mobile data terminal (MDT) due to limited/no wireless service. This may lead the excavator to start their work prior to the utility properly delineating the under-ground substructures.

The plan was compiled using SDG&E's current capabilities for evaluating and prioritizing mitigation measures. SDG&E has made its best effort to identify the drivers and consequences associated with each risk with the understanding that, over time, impacting factors may change and require adjustments to the plan. If any of the mitigations become mandated at a later date, cost and resource projects could also change.

Table 8 provides a summary of the Risk Mitigation Plan, including Control and Mitigation activities, associated costs, and the RSEs by tranche.

SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 8 were estimated using assumptions provided by SMEs and available accounting data.

Table 8: Risk Mitigation Plan Summary[39]
(Direct 2018 $000)[40]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-C1	Locate and Mark Training	T1	0	57	0	77 – 92	77 – 92	-
SDG&E-7-C2	Located and Mark Activities	T1	0	2,100	0	3,000 - 3,900	3,000 - 3,900	-

39 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

40 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

41 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

42 The capital presented is the sum of the years 2020, 2021, and 2022, or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

43 Total = 2020, 2021, and 2022 Capital + 2022 O&M amounts.

44 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-C3	Locate and Mark Annual Refresher Training and Competency Program	T1	0	12	0	12 – 62	12 – 62	-
SDG&E-7-C4	Locate and Mark Operator Qualification	T1	0	56	0	56 – 110	56 – 110	-
SDG&E-7-C5	Locate and Mark Quality Assurance Program	T1	0	14	0	14 – 39	14 – 39	5.22-10.41
SDG&E-7-C6	Damage Prevention Analyst Program	T1	0	59	0	110 – 130	110 – 130	92.03-183.55
SDG&E-7-C7	Prevention and Improvements - Refreshed Laptops	T1	0	0	370- 660	150 – 400	520 – 1,100	0.31-0.63
SDG&E-7-C8-T1	Public Awareness-Compliance - The Affected Public	T1	0	50	0	250 – 500	250 – 500	1.32-2.63
SDG&E-7-C8-T2	Public Awareness Compliance - Emergency Officials	T2	0	5	0	25 – 50	25 – 50	0.39-0.77

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-C8-T3	Public Awareness Compliance - Local Public Officials	T3	0	15	0	75 – 150	75 – 150	0.76-1.52
SDG&E-7-C8-T4	Public Awareness Compliance - Excavators	T4	0	30	0	150 – 300	150 – 300	3.96-7.89
SDG&E-7-C9	Increase Reporting of Unsafe Excavation	T1	0	14	0	14 – 65	14 – 65	1.68-3.35
SDG&E-7-C10	Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board	T1	0	1	0	1 – 27	1 – 27	-
SDG&E-7-C11	Public Awareness-Meet with Cities with Highest Damage Rates	T1	0	1	0	1 – 50	1 – 50	0.71 - 1.42

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance	T1	0	0	0	22 – 88	22 – 88	0.38 - 0.77
SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program	T1	0	21	0	21 – 22	21 – 22	-
SDG&E-7-C14	Locating Equipment	T1	0	21	0	21 – 250	21 – 250	-
SDG&E-7-C15	Remain Active Members of the 811 California One-Call Centers	T1	0	96	0	200 – 420	200 – 420	-
SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	T1	0	0	7,100 – 12,500	0	7,100 – 12,500	0.00-0.01
SDG&E-7-M2	Establish a program to address the area of continual excavation	T1	0	0	0	1 – 4	1 – 4	71.84-143.27

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	T1	0	0	0	140 – 290	140 – 290	0.14 - 0.28
SDG&E-7-M4	Utilize electronic positive response	T1	0	0	0	290 – 520	290 – 520	0.07 - 0.14
SDG&E-7-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	T1	0	0	0	50 - 1,000	50 - 1,000	0.36 - 0.71
SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	T1	0	0	0	180 – 230	180 – 230	1.03 - 2.05
SDG&E-7-M7	Leverage data gathered by locating equipment	T1	0	0	0	50 – 75	50 – 75	0.0023 - 0.0046

ID	Mitigation/Control	Tranche	2018 Baseline Capital[41]	2018 Baseline O&M	2020-2022 Capital[42]	2022 O&M	Total[43]	RSE[44]
SDG&E-7-M8	Install warning mesh above buried company facilities (above open trench new facilities only)	T1	0	0	0	51 – 64	51 – 64	30.42 - 60.67
	TOTAL COST		**0**	**2,600**	**7,500 – 13,000**	**5,000 – 8,800**	**12,000 – 22,000**	-

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

While all the Controls, Mitigations, and respective costs presented in Table 8 mitigate the Third Party Dig-in on a Medium Pressure Pipeline Risk, some of these activities also mitigate other risks presented in this RAMP Report, including: Third Party Dig-in on a High Pressure Pipeline Risk.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 9: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for no RSE Calculation
SDG&E-7-C1	Locate and Mark Training	Mandated compliance activity per CFR Part 192/GO 112-F
SDG&E-7-C2	Locate and Mark Activities	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SDG&E-7-C3	Locate and Mark Annual Refresher Training & Competency Program	Mandated compliance activity per CFR Part 192/GO 112-F
SDG&E-7-C4	Locate and Mark Operator Qualification	Mandated compliance activity per CFR Part 192 Subpart N
SDG&E-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	Mandated compliance activity per California Government Code 4216
SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SDG&E-7-C14	Locating Equipment	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SDG&E-7-C15	Remain Active Members of the California 811 One-Call Centers	Mandated compliance activity per CFR Part 192/GO 112-F

SDGE
A Sempra Energy utility

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the mitigations for the Third Party Dig-in on a Medium Pressure Pipeline risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SDG&E-7-A1 – Virtual Reality Training / Simulation to Improve Locator Proficiency

The virtual reality Locate and Mark training simulator provides a portable and scenario-based training system. It allows for instructors to simulate a variety of real-world locate and mark scenarios. Virtual reality provides more flexibility in training curriculum and allows for more focused educational opportunities. More research is needed to identify system requirements and standardization scores and identify impacts to existing locate equipment and performance management software.

Scope	Assuming 100% of locations would receive UTTO Virtual Reality Training Tools.
Effectiveness	Per internal SME assessment, utilizing UTTO Virtual Reality Locator Training Tools will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 2%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0002%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**337.9993**	
	CoRE	0.37	**0.51**	0.74

	Risk Score	125.45	**172.23**	250.20
	RSE	0.01	**0.01**	0.02

B. SDG&E-7-A2 – GPS Tracking of Excavation Equipment

SDG&E has supported the Gas Technology Institute (GTI) and other research organizations in their efforts to help the industry improve damage prevention practices. Past and ongoing efforts included real-time GPS tracking of excavation equipment operating in pipeline rights-of-way and quick-shut breakaway meter set valves.

Real-time tracking of excavation is done using a "black box" attached to the excavation equipment such as a backhoe, grader, etc. The black box monitors the location of the equipment and can sense when the equipment is getting ready to dig. There is sophisticated software that monitors the GPS data in relation to its proximity to spatial pipe locations. If the box is detected near a company asset, then an alarm is triggered on the equipment alerting the equipment operator that there is a pipeline in the area. There is also an alert that is sent to the Company so action may be taken to investigate the location.

The technology is not being pursued at this point in time since it gave too many false positives. There is more work that needs to be completed and testing done before the device is ready for production.

Scope	A middle ground of 25% of available opportunities will be used as the scope for GPS tracking.
Effectiveness	Per internal SME assessment, utilizing GPS tracking of excavation equipment will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 1%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.00003%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**338.000**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
Post-Mitigation	**LoRE**		**337.9999**	
	CoRE	0.37	**0.51**	0.74
	Risk Score	125.45	**172.23**	250.20
	RSE	0.0004	**0.0005**	0.0008

Table 10: Alternative Mitigation Summary
(Direct 2018 $000)

ID	Mitigation	2020-2022 Capital[45]	2022 O&M	Total	RSE
SDG&E-7-A1:	Virtual reality training / simulation to improve locator proficiency	0	100-120	100-120	00.01-00.02
SDG&E-7-A2:	GPS Tracking of Excavation Equipment	0	236-391	236-391	0.0004-0.0008

45 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-7-C1	Locate and Mark Training	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C2	Locate and Mark Activities	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C3	Locate and Mark Annual Refresher Training and Competency Program	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C4	Locate and Mark Operator Qualification	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C5	Locate and Mark Quality Assurance Program	DT.2; DT.4; DT.5; PC.1; PC.2; PC.4; PC.5; PC.6
SDG&E-7-C6	Damage Prevention Analyst Program	DT.1; DT.2; DT.4 PC.1; PC.2; PC.4; PC.5; PC.6
SDG&E-7-C7	Prevention and Improvements-Refreshed Laptops	DT.2; DT.3; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C8	Public Awareness Compliance	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C9	Increase Reporting of Unsafe Excavation	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	DT.1; DT.2; DT.3; DT.4; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C11	Public Awareness - Meet with Cities with Highest Damage Rates	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	DT.1; DT.3; DT.4; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C13	Continue to Participate in the Gold Shovel Standard Program	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C14	Locating Equipment	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-C15	Remain Active Members of the 811 California One-Call Centers	DT.1; DT.2; DT.3; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-7-M1	Automate Third Party Excavation Incident Reporting	DT.2; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M2	Establish a program to address the area of continual excavation	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M3	Recording photographs for each locate and mark ticket visited by locator	DT.2; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M4	Utilize electronic positive response	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M5	Enhance process to utilize and leverage emerging excavation technology to help with difficult locates	DT.2; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M6	Promote process and system improvements in USA ticket routing and monitoring	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M7	Leverage data gathered by locating equipment	DT.2; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-7-M8	Install warning mesh above buried company facilities	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

Risk Assessment Mitigation Phase

(Chapter SDG&E-8)

High Pressure Gas Pipeline Incident (Excluding Dig-in)

November 27, 2019

TABLE OF CONTENTS

Risk: High Pressure Gas Pipeline Incident

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation plan for San Diego Gas and Electric Company's (SDG&E or Company) High Pressure Gas Pipeline Incident risk. Each chapter in the Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.)16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report, activities are delineated between controls and mitigations, which is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's High Pressure Gas Pipeline Incident risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VI below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

---

3 *Id.* at 16.

4 *Id. at 17.*

SDG&E and Southern California Gas Company (SoCalGas), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' gas pipeline incident related chapters.[5]

A. Risk Definition

For purposes of this RAMP Report, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure – Maximum Allowable Operating Pressure (MAOP), greater than 60 psig) failure event, which results in serious injuries or fatalities. For purposes of this testimony, the failure event is when a high-pressure pipe ruptures as a result of eight threats identified by the Department of Transportation Pipeline and Hazardous Materials and Safety Administration. The medium pressure assets operating at a pressure of 60 psig and less are included in the RAMP chapter for incidents involving medium pressure pipelines. Similarly, events caused by third party damage are included in their own RAMP chapters.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[6] for each control and mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

5 The other gas pipeline incident related chapters in the 2019 RAMP Report include: SCG-5 – High Pressure Gas Pipeline Incident; SDG&E-6 – Medium Pressure Gas Pipeline Incident; and SCG-1- Medium Pressure Gas Pipeline Incident.

6 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger or Potential Consequence
DT.1	External corrosion
DT.2	Internal corrosion
DT.3	Stress corrosion cracking
DT.4	Manufacturing defects
DT.5	Construction and fabrication
DT.6	Outside forces (natural disaster, fire, earthquake)
DT.7	Incorrect operations
DT.8	Equipment failure
DT.9	Third party damage (except for underground damages)
DT.10	Incorrect /inadequate asset records
PC.1	Serious Injuries and/or fatalities
PC.2	Property Damage
PC.3	Operational and reliability impacts
PC.4	Adverse Litigation
PC.5	Penalties and Fines
PC.6	Erosion of Public Confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[7] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for the risks included in RAMP. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SDG&E-8-C1	Cathodic Protection
SDG&E-8-C2	Valve Maintenance
SDG&E-8-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A
SDG&E-8-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B
SDG&E-8-C4	Transmission Integrity Management Program (TIMP)
SDG&E-8-C5	Pipeline Maintenance
SDG&E-8-C6-T1	Pipeline Safety Enhancement Plan – Pressure Testing

[7] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

The drivers/triggers identified for High Pressure Gas Pipeline Incident risk are addressed through the 2018 baseline controls listed in the above table, and SDG&E will continue said regulatory compliance driven controls. Although SDG&E has considered alternatives to these controls, no new mitigations are forecasted to be implemented. The Commission's focus in addressing pipeline safety risk has resulted in robust regulations that guide SDG&E's efforts in addressing the safety of gas pipeline infrastructure. Although no new mitigations are forecasted, SDG&E is forecasting to increase annual activity levels within existing controls.

Finally, pursuant to the SA Decision,[8] SDG&E presents in Section VIII alternatives to the described mitigations for this risk and summarizes the reasons that the alternatives were not included in the mitigation plan in Section VII.

II. RISK OVERVIEW

The SDG&E transmission and distribution system spans from the California-Mexico border to the Pacific Ocean and to the SoCalGas territory border. In total, SDG&E operates 518 miles of high pressure pipelines in its service territory, which includes the 232 miles of transmission defined pipelines.

The number of miles operated by operating unit is listed in the table below:[9]

Table 3: SDG&E Assets

Operating Unit	Total High Pressure Miles (>60psig)	Number of High Consequence Area (HCA) Miles
Transmission	232	192
Distribution	286	4
Total	518	196

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and American Society of Mechanical Engineers (ASME) B31.8S,

8 *Id.* at 34.

9 The miles are based on DOTs definition of "transmission" whereas the table defines miles by department operating pipelines.

"Managing System Integrity of Gas Pipelines" categorizes eight types of threats that could lead to a high-pressure pipeline incident. They include:

1) External Corrosion
2) Internal Corrosion
3) Stress Corrosion Cracking
4) Manufacturing Defect
5) Construction & Fabrication
6) Outside Forces
7) Incorrect Operation
8) Equipment Threat

These factors, also known as potential risk drivers, can work independently and/or interactively together.

When a gas pipeline has a loss of product, PHMSA categorizes it as a non-hazardous release of gas or a leak. Specifically, when the loss of gas cannot be resolved by lubing, tightening or adjusting, it is defined as a "leak." A leak in and of itself may cause little-to-no risk of serious injury or fatality. Risk to the public and employees can increase when leaks are in close proximity to an ignition source and/or where there is a potential for gas to migrate into a confined space. The safety concern of the leak is addressed by SDG&E' leak indication prioritization and repair schedule procedures. In most cases, a pipe with a leak will continue to transport gas, and therefore is not considered a pipeline "failure" using the definition in ASME B31.8S.[10]

However, in some instances a pipeline may be weakened to the extent that the pipe can overload and "break open" or burst apart. This is referred to as a pipeline rupture and considered a failure of the pipeline as it can no longer function as intended. This type of failure could

[10] American Society of Mechanical Engineering standard B31.8S: Managing System Integrity of Gas Pipelines. B31.8S is specifically designed to provide the operator with the information necessary to develop and implement an effective integrity management program utilizing proven industry practices and processes.

release a high level of energy, and sometimes ignite, resulting in damage to the surrounding area, injury, and/or loss of life.

The leak verses rupture failure mode is generally dependent on the stress to the pipe, the pipe material properties and the geometry of the latent weak point on a pipeline. As a general rule, the rupture failure mode does not occur on a pipeline operating under 30% of Specified Minimum Yield Strength (SMYS), unless there is an egregious pipe anomaly acting as an initiation growth point and there is interacting threats involved.

Due to the nature of a potential rupture failure mode, this risk category discusses the potential consequences of a rupture event occurring on the Company's high-pressure gas system. The extent of damage of an incident can be modeled through the use of a potential impact radius (PIR) around a pipe. PHMSA has incorporated the PIR into its methods for determining an HCA along the pipeline right-of-way.

The presence of HCA miles in a transmission system provides an indication of the potential consequences of an incident to the public because HCA's consist of highly populated areas and identified sites where people regularly gather or live. Applying mitigative measures as outlined in Title 49 of the Code of Federal Regulations (CFR) Section (§) 192.935, such as increased inspections and assessments, additional maintenance, participation in a one-call system, community education and consideration of the installation of additional remote-controlled valves, can help reduce the likelihood or consequence of a rupture event in both high consequence and lesser populated areas.

The SDG&E high pressure gas pipeline risk is similar to the SoCalGas gas pipeline incident since the threats are the same and the system is managed in an integrated manner. The chapter is also similar in nature to the Medium Pressure Gas Pipeline Incident risk because the threats are comparable. The biggest differences are the threats of plastic pipeline since plastic is only used in medium pressure systems and high pressure has an increased potential for injuries and fatalities due to its operating pressure and defined potential impact areas. Since the high pressure gas pipeline asset is managed by two Operating departments (Transmission and Distribution) it is difficult to identify costs solely dedicated to high pressure pipelines managed by Distribution Operations. Therefore, the costs are primarily related to the Transmission Operations department.

Additionally, although not included in this RAMP filing, SDG&E is currently in the very preliminary stages of organizing and modeling a Facilities Integrity Management Program (FIMP) based on principles developed by the Canadian Energy Pipeline Association (CEPA) and the Pipeline Research Council International (PRCI). The FIMP is not intended to duplicate any systems, processes, or information that may already exist, but rather to supplement the already existing programs to enhance the safety and integrity of the integrated gas pipeline system.[11] FIMP will be a documented program, specific to the facilities portion of a pipeline system,[12] that identifies the practices used by the operator for purposes of "safe, environmentally responsible, and reliable service."[13] While SDG&E is currently in the preliminary stages of organizing and modeling a FIMP approach based on the principles of CEPA, FIMP is anticipated to be included in the next GRC. Although this concept of an overarching program is still maturing in the industry, SDG&E's intention of a FIMP is to better identify and reduce risks of facility assets, extend the life of assets, and achieve operational excellence, in alignment with both the principles of RAMP and the Company's existing Transmission and Distribution, Integrity Management Programs (TIMP, DIMP respectively).[14] Consistent with the SA

---

[11] SDG&E notes that there are certain facilities management systems and processes in place, for example Pipeline Research Council International (PRCI) – Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718.

[12] "Pipeline system" is defined by Pipeline Research Council International (PRCI) - Facility Integrity Management Program Guidelines – PRCI IM-2-1 Contract PR-186-113718 as "*Pipeline System is comprised of pipelines, stations, and other facilities required for the measurement, processing, gathering, transportations, and distribution of oil or gas industry fluids*."

[13] Canadian Energy Pipeline Association (CEPA), Facilities Integrity Management Program, Recommended Practice, 1st Edition (May 2013) at 7-8.

[14] Based on industry definitions, there are a variety of types of facilities; facilities are highly complex; a variety of equipment/asset types exist within facilities; and in this context facilities are not considered building structures.

Decision, a supplemental analysis will be conducted in the GRC for FIMP if it ultimately meets the criteria for inclusion in that proceeding.

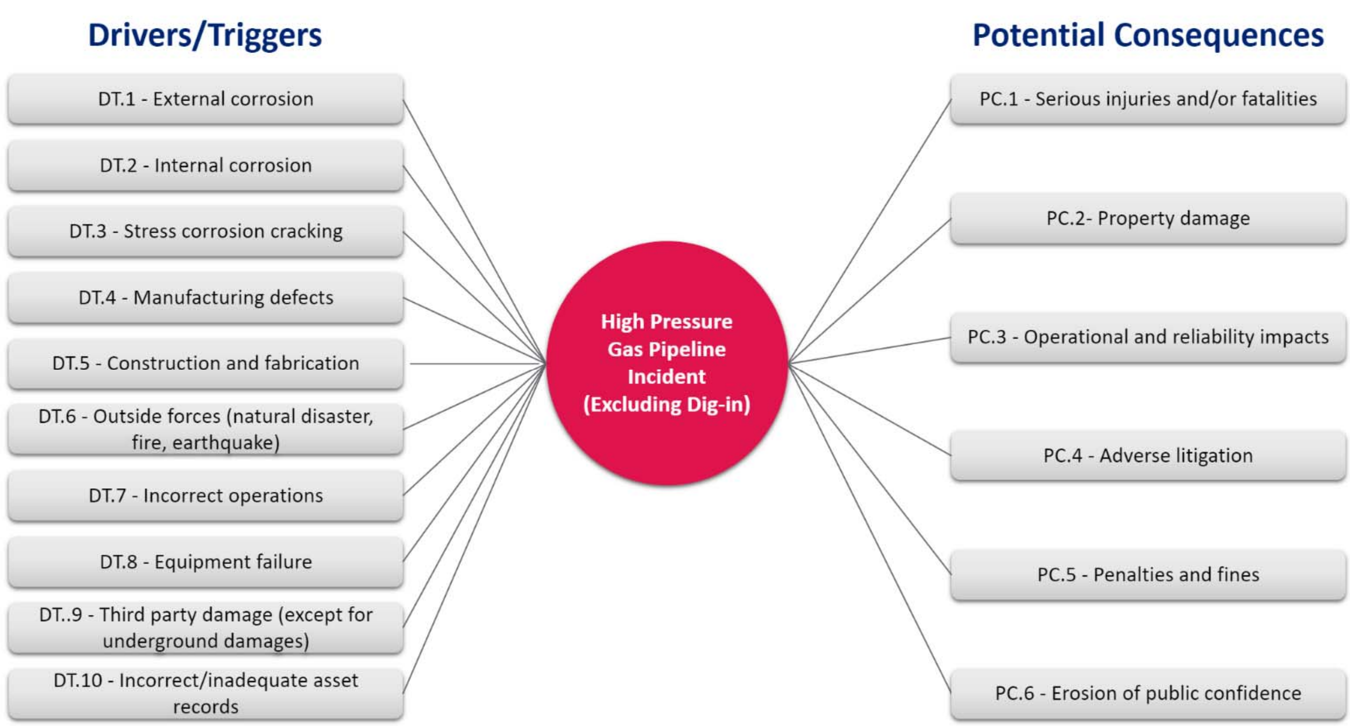
III. RISK ASSESSMENT

In accordance with the SA Decision,[15] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the High Pressure Gas Pipeline Incident risk.

A. Risk Bow-Tie

The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

Figure 1: Risk Bow Tie



[15] D.18-12-014at 33 and Attachment A, A-11 ("Bow Tie").

B. Asset Groups or Systems Subject to the Risk

The SA Decision[16] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. SDG&E' High Pressure Incident risk impacts all of SDG&E' high pressure natural gas infrastructure and assets.

Natural Gas Pipeline Distribution System - SDG&E's medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and their appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines. By definition, however, these assets are operated by Distribution Operations.

Natural Gas Pipeline Transmission System – SDG&E's high-pressure transmission pipeline system is comprised of steel pipelines and its appurtenances (e.g., meters, regulators, risers) operating over 20% of the pipeline's SMYS.

C. Risk Event Associated with the Risk

The SA Decision[17] instructs the utility to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a pipeline failure event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below.

D. Potential Drivers/Triggers[18]

The SA Decision[19] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for High Pressure Gas

---

[16] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

[17] *Id.* at Attachment A, A-11 ("Bow Tie").

[18] An indication that a risk could occur. It does not reflect actual or threatened conditions.

[19] D.18-12-014 at Attachment A, A-11 ("Bow Tie").

Pipeline Incident, SDG&E identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **D.T1 – External Corrosion:** A naturally occurring phenomenon commonly defined as the deterioration of a material (usually a metal) that results from a chemical or electrochemical reaction with its environment.[20]
- **D.T2 – Internal Corrosion:** Corrosion is the deterioration of metal that results from an electrochemical reaction with its immediate surroundings. This reaction causes the iron in the steel pipe or other pipeline appurtenances to oxidize (rust). Corrosion results in metal loss in the pipe. Over time, corrosion, if left unmitigated, can cause the steel to lose its strength and possibly render it unable to contain the fluid in the pipeline at its operating pressure. The loss of material from corrosion can eventually result in "pinhole" leakage, or a crack, split, or rupture of the pipeline unless the corrosion is repaired, the affected pipe section is replaced, or the operating pressure of the pipeline is reduced.[21]
- **DT.3 – Stress Corrosion Cracking:** A form of corrosion that produces a marked loss of pipeline strength with little metal loss. A type of environmentally assisted cracking usually resulting from the formation of cracks due to various factors in combination with the environment surrounding the pipeline that together reduces the pressure-carrying capability of the pipe.[22]
- **DT.4 – Manufacturing defects:** Attributable to material defect within the pipe, component or joint due to faulty manufacturing procedures, design

---

[20] L.S. Van Delinder, *Corrosion Basics, An Introduction* (1984); *see also* U.S. Dept. of Transportation, *Fact Sheet: Internal Corrosion*, *available at* https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm.

[21] *Id.*

[22] *Id.*

defects, or in-service stresses such as vibration, fatigue and environmental cracking.

- **DT.5 – Construction and fabrication:** Attributable to the construction mythology applied during the installation of pipeline components specifically based on the vintage of the construction standards, fabrication technics (welding, bending, etc.) and overall guiding regulations.
- **DT.6 – Outside forces (natural disaster, fire, earthquake):** Attributable to causes not involving humans, but includes effects of climate change such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, and high winds.
- **DT.7 – Incorrect operations**: May include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.
- **DT.8 – Equipment failure:** Attributable to malfunction of component including but not limited to regulators, valves, meters, flanges, gaskets, collars, couples, etc.
- **DT.9 – Third party damages (except for underground damages):** Attributable to outside force damage other than excavation damage or natural forces such as damage by car, truck or motorized equipment not engaged in excavation, etc.
- **D.T10 – Incorrect /inadequate asset records:** The use of inaccurate or incomplete information that could result in the failure to (1) construct, operate, and maintain SDG&E's pipeline system safely and prudently; or, (2) to satisfy regulatory compliance requirements.

E. Potential Consequences

Potential Consequences are listed to the right side of the bow tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

PC.1 – Serious injuries and/or fatalities;

PC.2 – Property damage;

PC.3 – Operational and reliability impacts;

PC.4 – Adverse litigation;

PC.5 – Penalties and fines; and

PC.6 – Erosion of public confidence.

These potential consequences were used in the scoring of the High Pressure Gas Pipeline Incident risk that occurred during the development of SDG&E's 2018 enterprise risk registry.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP,[23] including enhancements to the Interim Decision 16-08-018.[24] SDG&E used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

Table 4: Pre-Mitigation Analysis Risk Quantification Scores[25]

High Pressure Gas Pipeline Incident (Excluding Dig-in)	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	4	**31**	77
LoRE		**0.3**	
CoRE	12	**97**	238

23 D.18-12-014 at Attachment A.

24 *Id.* at 2-3.

25 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[26] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Scope

In-Scope for purposes of risk quantification:	The risk of damage, caused by a high pressure pipeline (maximum allowable operating pressure - MAOP greater than 60 psig) failure event, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification:	The risk of damage caused by a non-high-pressure pipeline failure event or third-party dig-ins which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision, the utility is instructed to use actual results and available and appropriate data (*e.g.*, Pipeline and Hazardous Materials Safety Administration (PHMSA) data).[27]

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SDG&E, the national average incident rate per mile per year was applied to the high-pressure pipeline miles at SDG&E.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA high-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

26 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

27 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

B. Sources of Input

The SA Decision[28] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Link: Annual Report mileage for Gas Distribution Systems
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: Pipeline and Hazardous Materials Safety Administration (PHMSA)
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data
- SDG&E high-pressure pipeline miles are from 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf

---

[28] *Id.* at Attachment A, A-8-A-9 (“Identification of the Frequency of the Risk Event”).

- SDG&E end user natural gas customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
  - Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[29] This section describes SDG&E's Risk Mitigation Plan by each selected Control for this risk, including the rationale supporting each selected Control.

As stated above, the High Pressure Gas Pipeline Incident risk is the risk of damage, caused by a high pressure pipeline failure event, which results in serious injury or fatalities. The Risk Mitigation Plan discussed below includes current controls that are expected to continue for the period of SDG&E's Test Year 2022 General Rate Case (GRC) cycle.[30] While there are no mitigations identified SDG&E is forecasting to expand the level of activity for certain controls as further described below.

The controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with compliance requirements that were in effect at that time. This section describes SDG&E's Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control.

This section describes SDG&E's Risk Mitigation Plan by each selected control for this risk, including the rationale supporting each selected control. Overall the compliance requirements set forth within the regulations (although considered minimum requirements) are robust in that they provide prescriptive preventative and maintenance guidance to the high

---

[29] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

[30] *Id* at 16 and 17. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

pressure assets. In addition, the Transmission Integrity Management Program (TIMP) regulations guide operators in completing enhanced assessment of transmission pipelines in high consequence areas. More recently, Public Utility Code 957 and 958 have been an additional layer to evaluate construction and manufacturing related threats through pressure testing and mitigation of additional threats through full replacement. To date, PSEP has pressure tested over 111 miles, replaced over 105 miles and completed 306 valve project bundles for SDG&E and SoCalGas. Within the RAMP chapter, the makeup of the portfolio is a healthy mix of compliance requirements and additional programs implemented by TIMP and PSEP within the last 7 years. The TIMP is continually evaluating the system threats and risk to determine if additional mitigations are required like the introduction of the Damage Program Analyst specifically covered within the Third Party Dig-In on a High Pressure Pipeline chapter.

These controls focus on safety-related impacts per guidance provided by the Commission in Decision (D.) 16-08-018 as well as controls and mitigations that may address reliability. SDG&E will continue its 2018 baseline controls. In addition, based on the foregoing assessment, SDG&E projects to expand its current/existing control activities to survey and maintain the Company's Right of Way (ROW) to increase span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and ROW maintenance.

A. SDG&E-8-C1 - Cathodic Protection

Corrosion threat is a natural process that can deteriorate metal assets and potentially lead to leaks or damages. Cathodic Protection, coating and monitoring is key to protecting and extending the life of a steel asset by keeping corrosion at bay. The on-going compliance controls for the threat of corrosion are prescribed by 49 CFR 192 Subpart I – Requirements for Corrosion Control Operations. The requirements include monitoring of cathodic protection areas, remediation of CP areas that are out of tolerance and preventative installations to avoid areas out of tolerance. These activities are intended to address threats as identified by PHMSA specifically external corrosion. These preventive measures provide an opportunity to address issues that otherwise could lead to a serious incident or a failure. The following section details the required intervals for completing these preventative measures as prescribed in 49 CFR 192 Subpart I:

- Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of § 192.463.
- Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months, to ensure that it is operating.

In addition to meeting these federal and state requirements, based on feedback from the Commission's Safety and Enforcement Division (SED) during a 2018 Safety Audit, and upon further review, SDG&E issued new guidelines requiring the re-evaluation of existing 100 mV polarization shift areas[31] at least every 10 years to verify their effectiveness as a measurement for adequate cathodic protection of an area. A pipeline utilizing the 100 mV polarization shift criteria must achieve a minimum of 100 mV of polarization along its entirety through the application of Cathodic Protection.

B. SDG&E-8-C2/C5 – Transmission Operations Maintenance (Valve Maintenance and Pipeline Maintenance)

Gas Transmission is responsible for the safe day-to-day operation and maintenance of gas transmission pipeline facilities and related infrastructure. Their responsibilities include gas measurement, pressure regulation, non-core customer equipment and facilities, instrumentation, cathodic protection, locate-and-mark activities, standby, patrol, leakage survey, class location survey, bridge and span inspections and valve inspections. In addition, pipeline and valve maintenance validates that the pipelines within the system operate appropriately which enhances public safety. Valve inspections may include flushing, repair or replacement, function test, and other activities (and should the valve be inoperable it needs to be addressed promptly.) The valve inspections are to be conducted once a year and not to exceed 15 months. Both valve and pipeline maintenance control activities have costs that are tracked separately and provide similar risk reduction profiles within each asset group. However, for ease of review and because both

[31] 49 CFR 192 at Appendix D – Criteria for Cathodic Protection and Determination of Measurements.

O&M activities are done under the same operating umbrella, the activities are grouped together here.

C. SDG&E-8-C3/-C6 – Pipeline Safety Enhancement Plan (PSEP) – Pipe Replacement/Pressure Testing

The primary objectives of the Pipeline Safety Enhancement Plan (PSEP) are to enhance public safety, comply with Commission directives, maximize cost effectiveness, and minimize customer impacts from safety investments. PSEP comprises Pipeline Replacement and Pressure Testing components. As directed by the Commission, the program includes a risk-based prioritization methodology that prioritizes pipelines located in more populated areas ahead of pipelines located in less populated areas and further prioritizes pipelines operated at higher stress levels above those operated at lower stress levels.

The PSEP is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B:

1. Phase 1A

Phase 1A encompasses replacing or pressure testing pipelines located in Class 3 and 4 locations and Class 1 and 2 locations in HCA's that do not have sufficient documentation of a pressure test to achieve at least 125% of the maximum allowable operating pressure (MAOP) of the pipeline. For reference, determination of the Class of a pipeline is dependent on the type and density of dwellings and human activity within 220 yards of the pipeline.

2. Phase 1B

The scope of Phase 1B, is to replace pipelines incapable of being assessed via inline smart inspection tools (non-piggable pipelines), installed prior to 1946, with new pipe constructed using state-of-the-art methods and to modern standards, including current pressure test standards.

3. Phase 2A

Phase 2A replaces transmission pipelines that do not have sufficient documentation of a pressure test to achieve at least 125% of MAOP and are located in Class 1 and 2 of non-HCA's.

4. Phase 2B

Phase 2B pipelines are those that have documentation of a pressure test that predates the adoption of federal testing regulations in 1970, specifically, Part 192 Subpart J of Title 49 of the CFR. There are no standalone Phase 2B projects[32] anticipated to begin within the next GRC cycle, and therefore none are associated with this control.

The primary focus of PSEP will be the replacement and pressure testing of Line 1600.[33] Line 1600 is a 16-inch outside diameter (OD) transmission pipeline installed in 1949 and historically operated at 800 psig. The pipeline runs approximately 50 miles from the Rainbow Metering Station in northern San Diego County into the city of San Diego. The pipeline primarily consists of flash welded seam pipe meeting API 5LX Grade X52. SDG&E has no documentary evidence that Line 1600 was hydrostatically pressure tested. In fact, Line 1600 was installed several years before the State of California required pressure testing as part of the pipeline commissioning process (in 1961), and before such practices were adopted in the gas pipeline industry. In addition, the pipe manufacturing process utilized by A.O. Smith company to produce flash welded seam pipe has been known to have deficiencies which create manufacturing defects/flaws. For example, SDG&E has observed seam flaws in the form of hook cracks on Line 1600 associated with the manufacturing process. PSEP provides a vehicle to address this type of pipelines as intended by the regulation. The replacements areas will eliminate the manufacturing threat and pressure testing will provide an assessment of the pipeline at the time of the pressure test.

---

[32] To date, SoCalGas and SDG&E have solely addressed Phase 2B segments within the scope of Phase 1 or Phase 2A projects for constructability and/or cost efficiency reasons. This is referred to as "accelerated" Phase 2B pipeline segments.

[33] As of the date of this RAMP report, the Commission is considering modifications to D.18-06-028. If adopted, the Decision would reopen the Pipeline Safety & Reliability Project (PSRP) proceeding (A.15-09-013) for a Phase 2 that will consider a cost forecast pertaining to SDG&E's and SoCalGas' Line 1600 PSEP. As such, it is uncertain whether the reasonableness of Line 1600 PSEP forecasted costs will be litigated in the next GRC.

D. SDG&E-8-C4 – Transmission Integrity Management Program (TIMP)

Through the TIMP, per 49 C.F.R. 192, Subpart O, SDG&E is federally mandated to identify threats to transmission pipelines in HCA's, determine the risk posed by these threats, schedule prescribed assessments to evaluate these threats, collect information about the condition of the pipelines, take actions to minimize applicable threat and integrity concerns to reduce the risk of a pipeline failure. At a minimum of every seven years transmission pipelines located within HCAs are assessed using In-Line-Inspection (ILI), Direct Assessment or Pressure Test and remediated as needed.

Detected anomalies are classified and addressed based on severity with the most severe requiring immediate actions. Remediations reduce risk by addressing areas where corrosion, weld or joint failure, or other forces are occurring or has occurred. Post-assessment pipeline repairs, when appropriate, and replacements are intended to increase public and employee safety by reducing or eliminating conditions that might lead to an incident. ILI is the primary assessment method used to identify potential pipeline integrity threats. When a threat is identified, the SDG&E might take immediate action to reduce risk until a repair is completed. These actions involve removing a pipeline from service or reducing operating pressure. In cases where the assessment involves a pressure test, immediate remediation is also required as the pressure test cannot be completed until the pipeline is repaired.

TIMP reduces the risk of failure to the pipeline transmission system and on a continual basis evaluates the effectiveness of the program and scheduled assessments. TIMP Risk Assessment evaluates the Likelihood of Failure (LOF) using the nine threat categories (External Corrosion, Internal Corrosion, Stress Corrosion Cracking, Manufacturing, Construction, Equipment, Third Party Damage, Incorrect Operations, and Weather Related and Outside Force) for transmission pipelines located within a HCA. Pipeline operational parameters and the area near the pipeline are considered to evaluate Consequence of Failure (COF). The LOF multiplied by the COF produces the pipelines Relative Risk Score. Further information is collected about the physical condition of transmission pipelines through integrity assessments. Action is taken to address applicable threats and integrity concerns to increase the safety and preclude pipeline failures.

The numbers and types of TIMP activities vary from year to year and are based on the timing of previous assessments done on the same locations. Approximately 132 miles out of 232 miles of SDG&E's transmission pipelines are located in HCA areas.

VI. POST-MITIGATION ANALYSIS OF RISK MITIGATION PLAN

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. Unless otherwise specified, all elements of the Bow Tie concerning Potential Consequences are assumed to be addressed by the below mentioned controls. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[34] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of Tranches is presented below.

SDG&E's comprehensive integrity and maintenance programs consist of policies, programs, and efforts designed to reduce the probability of a pipeline incident. The extensive activities SDG&E performs to mitigate pipeline risks have been grouped into the controls presented herein based on the similarity of their risk profiles.

SDG&E does differentiate some programs by asset type (*e.g.* steel vs plastic); however, as discussed in RAMP-G, costs are not tracked at a level of detail to allow for the logical disaggregation of assets or systems at a more granular level than the controls described in the mitigation plan.

PSEP is an established, phased, program to which tranches reflecting said phases was logically discernable and maintained within this control.

---

[34] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Table 6: Summary of Tranches

ID	Control	Tranche	Tranche ID
SDG&E-8-C3	Pipeline Safety Enhancement Plan – Pipeline Replacement	Phase 1A	SDG&E-8-C3-T1
		Phase 1B	SDG&E-8-C3-T2
SDG&E-8-C6	Pipeline Safety Enhancement Plan – Pressure Testing	Phase 1B	SDG&E-8-C6-T1

B. Post-Mitigation/Control Analysis Results

As described in RAMP-D and Section 4 above, SDG&E utilized both internal data/modeling as well as PHMSA data to build RSEs for the pipeline incident risk areas. In the determination of inputs for the RSE calculations, SMEs were heavily utilized to confirm and provide data including the effectiveness of each control. The effectiveness percentages shown below are the result of discussions with SMEs whose knowledge of the control heavily dictated the values selected.

The below sections detail the Risk Reduction Benefits of each control/mitigation as well as specifically outline the data used in conjunction with said SME input to develop the RSE values.

1. SDG&E-8-C1: Cathodic Protection (CP)

a. Qualitative Description of Risk Reduction Benefits

A steel pipeline can corrode externally and experience a degradation process that can lead to a structural incident. Corrosion control activities like Cathodic Protection (CP) are meant to manage or arrest structural changes. CP is a method to mitigate external corrosion on steel pipelines thereby extending the life of a steel asset. The activities associated with CP include installation, monitoring, and remediation. SDG&E has installed CP on all of its 3,571 miles of gas mains and 266,806 gas services. Given the mandated requirement to continuously monitor and evaluate the CP areas, the management of this control is cyclical in nature. Gas Transmission manages the implementation of the work associated with this control with engineering oversight from the Pipeline Integrity group.

CP reduces safety risks by controlling pipeline corrosion rates thus reducing the frequency of corrosion-related incidents. Minimizing corrosion has the additional benefits of reducing reconstruction costs from pipeline incidents, reducing risk to property, and the potential benefit of improved service reliability. SDG&E exceeds the minimum safety requirements for CP prescribed by 49 CFR 191 Subpart I, which includes monitoring of CP areas, remediation of CP areas that are out of tolerance, and preventative installations to avoid areas out of tolerance.

b. Elements of the Bow Tie Addressed

Cathodic protection addresses the following elements of the bow tie:

i. [DT.1] – External Corrosion

ii. [DT.3] – Stress corrosion cracking

iii. [DT.4] – Manufacturing defects

iv. [DT.5] – Construction and fabrication

c. RSE Inputs and Basis

Scope	The cathodically protected transmission system running at a pressure over 60 psi.
Effectiveness	Per internal SME assessment, the effectiveness is 95%.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 1 out of the 7 SoCalGas and SDG&E incident samples was corrosion-related (14%). Using these assumptions, this mitigation could improve safety risk by up to 10% of the current residual risk. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 10% of the current residual risk. **Financial**: Using these assumptions, this control tranche could improve financial risk by up to 10% of the current residual risk.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	LoRE		**0.35**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	4.29	**34.27**	84.23
	RSE	11.40	**91.00**	223.66

2. SDG&E-8-C2/C5: Transmission Operations Maintenance (Valve Maintenance and Pipeline Maintenance)

a. Qualitative Description of Risk Reduction Benefits

Transmission Operations Maintenance supports the effective operation of gas transmission pipeline facilities and related infrastructure, which enhances public safety. Transmission Operations Maintenance activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident by mitigating various risk sources, primarily corrosion and degradation. Given the mandated requirement to conduct Transmission Operations Maintenance, the management of this control is cyclical in nature. Valve inspections and maintenance, pipeline patrols, and pipeline maintenance increase public and employee safety. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

Transmission Operations Maintenance addresses the following elements of the bow tie:

i. [DT.1] – External corrosion

ii. [DT.2] – Internal corrosion

iii. [DT.3] – Stress corrosion cracking

iv. [DT.4] – Manufacturing defects

v. [DT.5] – Construction and fabrication

vi. [DT.6] – Outside forces

vii. [DT.7] – Incorrect operations [DT.8] – Equipment failure

viii. [DT.9] – Third party damage (except for underground damages)

3. SDG&E-8-C3/-C6 – Pipeline Safety Enhancement Plan – Pipe Replacement/Pressure Testing

a. Qualitative Description of Risk Reduction Benefits

SDG&E's Pipeline Safety Enhancement Plan (PSEP) program is divided into two phases and each phase is further subdivided into two parts resulting in four separate phases, Phase 1A, Phase 1B, Phase 2A, and Phase 2B. SDG&E is dividing the work to complete pressure testing on all pipelines without a record of a pressure test and complete pipeline replacements into three phases (Phase 1A, Phase 1B, and Phase 2A) The work is prioritized such that testing is completed in more populated areas first, HCA's, followed by less populated areas, non-HCAs.

Pressure testing is a pipeline integrity assessment tool. A pressure test can reveal weakened spots on a pipeline. A failed test requires immediate remediation. As part of the PSEP, SDG&E is conducting pressure tests on segments of pipelines where no records of pressure testing exist (pressure testing has been previously completed in these areas, but it was not recorded). Once segments are tested remediations, including pipeline replacement, are completed, and records are updated. PSEP projects are coordinated to reduce capability issues and customer impacts. Once the PSEP projects are completed, SDG&E will follow TIMP inspection protocols on these pipeline segments in the future.

The principal benefit of PSEP is the substantial reduction in the likelihood of a pipeline incident, which thereby increases public and employee safety. PSEP reduces risk to public and employee safety, as well as risk to property. Additionally, the PSEP improves service reliability and maximizes cost effectiveness by reducing the potential reconstruction costs from potential incidents.

b. Elements of the Bow Tie Addressed

Pipeline Safety Enhancement Plan – Pipe Replacement and Pressure Testing addresses the following elements of the bow tie:

i. *[DT.1] – External corrosion*

ii. *[DT.2] – Internal corrosion*

iii. *[DT.3] – Stress corrosion cracking*

iv. *[DT.4] – Manufacturing Defects*

v. *[DT.5] – Construction and fabrication*

vi. *[DT.6] – Outside forces*

vii. *[DT.9] – Third party damage (except for underground damages)*

viii. *[DT.10] – Incorrect /inadequate asset records*

c. **RSE Inputs and Basis**

i. **SDG&E-8-C3-T2: Pipeline Replacement: Phase 1B**

Scope	Replacing 39 miles of pipe out of 42 miles (93%).
Effectiveness	Per SME estimate, we assume 100% effectiveness. These segments are also assumed to be 3.4 times more likely for an incident to occur than their replacements.
Risk Reduction	**Safety**: 2 out of 7 historical, significant incidents are due to corrosion and natural forces according to SoCalGas and SDG&E data reported to PHMSA since year 2010. 83% of the risk is assumed to be HCA, with 17% non-HCA. Phase 1B is located within non-HCAs. Using these assumptions, this tranche could improve safety risk by up to 15%. **Reliability:** Using these assumptions, this control for this tranche could improve SDG&E HP Gas Incident reliability risk by up to 15%. **Financial:** Financial risk multiplied by 3 given the one incident causing a similar proportion of total property damage. Using these assumptions, this tranche could improve SDG&E High Pressure Gas Incident financial risk by up to 46%.

ii. **SDG&E-8-C6-T1: Pipeline Testing: Phase 1B**

Scope	Testing 4 miles of pipe out of 13 miles (31%).
Effectiveness	Per SME estimate, we assume 95% effectiveness.
Risk Reduction	**Safety**: In the absence of pressure testing, incipient failures would not be detected and the rate of pipeline failure might eventually be higher reaching an SME estimated plateau where the pipe is 1.6 times more likely to have an incident occur **Reliability:** Using these assumptions, this mitigation could improve the SDG&E HP Gas Incident reliability risk by up to 133% of the current residual risk.

	Financial: financial risk is multiplied by 3 with one incident causing a similar proportion of property damage. Using these assumptions, this mitigation could improve the SDG&E HP Gas Incident financial risk by up to 400% of the current residual risk.

d. Summary of Results

i. SDG&E-8-C3-T2: Pipeline Replacement: Phase 1B

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	LoRE		**0.37**	
	CoRE	12.86	**97.66**	239.00
	Risk Score	4.78	**36.29**	88.81
	RSE	0.20	**1.19**	2.83

ii. SDG&E-8-C6-T1: Pipeline Testing: Phase 1B

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	LoRE		**0.75**	
	CoRE	15.20	**100.00**	241.34
	Risk Score	11.43	**75.18**	181.44
	RSE	5.27	**30.84**	73.45

4. SDG&E-8-C4: Transmission Integrity Management Program (TIMP)

a. Qualitative Description of Risk Reduction Benefits

TIMP is a regulatory required program to assess and remediate, as necessary, transmission pipelines within HCA's every seven years using In-Line-Inspection, Direct Assessment or Pressure Test. TIMP supports the effective operation of transmission pipelines, which enhances public safety. TIMP activities are preventative in nature and are intended to reduce or eliminate conditions that might lead to an incident. Given TIMP mandated requirements per 49 C.F.R. § 192, Subpart O, the management of this control is cyclical in nature. The TIMP proactively identifies, evaluates, and reduces pipeline integrity risk thereby improving public and employee safety by reducing the likelihood of a transmission pipeline incident. A secondary activity that aids in the future risk analysis in the collection of data as part of TIMP which may reveal trends in the management of safety risks. Minimizing safety threats has the additional benefits of reducing reconstruction costs from equipment failure, reducing risk to property, and the potential benefit of improved service reliability.

b. Elements of the Bow Tie Addressed

TIMP addresses the following elements of the bow tie:

i. [DT.1] – External corrosion

ii. [DT.2] – Internal corrosion

iii. [DT.3] – Stress corrosion cracking

iv. [DT.4] – Manufacturing defects

v. [DT.5] – Construction and fabrication

vi. [DT.6] – Outside forces

vii. [DT.9] – Third party damage (except for underground damages)

viii. [DT.10] – Incorrect /inadequate asset records

c. RSE Inputs and Basis

Scope	Approximately 3/7 of the transmission system within the scope of TIMP to be assessed.
Effectiveness	Per internal SME assessment, this mitigation is 95% effective. In the absence of these assessments, risk levels are estimated to be 29 times higher than they would be otherwise.
Risk Reduction	**Safety**: Based on an assessment of PHMSA data, 7 natural gas incidents occurred at SoCalGas and SDG&E starting in 2010. 2 out of the 7 SoCalGas and SDG&E incident samples are assumed to be in-scope (29%). Using these assumptions, this control tranche could improve safety risk by up to 340% of the current residual risk. **Reliability**: Using these assumptions, this control tranche could improve reliability risk by up to 340% of the current residual risk.

	Financial: Using these assumptions, this control tranche could improve financial risk by up to 340% of the current residual risk.

d. **Summary of Results**

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	LoRE		**1.41**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	17.10	**136.53**	335.57
	RSE	2.81	**22.47**	55.22

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

As discussed, the existing controls outlined within this Chapter will continue and certain controls will increase in scope or at an accelerated pace. However, SDG&E, as a diligent operator, will monitor the controls to determine if any adjustments are needed during the implementation period. The programs could be influenced as additional information is gathered or understanding of risk and controls relationship changes. Should controls need to change, consideration will be given to available technology, labor resources, planning and construction lead time, compliance requirements, and operational and execution considerations.

The following table provides a summary of the Risk Mitigation Plan including controls, associated costs, and RSEs by tranche. SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in the table were estimated using assumptions provided by SMEs from associated operations, maintenance, and engineering functions within SDG&E and available accounting data.

Table 7: Risk Mitigation Plan Overview[35]
(Direct 2018 $000)[36]

ID	Mitigation /Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M	Total[39]	RSE[40]
SDG&E -8-C1	Cathodic Protection	T1	290	0	830 – 1,100	0	830 – 1,100	11.40 – 223.66
SDG&E -8-C2	Valve Maintenance	T1	130	0	300 - 390	0	300 - 390	-
SDG&E -8-C3	PSEP – Pipeline Replacement - Phase 1A	T1	0	0	0	0	0	-
SDG&E -8-C3	PSEP – Pipeline Replacement - Phase 1B	T2	7,600	0	100,000 – 130,000	0	100,000 – 130,000	0.2 - 2.83

35 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

36 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

37 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

38 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application. For PSEP capital, it is anticipated that SDG&E will include forecasts for 2022 – 2024 in the TY2022 GRC because prior PSEP capital projects will be recovered through PSEP reasonableness reviews.

39 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

40 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	T1	2,300	6,000	11,000 – 15,000	4,700 – 6,000	16,000 – 21,000	2.81 – 55.22
SDG&E-8-C5	Pipeline Maintenance	T1	0	140	0	110 - 150	110 - 150	-
SDG&E-8-C6-T1	PSEP – Pressure Testing – Phase 1B	T1	6,300	1,000	2,200 – 2,900	5,300 – 6,800	7,500 – 9,700	5.27 – 73.45
		TOTAL COST	**17,000**	**7,000**	**110,000 – 150,000**	**10,000 – 13,000**	**120,000 – 160,000**	**-**

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 8: Summary of RSE Exclusions

ID	Control Name	Reason for No RSE Calculation
SDG&E-8-C2	Valve Maintenance	Mandated activity per 49 CFR 192 Subpart M § 192.745
SDG&E-8-C3-T1	Pipeline Replacement: Phase 1A	No costs are anticipated for the TY2022 GRC cycle for Phase 1A projects.
SDG&E-8-C5	Pipeline Maintenance	Mandated activity per 49 CFR 192 Subpart M

VIII. ALTERNATIVE MITIGATION PLAN ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the described mitigations for the High Pressure Gas Pipeline Incident risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, including but not limited to operational, compliance and resource constraints.

A. SDG&E-8-A1 – Proactive Soil Sampling

1. Description of Risk Reduction Benefits

SDG&E collects soil samples during TIMP-related excavations along its pipelines. These soil samples are analyzed for chemical composition and characteristics that determine the corrosivity of the soil in the vicinity of the pipeline. Expanding this soil sampling program to include collecting soil samples at regular intervals, such as every mile, along pipelines with a history of corrosive activity may allow SDG&E to anticipate areas of their pipelines that may be susceptible to accelerated corrosion between inspection events. The cost estimate of sampling the 228 miles of transmission pipe is $355 thousand over the course of three years; on average, 14 samples per day will be tested at intervals of 2 samples per mile. The results of the soil sampling would be integrated into the SDG&E's pipeline GIS system and be used in a comprehensive evaluation of the SDG&E pipeline system. Soil sample data (i.e., resistivity and pipe-to-soil reads) would be used to determine corrosion rate, which is critical information in developing a mature risk assessment of corrosion threat. SDG&E has not initiated an expanded soil sampling program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a Relative Risk model to a Deterministic Risk model for the corrosion threat the benefit of additional information can be better understood. In the interim SDG&E will be researching available data sets and determining the benefit of additional soil property information.

a. RSE Inputs and Basis

Scope	Assuming 100% of soil would be sampled, as a one-time effort: once the soil is sampled, it does not need to be resampled.
Effectiveness	Per internal SME assessment, effectiveness of having additional data for making better decisions for pipe replacements will be minimal, at 1%.[41]
Risk Reduction	Risk addressed is 14%, due to 1 out of 7 corrosion-related significant events in company history since year 2010. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.1%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.32**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.17**	76.62
	RSE	0.02	**0.12**	0.31

B. SDG&E-8-A2 - Expanding Geotechnical Analysis

1. Description of Risk Reduction Benefits

SDG&E considered expanding its geotechnical analysis of pipelines potentially exposed to landslide, flood, and debris flow hazards. This analysis includes slope stability analysis and flood evaluation of terrain surrounding the pipelines and evaluating the likelihood and consequence of landslides and the resulting debris flow on the pipeline. SDG&E looks at areas susceptible to landslide, flooding, and debris flows using satellite monitoring, drones, light detection and ranging (LiDAR), strain gauges, inclinometers, and fiber optic cables. SDG&E has performed extensive analysis and evaluation of the slope stability, landslide, and debris flow conditions of pipelines that have been impacted by severe weather events by running models based off collected field data. The results of this analysis and evaluation have been used to

[41] Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

mitigate the potential impact of future severe weather events on these pipelines. SDG&E has considered identifying additional pipelines with potential exposure to severe weather events to perform analysis regarding slope stability, landslide, and debris flow. SDG&E has not initiated an expanded geotechnical analysis program since the potential benefit is related to the maturing of the risk assessment. As the risk assessment continues to mature from a Relative Risk model to a Deterministic Risk model the benefit of additional information can be better understood.

a. RSE Inputs and Basis

Scope	Per SME input, very few of the potential sites are to be remediated, the scope was set at 1%.
Effectiveness	Per internal SME assessment, the effectiveness of this mitigation is 50%.[42]
Risk Reduction	Risk addressed is assumed to be a fraction of the historical experience or 60% of 1 out of 7 significant events, for risk addressed of 9%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.04%.

b. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.22**	76.73
Post-Mitigation	**LoRE**		**0.32**	
	CoRE	12.14	**96.95**	238.29
	Risk Score	3.91	**31.20**	76.70
	RSE	0.00	**0.04**	0.09

42 Given the need for more mature data for this alternative, the RSEs calculated here are particularly speculative.

Table 9: Alternative Mitigation Summary
(Direct 2018 $000)[43]

ID	Mitigation	2020-2022 Capital[44]	2022 O&M	Total[45]	RSE[46]
SDG&E-8-A1	Proactive Soil Sampling	0	110 - 140	110 - 140	0.02 – 0.31
SDG&E-8-A2	Expanding Geotechnical Analysis	0	150 - 200	150 - 200	0.00 – 0.09

[43] The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

[44] The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

[45] Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

[46] The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-8-C1	Cathodic Protection	DT.1, DT.3, DT.4, DT. 5
SDG&E-8-C2	Valve Maintenance	DT.1, DT.2, DT.4, DT.5, DT.6, DT.7, DT.8, DT.9
SDG&E-8-C3-T1	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1A	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SDG&E-8-C3-T2	Pipeline Safety Enhancement Plan – Pipeline Replacement: Phase 1B	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10
SDG&E-8-C4	Transmission Integrity Management Program (TIMP)	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9, DT.10
SDG&E-8-C5	Pipeline Maintenance	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.9
SDG&E-8-C6-T1	Pipeline Safety Enhancement Plan – Pressure Testing	DT.1, DT.2, DT.3, DT.4, DT.5, DT.9, DT.10

Risk Assessment Mitigation Phase

(Chapter SDG&E-9)

Third Party Dig-in on a High Pressure Pipeline

November 27, 2019

TABLE OF CONTENTS

Risk: Third Party Dig-in on a High Pressure Pipeline

I. INTRODUCTION

The purpose of this chapter is to present the Risk Mitigation Plan for San Diego Gas & Electric Company's (SDG&E or Company) Third Party Dig-in on a High Pressure Pipeline risk. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

SDG&E has identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this Report. On an annual basis, SDG&E's Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR), which influenced how risks were selected for inclusion in the 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's General Rate Case (GRC). The costs presented in this 2019 RAMP Report are those costs for which SDG&E anticipates requesting recovery in its Test Year (TY) 2022 GRC. SDG&E's TY 2022 GRC presentation will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For the 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and are within the scope of the analysis required in this RAMP Report. Throughout the 2019 RAMP Report activities are delineated between controls and mitigations, which is consistent with the definitions adopted in the SA Decision Revised Lexicon. A "Control" is

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

defined as a currently established measure that is modifying risk. A "Mitigation" is defined as a measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event. Activities presented in this chapter are representative of those that are primarily scoped to address SDG&E's Third Party Dig-in on a High Pressure Pipeline risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, SDG&E did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted in order to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code statute, or General Order. Activities with no RSE score presented in this RAMP Report are identified in Section VII below.

SDG&E has also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of SDG&E's mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

SoCalGas and San Diego Gas & Electric Company (SDG&E), collectively the "Companies," own and operate an integrated natural gas system. The Companies collaborate to develop policies and procedures that pertain to the engineering and operations management of the gas system operated in both the SoCalGas and SDG&E territory to maintain consistency. However, execution of such policies and procedures are the responsibility of the employees at respective geographically delineated operating unit headquarters. Accordingly, there are similar mitigation plans presented in the 2019 RAMP Report across the Companies' third party dig-in related chapters.[3]

A. Risk Definition

For purposes of this TY 2022 RAMP Report, the Third Party Dig-in on a High Pressure Pipeline risk is defined as a dig-in on a high pressure pipeline [Maximum Allowable Operating Pressure (MAOP), greater than 60 pounds per square inch gauge (psig)] caused by third party activities which results in significant consequences including serious injuries and/or fatalities.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[4] for each Control and Mitigation presented herein, SDG&E has identified which element(s) of the Risk Bow Tie the mitigation addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Driver/Trigger and Potential Consequences
DT.1	Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation
DT.2	Locator error contributing to the incorrect marking of underground gas structures
DT.3	Hand excavation is not performed by excavator in the vicinity of located gas pipelines
DT.4	Company does not respond to 811 requests in required timeframe
DT.5	Company does not "standby" when third party excavates near gas pipelines
DT.6	Contractor fails to contact company "standby" personnel
DT.7	Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark
PC.1	Serious Injuries and/or Fatalities
PC.2	Property Damage
PC.3	Prolonged Outages
PC.4	Penalties and Fines
PC.5	Adverse Litigation

3 The other third party dig-in related chapters in the 2019 RAMP Report include: SCG-6 – Third Party Dig-in on a Medium Pressure Pipeline; SCG-7 – Third Party Dig-in on a High Pressure Pipeline; and SDG&E-7 – Third Party Dig-in on a Medium Pressure Pipeline.

4 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

ID	Description of Driver/Trigger and Potential Consequences
PC.6	Erosion of Public Confidence

C. Summary of Risk Mitigation Plan

Pursuant to the SA Decision,[5] SDG&E has performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. SDG&E's baseline controls for this risk consist of the following programs/activities:

Table 2: Summary of Controls

ID	Control Name
SDG&E-9-C1	Locate and Mark Training
SDG&E-9-C2	Locate and Mark Activities
SDG&E-9-C3	Locate and Mark Annual Refresher Training & Competency Program
SDG&E-9-C4	Locate and Mark Operator Qualification
SDG&E-9-C5	Locate and Mark Quality Assurance Program
SDG&E-9-C6	Damage Prevention Analyst Program
SDG&E-9-C7	Prevention & Improvements-Refreshed Laptops
SDG&E-9-C8	Public Awareness Compliance
SDG&E-9-C9	Increase Reporting of Unsafe Excavation
SDG&E-9-C10	Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board
SDG&E-9-C11	Public Awareness-Meet with the Cities with the Highest Damage Rates
SDG&E-9-C12	Public Awareness-Remain Active Members of the California Regional Common Ground Alliance
SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program
SDG&E-9-C14	Locating Equipment
SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers
SDG&E-9-C16	Install warning mesh above buried company facilities

SDG&E will continue the baseline controls identified above and describes additional projects and/or programs (*i.e.*, mitigations) as follows:

Table 3: Summary of Mitigations

ID	Mitigation Name
SDG&E-9-M1	Automate Third Party Excavation Incident Reporting

[5] *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SDG&E-9-M2	Establish A Program To Address The Area Of Continual Excavation
SDG&E-9-M3	Recording Photographs For Each Locate and Mark Ticket Visited By Locator
SDG&E-9-M4	Utilize Electronic Positive Response
SDG&E-9-M5	Enhance Process To Utilize And Leverage Emerging Excavation Technology To Help With Difficult Locates
SDG&E-9-M6	Promote Process And System Improvements In USA Ticket Routing And Monitoring
SDG&E-9-M7	Leverage Data Gathered By Locating Equipment

Finally, pursuant to the SA Decision,[6] SDG&E considered alternatives to the Mitigations for the Third Party Dig-in on a High Pressure Pipeline Risk and summarizes the reasons that the alternatives were not included into the mitigation plan in Section VIII.

II. RISK OVERVIEW

Excavation damage, or dig-ins, to high pressure underground gas infrastructure has been a risk to SDG&E for as long as pipe has been buried underground. This risk is not a risk unique to the Company. Third-party dig-ins are a common national problem for all industries and utilities with buried infrastructure. These "third-party" excavation activities can vary widely based on project scope and size. Examples can include a construction firm widening a freeway, a farmer working their land, or a city upgrading its aging municipal water or sewer systems. Third-party dig-ins, while always a concern, are especially dangerous when they involve a high pressure pipeline because the third party activity can damage or weaken the pipeline resulting in a leak, pipeline burst, or gas explosion. Thus, although this is a low occurrence event given, in part, the location of high pressure pipelines, it's a high consequence risk.

Third-party excavation damage can range from minor scratches or dents, to ruptures with an uncontrolled release of natural gas. The release of natural gas may not just occur at the time of the damage. A leak or rupture may also occur after the infrastructure has sustained more minor damage, but then becomes weakened over time. Once damaged, the responsible party may not report non-gas release damages, bypassing the effort of the Company to assess and make the appropriate repairs before a weakening of the pipe occurs.

6 *Id.* at 33.

Serious consequences may result if an event occurs because of this risk. For example, if a leak or rupture occurs, an ignition of the released gas could lead to an explosion, fire or both. The nearby public could be seriously injured, and property damage can be extensive. Federal and state agencies have responded to the third party dig-ins risk by adopting numerous regulations and industry standards[7] and have promoted other efforts[8] to help prevent third-party dig-ins. For example, the Department of Transportation (DOT) sponsored the "Common Ground Study", completed in 1999. The "Common Ground Study" then led to the creation of the Common Ground Alliance (CGA), a member-driven association of 1,700 individuals, organizations, and sponsors in every facet of the underground utility industry. With industry-wide support, CGA created a comprehensive consensus document that details the best practices addressing every stake-holder groups' activity in promoting safe excavation and preventing dig-in damages. While these efforts are important and commendable, and the number of dig-ins per 1,000 excavation tickets has been trending down, the numbers still remain high.

Under California State Law,[9] a third-party planning excavation work is required to contact the Regional Notification Center for their area, also known as 811 or Underground Service Alert (USA), at least two (2) full working days prior to the start of their construction excavation activities, not including the day of the notification. Eight-One-One (811) is the national phone number designated by the Federal Communications Commission (FCC), that connects homeowners who plan to dig with professionals through a local call center. California has two Regional Notification Centers, DigAlert and USA North, that split California at the Los Angeles /Kern county and Santa Barbara/San Luis Obispo county lines; USA North serves all counties north of the county lines and DigAlert serves all counties south of the county lines. DigAlert and USA North will be referenced as 811 USA for the remainder of this chapter. Once a third-party makes the contact, the Regional Notification Center will issue a USA Ticket

---

7 49 Code of Federal Regulations (CFR) § 192, *et al.*; *id.* at § 196; Cal. Govt. Code § 4216, General Order (GO) 112-F; American Petroleum Institute (API) Recommended Practice (RP) 1162.

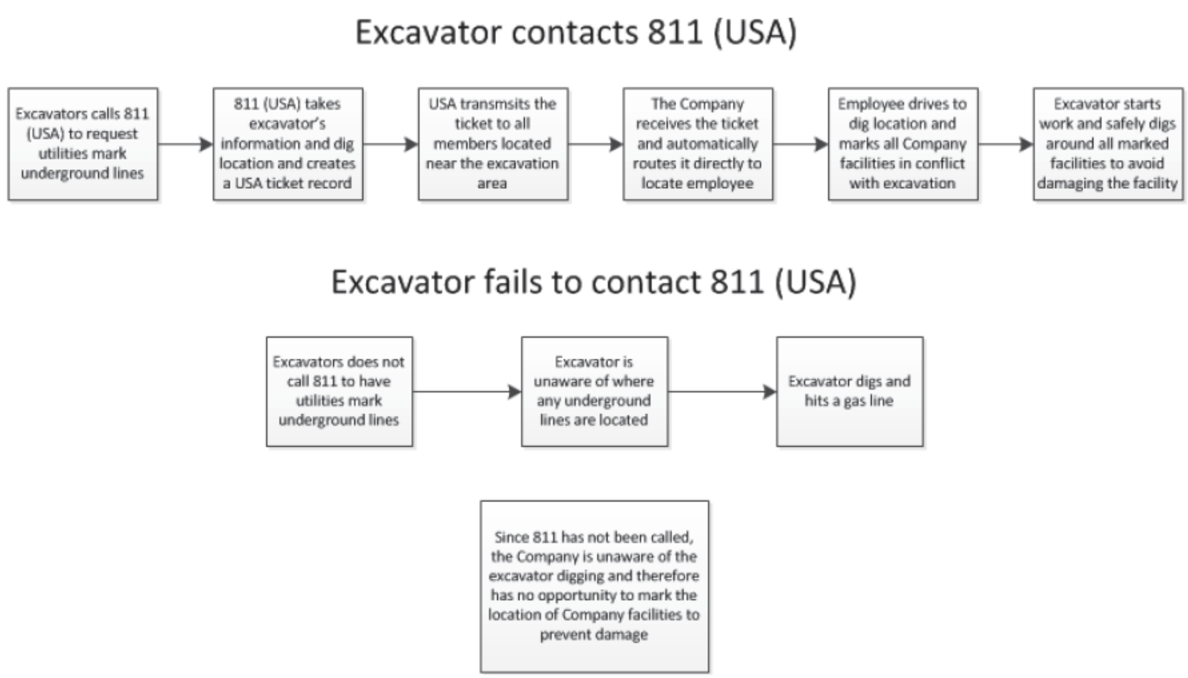
8 Common Ground Alliance (CGA), *Best Practices Guide* (March 2019), *available at* https://commongroundalliance.com/best-practices-guide.

9 Cal. Govt. Code § 4216.2(b).

notifying local utilities and other operators of the location and areas to be inspected for potential conflicts of underground infrastructure with the pending excavation work. Operators are required to provide a positive response to indicate that there are no facilities in conflict or mark their underground facilities via aboveground identifiers (e.g. paint, chalk, flags, whiskers) to designate where underground utilities are positioned, thus enabling third parties, like contractors and homeowners, to know where these substructures are located. The law also requires third-party excavators to use careful, manual (hand digging) methods to expose substructures prior to using mechanical excavation tools.

Figure 1 below illustrates the sequence of events that may occur when a third-party contacts 811 USA prior to conducting excavation work and, in contrast, the sequence that may occur when they do not.

Figure 1 : Excavation Contact Process Flow



As can be seen in the figure above, while there may be more steps when a third-party calls 811 USA prior to commencing the excavation work, it is more likely to result in a positive outcome compared to when a call is not made. When third-parties call 811 USA before excavating, the risk of a dig-in is significantly reduced.

SDG&E managed over 130,000 USA tickets and reported over 300 dig-in excavation damage incidents in 2018, most of them associated with medium pressure pipelines. Further analysis of the reported damages shows that 50% were due to a lack of notification to 811 USA for a locate and mark ticket and 28% were due to inadequate excavation practices even after the excavator obtained a one call ticket.[10]

In addition to the direct involvement with excavators and 811 USA, SDG&E engages in promoting safe digging practices through its Public Awareness Program (API 1162) and corporate safety messaging through stakeholder outreach. The message is presented by way of multi-formatted educational materials through mail, email, social media, television, radio, events, and association sponsorships. This control is further described in Section V.

III. RISK ASSESSMENT

In accordance with the SA Decision,[11] this section describes the Risk Bow Tie, possible drivers, and potential consequences of the Third Party Dig-in on a High Pressure Pipeline risk.

A. Risk Bow Tie

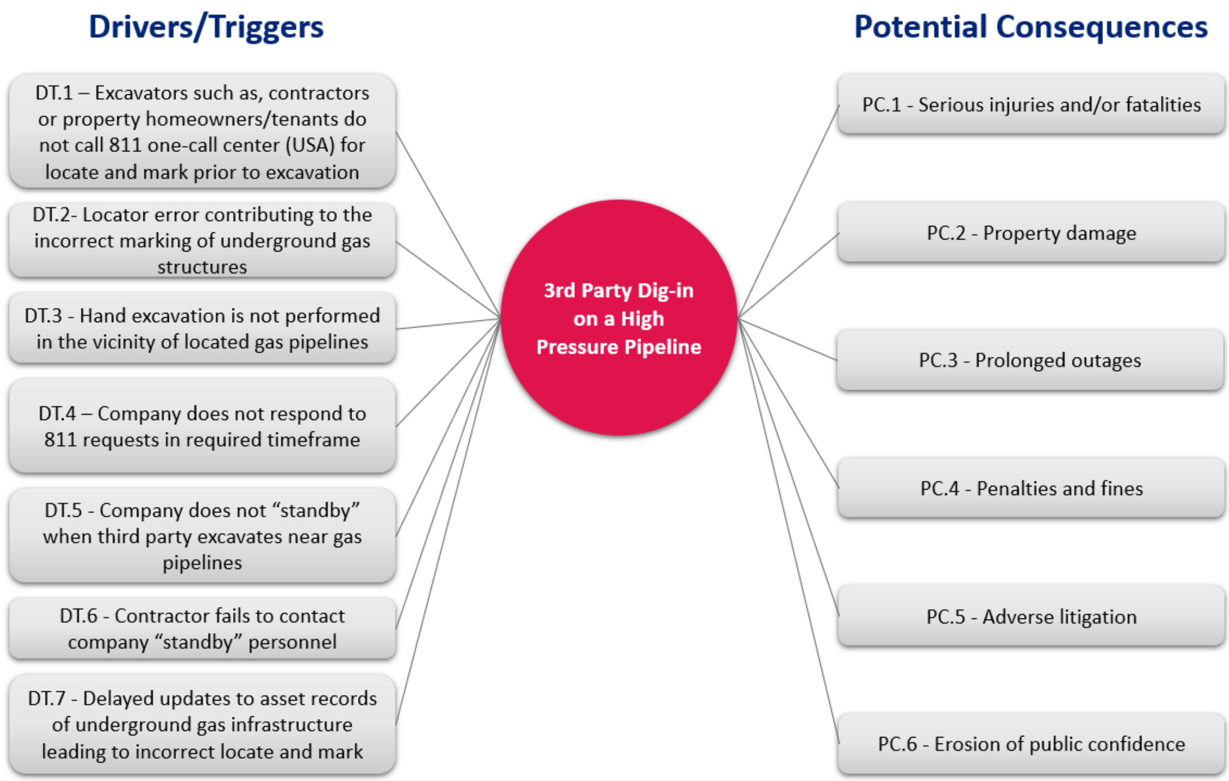
The Risk Bow Tie shown in Figure 1 below is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. SDG&E applied this framework to identify and summarize the information provided above. A mapping of each Control/Mitigation to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

---

10 Common Ground Alliance, *CGA Released 2018 Damage Information Reporting Tool (DIRT) Report*, *available at* https://commongroundalliance.com/DIRT.

11 D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 2: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[12] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. These assets include:

- Natural Gas Pipeline Distribution System – SDG&E's medium and high-pressure distribution pipeline system is comprised of plastic and steel pipelines and its appurtenances (e.g., meters, regulators, risers). The aforementioned portions operating over 60 psig comprise the high-pressure portion of the system. Some Distribution pipelines operate at over 20% of the pipeline's Specified Minimum Yield Strength (SMYS), and they are considered to be transmission pipelines by definition; however, these assets are operated by Distribution Operations.

---

12 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

- Natural Gas Pipeline Transmission System – SDG&E's high-pressure transmission pipeline system is comprised of steel pipelines and its appurtenances (*e.g.*, meters, regulators, risers) operating over 20% of the pipeline's SMYS.

C. Risk Event Associated with the Risk

The SA Decision[13] instructs the utility to include a Bow Tie illustration for each risk included in RAMP. As illustrated in the above Bow Tie, the risk event (center of the bow tie) is a third party dig-in on a medium pressure pipeline event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. The Risk Scenario (*i.e.*, a potential reasonable worst-case scenario used to assess the residual risk impacts and frequency) is assessed for SDG&E's 2018 ERR. This scenario does not necessarily address all Drivers/Triggers and Potential Consequences and does not reflect actual or threatened conditions.

D. Potential Drivers/Triggers[14] of Risk Event

When performing the risk assessment for Third Party Dig-in on a High Pressure Pipeline, SDG&E identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT. 1 – Excavators such as, contractors or property homeowners/tenants do not call 811 one-call center (USA) for locate and mark prior to excavation:** Despite the creation of Regional Notification Centers to inform and allow excavators to have underground infrastructure located and marked, and advertising campaigns alerting the excavator of the need to do so, incidents still occur where excavations are conducted without first calling 811 USA. In fact, third party failure to contact the Regional Notification Center prior to excavating is the leading contributor of damages to Company pipelines. Third parties can damage or rupture underground pipelines and potentially cause property damage,

---

13 *Id.* at Attachment A, A-11 ("Bow Tie").

14 An indication that a risk could occur. It does not reflect actual or threatened conditions.

injuries, or even death if gas lines are not properly marked before excavation activities begin. Without receiving an 811 USA ticket, the Company has no opportunity to mark its facility within the area of excavation.

- **DT. 2 – Locator error contributing to the incorrect marking of underground gas structures:** The Company, in some cases, inaccurately mark facilities due to incorrect operations, such as mapping/data inaccuracies, equipment signal interference, and human error. When this happens, third parties are not provided with accurate knowledge of underground structures in the vicinity of their excavations and the risk of damaging or rupturing gas pipelines increases.
- **DT.3 – Hand excavation is not performed in the vicinity of located gas pipelines:** Before using any power operated excavation equipment or boring equipment, the excavator is required to hand expose, using "Hand Tools," [15] to the point of no conflict 24 inches on either side of the High Pressure Gas Pipeline to determine the exact location of these structures. If excavators do not use care when digging near natural gas pipelines they put themselves and others at risk for injuries.
- **DT. 4 – Company does not respond to 811 requests in required timeframe:** Company may not respond to 811 USA requests within the 'Legal excavation start date and time' [16] (within two working days of notification, excluding weekends and holidays, or before the start of the excavation work, whichever is later, or at a time mutually agreeable to the operator and the excavator.) This may happen because of human error, poor communication, or system failures. In these cases, the third party may not know that the locate and mark activity was not performed and may wrongly assume that not seeing any marking at their excavation site indicates there is no gas infrastructure nearby. Without the

[15] Cal. Govt. Code § 4216(i).

[16] *Id.* at § 4216(l).

marked gas infrastructure, third parties may damage or rupture the infrastructure if they are performing excavation activities near pipelines.

- **DT.5 – Company does not "standby" when third party excavates near gas pipelines:** High Pressure pipelines (those that operate over 60 psig) pose a higher risk of hazard to life and property when damaged or ruptured. Thus, additional precautions are taken by the Company to observe excavation activities in the vicinity of these facility. Qualified Company personnel are required to be present during excavation activities within 10 feet of any high pressure gas line (the presence commonly referred to as "stand-by"). The stand-by presence allows for redundancy via a Company representative should the third party not follow proper protocol during the excavation (e.g., not hand excavate near the pipeline), or the marks are determined to be inaccurate. Stand-by presence increases the excavator's awareness of all excavation requirements near the high pressure facility.
- **DT.6 – Contractor fails to contact company "standby" personnel:** An excavator may fail to contact the Utility's "standby" personnel for the prevention of damage to High Pressure Gas Pipelines when required, prior to excavating within 24 inches of a High-Pressure Gas Pipeline. This would increase the risk that the excavator damages a high pressure pipeline.
- **DT.7 – Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark:** The Company may fail to supply the necessary information in a timely manner to update permanent mapping records necessary to meet federal, state, local and regulations, as well as corporate needs. This could result in underground infrastructure being incorrectly marked. If maps are not updated in a timely manner, new mains and services may not be marked and located if a USA ticket is requested. This could lead to third party damage if the excavator does not have the correct information on infrastructure location. In addition, in the event in which a pipeline is damaged, obsolete maps could cause delays in performing the necessary repairs.

E. Potential Consequences of Risk Event

Potential Consequences are listed to the right side of the Bow Tie illustration provided above. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- Serious injuries[17] and/or fatalities;
- Property damage;
- Prolonged outages;
- Adverse litigation;
- Penalties and fines; and
- Erosion of public confidence.

These Potential Consequences were used in the scoring of SDG&E's Third Party Dig-in on a High Pressure Pipeline Risk that occurred during the development of SDG&E's 2018 ERR.

IV. RISK QUANTIFICATION

The SA Decision sets minimum requirements for risk and mitigation analysis in RAMP, including enhancements to the Interim Decision 16-08-018. SDG&E has used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

[17] As defined by Cal/OSHA as "any injury or illness occurring in a place of employment or in connection with any employment which requires inpatient hospitalization for a period in excess of 24 hours for other than medical observation or in which an employee suffers a loss of any member of the body or suffers any serious degree of permanent disfigurement, but does not include any injury or illness or death caused by the commission of a Penal Code violation, except the violation of Section 385 of the Penal Code, or an accident on a public street or highway." *See* 8 CCR § 330(h).

Table 4: Risk Quantification Scores[18]

Third Party Dig-in on a High Pressure Pipeline	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	1	4	11
LoRE	0.25		
CoRE	2	18	45

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[19] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 5: Risk Quantification Scope

In-Scope for purposes of risk quantification	The risk of a dig-in on a high-pressure line (MAOP greater than 60 psig), caused by third party activities, which results in consequences such as injuries or fatalities or outages.
Out-of-Scope for purposes of risk quantification	The risk of event unrelated to a third-party dig-in on a high-pressure line (MAOP greater than 60 psig) which results in consequences such as injuries or fatalities or outages.

Pursuant to Step 2A of the SA Decision , the utility is instructed to use actual results, as well as available and appropriate data.[20]

---

18 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score"), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

19 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

20 *Id.* at Attachment A, A-8 ("Identification of Potential Consequences of Risk Event").

Historical PHMSA data and internal SME input was used to estimate the frequency of incidents. To determine the incident rate per year for SDG&E, the national average incident rate per mile per year was applied to the high-pressure pipeline miles at SDG&E.

The safety risk assessment primarily utilized data from the PHMSA, the reliability risk assessment was based on internal data, and the financial risk assessment was estimated based on both PHMSA and internal data. Internal SME input, based on recent damage repair costs, was used to estimate the financial consequence of incidents. Historical PHMSA high-pressure gas incidents were also used in estimating financial and safety consequences. The reliability incident rate per year was estimated using internal data. Additionally, Monte Carlo simulation was performed to understand the range of possible consequences.

B. Sources of Input

The SA Decision[21] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

- Annual Report Mileage for Natural Gas Transmission & Gathering Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems
- Link: Annual Report mileage for Gas Distribution Systems
  - Agency: PHMSA
  - Link: https://cms.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-gas-distribution-systems
- Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data
  - Agency: PHMSA
  - Link: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

21 *Id.* at Attachment A, A-8 ("Identification of the Frequency of the Risk Event").

- SDG&E high-pressure pipeline miles
  - 2017 internal SME data
- Gas industry sales customers
  - Agency: AGA (2016Y)
  - Link: https://www.aga.org/contentassets/d2be4f7a33bd42ba9051bf5a1114bfd9/section8divider.pdf
- SDG&E end user natural gas customers
  - Source: SNL (2016Y, from the FERC From 2/2-F, 3/3-A or EIA 176)
  - Link: https://platform.mi.spglobal.com/web/client?auth=inherit&newdomainredirect=1&#company/report?id=4057146&keypage=325311

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[22] This section describes SDG&E's Risk Mitigation Plan by each selected Control and Mitigation for this risk, including the rationale supporting each selected Control and Mitigation.

As stated above, SDG&E's Third Party Dig-in on a High Pressure Pipeline Risk involves impact to gas infrastructure arising from third party dig-ins resulting in significant consequences including serious injuries and/or fatalities. The Risk Mitigation Plan discussed below includes both controls that are expected to continue and mitigations for the period of SDG&E's TY 2022 GRC cycle. The controls are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time.

A. SDG&E-9-C1 – Locate and Mark Training

This program provides employees with the tools to perform activities associated with locate and mark. Adequately preparing employees by offering educational opportunities and

[22] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

resources gives them the knowledge to implement State and Company policies and procedures in a safe manner. This, in turn, helps SDG&E operate and maintain its system, as well as protect employees, contractors, and the public from the threat of an event attributable to this risk.

Locate and Mark Training consists of approximately seven days of classroom and hands-on training at a centralized training facility, as well as eLearning. SDG&E will continue to implement a competency based training program that will encompass training on any policy or procedural changes impacting third-party dig-ins. A competency based online/video training module system enhances SDG&E's ability to incorporate new policies and increase learning at a faster pace. This system will use a comprehensive, multimedia, competency-based training approach which will include self-paced, individualized, modular instruction, eLearning, just-in-time training, structured on-the-job training, and mentoring. This is a mandated activity in order to comply with Operator Qualification requirements and to provide the basic knowledge necessary to satisfactorily perform this critical task. The training schedule is dependent on annual demand, but occurs, on average, about every two months.

The training provides the participating employees several key components of locating, enabling them to locate and mark the below ground facilities accurately and in the appropriate time frame. The marked facilities provide the excavator with approximate locations of where the gas lines exist in the work area which enables the excavator to either avoid the areas or dig with hand tools so underground substructures are not accidentally damaged by the excavation work.

B. SDG&E-9-C2 – Locate and Mark Activities

This control is comprised of three activities that are related to performing or supporting locate and mark work: (1) Locate and Mark, (2) Pipeline Observation (stand-by), and (3) Staff Support. Verifying that SDG&E is executing such tasks safely can reduce the potential of an event occurring.

The first activity is Locate and Mark, which is the actual work performed by SDG&E gas operations which is required to respond to over 130,000 USA notifications per year.[23] To do this activity, SDG&E physically goes to the job site and locates and marks any and all company

---

[23] Represents 811 USA notifications for SDG&E's distribution and transmission system.

operated pipelines in the delineated work area. Understanding the physical location of the pipeline allows the third-party to avoid that area or carefully perform the excavation work to avoid contact with the pipeline. This activity is mandated by both State[24] and Federal law.[25] This control activity also includes all aspects necessary to performing the mandated locate and mark activities, including locators, vehicles, tools, Mobile Data Terminals (MDTs), Geographical Information System (GIS)-related costs, ticket routing systems, locating materials, fees to Regional Notification Centers, and quality assurance.

The second Locate and Mark activity is Pipeline Observation (stand-by). In accordance with Title 49 Code of Federal Regulation, section 192.935, Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. This activity occurs daily in both Distribution and Transmission operations. The purpose for this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having another pair of qualified eyes observing the work being done. This is a best practice in the gas industry and is critical to the safety of employees, contractors, and the public.

The third activity is staff support. Support staff consists of employees who are responsible for developing and maintaining policies, processes, and procedures that guide and direct locators in properly performing their assigned tasks in compliance with Federal and State regulations. Staff is engaged daily in supporting operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, and providing refresher training as requested. This is a critical activity that allows the Company to meet or exceed State and Federal requirements and align with industry best practices when applicable.

C. SDG&E-9-C3 – Locate and Mark Annual Refresher Training & Competency Program

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards with the locate and mark workforce. All employees are required to pass the refresher training in

---

24 Cal. Govt. Code § 4216.

25 49 CFR § 192.614.

order to continue locate and mark activities. This refresher training involves all aspects of the Locate and Mark procedures to allow personnel to be able to successfully receive a ticket and provide a proper positive response. Similar to the Locate and Mark training mentioned above, refresher training will also be an interactive eLearning course, which potentially will consist of on-the-job training and mentoring. This is a mandated activity in order to comply with regulations and code requirements and to provide employees with the basic knowledge to satisfactorily perform this critical task.[26]

D. SDG&E-9-C4 – Locate and Mark Operator Qualification

Locate and Mark Operator Qualification (OQ) training is enhanced training which requires pipeline operators to document that certain employees have been adequately trained to recognize and react to abnormal operating conditions that may occur while performing specific tasks. It provides for an employee to field-demonstrate the employee's knowledge and competency to perform specific locate and mark tasks. The training demonstrates an employee's knowledge and competency to perform locate and mark activities and is mandated by PHMSA.[27] Employing resources that are formally trained to be aware and react to unusual pipeline conditions allows SDG&E to potentially protect against an adverse event before its occurrence. Locators are qualified at the end of training and then every five years. This certification is an industry standard qualification program.

E. SDG&E-9-C5 – Locate and Mark Quality Assurance Program

The Locate and Mark quality assurance audit program reviews work activity to determine whether proper processes and procedures are being met. This includes, but is not limited to, employee qualification, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and markings, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations.

SDG&E has developed guidelines for quality assessments of locate and mark activities. The Gas Compliance Quality Management (GCQM) team conducts the re-occurring assessments

---

[26] *See* Cal. Govt. Code § 4216.

[27] 49 CFR 192.801 – 192.809.

of all districts (or bases) in order to provide an independent check of processes and to verify that applicable documentation is accurate and complete. The assessments include equipment testing, documentation reviews, field checks, and operator qualification reviews. After the assessment is complete, the GCQM will review findings with base management and gas distribution operations. Base management acknowledges the final report and develops plans for corrective actions, which are provided to GCQM. Findings are tracked, recorded, and monitored by base supervision.

Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

F. SDG&E-9-C6 - Damage Prevention Analyst

SDG&E Damage Prevention Analysts work to reduce the number of third-party excavation incidents in cities and jurisdictions with the highest number of reported occurrences by addressing the contractors and excavators operating in these jurisdictions. The intent of the SDG&E's Damage Prevention Analyst Program is to promote safe excavation practices and reduce the number of excavation damages. An important method of achieving this goal is to build and foster positive relationships with the excavator community through visibility, communication, and safe excavation education. Through this effort the desire is also for these employees to be viewed as a resource for contractors and to help overcome obstacles when excavating in the vicinity of underground SDG&E infrastructure. To achieve these objectives, the Analysts are equipped with the current 811 USA ticket information, and GIS/mapping information for the local pipe network. Analysts regularly partner with SDG&E's operating district personnel if additional infrastructure location information is needed.

The Damage Prevention Analysts prioritize their daily job site visits with the aid of a ticket prioritization software. Certain construction jobs may be more prone to excavation damage than others due to specific 811 USA ticket attributes and local environmental conditions. Eight-One-One USA ticket prioritization utilizes historical damage information as well as geographic, environmental and other publicly available information. The software weighs the pertinent attributes and performs calculations using complex algorithms to identify excavation sites that may be more susceptible to third party damages. This prioritization allows for the Company to take appropriate and timely measures to avoid damages such as making an extra phone call or email to the excavator or scheduling a pre-excavation site meeting to discuss the project in detail.

The Damage Prevention Analysts routinely visit active construction sites with known 811 USA tickets in their jurisdiction but will also look out for other active construction sites that do not appear on their 811 USA ticket listing. The purpose for visiting the latter is to make positive contact with the excavator and determine whether the supervision and workers at those projects have followed the safe digging practices. If not, the Analyst explains the safety risks, law violations and potential ramifications and asks the excavator to stop their job and contact 811 USA to get the proper underground markings. These interactions have been very successful in getting the excavator to halt further excavation work until 811 USA contact was established. The most common reason for "Stopping-The-Job" was due to the excavator not having an 811 USA ticket. In addition, some were due to unsafe excavation practices.

The Damage Prevention Analysts also visit with the local municipality personnel to discuss the importance of safe excavation with the Planning and Permitting departments. Gaining a safe-excavation partnership with the entities that approve, permit, and inspect excavation work is seen as an integral part of the Damage Prevention Program. During the interactions with City officials, the Analysts offer to present educational information regarding the Dig Safe laws and practices to interested parties.

Another key activity that falls within the Damage Prevention Analyst job responsibilities is responding to dig-in damages. Their role is to support the Operations response team through accurate documentation of the incident and collecting all relevant information to enable accurate regulatory reporting, damage-cause trending, and appropriate cost recovery where warranted. This data is used by the Damage Prevention Strategy and Distribution Integrity Management Program teams to evaluate and trend the causes of excavation damage and pursue the appropriate mitigation activities.

G. SDG&E-9-C7 – Prevention and Improvements – Refreshed Laptops

Locate and Mark laptops and software are utilized by SDG&E to comply with the requirements of state and federal regulations.[28] SDG&E provides locate and mark technicians rugged laptops called Mobile Data Terminals (MDTs) containing KorMobile© Ticket Management Software to respond to an 811 USA tickets real-time. Using obsolete technology increases wait times, contributes to data communication failure and increases likelihood of not responding to an 811 USA request in the required timeframe.

SDG&E has a service territory that covers about 4,100 square miles, from San Diego to southern Orange counties. The service territory covers 2 counties, and 25 communities. Providing durable refreshed laptops increases efficiency and the ability to work in a rugged outdoor setting. Increasing the processor speed and extending the battery life also allows for prolonged working hours. The refreshed laptops contain a detachable screen with a built in camera allowing the on-site technician to photograph their surroundings and the excavating equipment associated with an 811 USA ticket. A 4G LTE Advanced multi carrier mobile broadband facilitates the response to 811 USA tickets real-time.

H. SDG&E-9-C8 – Public Awareness Compliance

It is important for contractors and excavators to be informed of the potential safety issues that might arise when working around natural gas pipelines. Underground pipelines can be located anywhere, including under streets, sidewalks and private property – sometimes just inches below the surface. Hitting one of these pipelines while digging, planting or doing demolition work can cause serious injury, property damage, and loss of utility service.

Under Title 49 Code of Federal Regulation, section 192.616, SDG&E is required to educate the public, appropriate government organizations, and persons engaged in excavation related activities (1) about the use of a one-call notification system (811 USA) prior to excavation, (2) other damage prevention activities, (3) possible hazards associated with the unintended release from a gas pipeline facility, (4) physical indications of a natural gas release, (5) steps to be taken in the event of a gas pipeline release, and (6) procedures for reporting such

[28] 49 CFR 192.614; Cal. Govt. Code § 4216.

an event. In addition to undertaking actions to meet the minimum requirements of section 192.616, SDG&E participates, promotes, and contributes to other public awareness and excavation improvement programs. To promote public awareness of the 811 USA program SDG&E utilizes various communication methods such as utilized bill inserts, media campaigns, damage prevention industry memberships, sponsorships, radio advertising, internet advertising, billboard advertising, and safety meetings. Specifically, the four types of audience identified in Title 49 CFR 192.616 are the affected public, emergency officials, local public officials, and excavators. These types of audiences make up the four tranches further described below in Section VI.

I. SDG&E-9-C9 – Increase Reporting of Unsafe Excavation

Senate Bill (SB) 661 modified existing California Government Code section 4126 by establishing the California Underground Facilities Safe Excavation Board (Dig Safe Board). SDG&E has two groups involved in identifying excavators who frequently utilize unsafe practices and reporting those contactors to the appropriate state board. The Damage Prevention Strategies team informs Dig Safe Board investigators about unsafe practices SDG&E witnesses in the field. The Claims Recovery team reports incidents to the Contractor State Licensing Board (CSLB) when it becomes aware of them through its involvement with insurance and financial considerations as a result of incidents. The Dig Safe Board is developing regulations related to reporting and SDG&E plans to implement any new requirements.

J. SDG&E-9-C10 – Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board

SDG&E continues to actively participate in regulatory proceedings that will support the effectiveness of federal and state safe digging laws through legislation and enforcement of sanctions and penalties. Sanctions and penalties should be enforced against parties not following the well-established rules requiring third parties to call 811 USA to have pipelines marked prior to excavation. SDG&E supported California State Senate Bill SB 661, which modified California Government Code, section 4216, establishing the Dig Safe Board, by providing proposed language to increase protection of underground substructures.

In addition, SDG&E participates at board meetings of the Dig Safe Board, which was created by the Dig Safe Act of 2016 and is included in California's Government Code 4216.12, Safe Digging law. The Dig Safe Board's charter is to coordinate education and outreach activities that encourage safe excavation practice; develop standards that support safe excavation practices; investigate possible violations of GC 4216; and enforce GC 4216 to the extent of granted authority.

Company involvement and participation at Dig Safe Board meetings and workshops help foster a positive working relationship with all stakeholders. These meetings and workshops provide the opportunity to raise the issues and concerns facing the Natural Gas industry and issues pertaining to excavation damage prevention.

K. SDG&E-9-C11 – Public Awareness-Meet with Cities with Highest Damage Rates

SDG&E Damage Prevention Analysts work to reduce the number of third party excavation incidents in cities and jurisdictions with the highest number of reported occurrences. To achieve this objective, they partner with SDG&E's operating districts management and represented personnel to identify and meet with city officials with functions and responsibilities related to construction and excavation activities in their respective jurisdictions. This effort provides outreach and education to these officials on the proper 811 USA one-call process and safe digging techniques. The officials can then pass those requirements on to the contractors operating in their cities as permits are granted or city inspectors visit job sites.

Cities have many resources and avenues for promoting and executing excavation safety within their communities. All planned work requiring a permit must start at the planning and permits department. Cities thus often have the first opportunity to educate applicants about excavation safety by providing 811 USA literature. On-site City inspectors could also potentially be tasked with patrolling and enforcing California Government Code section 4216 compliance as part of their daily work. City inspectors hold the authority to stop any job that violates code. Cities may also consider preventing excavators from working in their boundaries if the excavator is known to cause frequent excavation violations.

L. SDG&E-9-C12 - Public Awareness - Remain Active Members of the California Regional Common Ground Alliance

The California Regional Common Ground Alliance (CARCGA) is the group of California-based stakeholders who are impacted by excavation activities. CARGA is the regional group within the Common Ground Alliance (CGA). The CGA works with its membership to establish best practices in the One-Call Centers, underground facility owners; Excavators, Locators, Project Owners, and Designers. Through its Damage Prevention Strategies function, SDG&E participates with CARCGA members to inform CGA objectives from a regional perspective.

M. SDG&E-9-C13 – Continue to Participate in the Gold Shovel Standard Program

SDG&E requires construction contractors doing work on its behalf to participate in the Gold Shovel program. The program certifies an excavator's policies and procedures against the Gold Shovel Standard, a set of excavator training procedures designed to protect underground facilities. The Gold Shovel standard also publishes a rating which is an ongoing measure of an excavator's digging-safety-worthiness. This requirement serves to incentivize construction contractors to follow safe excavation laws and practices. The Gold Shovel Standard (GSS) is a nonprofit organization committed to improving workforce and public safety and the integrity of buried infrastructure. GSS believes that greater transparency in all aspects of damage prevention among buried-asset operators, locators, and excavators is essential to drive continuous improvement, and vital to increasing safe working conditions and communities. Certifying excavators who participate in the Gold Shovel Program complies with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

N. SDG&E-9-C14 – Locating Equipment

SDG&E utilizes locating equipment, updated GIS maps, and/or excavating (daylighting) to verify the physical locations of underground infrastructure. Part of this process involves uploading scanned construction drawings temporarily until the job is posted officially to GIS. SDG&E continues to remain compliant with codes and regulations and follow industry best practices and company policies and procedures as they apply to the safe and effective locating and marking of underground facilities. This control includes written and accessible procedures, availability of proper equipment, and access to required information to enable personnel to successfully perform their duties. Locating equipment is utilized to comply with the requirements of Title 49 Code of Federal Regulations, section 192.614 and California Government Code, section 4216.

O. SDG&E-9-C15 – Remain Active Members of the 811 California One-Call Centers

Title 49 Code of Federal Regulations, section192.614 and California Government Code, section 4216 require natural gas utilities to remain members and actively participate in the activities of 811 USA local one-call centers. Excavators are required to notify the one call centers of their intent to dig. Owners of underground facilities in close proximity to the dig site are required to provide a positive response with the location of their facilities that may be in conflict with the excavation and also to provide any other efforts that may be required to protect the integrity of their underground facilities. The members of the one-call centers actively meet to make the 811 USA process easier for excavators while also exploring ways to make the service more accessible on a variety of platforms. They also work to promote the safe digging message through various avenues.

P. SDG&E-9-C16 – Install Warning Mesh Above Buried Company Facilities

Plastic underground warning mesh is a high strength polypropylene mesh and designed to alert excavators of the presence of buried utilities. It is typically installed at a minimum of 18 inches above the buried facility which provides the excavator awareness of a buried pipeline below. If an excavator was not expecting buried facilities in their excavation the mesh serves to alert them, identifies the presence of a gas line, and directs them to contact "811" before proceeding so the proper precautions can be implemented before further excavation. Providing this type of warning before excavating further into an underground gas facility substantially reduces the risk of third-party damage and the associated consequences. SDG&E installs warning mesh during new pipeline installations. Warning mesh installation applies to high pressure pipelines (MAOP > 60 psig) and medium pressure pipelines (MAOP ≤ 60 psig).

The Controls addressed above will continue to be performed. The Company's Mitigations, addressed below, aim to further reduce the frequency of third party dig-Ins.

Q. SDG&E-9-M1 – Automate Third Party Excavation Incident Reporting

Timely and accurate reporting of excavation incidents is a critical component of the continual improvement process. Enhancing the data collection of incidents is used to measure the performance of adhering to compliance reporting obligations, and also assists the Company in filing various regulatory reports. The reporting system is the basis for excavation incident analysis and is used to understand the Company's opportunities for internal improvement for locate and mark activities. Through this analysis of excavation incidents, SDG&E can further understand the internal and external leading causes of dig-ins, trend incident locations, trend frequency of damages caused by individual excavators, trend which facilities are damaged the most, and stay informed about the most common damaging excavation equipment.

SDG&E is actively enhancing its ability to improve data capture, data validation, and automated escalations. New Third Party Excavation Incident Reporting systems will provide accessibility and efficiency across multiple platforms reducing reporting and notification times by automating the reporting process. The upgraded reporting system efficiently analyzes accurate incident data and provides course corrections as locate and mark trends are identified.

R. SDG&E-9-M2 – Establish a Program to Address the Areas of Continual Excavation

Generally, a typical 811 USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[29] Agricultural excavators who perform repetitive excavations prefer 811 USA Tickets that are valid for longer periods of time. Requiring 811 USA notifications every 28 days could discourage participation in the 811 USA process by agricultural excavators, who may find it too burdensome to renew a ticket. These situations are typically in flood control channels and agricultural fields where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement[30] to develop a process that would allow for certain agreements for continual

---

[29] *See* Cal. Govt. Code § 4216.2(e).

[30] SB 661 modified Cal. Govt. Code § 4216 establishing an Area of Continual Excavation (ACE) Ticket.

excavation, called ACE tickets. In flood control and agricultural situations, SDG&E will meet with the landowner and develop an annual agreement that would allow for safe continual excavation activity within the parameters of the agreement.

Starting in July 2020, excavators working on agricultural and flood control lands may obtain an ACE ticket. The Dig Safe Board has drafted regulations[31] requiring operators to address ACE tickets by completing newly developed forms, conducting onsite meetings, potentially excavating the facility, and providing additional records. ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators.

S. SDG&E-9-M3 – Recording Photographs for Each Locating Mark Ticket that is Visited by the Locator

Under this Mitigation, locators will take photographs of the areas located and marked and the areas the excavators delineated either using white paint or other approved marking methods for each ticket they complete. The pictures taken by the locators will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Pictures will also mitigate potential disputes between excavators and SDG&E by providing visual confirmation of the location marks at the time the ticket was located and marked. The photographs will include a digital time stamp and geographical identification metadata.

T. SDG&E-9-M4 – Utilize Electronic Positive Response

SDG&E will utilize an electronic positive response system (EPS) which informs an excavator once a locate and mark activity is completed for the excavator's 811 USA ticket. For example, if the locator marks the jobsite, the excavator will be notified on their USA ticket that the company has completed markings at the ticket location. EPS gives excavators and the company a shared record of locate and mark activity completed by the locator. This will help excavators by providing them with the appropriate documented communication before they dig. Enhancing electronic positive response will be used to measure the performance of adhering to Title 49 Code of Federal Regulations, section 192.614.

---

[31] Dig Safe Board, Resolution No. 19-07-01, *available at* https://digsafe.fire.ca.gov/media/2197/resolution-19-07-01.pdf.

U. SDG&E-9-M5 – Enhance Process to Utilize and Leverage Emerging Excavation Technology to Help With Difficult Locates (Vacuum Excavation Technology)

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SDG&E will work with the requesting contractor to help fulfill their request without creating an unsafe situation. More specifically, SDG&E will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging technologies. These alternatives include stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Vacuum excavation is recognized by the damage prevention industry as the safest excavation method that can be used today because the water and air used for excavation is adjustable, preventing damage to pipe and coatings. The Company plans to enhance its excavation practices by using hydro vacuum excavation technology which is typically installed onto a truck or portable trailer and allows the excavator to perform a keyhole excavation process, when applicable. Generally, a keyhole excavation process is utilized to excavate targeted areas.

Hydro vacuum excavation uses water at a high pressure to loosen the soil, this allows for precise excavation and vacuuming of the material. The use of water at a high pressure reduces the soil's cohesiveness thus helping to break the soil and suction easily. Dirt is stored in a debris tank, keeping the work area cleaner and avoiding the creation of dirt spoils. Hydro vacuum excavation is less invasive compared to other traditional methods of excavation. The benefits of hydro vacuum excavation include a reduced likelihood of causing third party damages, faster and precise excavations, and it also requires less manpower compared to conventional excavations.

The keyhole excavation process cost-effectively and safely exposes underground infrastructure to allow operators to perform repairs and maintenance without resorting to more costly and disruptive conventional excavation methods. The keyhole excavation process consists of performing work on the surface with smaller excavations, which can be performed on paved or non-paved areas. Pavement removal can be accomplished often by saw cutting and coring. The size of the pavement opening is determined upon the scope of the task at hand. The normal process utilizing keyhole excavation involves coring, vacuum excavation, construction and maintenance activities, and finally backfill and pavement restoration.

The Company will enhance its processes to utilize this excavation technology to facilitate hard to locate facilities.

V. SDG&E-9-M6 – Promote Process and System Improvements in USA Ticket Routing and Monitoring

As part of continuous improvement, an assessment of the current state of the 811 USA one-call ticket routing and monitoring is underway. The intent is to query system users and managers on potential improvements that would provide benefits to the process. The software vendor, Korterra, has been engaged to provide software solutions for identified system enhancements that will allow for more streamlined data collection, better documentation capture capability, and more detailed reports for process supervision.

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulations, section 192.614.

These new tools will give the company the ability to better manage the 811 USA ticket load across the company. The tools and enhancements entail workflows requiring locators to input specific data into dedicated fields detailing mutual agreements. These fields will enable reporting for all mutual agreements giving SDG&E additional measures for ticket compliance. Other tools include automated notifications in the form of emails and/or texts for management when tickets are approaching the mutual agreement due dates. This will trigger follow up action to address tickets on time. This mitigation will include the resources that support the enhanced data collection and field management of ticket efforts and will also support 811 USA ticket prioritization. These resources are needed to manage data, perform analytics on the new volume of data and to identify system enhancements.

W. SDG&E-9-M7 – Leverage Data Gathered by Locating Equipment

SDG&E uses locating equipment that automatically captures GPS coordinates as the locator performs their locating activities. The GPS data may also be manually recorded when the locator pushes a designated button on the equipment console. The equipment's GPS data is downloaded through a physical connection with a terminal allowing the data to be saved then transmitted to the GIS group. Future enhancements may include the ability to wirelessly transmit the GPS data. The GPS data can then be used in GIS to compare real world locating data with GIS mapping data to evaluate discrepancies and potentially catching mapping errors or locating errors thereby increasing the accuracy of the locating activity . Correcting mapping errors or omissions using this data may potentially reduce damages caused by mapping issues. Leveraging data gathered by locating equipment improves adherence to Title 49 Code of Federal Regulations, section 192.614.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, SDG&E has performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision. SDG&E has not calculated an RSE for activities beyond the requirements of the SA Decision but provides a qualitative description of the risk reduction benefits for each of these activities in the section below.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[32] instructs the utility to subdivide the group of assets or the system associated with the risk into tranches. Risk reduction from controls and mitigations and RSEs are determined at the tranche level. For purposes of the risk analysis, each tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). SDG&E's rationale for the determination of tranches is presented below.

Third Party Damage prevention consists of training courses, policies, programs, and efforts aimed at reducing risk of injuries or fatalities to the public, employees and contractors. Given the vast number of activities SDG&E performs to mitigate the Third Party Dig-in on a High Pressure Pipeline risk, SDG&E grouped like activities with like risk profiles into mitigation programs.

Table 6: Summary of Tranches

ID	Mitigation/Control	Tranche	Tranche ID

32 D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

SDG&E-9-C8	Public Awareness	External Education - The Affected Public	SDG&E-9-C8-T1
		External Education - Emergency Officials	SDG&E-9-C8-T2
		External Education - Local Public Officials	SDG&E-9-C8-T3
		External Education - Excavators	SDG&E-9-C8-T4

B. Post-Mitigation/Control Analysis Results

For purposes of this post-mitigation and post-control analysis, SDG&E utilized historical gas dig-in results year-over-year to calculate an overall risk reduction benefit of performing these activities.[33] SDG&E then looked at existing/continuing programs (*i.e.*, Controls), with the expectation of observing similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). SDG&E also accounted for the risk increase that would occur over time if the risk reduction activities were reduced or cancelled. For new and/or incremental Mitigations, SDG&E expects to achieve further risk reduction. The specific risk reduction benefit percentages used for each identified Control/Mitigation is included under each of the program headings below.

1. SDG&E-9-C1 – Locate and Mark Training

A single tranche is appropriate for this program because SDG&E has an obligation to provide Locate and Mark Training for all Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Training has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and mark training provides participating employees with the necessary knowledge and capabilities to locate and mark the below ground gas facilities accurately and in the appropriate time frame. At SDG&E, the Locator function has the responsibility to locate and mark gas facilities in response to an excavation request. Gas Operations Training provides each Locator with one-time locate and mark training upon employment with SDG&E or upon an

---

[33] *Id.* at Attachment A, A-5 ("MAVF Principle 4 – Risk Assessment").

existing employee being newly assigned to Locator position. A Locator is not certified to locate or mark gas facilities until they have successfully completed this training.

It is necessary to have a trained workforce to accurately locate and mark gas infrastructure to provide the necessary information to a third-party excavator to perform their work as safely as possible. Marked facilities provide the excavator with approximate locations of where the gas facilities exist, within the delineated work area. Awareness of underground gas facilities allows the excavator to either avoid the areas or carefully dig with hand tools to prevent damage caused by the excavation work. Since a vast majority of the utility's assets are buried below ground it is imperative that proper action is taken to reduce the risk of accidental damage to these facilities by accurately communicating the locations to the excavators. Without a highly skilled and trained locate and mark workforce, excavators would have little knowledge and confidence of gas line locations which could lead to third party excavation damage. Locate and mark training is a critical part of the safe excavation process as it develops competency of the workforce in equipment operation and procedure implementation, leading to increased accuracy in US markings and communications to the excavator which ultimately leads to the reduction of the risk to excavation damage. By improving knowledge and competency through training, locate and mark accuracy will increase, and the number of mismarks should be reduced, leading to a decrease in the risk of third party excavation damage. Additionally, this training provides the workforce with the necessary understanding of not only the requirements for accurate locating and marking but also the importance of two-way communication with an excavator, thorough job documentation and timeliness of locate and mark completion.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C1 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center

(USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

2. SDG&E-9-C2 – Locate and Mark Activities

A single tranche is appropriate for this program because SDG&E has an obligation to perform Locate and Mark Activities across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and California Government Code, section 4216. Therefore, Locate and Mark Activities has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Activity is to prevent damage to gas infrastructure caused by third party excavators. The Locate and Mark Activity includes three efforts: (1) locating and marking underground gas facilities before excavation occurs, (2) observing (stand-by) pipeline excavation activities; and (3) providing staff support for compliance and improvement.

The first of these activities, locating and marking, refers to the actual physical act of locating and marking of underground facilities. In 2018, SDG&E Gas Field Operations fulfilled approximate 130,000 locate and mark requests, with nearly all being classified as medium pressure. By providing a visual indication of the location of underground facilities, the excavator has the necessary information to proceed with their activities in a safe and controlled manner. The second locate and mark activity is Pipeline Observation (stand-by) in specific required situations. Pipeline Observation (stand-by) is a mandated activity that requires a qualified Company representative to be present anytime excavation activities take place near a covered pipeline segment. The purpose for this function is to decrease the likelihood of an event occurring that otherwise could have been prevented by having a dedicated employee representing the operator who is specifically there to maintain the integrity of the gas pipeline to reduce the risk of a damage while observing the work being done. The third activity involves staffing to provide daily support in operations by interpreting policies, tracking compliance, evaluating locate and mark tools and technologies, providing refresher training as requested, and track and trend locate and mark data to proactively identify areas for improvement. This is a critical risk reduction activity that directly supports the field locator personnel in their daily activities and looking for enhancement opportunities that lead to more accurate and timely responses to locate and mark tickets.

Locating and marking underground gas infrastructure provides the excavator with the information necessary to avoid hitting or damaging gas facilities. This is done by understanding what type of facilities are underground and the approximate location. Once the facility is marked, the excavator can take the necessary steps to work around the gas pipe and/or use the appropriate excavation techniques. Third party excavation damage can result in an immediate gas leak or explosion, or it can create a situation where a leak or explosion could develop in the future. The activity also must be completed in a required timeframe. Performing an accurate and timely locate and mark activity helps to reduce serious injuries and/or fatalities, property damage, prolonged outages, penalties and fines, and adverse litigation.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C2 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

3. SDG&E-9-C3 – Locate and Mark Annual Refresher Training & Competency Program

A single tranche is appropriate for this program because SDG&E has an obligation to provide a Locate and Mark Annual Refresher Training & Competency program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Annual Refresher Training & Competency Program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

All resources performing locate and mark activities must complete an annual re-training and re-fresh program. This program consists of local supervisors reviewing the gas standards with the locate and mark workforce. All employees are required to pass the refresher training in order to continue locate and mark activities.

The Locate and Mark Refresher Training and Competency program reinforces several key components of locate and mark. By reviewing the gas standards on an annual basis, employees performing locate and mark activities are provided an opportunity to review expected procedures, learn changes in procedures, and obtain clarification. Without an opportunity to refresh their understanding, the locate and mark workforce might not be up to date on the latest procedure, requirement, or technology. Refresher training enables trained personnel to perform their duties with greater accuracy and efficiency, and it increases trained personnel's ability to adopt to new technologies and methods. Marking facilities accurately provides the excavator and public with a greater safety assurance. It enables the excavator to either avoid the delineated areas or dig with hand tools to avoid damage that could result in an immediate or future incident.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C3 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

4. SDG&E-9-C4 – Locate and Mark Operator Qualification Program

A single tranche is appropriate for this program because SDG&E has an obligation of providing a Locate and Mark Operator Qualification program for Locators across its entire service territory as mandated by Title 49 Code of Federal Regulations, section 192 and General Order 112-F. Therefore, Locate and Mark Operator Qualification program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

Locate and Mark Operator Qualification (OQ) training demonstrates an employee's knowledge and competency to perform specific locate and mark activities that allow the employee to recognize and react to abnormal operating conditions that could occur, such as fire over the pipeline, the smell of gas, and dirt blowing from the hole. Locate and Mark Operator Qualification is administered by the Operator Qualification – Gas System Integrity function at SDG&E and OQ certification is required every five years. This training is mandated by PHMSA.[34]

Employing resources that are formally trained and Operator Qualified to perform Locate and Mark functions demonstrates both procedural knowledge and field implementation of the necessary tasks required to successfully perform these functions. Maintaining this level of prepared and qualified workforce allows SDG&E to meet its regulatory requirements and the demands of the excavator community and helps provide for a safe excavation environment.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C4 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

---

[34] 49 CFR §§ 192.801 - 192.809.

b. Elements of the Bow Tie Addressed

SDG&E-9-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

5. SDG&E-9-C5 – Locate and Mark Quality Assurance Program

A single tranche is appropriate for this program because SDG&E has an obligation to perform quality assurance activities for Locators across its entire service territory. Therefore, Locate and Mark Quality Assurance program has a single risk profile and does not warrant further tranching.

a. Description of Risk Reduction Benefits

The purpose of the Locate and Mark Quality Assurance Program is to verify that proper processes and procedures are being followed and implemented by the locate and mark workforce and to correct those instances where processes and procedures are not being followed. SDG&E's Pipeline Safety and Compliance function visits every transmission base at least once per year and perform 4 audits each day. During this visit, they evaluate employee qualifications, equipment setup and use, regulatory code requirements, Company Gas Standard requirements, accuracy of locate and markings, proper and thorough documentation, use of the Korterra ticket management system, job observations, and stand-by observations, for example. Feedback on a quality assurance audit is provided to each local supervisor who is responsible to follow-up with individuals or crews needing further or refresher training.

The Locate and Mark Quality Assurance Program provides a variety of benefits to reducing the number and potential of damage to gas infrastructure by a third party. By evaluating locate and mark activities that have been completed or are being performed, SDG&E can address gaps in performance with additional training or updating company documentation or recordation of assets. The locate and mark workforce errors can result in an incorrect locate and mark or one that is not done within the required timeframe. Additionally, the QA review can highlight errors in the timely and/or accurate documentation of its assets, which could result in an incorrect locate and mark. All issues could potentially result in damage to the gas infrastructure with serious injuries and/or fatalities and property damage. Adherence to proper company policy and procedures reduces the percentage of Locate and Mark mismarks, increases the overall awareness of unsafe activity, and expedites response times.

b. Elements of the Bow Tie Addressed

SDG&E-9-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Subject Matter Experts (SMEs) estimate that 100% of activities in the program would benefit from this mitigation.
Effectiveness	Assuming 5% effectiveness as QA program has above-marginal impact on reducing mismarks.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96

Post-Mitigation	**LoRE**		**0.2456**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.45**	10.94
	RSE	0.20	**1.58**	3.87

6. SDG&E-9-C6 – Damage Prevention Analyst Program

The Damage Prevention Analyst Program works to reduce the number of third-party damage to gas facilities by identifying at risk excavating contractors and educating them on proper 811 USA process and safe digging techniques. Therefore, any excavating contractors at risk that are identified by the damage prevention analysts pose the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

The Damage Prevention Analyst Program works to reduce the number of third party damage to gas facilities by identifying at risk excavating contractors and educating them on proper 811 USA one-call and safe digging techniques. Through the Damage Prevention Strategies function, Damage Prevention Analysts focus on the districts with the greatest number of reported incidents, by driving to and physically inspecting excavation projects with 811 USA ticket requests. The Analysts will also stop at other construction projects to investigate whether proper one-call and digging techniques are being used. In cases where the Analysts find an offense, they will stop the job and provide education to the contractor on the correct safe digging practices and procedures.

The benefits of the Damage Prevention Analyst function are threefold. First, it enables SDG&E to stop a job before an incident occurs if no underground markings are present or the excavator is not practicing safe digging techniques. Second, it provides an opportunity to educate contractors on their requirements before digging or when digging around gas facilities before damage is done. This education has far-reaching benefits as the contractor will perform future projects in other districts not currently part of the program, and the education could be applied to those future projects. Third, it creates a list of contractors who might be repeat offenders or of site characteristics to improve prioritization of future construction site inspections.

b. Elements of the Bow Tie Addressed

SDG&E-9-C6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Damage Prevention Analyst program focuses on 100% of the excavation tickets through risk assessment.
Effectiveness	The effectiveness is assumed at 25% as analysts prioritize work, support training, stop unsafe jobs, support all districts, etc.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 9%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Miti	LoRE		**0.2684**	

	CoRE	2.28	**18.13**	44.55
	Risk Score	0.61	**4.87**	11.96
	RSE	2.68	**21.27**	52.26

7. SDG&E-9-C7 – Prevention and Improvements – Refreshed Laptops

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and efficiently provide correct information helps with accurately locating underground infrastructure. Laptops with the applicable Software are deployed across SDG&E's territory. SDG&E has a service territory that covers about 4,100 square miles, from San Diego to southern Orange counties. The service territory covers 2 counties, and 25 communities. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The workforce that performs the locate and mark activities relies on laptops, USA tickets, asset mapping, records data, and software. Using laptops in an outdoor setting, and often in construction areas, can reduce life expectancy due to the harsh environment. Therefore, SDG&E provides its workforce with ruggedized laptops that are designed to better withstand their operating environment. Additionally, as software and data are updated and new features are added, new laptops with advanced capabilities are required so that all information can be provided to the locate and mark workforce and data can be updated. Approximately 40 laptops are replaced every 4 years.

Providing hardware that is appropriate for the rugged outdoor environment and updated to run and provide the right information in a timely manner helps with locating infrastructure correctly in a timely manner and using updated company maps and asset records. Updated ruggedized laptops contain a longer battery life and are able to run the required software faster and more efficiently. Updated hardware and software increase the effectiveness of performing locate and mark. The ruggedized laptops also have the ability to take a picture of the surroundings conditions of the excavation site to update mapping information for improved asset and mapping information. All features of the refreshed laptops work to reduce the number of errors that might occur in locating gas infrastructure through improved data and could be used to support the development of improved safe-digging procedures.

b. Elements of the Bow Tie Addressed

SDG&E-9-C7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of laptops will be refreshed.
Effectiveness	Assuming negligible improvement in effectiveness (0.25%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 36% of the causes (36% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.09%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2462**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.97
	RSE	0.01	**0.09**	0.22

8. SDG&E-9-C8 – Public Awareness Compliance

For the purposes of an RSE analysis, SDG&E separated Public Awareness into four tranches. Each of the four tranches reduces the likelihood of third party damage differently according to the RSEs.

Title 49 Code of Federal Regulation, section 192.616 requires utilities/natural gas providers to include efforts to educate the public, appropriate government organizations, and persons engaged in excavation related activities. The four types of groups identified in section192.616[35] are the affected public, emergency officials, local public officials, and

---

35 49 CFR § 192.616 (emphasis added):

(d) The **operator's** program must specifically include provisions to educate the public, appropriate government organizations, and **persons** engaged in excavation related activities on:

(1) Use of a one-call notification system prior to excavation and other damage prevention activities;

(2) Possible hazards associated with unintended releases from a **gas pipeline facility**;

(3) Physical indications that such a release **may** have occurred;

(4) Steps that should be taken for public safety in the event of a **gas pipeline** release; and

(5) Procedures for reporting such an event.

excavators. Thus SDG&E-6-C8 – Public Awareness has been tranched to match the four groups identified in section 192.616.

Periodically SDG&E participates in Distribution Public Awareness Council (DPAC) Benchmark studies to collect and compare membership data related to the effectiveness of public awareness and community safety outreach programs managed by gas utilities. There is a clear distinction between the general level of awareness between the affected public, emergency officials, local public officials, and excavators. In order to address this gap and reduce third party damage, targeted messaging campaigns are performed for each subgroup to increase overall awareness and education. Emergency officials and local public officials are often met with in person to discuss municipal third party damage trends. The public and excavators are further informed of 811 USA and safe digging practices using bill inserts, media campaigns, SDG&E damage prevention analysts, radio advertising, internet advertising, billboard advertising, and safety meetings. Public Awareness is mandated pursuant to section 192.616 and its purpose is to develop and implement a continuing public education program focused on use of the 811 USA one-call notification system, hazards associated with the unintended release of gas, physical indications that an unintended release of gas has occurred, steps that should be taken to protect public safety in the event of gas release, and procedures for reporting unintended releases of gas. A summary of SDG&E's 2018 public awareness activities is shown in the table below.

Table 7: Summary of SDG&E's 2018 Public Awareness Activities

	Mailers	**Email messages**	**Public Service Announcements (2019)**	**811 Unique Page views (2019 data)**
Excavators	29,000	6.,500	1	Over 15,000 page views CYTD for the gas safety-related pages on SDG&E.com
Public Officials	189,000	220	0	
Affected Public	550,000 customers and 175,000 live/work near high pressure	630,000	1	

Emergency Officials	339,000	4	0	

A comprehensive public awareness program works to reduce the number of gas incidents by educating the general public on the indication of a gas leak and what to do if they do identify the potential for one. This allows first responders and SDG&E to respond in a timely manner to avoid a gas incident or minimize its impact. More specifically, the Public Awareness Program works to reduce the number of potential gas incidents due to third party excavation activities. Third parties refer to a broader group than just excavators, it can also include "do it yourself" home and business owners. By providing information of the 811 USA one-call process and safe digging practices to these audiences, SDG&E can increase the number of locates performed by the gas utility and potentially reduce the number of incidents of damage to gas infrastructure.

9. SDG&E-9-C8-T1 – Public Awareness Compliance – The Affected Public

a. Description of Risk Reduction Benefits

Unsafe digging from construction and landscaping activities resulted in almost 400 natural gas leaks in San Diego and southern Orange counties in 2019. In observance of National Safe Digging Day, SDG&E joined energy companies across America to highlight the importance of calling 811 USA to have underground utility lines marked before digging. SDG&E promotes the awareness of the importance of calling 811 USA before digging underground utilizing various communication methods to reach the public such as bill inserts, media campaigns, radio advertising, internet advertising and billboard advertising. Homeowners should call 811 USA, or submit a request at Call811.com, at least two business days prior to digging. SDG&E will then mark the location of buried gas lines free of charge. It typically takes only 24–48 hours to complete a request to mark underground utility lines.

b. Elements of the Bow Tie Addressed

SDG&E-9-C8-T1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines,

PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The affected public tranche of public awareness is assumed to impact 50% of the risk.
Effectiveness	Per SME input, effectiveness is marginal (1%). More effective than targeting local public and emergency officials, but less effective than excavators.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 97% of the causes (97% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	**LoRE**		**0.2472**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.48**	11.01
	RSE	0.05	**0.39**	0.96

10. SDG&E -9-C8-T2 – Public Awareness Compliance – Emergency Officials

a. Description of Risk Reduction Benefits

Third party damages can result in a wide-range of inconveniences to the public including service outages and closed streets and places a strain on emergency officials. SDG&E coordinates liaison activities with Fire, Law Enforcement, Dispatch Centers, and other Cooperating Agencies to comply with the requirements of Title 49 Code of Federal Regulations, sections 192,192.615 and 192.616(e). There are significant benefits to creating strategic partnerships and promoting awareness with emergency officials. Communication and coordination are improved when it matters most. Public Awareness for Emergency Officials reduces the likelihood of third party damages and improves coordination during any kind of natural gas emergency.

b. Elements of the Bow Tie Addressed

SDG&E-9-C8-T2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The emergency official's tranche of public awareness is assumed to impact 5% of the risk.
Effectiveness	Emergency officials can help with all excavation cause codes and are assumed to have the same effectiveness as the Affected Public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 28% of the causes (28% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2460**	
	CoRE	2.28	**18.13**	44.55

	Risk Score	0.56	**4.46**	10.96
	RSE	0.01	**0.12**	0.29

11. SDG&E -9-C8-T3 – Public Awareness Compliance – Local Public Officials

a. Description of Risk Reduction Benefits

Working directly with city officials involved in construction activities within their jurisdictions helps to educate external personnel to support SDG&E's enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. This interaction can involve several efforts. First is educating city personnel on the specific requirements of the California safe excavation laws. We have found that many of these officials are not aware of the law. Second is helping them to understand their role in helping to enforce the laws by promoting the use of 811 USA for excavation tickets through their project review and permitting activities as well as the field inspections their employees perform. Third is to explain the city's potential cost savings for avoiding their emergency personnel having to respond to a blowing gas emergency due to a non-compliant excavation damage. They can help avoid unnecessary emergency response if they promote safe excavation practices during their routine daily planning and permitting work. The following outreach is performed to be compliant with Title 49 Code of Federal Regulations, section 192.616 (d) subsections 1-5.

b. Elements of the Bow Tie Addressed

SDG&E-9-C8-T3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The local public official's tranche of public awareness is assumed to impact 15% of the risk.
Effectiveness	Minimal impact since they're not the excavators; assuming 1%.

Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 56% of the causes (56% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.08%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2462**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.97
	RSE	0.03	**0.22**	0.54

12. SDG&E -9-C8-T4 – Public Awareness Compliance – Excavators

a. Description of Risk Reduction Benefits

Excavator awareness of 811 USA is very important. According to the Common Ground Alliance (CGA) Damage Information Reporting Tool (DIRT) Report, an underground utility line is damaged every six minutes in the United States because someone decided to dig but did not call 811 USA. Less than 1% of excavations cause damages in instances where excavators simply provide proper notice to one-call before excavating. Promoting awareness of 811 USA amongst excavators can significantly reduce the number of unintended third party damages. Unreported damage, where gas lines are nicked or hit, can also lead to corrosion that can cause problems months or even years later. Contacting 8-1-1 before starting any project involving digging is the best way to avoid damage to underground utilities. Excavator outreach is performed to compliant with Title 49 CFR 192.616 subpart (d) section 1-5.

b. Elements of the Bow Tie Addressed

SDG&E-9-C8-T4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	The excavator's tranche of public awareness is assumed to impact 30% of the risk.
Effectiveness	Public awareness campaigns for excavators are expected to be more effective than for other diggers, and the effectiveness is set to a higher number of 3%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 97% of the causes (97% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.9%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	**LoRE**		**0.2481**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.57	**4.50**	11.05
	RSE	0.15	**1.18**	2.91

13. SDG&E-9-C9 – Increase Reporting of Unsafe Excavation

The purpose of Increased Reporting of Unsafe Excavation is to identify and report excavators who frequently utilize unsafe excavation practices and to report those contractors to the Dig Safe Board and/or State Licensing Board (CSLB). Reporting of unsafe excavation is applicable to the entire SDG&E territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of Increased Reporting of Unsafe Excavation is to consolidate and formalize the Company's internal procedures for identifying and reporting excavators who frequently utilize unsafe excavation practices and to report those contractors to the California Dig Safe Board and/or State Licensing Board (CSLB). This includes consolidating the efforts of the Damage Prevention Strategies Team with the Claims Recovery Team. Both internal groups engage in excavator education and outreach efforts on safe digging practices. The consolidation of efforts-includes a consistent methodology for identifying targeted excavators. Education and outreach efforts provides the excavators understanding of the implications of unsafe excavation practices.

By combining the information from two functions within SDG&E, this program provides a more complete effort to achieve the benefits of reducing the third party damage. First, it provides the names of unsafe excavators to the appropriate state boards to support the state's objectives. Second, it provides an opportunity for the excavators to be educated and informed on their obligations, such as the contractor's requirement to call 811 USA prior to any excavation activity and to perform hand excavation in the vicinity of gas pipelines. With a better informed contracting community, who follows the appropriate procedures, the number of excavation activities around gas infrastructure without location marks or without following the correct excavation procedures should decrease. The number of resulting incidents from these contractors should also decrease.

b. Elements of the Bow Tie Addressed

SDG&E-9-C9 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that of excavators that are causing issues less than 1% are reported.
Effectiveness	Once the process is established, an increase in excavator notifications of 30% has been observed.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 27% of the causes (27% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.08%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2462**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.97
	RSE	0.06	**0.49**	1.20

14. SDG&E-9-C10 – Public Awareness-Secure Greater Enforcement through Legislation and California State Digging Board

The purpose of securing greater enforcement through Legislation and the Dig Safe Board is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the Dig Safe Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SDG&E actively participates in the California Underground Safe Excavation Board (Dig Safe Board) to provide input and education from the natural gas utility perspective. The purpose of this participation is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority.

Through its involvement in board meetings and workshops and collaborating to achieve common objectives related to damage prevention, SDG&E fosters a positive and stronger working relationship with all stakeholders. By playing an active role in developing and enforcing utility and contractor requirements, a more complete education and cooperative environment can be achieved among all stakeholders and new standards that get developed have had the benefit of comprehensive input. The Dig Safe Board provides a way in which effective safe excavation requirements can be cooperatively developed and disseminated to reduce third party damage.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C10 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C10 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or

Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

15. SDG&E-9-C11 – Public Awareness-Meet with Cities with Highest Damage Rates

The activities associated with this program include providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. Public awareness, meeting with cities with the highest damage rates is applicable to all cities across SDG&E' territory. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of meeting with cities with highest damage rates is to reduce the number of third party excavation incidents by providing outreach and education on safe digging practices to city and community leaders, and in turn, to the excavators operating in those areas. More specifically, using its Damage Prevention Analyst function, SDG&E will meet with leaders in all of the approximately 19 municipalities in its service territory. Priority is given to the cities with the highest number of excavation incidents.

The Damage Prevention Analysis will meet with the permitting, inspection, and/or other pertinent officials within the municipalities to develop a strong working relationship to reduce third party damage. Concepts are discussed, such as asking the city inspectors to also look for proper utility markings, stop the job, or incorporate 811 USA literature with the permit application.

Working directly with the city officials involved in construction activities within their jurisdictions helps to develop an extended education and enforcement workforce to stop unsafe excavation practices that could result in damage to underground facilities. It also creates an additional opportunity to identify poor practices and the offending excavators so that education on contacting 811 USA prior to digging and on utilizing proper excavation techniques can be provided before any digging or damage has occurred. As excavators operate in multiple jurisdictions, any education of a contractor that occurs in one city can also be applied to the contractor's future jobs in other jurisdictions. Finally, as the number of excavation incidents decreases, the demands on local first responders will also decrease.

b. Elements of the Bow Tie Addressed

SDG&E-9-C11 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Meeting with the top 3% of cities (7 cities out of 240 total).
Effectiveness	Minimal impact since they are not the excavators. Assuming same effectiveness as public awareness for the affected public (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 89% of the causes (89% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2461**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.03	**0.22**	0.54

16. SDG&E-9-C12 – Public Awareness-Remain Active Members of the California Regional Common Ground Alliance

The purpose of remaining active members of the California is to work with all members of the excavation community in achieving the Dig Safe Board's objectives of providing education and outreach, developing safe excavation practices, investigating violations, and supporting the Board's authority. Securing greater enforcement through legislation and working with the California State Digging Board is applicable to all third party excavations. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

SDG&E is an active member in the California Regional Common Ground Alliance (CARGA) through its Damage Prevention Strategies function. CARGA is the regional organization associated with the Common Ground Alliance (CGA). The CGA is an underground utility industry association, across North America, whose mission is to prevent damage to underground infrastructure and to protect those who live and work near these assets through the shared responsibilities of stakeholders. CGA helps to develop best practices among industry stakeholders in all aspects of the safe excavation practices of underground infrastructure.

By participating in CARGA, SDG&E is able to play a role in developing best practices with other regional membership, to inform and help develop best practices on the national level, highlight localized issues that need to be addressed, and interact with contractors and other utilities to create safer excavation techniques and requirements. By working with all members of the underground industry, both locally and nationally, SDG&E not only helps to develop best practices but also be informed of other best practices in the industry which will help to improve utility and contractor implementation of safe digging techniques and procedures.

b. Elements of the Bow Tie Addressed

SDG&E-9-C12 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged

Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate is 50% as not all policies are affected.
Effectiveness	Maybe once every decade there is a practice that can be improved; however, improvement is marginal (0.05%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 100% of the causes (100% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	**LoRE**		**0.2461**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.01	**0.11**	0.26

17. SDG&E-9-C13 - Continue to Participate in the Gold Shovel Standard Program

The Gold Shovel Standard (GSS) Program utilizes an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. This program is applicable to all third party contractors working for SDG&E. All third party damage caused by contractors working for SDG&E poses the same safety risk. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The Gold Shovel Standard (GSS) Program is an external organization that certifies contractor's policies and procedures to protect underground facilities against an established Gold Shovel Standard. The GSS provides positive reinforcement and reviews the contractor's excavation performance. SDG&E requires all of its contractors to participate in the Gold Shovel Program.

The GSS provides positive guidance to underground contractors, aligning their excavation practices against established safe digging practices and procedures. It helps to educate contractors on expected industry excavation standards and identify and address gaps in their processes. SDG&E requires Contractors who perform excavation on behalf of SDG&E to be GSS certified. GSS serves as an additional quality check for its contractors. Actively supporting the Gold Shovel Standard Program helps to improve excavation contractors use of the one-call requirement and to improve their safe digging techniques, such as hand-digging when near gas pipelines.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C13 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C13 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

18. SDG&E-9-C14 – Locating Equipment

SDG&E provides the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure, as mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Locating Equipment Program is to utilize technology to standardize locating procedures and to provide the locate and mark workforce with the tools and information needed to accurately locate and mark underground gas infrastructure. The Locating Equipment program will provide the locate and mark workforce with standardized and compliant location devices and tools that are equipped with 811 USA ticket, asset records, and mapping information. Equipment will be provided to the workforce as part of the normal replacement cycle.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Finally, providing standardized equipment allows for consistent training and field use for the equipment across all operating districts for improved locate accuracy by the workforce.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C14 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C14 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

19. SDG&E-9-C15 – Remain Active Members of the 811 California One-Call Centers

The California One-Call Centers serves as the communication conduit between SDG&E and excavators. SDG&E is an active member of both Dig Alert and USA North. Dig Alert's territory includes nine Southern California Counties. They include: Imperial, Inyo, Los Angeles, Orange, San Bernardino, San Diego, Santa Barbara, Riverside and Ventura. USA North covers fifty Northern California Counties. SDG&E is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to remain an active member of the California One-Call Centers. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The California One-Call Centers serves as the communication conduit between SDG&E and excavators to support safe digging practices. Excavators contact the one-call centers of their intent to excavate in a specific location. This information is made available to the owners and operators of underground infrastructure to provide location information before excavation occurs. SDG&E is an active member of local one-call centers. In calendar year 2018, SDG&E responded to approximately 13,000 requests for locate and mark activities of its transmission system through the local one-call centers, nearly all transmission pipe is considered as high pressure.

As a member of the once-call centers, SDG&E actively works with other industry stakeholders toward simplifying the process, improving its accessibility, and educating safe digging practices. The California one-call centers play a critical role in safe excavation practices and reducing the number of third party damages. It provides a single source for all excavators to contact as well as a source of that activity for utilities, simplifying the communication process between many contractors and the various utilities, many of which are not known by the contractors. The one-call process also allows this communication process to take place before digging occurs, so that utilities can correctly locate and mark their facilities within an expected timeframe. Excavating with these marks, allows the contractors to practice safe digging techniques, minimizing the potential of hitting or damaging gas piping as they complete their work.

SDG&E has not performed an RSE Evaluation on SDG&E-9-C15 because the program elements are mandated by law and/or regulation. SDG&E is required to comply with all applicable laws/regulations, and thus, SDG&E has not calculated the risk reduction benefits received for performing this activity.

b. Elements of the Bow Tie Addressed

SDG&E-9-C15 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

20. SDG&E-9-C16 – Install Warning Mesh Above Buried Company Facilities

Warning mesh is a mitigation against those excavators that do not adhere to the 811 USA excavation safety notification requirement. Approximately 50% of company damages are caused by excavators not contacting 811 USA before they dig. Warning mesh would be installed when any new open trench company facility is installed before backfilling. This program is applicable to all SDG&E open trench buried new company facilities. Therefore, no further tranching is required.

a. Description of Risk Reduction Benefits

The purpose of installing warning mesh above underground gas pipelines is to provide a visual warning to excavators who have not called 811 USA of the existence of gas infrastructure. Warning mesh will be installed in all open trench applications in new construction.

The warning mesh is a visual indicator that can be exposed before the excavator damages the underlying gas infrastructure and can help to address other shortcomings in the mark and locate and safe digging process by both the utility and the excavator. It can serve as a reminder to the excavator to apply hand-digging techniques, it can act as a correction for inaccurate surface locate markings, and it could serve as a warning to an excavator who did not call to have underground facilities marked.

b. Elements of the Bow Tie Addressed

SDG&E-9-C16 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	Used mesh procured with the proposed funding to arrive at the scope percentage (9%).
Effectiveness	Assuming 50% effectiveness since large machines can still cause damage.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 35% of the causes (35% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 1.6%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96

Post-Mitigation	**LoRE**		**0.2499**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.57	**4.53**	11.13
	RSE	4.01	**31.85**	78.24

21. SDG&E-9-M1 – Automate Third Party Excavation Incident Reporting

Automating Third Party Excavation incident reporting into one system will centralize the reporting and data analysis. This will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. SDG&E is mandated by Title 49 Code of Federal Regulation, section 192.614 and California Government Code, section 4216 to collect data on third Party Excavation Incidents. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

Automating third party excavation incident reporting will be the result of an effort to consolidate and simplify the data collection process involved in investigating a gas incident. Field supervisors complete the investigations of gas incidents. Currently, there are multiple systems and processes used to capture and report data, internally and externally, as a result of a gas incident. All systems and processes might not be updated simultaneously, thereby creating additional manual steps when using the data for internal analysis for process improvements, or to generate reports for internal or external stakeholders. SDG&E is undertaking an initiative to consolidate these processes and systems into one system of record to minimize data quality issues, simplify reporting, and standardize data collection among its field supervisors.

Standardizing data collection into one system will centralize reporting and data analysis will assist in meeting compliance reporting obligations, developing a better understanding of the data collected in an investigation, simplifying reporting, and enhancing data analysis processes. This will facilitate improvements in SDG&E's accuracy and timeliness in locating and marking its infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-9-M1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Marginal improvement is expected (1%).
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.01%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2460**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.0029	**0.0040**	0.0059

22. SDG&E-9-M2 – Establish a Program to Address the Area of Continual Excavation

SB 661 modified California Government Code 4216 establishing an ACE Ticket. An ACE ticket's purpose is to improve communication and dialog between the agricultural industry and operators. Starting in July 2020, excavators working on agricultural and flood control lands may obtain an Area Continual Excavation (ACE) ticket. This ticket is applicable to areas within SDG&E territory. All excavations performed with the use of an ACE ticket poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

Generally, a typical USA ticket is valid for 28 days. However, there are some instances where a locate and mark request can be valid for longer.[36] These situations are typically in flood control channels and agricultural field where excavation and digging activities can occur continually. This mitigation program fulfills the California requirement to develop a process that would allow for certain agreements for continual excavation. In flood control and agricultural situations, SDG&E will meet with the landowner and develop an annual agreement that will allow for safe continual excavation activity within the parameters of the agreement. There are approximately 10 miles of high pressure gas piping in agricultural fields within the SDG&E service territory.

Having to continually renew an 811 USA ticket may discourage some excavators from using the 811 USA process. This program will reduce dig-in risk as it will encourage landowners to use the one-call process before excavating and reduce the need to continually call every time digging needs to occur in the same area over the one-year timeframe of the ticket. By informing the 811 USA one-call center, and then the utility, the landowner can be made aware of gas infrastructure in the area and develop an agreed-upon process to employ safe-digging techniques within the parameters established in the ACE ticket. Additionally, this process will assist the utility in accurately and timely marking the facilities as they will not have to make multiple, repeat visits to the same excavation site. By providing a mechanism to reduce effort

---

[36] Although USA tickets are valid for 28 days from the date of issuance. If work continues beyond 28 days, the excavator may renew the ticket per California Government Code, § 4216.2(e).

for both the landowner and the utility, and providing the location of gas infrastructure to the landowner, the use of safe-digging practices should increase, and the amount of infrastructure damage should decrease.

b. Elements of the Bow Tie Addressed

SDG&E-9-M2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT.1 - Excavators such as, contractors or property homeowners/tenants do not call one-call center (USA) for locate and mark prior to excavation , DT.3 - Hand excavation is not performed by excavator in the vicinity of located gas pipelines, DT.5 Company does not "standby" when third party excavates near gas pipelines, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	For assessment purposes, SMEs consider farmers to be equivalent to excavators fielding heavy machinery. The proportion of farmers to heavy machinery excavators is assumed to be 1 to 100, hence a scope of 1%.
Effectiveness	Effectiveness assumed to be high (90%) as the percentage of the targeted people (farmers) are likely to follow procedure and prevent a dig-in once aware of the situation.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 40% of the causes (40% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.4%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96

Post-Mitigation	**LoRE**		**0.2451**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.44**	10.92
	RSE	0.14	**1.09**	2.69

23. SDG&E-9-M3 – Recording Photographs for Each Locate and Mark Ticket Visited by Locator

Recording photographs for each locate and mark ticket visited by locator is planned for all SDG&E's above and belowground facilities within its entire service territory. These pictures will help the company audit the quality of locates and provide an opportunity to improve future marking efforts for the same location. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of recording photographs of each locate and mark ticket is to improve the accuracy of the locating activity and to inform process improvements based on investigations of gas incidents and quality assurance audits. By having a record of the locate marks, SDG&E would be able to better perform root cause analyses of QA activities and investigations into gas incidents. These photographs could show incorrect markings, which would result in improved training, or they could show incorrect mapping and asset data, which could result in improved utility data. The benefits of this mitigation is its role in improving future locate and mark accuracy to avoid damage to gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-9-M3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets will have associated photographs.
Effectiveness	The effectiveness is marginal in nature and considered to be 1% as the impact is only on lessons learned.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	**LoRE**		**0.2459**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.01	**0.04**	0.10

24. SDG&E-9-M4 – Utilize Electronic Positive Response

Electronic positive response is an electronic response provided to the regional notification center (DigAlert and USA North) that informs the excavator, prior to their excavation date, if the facility has been marked or if there is no conflict with the proposed excavation. Utilizing electronic positive response is applicable to all areas within SDG&E's territory. All excavations utilizing electronic positive response poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

SDG&E is required to locate and mark its underground infrastructure within two days of receiving a locate and mark ticket request. Implementing a positive response feature with the regional notification centers, such as USA North and DigAlert, improves communication between SDG&E and excavating contractors. The system will inform the contractor that the utility has completed their task or if no gas infrastructure is in conflict with their excavation activities. The effort also provides a means to communicate stand-by requirements or if the locate task was not able to be completed due to weather or accessibility issues.

This program requires participation from contractors and SDG&E. It will avoid the potential of damage to gas infrastructure due to miscommunication between the contractors and SDG&E. This is especially important in situations where the utility was not able to provide markings within the required timeframe, but the contractor assumes no markings means no gas infrastructure. When there are no markings, the contractor may not employ safe digging procedures resulting in a hit to gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-9-M4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, DT.6 Contractor fails to contact company "standby" personnel, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	100% of tickets will have electronic positive response available.
Effectiveness	This mitigation improves communication but has a marginal impact on excavator behavior, therefore the effectiveness is assumed to be 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.03%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2459**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.0026	**0.0208**	0.0511

25. SDG&E-9-M5 – Enhance Process to Leverage Excavation Technology to Help with Difficult Locates (Vacuum Excavation Technology)

Vacuum excavation technology is an example of a hydro excavation tool that can be deployed to find the location of buried company facilities when a locator is not getting an indication of where the facility is located. Technology such as this has proven itself in the damage prevention industry as a safe alternative to hand tools to prevent damage when unknown buried facilities are encountered. Vacuum excavation is utilized on an as-needed, case-by-case basis during Locate and Mark activities or in a more programmatic way by first identifying areas that are known to be hard to locate. Vacuum excavation is applicable to all areas within SDG&E's territory. All excavations utilizing vacuum excavation technology poses the same safety risk and a single tranche is appropriate.

a. Description of Risk Reduction Benefits

At times, an accurate locate cannot be made using the standard tools available to the locate and mark workforce. In these instances, SDG&E will work with the requesting contractor to help fulfill their request without creating an unsafe situation. SDG&E will establish a process to work with the excavator to utilize various alternatives to locate gas facilities or enhance safe-digging techniques. These alternatives include: stand-by and observe the contractor as they perform their excavation or use other tools such as a Jameson locator or vacuum technology that can expose the physical pipe for visual verification.

Using locating tools that can provide the actual location of gas infrastructure by safely exposing the pipe will provide the most accurate location of the gas infrastructure. With this knowledge, the contractor is aware of when to employ safe digging techniques and company records can be updated with the actual piping location. Both of these benefits will work toward reducing the potential for damage to underground piping for the current project and future projects.

b. Elements of the Bow Tie Addressed

SDG&E-9-M5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 15% of targeted locations will be assisted with emerging excavation technology.
Effectiveness	Effectiveness is high and assumed to be 95%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 3% of the causes (3% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.5%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96

Post-Mitigation	**LoRE**		**0.2449**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.44**	10.91
	RSE	0.04	**0.36**	0.87

26. SDG&E-9-M6 – Promote Process and System Improvements in USA Ticket Routing and Monitoring

The primary focus of system improvements to the 811 USA ticket routing and monitoring will be to upgrade the ticket management system to automatically provide periodic reports on the status of ticket requests, send notifications as a ticket is approaching its deadline, and to capture and report data that will be used to monitor and evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

As part of continuous improvement, an assessment of the current state of the one-call ticket routing and monitoring is underway. The primary focus of system improvements to the USA ticket routing and monitoring will be to upgrade the ticket management system to provide increased abilities to monitor and manage locate and mark ticket requests and to evaluate and measure performance on meeting timing commitments. In calendar year 2018, SDG&E fulfilled approximately 13,000 USA ticket requests from excavators for its transmission system, nearly all transmission pipe is considered to be high pressure.

SDG&E has a time requirement to fulfill locate and mark ticket requests. If these time requirements are not met, contractors might assume that no marks mean there are no utilities in conflict with their project, and they might start their excavation processes. If this occurs, contractors could hit and damage underground gas infrastructure due to the lack of surface markings. By providing enhanced capabilities to monitor and manage ticket request workload, SDG&E will have the potential to be better able to prioritize ticket requests, assign crews, and balance workload among the mark and locate crews. Additionally, the data capture and reporting enhancements can improve SDG&E's ability to monitor its own processes and identify process improvements. These enhancements work toward improving SDG&E's performance in meeting the locate and mark timeframe, thereby reducing the potential of contractors digging without knowledge of underground gas infrastructure.

b. Elements of the Bow Tie Addressed

SDG&E-9-M6 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 4 – Company does not respond to regional notification center (USA) request in required timeframe, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	SMEs estimate that 100% of tickets are affected by improved routing and will be automated so that tickets are not lost (applies to all stakeholder groups).
Effectiveness	Improvement of up to 15%. This mitigation is closely tied to the Damage Prevention Analysts program.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.2%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		0.246	
	CoRE	2.28	18.13	44.55
	Risk Score	0.56	4.46	10.96
Post-Mitigation	**LoRE**		0.2456	
	CoRE	2.28	18.13	44.55
	Risk Score	0.56	4.45	10.94
	RSE	0.038	0.304	0.746

27. SDG&E-9-M7 – Leverage Data Gathered by Locating Equipment

The current locating equipment has the availability has the capability of recording all information from a locate. This information could be used to assess the quality of each locate and the relative accuracy of pipe location in the GIS system. By having a quality measurement for each locate the company can further determine areas that need improvement. The data gathered by leveraging locating equipment will be used to evaluate performance per Title 49 Code of Federal Regulation, section 192.614. Therefore, no further tranching is appropriate.

a. Description of Risk Reduction Benefits

The purpose of the Leveraging Data Gathered by Locating Equipment Program is to utilize technology to improve the speed with which SDG&E mapping and asset records are updated and improve the accuracy of the resulting locate and mark activities. It provides the locate and mark workforce with the tools and technology to facilitate the ability to update Company records by capturing location coordinates found in the field, which can then be used to evaluate against existing company records to identify any mapping, records, or locating errors.

Reducing the potential for damage to underground facilities that is caused by excavation activities requires correct facility markings. Excavators use these markings to know when hand-digging and other safe digging practices should be followed. Using equipment with the latest technology assists in locating the infrastructure more accurately by providing specific location coordinates to the company's GIS system for updated records. Accurate mapping and company records on its facilities improves the accuracy of future locate and mark activities thereby providing excavators with an improved vision of underground piping.

b. Elements of the Bow Tie Addressed

SDG&E-9-M7 addresses several Drivers/Triggers and Potential Consequences as outlined above in Section I. These include DT. 2 – Locator error contributing to the incorrect marking of underground gas structures, DT.7 - Delayed updates to asset records of underground gas infrastructure leading to incorrect locate and mark, PC.1 – Serious Injuries and/or Fatalities, PC.2 – Property Damage, PC.3 – Prolonged Outages, PC.4 – Penalties and Fines, PC.5 – Adverse Litigation and PC.6 – Erosion of Public Confidence.

c. RSE Inputs and Basis

Scope	A 25% scope is used as a middle ground (between 13% for damages on mains and 40% for damages from backhoes).
Effectiveness	Assume marginal effectiveness of 1%.
Risk Reduction	Based on a mapping of the 2018 DIRT data causes, this mitigation addresses 1% of the causes (1% risk addressed). Using these assumptions, this mitigation could improve Dig-Ins safety, reliability, and financial risk by up to 0.003%.

d. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	**LoRE**		**0.2456**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.45**	10.94
	RSE	0.0001	**0.0007**	0.0017

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

SDG&E evaluated the constraints and challenges for the plan. Third Party Excavation Damage on high pressure lines are typically due to a lack of securing an 811 USA ticket and/or failure to follow safe excavation practices. These challenges are in spite of the communication and education efforts being taken by numerous utilities, associations, and other stakeholder groups who advocate for safe excavation laws and practices. Affecting positive behavioral changes to these excavators remains a significant challenge in preventing excavation damage to high pressure pipelines, a low occurrence but high consequence risk. To continue to improve damage prevention, new technologies and strategies must continue to be evaluated. It must also be determined how new technologies complement the existing portfolio of mitigation measures.

Below ground utility infrastructure can be challenging to locate. It requires a trained and seasoned workforce, use of sophisticated electronic equipment, and access and use of online GIS, mapping, and historical installation information to accurately identify locations. Throughout the years, due to growth and modernization, the density of underground utilities within rights-of-way has increased significantly. This in turn can lead to increased difficulty in locating individual facilities due to locating signal interference from adjacent infrastructure. Techniques learned over the years by seasoned locators are invaluable when faced with hard to locate areas. The influx and turn-over of a less experienced workforce who have yet to acquire varying degrees of institutional knowledge and technique development could contribute to the challenges of locate and mark activities.

Additionally, implementing, operating and maintaining a mitigation such as an 811 USA ticket risk assessment tool assumes that the algorithm will properly identify the riskiest evacuations and operators. The Company has to rely on legacy software programs and frequently perform updates to it in order to maintain the 811 USA ticket risk assessment tool. Computer hardware improvements increase the performance of the software and allow the Locate and Mark Technician to collect additional data and photographic documentation of the site with utility markings. Additional challenges on the locate and mark program are the occasions when tickets fail to be transmitted through the mobile data terminal (MDT) due to limited/no wireless service. This may lead to the excavator starting their work prior to the utility properly delineating the under-ground substructures. High pressure pipelines often traverse remote or rural areas where routine public access is infrequent. In addition, the use of non-local sub-contractor excavation companies, for example plowing agricultural fields, who are not familiar with underground utilities can lead to devastating consequences. SDG&E's service territory size and the driving of miles (or aerial miles) that would be required to reach remote locations inhibits SDG&E's ability to more closely monitor right of way activity in remote or rural locations.

The inclusion of warning mesh and fiber optics for open trench high pressure pipeline installation are both relatively new. Near term benefits of these mitigations are incremental. The wide spread benefits will only be realized as significantly more pipe installations, that include these mitigations, have been completed.

The plan was compiled using SDG&E's current capabilities for evaluating and prioritizing mitigation measures. SDG&E has made its best effort to identify the drivers and consequences associated with each risk with the understanding that, over time, impacting factors may change and require adjustments to the plan. If any of the Mitigations become mandated at a later date, cost and resource projects could also change.

Table 8 provides a summary of the Risk Mitigation Plan, including Controls and Mitigations activities, associated costs, the RSEs by tranche.

SDG&E does not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Table 8 were estimated using assumptions provided by SMEs and available accounting data.

Table 8: Risk Mitigation Plan Summary[37]
(Direct 2018 $000)[38]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[39]	2018 Baseline O&M	2020-2022 Capital[40]	2022 O&M	Total[41]	RSE[42]
SDG&E-9-C1	Locate and Mark Training	T1	0	7	0	9 – 11	9 – 11	-
SDG&E-9-C2	Located and Mark Activities	T1	0	250	0	350 – 460	350 – 460	-

37 Recorded costs and forecast ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

38 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

39 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

40 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E's Test Year 2022 GRC Application.

41 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

42 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

ID	Mitigation/Control	Tranche	2018 Baseline Capital[39]	2018 Baseline O&M	2020-2022 Capital[40]	2022 O&M	Total[41]	RSE[42]
SDG&E-9-C3	Locate and Mark Annual Refresher Training and Competency Program	T1	0	1	0	1 – 8	1 – 8	-
SDG&E-9-C4	Locate and Mark Operator Qualification	T1	0	7	0	7 – 13	7 – 13	-
SDG&E-9-C5	Locate and Mark Quality Assurance Program	T1	0	2	0	2 – 5	2 – 5	0.2-3.87
SDG&E-9-C6	Damage Prevention Analyst Program	T1	0	8	0	13 – 17	13 – 17	2.68-52.26
SDG&E-9-C7	Prevention and Improvements – Refreshed Laptops	T1	0	0	51-90	18 – 48	69 – 140	0.01-0.22
SDG&E-9-C8-T1	Public Awareness Compliance – The Affected Public	T1	0	6	0	30 – 60	30 – 60	0.05-0.96
SDG&E-9-C8-T2	Public Awareness Compliance – Emergency Officials	T2	0	1	0	3 – 6	3 – 6	0.01-0.29
SDG&E-9-C8-T3	Public Awareness Compliance – Local Public Officials	T3	0	2	0	9 – 18	9 – 18	0.03-0.54

ID	Mitigation/Control	Tranche	2018 Baseline Capital[39]	2018 Baseline O&M	2020-2022 Capital[40]	2022 O&M	Total[41]	RSE[42]
SDG&E-9-C8-T4	Public Awareness Compliance – Excavators	T4	0	4	0	18 – 36	18 – 36	0.15-2.91
SDG&E-9-C9	Increase Reporting of Unsafe Excavation	T1	0	2	0	2 – 8	2 – 8	0.06-1.2
SDG&E-9-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	T1	0	1	0	1 – 3	1 – 3	-
SDG&E-9-C11	Public Awareness - Meet with Cities with Highest Damage Rates	T1	0	1	0	1 – 6	1 – 6	0.03-0.54
SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	T1	0	0	0	3 – 12	3 – 12	0.01-0.26
SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program	T1	0	3	0	3 – 4	3 – 4	-
SDG&E-9-C14	Locating Equipment	T1	0	3	0	3 – 30	3 – 30	-

ID	Mitigation/Control	Tranche	2018 Baseline Capital[39]	2018 Baseline O&M	2020-2022 Capital[40]	2022 O&M	Total[41]	RSE[42]
SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers	T1	0	12	0	12 – 50	12 – 50	-
SDGE-9-C16	Install warning mesh above buried company facilities	T1	0	51	0	51 – 64	51 – 64	4.01-78.24
SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	T1	0	0	860 - 1,500	0	860 – 1,500	0.00297-0.00592
SDG&E-9-M2	Establish a program to address the area of continual excavation	T1	0	0	0	13 – 16	13 – 16	0.14-2.69
SDG&E-9-M3	Recording photographs for each locate and mark ticket visited by locator	T1	0	0	0	16 – 35	16 – 35	0.0053-0.1030
SDG&E-9-M4	Utilize electronic positive response	T1	0	0	0	34 – 6 3	34 – 63	0.0026-0.0511
SDG&E-9-M5	Enhance process to leverage excavation technology to help with difficult locates (vacuum excavation technology)	T1	0	0	0	6 – 120	6 – 120	0.04-0.87

ID	Mitigation/Control	Tranche	2018 Baseline Capital[39]	2018 Baseline O&M	2020-2022 Capital[40]	2022 O&M	Total[41]	RSE[42]
SDG&E-9-M6	Promote process and system improvements in USA ticket routing and monitoring	T1	0	0	0	22 – 28	22 – 28	0.038-0.746
SDG&E-9-M7	Leverage data gathered by locating equipment	T1	0	0	0	6 – 9	6 – 9	0.0001-0.0017
TOTAL COST			**0**	**360**	**910 – 1,600**	**630-1,100**	**1,500-2,700**	

It is important to note that SDG&E is identifying potential ranges of costs in this Risk Mitigation Plan and is not requesting funding herein. SDG&E will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

SDG&E also notes that there are activities related to the Third Party Dig-in on a High Pressure Pipeline risk that will be carried over to the GRC for which the costs are primarily internal labor (*e.g.*, various training). The costs associated with these internal labor activities are not captured in this chapter because SDG&E does not track labor in this manner.

In addition, as discussed in Section VI above, the table below summarizes the activities for which an RSE is not provided:

Table 9: Summary of RSE Exclusions

ID	Control/Mitigation Name	Reason for no RSE Calculation
SDG&E-9-C1	Locate and Mark Training	Mandated compliance activity per CFR Part 192/GO 112-F
SDG&E-9-C2	Locate and Mark Activities	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SDG&E-9-C3	Locate and Mark Annual Refresher Training & Competency Program	Mandated compliance activity per CFR Part 192/GO 112-F
SDG&E-9-C4	Locate and Mark Operator Qualification	Mandated compliance activity per CFR Part 192 Subpart N
SDG&E-9-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	Dig Safe Act of 2016 and is included in California's Government Code 4216.12
SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program	Mandated compliance activity per California Government Code 4216
SDG&E-9-C14	Locating Equipment	Mandated compliance activity per CFR Part 192.614. California Government Code 4216
SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers	Mandated compliance activity per CFR Part 192.614. California Government Code 4216

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, SDG&E considered alternatives to the mitigations for the Third Party Dig-in on a High Pressure Pipeline risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost. The alternatives analysis for this Risk Mitigation Plan also took into account modifications to the plan and constraints, such as budget and resources.

A. SDG&E-9-A1 – Virtual Reality Training/Simulation to Improve Locator Proficiency

The virtual reality Locate and Mark training simulator provides a portable and scenario-based training system. It allows for instructors to simulate a variety of real-world locate and mark scenarios. Virtual reality provides more flexibility in training curriculum and allows for more focused educational opportunities. More research is needed to identify system requirements and identify impacts to existing locate equipment and performance management software.

Scope	Assuming 100% of locations would receive UTTO Virtual Reality Training Tools.
Effectiveness	Per internal SME assessment, utilizing UTTO Virtual Reality Locator Training Tools will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 2%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.0002%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	**LoRE**		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96

Post-Mitigation	**LoRE**		**0.2460**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	0.000	**0.0004**	0.0009

B. SDG&E-9-A2 – GPS Tracking of Excavation Equipment

SDG&E has supported the Gas Technology Institute (GTI) and other research organizations in their efforts to help the industry improve damage prevention practices. Past and ongoing efforts included real-time GPS tracking of excavation equipment operating in pipeline rights-of-way and quick-shut breakaway meter set valves.

Real-time tracking of excavation is done using a "black box" attached to the excavation equipment such as a backhoe, grader, etc. The black box monitors the location of the equipment and can sense when the equipment is getting ready to dig. There is sophisticated software that monitors the GPS data in relation to its proximity to spatial pipe locations. If the box is detected near a company asset, then an alarm is triggered on the equipment alerting the equipment operator that there is a pipeline in the area. There is also an alert that is sent to the Company so action may be taken to investigate the location.

The technology is not being pursued at this time since it gave too many false positives. There is more work that needs to be completed and testing done before the device is ready for production.

Scope	A middle ground of 25% of available opportunities will be used as the scope for GPS tracking.
Effectiveness	Per internal SME assessment, utilizing GPS tracking of excavation equipment will have minimal impact on risk reduction, reducing risk by up to 0.01%.
Risk Reduction	The percent of dig ins risk addressed is assumed to be 1%. Using these assumptions, this mitigation could improve storage safety, reliability, and financial risk by up to 0.00003%.

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.246**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
Post-Mitigation	LoRE		**0.2460**	
	CoRE	2.28	**18.13**	44.55
	Risk Score	0.56	**4.46**	10.96
	RSE	00.00	**00.00**	00.00

Table 10: Alternative Mitigation Summary
(Direct 2018 $000)[43]

ID	Mitigation	2020-2022 Capital[44]	2022 O&M	Total[45]	RSE[46]
SDGE-9-A1	Virtual reality training / simulation to improve locator proficiency	0	100-120	100-120	**00.00-0.0009**
SDGE-9-A2	GPS Tracking of Excavation Equipment	0	236-391	236-391	**00.00-00.00**

43 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

44 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total.

45 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

46 The RSE ranges are further discussed in Chapter RAMP-C and in Section VI above.

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-9-C1	Locate and Mark Training	DT.2; DT.4; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C2	Locate and Mark Activities	DT.2; DT.4; DT.5; PC.1; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C3	Locate and Mark Annual Refresher Training & Competency Program	DT.2; DT.4; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C4	Locate and Mark Operator Qualification	DT.2; DT.4; DT.5 PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C5	Locate and Mark Quality Assurance Program	DT.2; DT.4; DT.5; DT.7; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C6	Damage Prevention Analyst Program	DT.1; DT.2; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C7	Prevention & Improvements-Refreshed Laptops	DT.2;DT.7; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C8	Public Awareness Compliance	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C9	Increase Reporting of Unsafe Excavation	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C10	Public Awareness - Secure Greater Enforcement through Legislation and California State Digging Board	DT.1;DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C11	Public Awareness - Meet with the Cities with the Highest Damage Rates	DT.1; DT.3; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C12	Public Awareness - Remain Active Members of the California Regional Common Ground Alliance	DT.1;DT.3; DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C13	Continue to Participate in the Gold Shovel Standard Program	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C14	Locating Equipment	DT.2; DT.4;; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

ID	Control/Mitigation Name	Drivers/Triggers/Potential Consequences Addressed
SDG&E-9-C15	Remain Active Members of the 811 California One-Call Centers	DT.1; DT.2; DT.3; DT.4; DT.5; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-C16	Install warning mesh above buried company facilities	DT.1; DT.3; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M1	Automate Third Party Excavation Incident Reporting	DT.2; DT.4; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M2	Establish A Program To Address The Area Of Continual Excavation	DT.1; DT.3; DT.5; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M3	Recording Photographs For Each Locate and Mark Ticket Visited By Locator	DT.2; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M4	Utilize Electronic Positive Response	DT.4; DT.6; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M5	Enhance Process To Utilize And Leverage Emerging Excavation Technology To Help With Difficult Locates	DT.2;DT.7; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M6	Promote Process And System Improvements In USA Ticket Routing And Monitoring	DT.4; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6
SDG&E-9-M7	Leverage Data Gathered By Locating Equipment	DT.2; DT.7; PC.1; PC.2; PC.3; PC.4; PC.5; PC.6

Risk Assessment Mitigation Phase
(Chapter SDG&E-10/SCG-9)
Cybersecurity

November 27, 2019

TABLE OF CONTENTS

Risk: Cybersecurity

I. INTRODUCTION

The purpose of this chapter is to present the risk mitigation plan San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, the Companies) for the risk of Cybersecurity. This risk chapter is identical for both Companies given that the Cyber risk is currently managed centrally at the Companies. Each chapter in this Risk Assessment Mitigation Phase (RAMP) Report contains the information and analysis that meets the requirements adopted in Decision (D.) 16-08-018 and D.18-12-014, and the Settlement Agreement included therein (the SA Decision).[1]

The Companies have identified and defined RAMP risks in accordance with the process described in further detail in Chapter RAMP-B of this RAMP Report. On an annual basis, the Companies' Enterprise Risk Management (ERM) organization facilitates the Enterprise Risk Registry (ERR) process, which influenced how risks were selected for inclusion in this 2019 RAMP Report, consistent with the SA Decision's directives.

The purpose of RAMP is not to request funding. Any funding requests will be made in SDG&E's and SoCalGas' respective General Rate Case (GRC) applications. The costs presented in this 2019 RAMP Report are those costs for which the Companies' anticipate requesting recovery in their respective Test Year (TY) 2022 GRCs. The Companies' TY 2022 GRC presentations will integrate developed and updated funding requests from the 2019 RAMP Report, supported by witness testimony.[2] For this 2019 RAMP Report, the baseline costs are the costs incurred in 2018, as further discussed in Chapter RAMP-A. This 2019 RAMP Report

---

1 D.16-08-018 also adopted the requirements previously set forth in D.14-12-025. D.18-12-014 adopted the Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with modifications and contains the minimum required elements to be used by the utilities for risk and mitigation analysis in the RAMP and GRC.

2 *See,* D.18-12-014 at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

presents capital costs as a sum of the years 2020, 2021 and 2022 as a three-year total; whereas, O&M costs are only presented for TY 2022.

Costs for each activity that directly addresses each risk are provided where those costs are available and within the scope of the analysis required in this RAMP Report. Throughout this 2019 RAMP Report activities are delineated between controls and mitigations, consistent with the definitions adopted in the SA Decision's Revised Lexicon. A "Control" is defined as a "[c]urrently established measure that is modifying risk."[3] A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."[4] Activities presented in this chapter are representative of those that are primarily scoped to address the Companies' Cybersecurity risk; however, many of the activities presented herein also help mitigate other risk areas as outlined in Chapter RAMP-A.

As discussed in Chapter RAMP-D, Risk Spend Efficiency (RSE) Methodology, no RSE calculation is provided where costs are not available or not presented in this RAMP Report (including costs for activities that are outside of the GRC and certain internal labor costs). Additionally, the Companies did not perform RSE calculations on mandated activities. Mandated activities are defined as activities conducted to meet a mandate or law, such as a Code of Federal Regulation (CFR), Public Utilities Code, or General Order. Activities with no RSE score presented in this 2019 RAMP Report are identified in Section VII below.

The Companies have also included a qualitative narrative discussion of certain risk mitigation activities that would otherwise fall outside of the RAMP Report's requirements, to aid the California Public Utilities Commission (CPUC or Commission) and stakeholders in developing a more complete understanding of the breadth and quality of the Companies' mitigation activities. These distinctions are discussed in the applicable control/mitigation narratives in Section V. Similarly, a narrative discussion of certain "mitigation" activities and their associated costs is provided for certain activities and programs that may indirectly address

3 *Id*. at 16.

4 *Id.* at 17.

the risk at issue, even though the scope of the risk as defined in the RAMP Report may technically exclude the mitigation activity from the RAMP analysis. This additional qualitative information is provided in the interest of full transparency and understandability, consistent with guidance from Commission staff and stakeholder discussions.

A. Risk Definition

For purposes of this 2019 RAMP Report, the Companies' Cybersecurity risk is defined as the risk of a major cybersecurity incident, which results in disruptions to electric or gas operations (*e.g.,* Industrial Control Systems, supply, transmission, distribution) and/or damage or disruption to the Companies' operations (*e.g.,* Human Resources, payroll, billing), reputation, or disclosure of sensitive customer or Company data.

B. Summary of Elements of the Risk Bow Tie

Pursuant to the SA Decision,[5] for each Control and Mitigation presented herein, the Companies have identified which element(s) of the Bow Tie the risk mitigation activity addresses. Below is a summary of these elements.

Table 1: Summary of Risk Bow Tie Elements

ID	Description of Drivers/Triggers and Potential Consequences
DT.1	Manipulated data or integrity failure
DT.2	Infrastructure or availability failure
DT.3	Access control or confidentiality failure
DT.4	Malicious software intrusions
DT.5	Cybersecurity control failures
DT.6	Operational system failures
DT.7	Equipment loss or theft
DT.8	Human error
PC.1	Disruption of energy flow systems
PC.2	Data corruption or unavailability
PC.3	Theft or destruction of systems/data
PC.4	Exposure of sensitive Company and customer data
PC.5	Adverse litigation
PC.6	Regulatory non-compliance fines and/or sanctions
PC.7	Erosion of public confidence
PC.8	Human Injury

5 *Id.* at Attachment A, A-11 ("Bow Tie").

C. Summary of Risk Mitigation Plan

The Companies' Risk Mitigation Plan for the Cybersecurity risk consists of five utility-focused operational cybersecurity categories:

1. Perimeter Defenses;
2. Internal Defenses;
3. Sensitive Data Protection;
4. Operational Technology (OT) Cybersecurity; and
5. Obsolete Information Technology (IT) Infrastructure and Application Replacement.

The Companies' Risk Mitigation Plan includes both baseline controls and new mitigation activities. Based on the foregoing assessment, the Companies' set forth future mitigations. In the previous RAMP filing, the Cybersecurity mitigation plan was structured using the National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) to group like security controls. In this 2019 RAMP Report, the Companies are using operational groups to describe, and group mitigations in a more business-aligned approach. More detail can be found in Section V, below. A summary of the operational categories includes:

1. Perimeter Defenses

Enhancements to the Companies' existing Perimeter Defenses, privileged access management, firewall solutions for web applications and penetration testing consulting services to improve our solutions' ability to defend against an advanced, intelligent adversary.

2. Internal Defenses

Enhancements designed to detect and prevent malicious users (and/ or code from propagating) inside of the perimeter.

3. Sensitive Data Protection

Enhancements of security controls that will protect sensitive data throughout the technology systems.

4. **Operational Technologies (OT) Cybersecurity**

Enhancements to the management and protection of operational technology assets, improving threat intelligence and vulnerability management, and securing the communication infrastructure.

5. **Obsolete Information Technology (IT) Infrastructure and Application Replacement**

Enhancements to Information Technology (IT) components and capabilities that present cybersecurity risks to the Companies addressed via the necessary replacement and/or upgrades of obsolete and vulnerable IT operating systems, software, applications, hardware, monitoring tools, and other infrastructure components.

Pursuant to the SA Decision,[6] the Companies have performed a detailed pre- and post-mitigation analysis of controls and mitigations for each risk selected for inclusion in RAMP, as further described below. The Companies' 2018 Controls for this risk consist of the following:

Table 2: Summary of Controls

ID	Control Name
SDG&E-10-C1 SCG-9-C1	Perimeter Defenses
SDG&E-10-C2 SCG-9-C2	Internal Defenses
SDG&E-10-C3 SCG-9-C3	Sensitive Data Protection
SDG&E-10-C4 SCG-9-C4	Operational Technology (OT) Cybersecurity
SDG&E-10-C5 SCG-9-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement

6 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

Finally, pursuant to the SA Decision,[7] the Companies considered alternatives to the Risk Mitigation Plan for the Cybersecurity risk and we summarize the reasons that the alternatives were not included in the Risk Mitigation Plan discussed in Section VIII, below.

D. Sensitive, Confidential Information to Be Protected

What is unique about the Cybersecurity risk, as compared to other risks driven by operations, asset management, or natural hazards, is that there is an intelligent adversary that is attempting to 1) understand the Companies' controls and 2) gain access to Company systems or information to achieve the adversary's objectives. It is important for our stakeholders to understand that some information about the Companies' mitigation plans or our worst-case scenarios would be useful to an adversary – and would indirectly harm our stakeholders. While some of our controls and strategies are considered standard practice, publishing some of these controls, intelligence, strategies, or tactics in the public record could aid our enemy, the criminal gang or nation state that is attempting to disrupt our systems and society. Sensitive details noted herein are available upon Commission request for discussion in person.

II. RISK OVERVIEW

Cybersecurity threats continue to rapidly evolve. As such, our strategy to counter cybersecurity threats must be flexible and allow us to adapt to these evolving threats over time.

Timely and accurate cybersecurity threat intelligence is key to staying abreast of this rapidly evolving threat landscape. We obtain cybersecurity threat intelligence from a variety of entities and sources, including Information Sharing and Analysis Centers (ISACs), the Federal Bureau of Investigations (FBI), the Federal Energy Regulatory Commission (FERC), the Department of Energy (DOE), the Department of Homeland Security (DHS) and a variety of United States (US) Intelligence Community agencies. Information from threat intelligence in the utility industry continues to reveal adversaries that are using advancing tradecraft to try and access our nation's utility systems.

---

7 *Id.* at 33.

A. The Companies are Faced with an Evolving Cybersecurity Threat

At the FERC 2018 Reliability Technical Conference;[8] "Addressing the Evolving Cybersecurity Threat" panel, it was noted that, "There is a widespread understanding among policymakers and industry that cyberattacks are a persistent and growing threat to the reliable or resilient operation of the Bulk-Power System."[9]

A representative sample of recent threats facing our industry are provided below:

OT Attacks on Utility Infrastructure

- ***Attack on Ukrainian Electric Operator*** (https://www.us-cert.gov/ics/alerts/IR-ALERT-H-16-056-01) This was a well-publicized and understood attack by a nation state on the electrical transmission system in Ukraine. This was an advanced attack that migrated from the IT to OT system and resulted in the loss of electric load to approximately 200,000 customers.
- ***May 2019 reporting on Western Energy Firm attack*** (https://www.dispersive.io/blog/first-of-its-kind-denial-of-service-attack-on-western-u.s.-utility*)* A distributed denial of service (DDOS) attack aimed at a Northwestern US power company, disrupted operations but did not result in a loss of electric load.

Insider Attacks

- ***Capital One former insider*** (https://www.bloomberg.com/news/articles/2019-07-29/capital-one-data-systems-breached-by-seattle-woman-u-s-says*)* An insider, formerly employed by Amazon Web Services (AWS), illicitly penetrated vulnerabilities in the AWS configurations to enable access to the Capital One customer data.

---

8 Federal Energy Regulatory Commission, Supplemental Notice of Technical Conference (July 17, 2018), *available at* https://www.ferc.gov/CalendarFiles/20180724131230-notice-AD18-11.pdf.

9 *Id.* at 5.

Supply Chain

- ***Russian attack on electric utility suppliers*** *(*https://www.wsj.com/articles/americas-electric-grid-has-a-vulnerable-back-doorand-russia-walked-through-it-11547137112*)*

  Reports that a Russian group accessed an electric utility via one of the utility's smaller vendors. The Companies are monitoring a growing concern in cyber with respect to harmful vulnerabilities introduced in the supply chain.

IT Cybersecurity

- ***NotPetya*** *(*https://www.wired.com/story/notpetya-cyberattack-ukraine-russia-code-crashed-the-world/*)* A Russian-driven attack on IT systems, using "ransomware" malicious software that resulted in damages to the IT hardware after infection.

B. Adversaries

The adversaries the Companies face include various types of actors with varying intent to cause harm; they are not just criminal entities or hackers looking to make a political statement or achieve financial gain. They also include advanced adversaries, often aligned to nation states, that are targeting critical infrastructure for economic exploit, espionage, or covert action in preparation for some overt act (*e.g.*, disrupting energy supply). The Companies believe their investment and spend in Cybersecurity is prudent and reasonable to address the existing and growing threat.

Adversaries continue to use an evolving and more sophisticated set of tools and strategies to conduct attacks on the energy sector. Their suite of capabilities was touched on above but also includes advanced malware, more complex phishing attacks, among others. Adversaries are also conducting other campaigns to target utility employees, akin to the recently publicized targeting of US Government officials through LinkedIn.[10]

[10] U.S. Army Cyber Command, *Army Cyber Fact Sheet: LinkedIn Scams* (September 26, 2019), *available at* https://www.arcyber.army.mil/Info/Fact-Sheets/Fact-Sheet-View-Page/Article/1972156/army-cyber-fact-sheet-linkedin-scams.

C. Cybersecurity Program

At the Companies, cybersecurity is critical to the safe and reliable delivery of electric and gas service to our customers, including critical infrastructure providers in our Southern California service territory (*e.g.,* financial services, telecommunication providers, other utilities). Our service territory includes millions of people, one of the Nation's busiest ports, largest cities, most critical military bases, countless defense contractors and small businesses.

At the Companies, everyone plays a part in cybersecurity. The cybersecurity program is led by the Cybersecurity department. The mitigations discussed in this chapter focus on those control activities performed or supported directly by the Cybersecurity department as a shared service for SDG&E, SoCalGas, and Sempra Energy. The Cybersecurity department manages cybersecurity risks across the enterprise, including information technology and operational technology.

The Cybersecurity program utilizes risk management frameworks, including but not limited to, the NIST Cybersecurity Framework, Center for Internet Security (CIS-20), and NIST 800-53. Additionally, we comply with all applicable laws and regulations both at the State and Federal level.

III. RISK ASSESSMENT

In accordance with the SA Decision,[11] this section describes the Risk Bow Tie, possible Drivers/Triggers, and Potential Consequences of the Cybersecurity risk.

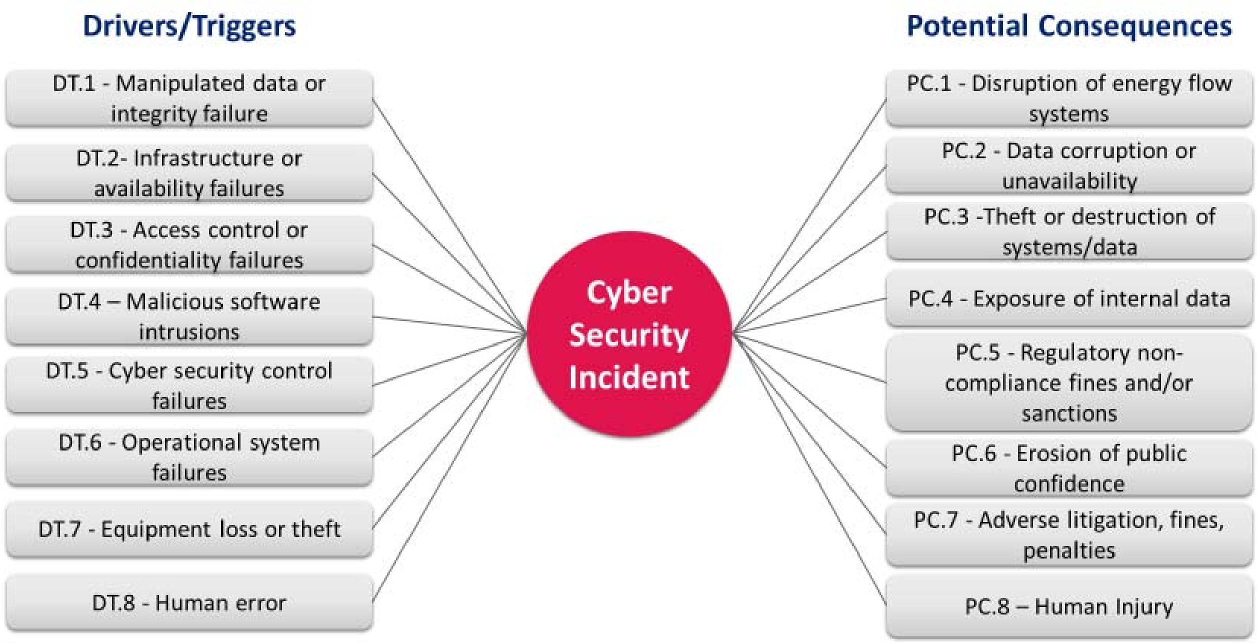
A. Risk Bow Tie

The Risk Bow Tie shown in Figure 1, below, is a commonly-used tool for risk analysis. The left side of the Risk Bow Tie illustrates drivers that lead to a risk event and the right side shows the potential consequences of a risk event. The Companies applied this framework to identify and summarize the information provided above. A mapping of each Control to the element(s) of the Risk Bow Tie addressed is provided in Appendix A.

---

[11] D.18-12-014 at 33 and Attachment A, A-11 ("Bow Tie").

Figure 1: Risk Bow Tie



B. Asset Groups or Systems Subject to the Risk

The SA Decision[12] directs the utilities to endeavor to identify all asset groups or systems subject to the risk. The Cybersecurity risk is a "cross-cutting" risk impacting all of the Companies' electric and gas operations assets, infrastructure, and systems, including: information technology (IT) perimeter, the IT internal systems, sensitive data within the IT systems, legacy technology infrastructure, and operational technology.

C. Risk Event Associated with the Risk

The SA Decision[13] instructs the utilities to include a Risk Bow Tie illustration for each risk included in RAMP. As illustrated in the above Risk Bow Tie, the risk event (center of the bow tie) is a Cybersecurity event that results in any of the Potential Consequences listed on the right. The Drivers/Triggers that may contribute to this risk event are further described in the section below. There are many possible ways in which a cybersecurity event can occur. The

---

12 *Id.* at Attachment A, A-11 ("Definition of Risk Events and Tranches").

13 *Id.* at Attachment A, A-11 ("Bow Tie").

scenario below represents a situation that could happen, within a reasonable timeframe, and lead to a relatively significant adverse outcome.

Possible scenario: A malicious cyber attacker successfully accesses Company information or technology assets, which results in disruption in energy delivery, creates an unsafe condition with safety impacts, damages financial or other operational systems, and/or exposes customer data.

D. Potential Drivers/Triggers[14]

The SA Decision[15] instructs the utility to identify which element(s) of the associated bow tie each mitigation addresses. When performing the risk assessment for Cybersecurity, the Companies identified potential leading indicators, referred to as drivers. These include, but are not limited to:

- **DT.1 - Manipulated data or integrity failure**: Any unintended changes to data as the result of a storage, retrieval or processing operation, including malicious intent, unexpected hardware failure, and human error.
- **DT.2- Infrastructure or availability failure**: Refers to an unplanned, severe, extensive and/or large-scale system outage caused by a cybersecurity-related event or incident.
- **DT.3 -Access control or confidentiality failure**: Inability to effectively perform identification authentication and authorization of users and entities by evaluating required login credentials that can include passwords, personal identification numbers (PINs), biometric scans, security tokens or other authentication factors.
- **DT.4 - Malicious software intrusions**: Describes any malicious program or code that is harmful to systems. Malware seeks to invade, damage, or disable computers, computer systems, networks, tablets, and mobile devices, often by taking partial control over a device's operations.

---

14 An indication that a risk could occur. It does not reflect actual or threatened conditions.

15 D.18-12-014 at Attachment A, A-11 ("Bow Tie").

- **DT.5 - Cybersecurity control failures**: Refers to a general failure of a Cybersecurity control(s). *E.g.,* a vulnerability scanner ceases functioning, allowing an exploitable vulnerability to go unnoticed in the environment.
- **DT.6 - Operational system failures**: A system failure occurring due a cybersecurity event/incident, causing the system to freeze, reboot, or stop functioning altogether.
- **DT.7 - Equipment loss or theft**: A type of data breach where there is a loss of a laptop, mobile device, or storage device such as backup tapes, hard drives, and flash drives whether by accidental loss or through malicious intent.
- **DT.8 - Human error (*e.g.*, clicking on a phishing email):** Refers to an accidental cybersecurity event/incident conducted by a human.

E. Potential Consequences

There are several potential worst-case scenarios that the Companies consider. However, as noted earlier, we are intentionally not sharing the details of these scenarios to avoid informing adversaries. If one or more of the Drivers/Triggers listed above were to result in an incident, the Potential Consequences, in a reasonable worst-case scenario, could include:

- **PC.1 - Disruption of energy flow systems**: Refers to a power outage, or failure of gas distribution, where there is the loss of electrical power, or natural gas supply, to an end user. Energy delivery failures are particularly critical at sites where the environment and public safety are at risk.
- **PC.2 - Data corruption or unavailability**: A situation where data is made unavailable or modified via failures in storage, transmission, processing, or a cybersecurity incident (*e.g.*, "Ransomware" attack).
- **PC.3 - Theft or destruction of systems/data**: A situation where data is accidentally or maliciously destroyed (made unavailable) or stolen causing an impact to business operations, reputation and/or financial harm.
- **PC.4 - Exposure of sensitive Company and customer data**: Exposure of sensitive Company and customer data can be a significant cybersecurity

incident to an organization with consequences that can include loss of customer confidence, public trust, financial penalties, among others.

- **PC.5 - Regulatory non-compliance fines and/or sanctions:** The risk of a regulatory compliance failure which results in potential penalties/fines or sanctions.
- **PC.6 - Erosion of public confidence:** Refers to a cybersecurity event/ incident causing a potential loss to financial capital, social capital and/or market share resulting from damages to a firm's reputation.
- **PC.7 - Adverse litigation:** Refers to Litigation risk, which is the possibility that legal action will be taken because of an individual's or corporation's actions, inaction, products, services or other events. Corporations generally employ some type of litigation risk analysis and management to identify key areas where the litigation risk is high, and thereby take appropriate measures to limit or eliminate those risks**.**
- **PC.8 – Human injury:** Refers to physical trauma to the body.

These Potential Consequences were used in the scoring of the Companies' Cybersecurity Risk during the development of the 2018 Enterprise Risk Registry.

IV. RISK QUANTIFICATION

The SA Decision[16] sets minimum requirements for risk and mitigation analysis in RAMP, including enhancements to the Interim Decision 16-08-018.[17] The Companies used the guidelines in the SA Decision as a basis for analyzing and quantifying risks, as shown below. Chapter RAMP-C of this RAMP Report explains the Risk Quantitative Framework which underlies this Chapter, including how the Pre-Mitigation Risk Score, Likelihood of Risk Event (LoRE), and Consequence of Risk Event (CoRE) are calculated.

---

[16] *Id.* at Attachment A.

[17] *Id.* at 2-3.

Table 3: Pre-Mitigation Analysis Risk Quantification Scores[18]

Cyber Security	Low Alternative	Single Point	High Alternative
Pre-Mitigation Risk Score	897	**920**	958
LoRE		**0.02**	
CoRE	44873	**46018**	47925

A. Risk Scope & Methodology

The SA Decision requires a pre- and post-mitigation risk calculation.[19] The below section provides an overview of the scope and methodologies applied for the purpose of risk quantification.

Table 4: Risk Quantification Scope

In-Scope for purposes of risk quantification:	Major cybersecurity incident on the SCADA system[20] which results in disruptions to electric or gas operations.
Out-of-Scope for purposes of risk quantification:	Disruption to Company operations (*e.g.,* HR, payroll, billing), reputation, or disclosure of sensitive customer or Company data.

Given the emerging and evolving nature of cyber risk particularly in the Operational Technology (OT) domain there is limited information to assess the risk using historical information. Therefore, the Companies used multiple indicators in predicting the likelihood and consequence of such an event.

18 The term "pre-mitigation analysis," in the language of the SA Decision (Attachment A, A-12 ("Determination of Pre-Mitigation LoRE by Tranche," "Determination of Pre-Mitigation CoRE," "Measurement of Pre-Mitigation Risk Score")), refers to required pre-activity analysis conducted prior to implementing control or mitigation activity.

19 D.18-12-014 at Attachment A, A-11 ("Calculation of Risk").

20 SCADA is an acronym for supervisory control and data acquisition, a computer system for gathering and analyzing real time data.

Several data points and sources were used to help the Companies' subject matter experts (SME) estimate the likelihood of this event. According to the "Lloyd's Report – The Insurance Implications of a Cyber Attack on the US Power Grid," there have been 15 suspected cyber-attacks or events on the US electric grid from 2000 to 2015.[21] The estimate of the likelihood of the scenario based on that report is in the order of 2% (1 in 50 years). In addition, the Accenture, "Cost of Cyber Crime Study,"[22] indicates a rapidly evolving risk increasing at an annual rate of 27%.[23] Given this information, the Companies' SMEs provide a likelihood of 2% for the cyber risk or 1:50 years.

To determine the Potential Consequences, the Companies, including SMEs from Cybersecurity, electric operations, and gas operations, evaluated relevant industry event scenarios to determine a credible worst-case scenario of a cyberattack at the Companies. The scenarios evaluated account for the potential unavailability of a compromised SCADA system for restoration:

1. <u>Ukraine 2015 and 2016/2018</u> – In 2015, remote cyber intrusions caused outages at three regional electric power distribution companies impacting approximately 225,000 customers for 6 hours in Ukraine. In 2016, hackers used a more sophisticated malware ("Crash Override") to attempt to disable protective relay devices through a denial of service (DoS) attack. Though the 2016 attack only caused a one-hour outage, recent research suggests that hackers intended to inflict lasting damage that could have led to outages for weeks or even months.
2. <u>2011 South West Outage</u> – In 2011, a maintenance procedure in Yuma, Arizona caused a cascade of power failures across the Southwest resulting in widespread impact to SDG&E's service territory. As the failure spread, grid operators were

21 Lloyd's, *Emerging Risk Report – 2015, Business Blackout, The Insurance Implications of a Cyber Attack on the US Power Grid* (May 2015) at 53, *available at* https://www.lloyds.com/news-and-risk-insight/risk-reports/library/society-and-security/business-blackout.

22 Accenture, *2017 Cost of Cyber Crime Study, Insights on the Security Investments That Make A Difference*, *available at* https://www.accenture.com/_acnmedia/PDF-62/Accenture-2017CostCybercrime-US-FINAL.pdf#zoom=50.

23 *Id.* at 4.

unaware of many rapid-fire events outside their territories. Electrical service was restored to most SDG&E customers within 12 hours.

3. 2003 North East Outage – The biggest blackout in North America occurred in 2003. High voltage power lines came into contact with vegetation, and a combination of human error and equipment failures resulted in outages for 50 million people.

4. Lloyds Scenarios (Scenario 1) - A report produced by Lloyd's and the University of Cambridge considered the impact of a hypothetical cyber-attack. In the scenario, malware infects generation control rooms in Northeast US. The malware goes undetected until triggered and tries to take control of generators. While power is restored to some areas within 24 hours, others remain without electricity for weeks.

B. Sources of Input

The SA Decision[24] directs the utility to identify Potential Consequences of a Risk Event using available and appropriate data. The below provides a listing of the inputs utilized as part of this assessment.

1. Richards, Kevin, "Accenture Report the Cost of Cyber Crime," dated 2017;
2. Maynard, Trevor, "Lloyd's Report the Insurance Implications of a Cyber Attack on the US Grid," dated May 2015; and
3. Slowick, Joe, "Dragos Inc CRASHOVERRIDE: Reassessing the 2016 Ukraine Electric Power Event as a Protection-Focused Attack," August 16, 2019.

V. RISK MITIGATION PLAN

The SA Decision requires a utility to "clearly and transparently explain its rationale for selecting mitigations for each risk and for its selection of its overall portfolio of mitigations."[25] This section describes the Companies' Risk Mitigation Plan by each selected Control for this risk, including the rationale supporting each selected Control.

---

[24] D.18-12-014 at Attachment A, A-8 – A-9 ("Identification of the Frequency of the Risk Event").

[25] *Id.* at Attachment A, A-14 ("Mitigation Strategy Presentation in the RAMP and GRC").

The Cybersecurity Risk Mitigation Plan discussed below includes the five operational categories introduced in Section I above. The Risk Mitigation Plan includes Controls and Mitigations that are expected to continue for the period of the Companies' TY 2022 GRC cycle.[26] The Controls (*i.e.,* those with a "C" identifier below) are those activities that were in place as of 2018, most of which have been developed over many years, to address this risk and include work to comply with laws that were in effect at that time. In addition, the Companies have considered the evolving threat and regulatory landscape in the design of its plan. The Companies have adopted a comprehensive and enhanced control portfolio that balances risk mitigation and cost effectiveness while also establishing foundational security capabilities that will serve to mitigate risks from evolving threats. The Presented Portfolio is designed to provide adequate risk reduction to offset the projected cyber risk increase to maintain this risk at a manageable level.

A. SDG&E-10-C1/SCG-9-C1: Perimeter Defenses

The Perimeter Defenses category includes activities that the Companies take to protect the perimeter of its information technology systems. A robust set of controls at the perimeter of corporate systems contributes to the Companies' *defense-in-depth* strategy. The purpose of the defense-in-depth strategy is to manage risk with diverse defenses, so that if one layer of defense turns out to be inadequate, the additional layers of defense will prevent further impacts and/or a full breach.

Perimeter Defenses are designed to prevent attacks, protect the integrity of, and detect unauthorized access to the Companies' internal information technology systems. The information technology environment includes the entire business technology system, including email, information storage, billing and customer records, among others. The operational technology environment also uses perimeter defenses to protect operational technology assets.

Examples of the Companies' existing Perimeter Defenses include:

- Web application firewalls;

---

[26] *Id.* at 16-17 and 33. A "Control" is defined as a "[c]urrently established measure that is modifying risk." A "Mitigation" is defined as a "[m]easure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event."

- Access management at the perimeter;
- Penetration testing of our perimeter to regularly challenge our defense capabilities;
- Multi-factor authentication to enhance user access controls;
- Enhanced firewalls, intrusion detection and prevention technologies;
- Email security gateway to enhance email system security; and
- Web content filter to enhance safer web site browsing/access.

B. SDG&E-10-C2/SCG-9-C2: Internal Defenses

Program activities in the Internal Defenses category are designed to detect and prevent unauthorized users, those misusing authorized credentials, and malicious software (*i.e.*, malware) from propagating inside of the perimeter. As another layer of defense-in-depth, the activities within this category include investments that will directly reduce the risk to internal assets and information. This control focuses on:

- Preventing unauthorized access to technology, systems and/or information;
- Validating that only authorized users are using a profile or credentials associated with that user (authorized employee);
- Analysis of potentially unusual and/or malicious activities;
- Automating threat detection and response activities to decrease cybersecurity risk;
- Improve ability to meet compliance requirements (*e.g.*, CCPA, NERC CIP, etc.);[27]
- Enhancing cloud security (*i.e.,* as an extension of the internal Company system); and
- Network security monitoring.

[27] California Consumer Privacy Act, North American Electric Reliability Corporation Critical Infrastructure Protection standards.

C. SDG&E-10-C3/SCG-9-C3: Sensitive Data Protection

Sensitive data protection is a core component of the Companies' defense-in-depth strategy for cybersecurity. The Sensitive Data Protection activities outlined below enhance technology to reduce the risk of unauthorized access. The Companies' current control activities target sensitive data within information technology systems, including laptops and other mobile computing devices. Sensitive data protection controls are designed to:

- Automatically scan assets to identify location of sensitive data;
- Identify the movement, copying, or dissemination of data from central and mobile technology systems;
- Monitor unauthorized patterns of data movement;
- Multi-factor authentication to enhance user access controls; and
- Data loss prevention to enhance our capabilities in securing information.

D. SDG&E-10-C4/SCG-9-C4: Operational Technology (OT) Cybersecurity

The OT Cybersecurity category focuses on securing the operational technology environments for the Companies. OT environments enable critical business functions, including safe and reliable energy delivery to customers throughout the service territory.

OT cybersecurity requires a specialized approach in order to balance operational needs with cybersecurity risk. The Companies' cybersecurity program prioritizes operational technology controls, including: the management of its existing technology assets, improving threat intelligence and vulnerability management, and securing the communication infrastructure. The Companies are focused on maintaining a secure operational environment to support safe, reliable gas and electric systems and service. The Companies' OT Cybersecurity Controls include:

- OT network anomaly detection to identify and prevent potentially malicious network traffic;
- Physical and cybersecurity operations center visibility into operational technology systems;
- Monitoring of endpoint technology devices that control electric and gas assets;

- Visibility into the status and location of all operational technology through asset management;
- Enhanced whitelisting capabilities (to validate that only approved computer programs can run);
- Secure telecommunication network capabilities; and
- Multi-factor authentication to enhance user access controls.

E. SDG&E-10-C5/SCG-9-C5: Obsolete Information Technology (IT) Infrastructure and Application Replacement

One of the fundamental practices that supports a strong cybersecurity program is the refresh of technology, both hardware and software, at regular intervals, to minimize risks posed by vulnerable, obsolete technologies. Technology lifecycles are short and require frequent upgrades to meet modern security standards and capabilities. In addition to technology obsolescence, this approach also addresses security obsolescence. Security obsolescence refers to cybersecurity tools and/or processes that are no longer effective, and/or potentially could create new vulnerabilities. The controls presented in this section include:

- Technology refreshes, including, but not limited to:
    - Infrastructure;
    - Operating systems;
    - Middleware; and
    - Applications.
- System maintenance to confirm continued secure configurations, patching, upgrading, among others.
- Use of effective architecture and other mechanisms to confirm high availability and service continuity for critical systems.

In addition, there are fundamental, baseline control activities required to support and effectively manage the cybersecurity capabilities listed in the previous sections. These baseline activities referenced in the O&M budget outlook (tables 2 and 3) support the capital investments. Some examples of these baseline controls include, but are not limited to:

- A security policy framework

- Risk management & assessments
- Cybersecurity awareness and training
- Security assessment
- Asset management
- Protective technologies (Network, User, Application)
- System authentication – public key infrastructure (PKI)
- Security Operations Center
    - Monitors security-related activities in systems and applications
    - Anomaly detection
    - Security event detection and escalation
    - Monitors detection infrastructure systems to investigate security events
    - Incident response
    - Exercises/drills

The combination of existing cybersecurity controls and enhancements will help the Companies keep pace with the rapidly evolving cybersecurity threats.

VI. POST-MITIGATION ANALYSIS

As described in Chapter RAMP-D, the Companies have performed a Step 3 analysis where necessary pursuant to the terms of the SA Decision.

A. Mitigation Tranches and Groupings

The Step 3 analysis provided in the SA Decision[28] instructs the utility to subdivide the group of assets or the system associated with the risk into Tranches. Risk reduction from controls and mitigations and RSEs are determined at the Tranche level. For purposes of the risk analysis, each Tranche is considered to have homogeneous risk profiles (*i.e.*, the same LoRE and CoRE). The Companies' rationale for the determination of Tranches is presented below.

A single tranche is appropriate for a Cybersecurity risk event as there is no logical disaggregation of assets or systems related to the controls presented in the mitigation plan. The Controls for this risk are evaluated at the category level due to the availability of data, the rapidly

[28] D.18-12-014 at Attachment A, A-11 ("Definition of Risk Events and Tranches").

changing threats and applicable counter measures. Therefore, the level of granularity for quantifying RSE is currently at the operational category level (*i.e.*, perimeter defenses, internal defenses, sensitive data protection, OT cybersecurity and Obsolete IT infrastructure and asset replacement) rather than each individual risk mitigation activity for the Cybersecurity risk.

B. Post-Mitigation/Control Analysis Results

For purposes of the post-mitigation and post-control analysis, the Companies looked at historical safety performance results and the improvements year-over-year to calculate an overall risk reduction benefit of performing these activities.[29] The Companies then looked at existing/continuing programs (*i.e.*, Controls), and expect to get similar results (*i.e.*, percentage of risk reduction benefit by continuing the activity). The Companies also accounted for the risk increase that would occur over time if we stopped performing these activities. The specific risk reduction benefit percentages used for each identified control/mitigation is included under each program heading below.

C. SDG&E-10-C1/SCG-9-C1: Perimeter Defenses

1. Description of Risk Reduction Benefits

Perimeter Defenses reduce the frequency or probability of successful attacks. As a security strategy, it accomplishes this by limiting access to authorized users, reducing the likelihood that malicious code will enter the information technology environment, and delaying or frustrating potential attackers. This strategy also helps us to understand the number of pathways into or out of the perimeter while simultaneously monitoring the perimeter in real time.

Perimeter Defenses are an important component of defense-in-depth but can only reduce the probability of an adversary having unauthorized access to internal systems and data. This control includes enhancements to firewalls and other intrusion protection measures to maintain the risk at the current manageable level and keep up with the increasing potential threats to our perimeter.

[29] *Id.* at Attachment A, A-12 ("Determination of Post-Mitigation LoRE," "Determination of Post-Mitigation CoRE," "Measurement of Post-Mitigation Risk Score," "Measurement of Risk Reduction Provided by a Mitigation").

2. Elements of the Bow Tie Addressed

SDG&E-10-C1/SCG-9-C1 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Infrastructure or availability failure (DT.2), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Equipment Loss or Theft (DT.7), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0270**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1212.48	**1243.40**	1294.93
	RSE	127.50	**130.75**	136.17

D. SDG&E-10-C2/SCG-9-C2: Internal Defenses

1. Description of Risk Reduction Benefits

Internal Defense controls support the Companies' defense-in-depth strategy, which helps to detect and prevent unauthorized users, those misusing authorized credentials, and malicious software (*i.e.*, malware) from propagating once inside of the perimeter. The controls in this category are designed to detect unauthorized users from moving laterally or vertically within the IT system or into the OT system, which improves our ability to identify and respond to threats more quickly. The enhancements to our IT and OT systems' Access Management system will allow us to keep our current risk level steady/static.

2. Elements of the Bow Tie Addressed

SDG&E-10-C2/SCG-9-C2 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated data or integrity failure (DT.1), Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Equipment Loss or Theft (DT.7), Human error (DT.8), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0256**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1149.48	**1178.79**	1227.64
	RSE	24.49	**25.12**	26.16

E. SDG&E-10-C3/SCG-9-C3: Sensitive Data Protection

1. Description of Risk Reduction Benefits

The Sensitive Data Protection control helps reduce the risk of unauthorized access to the Companies' information by understanding where sensitive data is stored, how it is transmitted, and how it is used. This helps to further protect customer and Company information. The activities for this control will help us continue the prudent management of sensitive data.

2. Elements of Bow Tie Addressed

SDG&E-10-C3/SCG-9-C3 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated

data or integrity failure (DT.1), Access control or confidentiality failure (DT.3), Cybersecurity control failures (DT.5), Human error (DT.8), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Adverse Litigation (PC.5), Regulatory non-compliance fines and/or sanctions (PC.6), Erosion of public confidence (PC.7).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	58.13	**59.61**	62.08

F. SDG&E-10-C4/SCG-9-C4: Operational Technology (OT) Cybersecurity

1. Description of Risk Reduction Benefits

The OT environment requires a slightly different approach from IT Cybersecurity. OT activities are intended to reduce the risk of an adversary controlling or disabling the Companies' operational technology. Improving asset management helps identify unauthorized systems, which could potentially be a source of an attack. Anomaly detection, endpoint detection, and security event monitoring improves visibility into the OT environment, which allows for faster response and remediation. Enhanced secure access technologies help reduce risk of unauthorized access. These risk mitigation activities strengthen our capabilities by securing the foundation of OT security. These enhancements are necessary to maintain a secure OT system and mitigate the increasing potential threat on that critical system.

2. Elements of the Bow Tie Addressed

SDG&E-10-C4/SCG-9-C4 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Human error (DT.8), Disruption of energy flow systems (PC.1), Data corruption or unavailability (PC.2), Adverse litigation (PC.5), Regulatory non-compliance fines and/or sanctions (PC.6), Erosion of public confidence (PC.7).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0284**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1275.48	**1308.01**	1362.21
	RSE	51.60	**52.92**	55.11

G. SDG&E-10-C5/SCG-9-C5: Obsolete Information Technology (IT) Infrastructure and Application Replacement

1. Description of Risk Reduction Benefits

Vulnerabilities inherent in legacy technology can provide a foothold for entry or movement within the Companies' environment. Failure to invest in modern technologies could degrade the value of modern investments due to compatibility restrictions. Replacing legacy technology is a necessary method of managing cybersecurity risk.

2. Elements of the Bow Tie Addressed

SDG&E-10-C5/SCG-9-C5 addresses several Drivers/Triggers and Potential Consequences as outlined above in Figure 1 and in Appendix A. These include: Manipulated

data or integrity failure (DT.1), Infrastructure or availability failure (DT.2), Access control or confidentiality failure (DT.3), Malicious software intrusions (DT.4), Cybersecurity control failures (DT.5), Operational system failures (DT.6), Disruption of energy flow systems (PC.1), Data corruption or unavailability (PC.2), Theft or destruction of systems/data (PC.3), Exposure of sensitive Company and customer data (PC.4), Regulatory non-compliance fines and/or sanctions (PC.6).

3. Summary of Results

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0242**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1086.48	**1114.18**	1160.36
	RSE	66.06	**67.74**	70.55

VII. SUMMARY OF RISK MITIGATION PLAN RESULTS

The Companies' Risk Mitigation Plan takes into account recent data and trends related to Cybersecurity, possible labor constraints and the feasibility of mitigations. The Companies have performed RSEs, in compliance with the S-MAP decisions, but ultimate mitigation selection can be influenced by other factors, including technology, planning, resources, compliance requirements, and operational and execution considerations.

The tables below provide a summary of the Risk Mitigation Plan, including controls, associated costs, and RSEs.

The Companies do not account for and track costs by activity, but rather, by cost center and capital budget code. Thus, the costs shown in Tables 5 and 6 below were estimated using assumptions provided by SMEs and available accounting data.

Table 5: SoCalGas Risk Mitigation Plan Summary[30]
(Direct 2018 $000)[31]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[32]	2018 Baseline O&M	2020-2022 Capital[33]	2022 O&M	Total[34]
SCG-9-C1	Perimeter Defenses	T1	5,400	60	6,100 - 7,800	160 - 210	6,300 – 8,000
SCG-9-C2	Internal Defenses	T1	17,000	180	36,000 - 47,000	500 - 630	37,000 – 48,000
SCG-9-C3	Sensitive Data Protection	T1	-	180	5,700 - 7,300	500 - 630	6,200 – 8,000
SCG-9-C4	Operational Technology (OT) Cybersecurity	T1	2,800	150	17,000 - 21,000	410 – 520	17,000 – 22,000
SCG-9-C5	Obsolete IT Infrastructure and Application Replacement	T1	3,300	30	7,400 - 9,500	80 - 110	7,500 – 10,000
TOTAL COST			**29,000**	**600**	**72,000 - 93,000**	**1,700 - 2,000**	**74,000 – 95,000**

30 Recorded costs and ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

31 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

32 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 "baseline" capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

33 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SoCalGas' Test Year 2022 GRC Application.

34 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

Table 6: SDG&E Risk Mitigation Plan Summary[35]

(Direct 2018 $000)[36]

ID	Mitigation/Control	Tranche	2018 Baseline Capital[37]	2018 Baseline O&M	2020-2022 Capital[38]	2022 O&M	Total[39]
SDG&E-10-C1	Perimeter Defenses	T1	-	830	0	1,200 - 1,500	1,200 - 1,500
SDG&E-10-C2	Internal Defenses	T1	-	1,000	0	1,300 - 1,700	1,300 - 1,700
SDG&E-10-C3	Sensitive Data Protection	T1	-	380	0	520- 670	520- 670
SDG&E-10-C4	Operational Technology (OT) Cybersecurity	T1	280	600	8,400 – 11,000	910 - 1,200	9,310 – 12,200
SDG&E-10-C5	Obsolete IT Infrastructure and Application Replacement	T1	1,400	1,000	0	1,300 - 1,700	1,300 - 1,700
TOTAL COST			**1,700**	**3,800**	**8,400 - 11,000**	**5,200 -6,800**	**14,000 – 18,000**

35 Recorded costs and ranges were rounded. Additional cost-related information is provided in workpapers. Costs presented in the workpapers may differ from this table due to rounding.

36 The figures provided are direct charges and do not include company loaders, with the exception of vacation and sick time. The costs are also in 2018 dollars and have not been escalated to 2019 amounts.

37 Pursuant to D.14-12-025 and D.16-08-018, the Company provides the 2018 “baseline” capital costs associated with Controls. The 2018 capital amounts are for illustrative purposes only. Because capital programs generally span several years, considering only one year of capital may not represent the entire activity.

38 The capital presented is the sum of the years 2020, 2021, and 2022 or a three-year total. Years 2020, 2021 and 2022 are the forecast years for SDG&E’s Test Year 2022 GRC Application.

39 Total = 2020, 2021 and 2022 Capital + 2022 O&M amounts.

It is important to note that the Companies are identifying potential ranges of costs in this Risk Mitigation Plan and are not requesting funding herein. The Companies will integrate the results of this proceeding, including requesting approval of the activities and associated funding, in the next GRC.

VIII. ALTERNATIVE ANALYSIS

Pursuant to D.14-12-025 and D.16-08-018, the Companies considered alternatives to the Risk Mitigation Plan for the Cybersecurity risk. Typically, analysis of alternatives occurs when implementing activities to obtain the best result or product for the cost.

The alternatives analysis for this Risk Mitigation Plan also considered modifications to the Presented Portfolio and constraints, such as budget and resources. The Companies considered two Alternative Portfolios to the Presented Portfolio identified above as it developed the Risk Mitigation Plan to address the Companies' Cybersecurity risk. Alternatives were analyzed in the context of risk-spend efficiency, outlined in the tables below, and considered as portfolios rather than individual mitigations.

For the alternative analysis, the Companies analyzed the effectiveness of three portfolios:

1. Presented Portfolio,
2. Alternative 1, and
3. Alternative 2.

To create these three different portfolios, the Companies first assessed the potential impact of each capital project under consideration, identifying each as high/medium/low based on several criteria:

- Project implementation's impact on the maturity of cybersecurity at the Companies;

- Extent to which each project addresses recommendations from CSC 20,[40] ICS-CERT,[41] and other frameworks;
- Extent to which each project addresses threats to cybersecurity of high impact and likelihood; and
- Effectiveness in mitigating a credible attack impacting safety.

After each project was tagged as High/Medium/Low, the following three portfolios were developed: Presented Portfolio, Alternative Portfolio 1 and Alternative Portfolio 2.

A. Presented Portfolio

The Companies' Presented Portfolio (*i.e.*, the Risk Mitigation Plan as described in Sections V and VI, above) includes a mix of "high" impact and "medium" impact projects. The identified high-impact and medium-impact projects were grouped into the five categories described above: 1) Perimeter Defenses, 2) Internal Defenses, 3) Sensitive Data Protection, 4) Operational Technology Cybersecurity, and 5) Obsolete IT Infrastructure and Application Replacement. The post-mitigation analysis demonstrates that the Companies' Presented Portfolio of high- and medium-impact projects is the most cost-effective portfolio for managing the increase in cybersecurity risk, as is demonstrated by the high RSE compared to other alternative portfolios. Company SMEs estimated that the Presented Portfolio will have an effectiveness proportional to the growth rate of the risk of cybersecurity threats, hence funding at this level will maintain the risk at a manageable level.

---

40 CSC-20: The Twenty (20) Critical Security Controls (CSC) for Cyber Defense are a culmination of exhaustive research and development of information security initiatives that advocate a "offense must inform defense approach," as noted by the SANS institute.

41 ICS-CERT: The Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) provides a control system security focus in collaboration with US-CERT to:
- Conduct vulnerability and malware analysis
- Provide onsite support for incident response and forensic analysis
- Provide situational awareness in the form of actionable intelligence
- Coordinate the responsible disclosure of vulnerabilities/mitigations
- Share and coordinate vulnerability information and threat analysis through information products and alerts.

B. Alternative Portfolio 1

The Companies' Alternative Portfolio 1 consists of "high" impact projects only. The identified high-impact projects were grouped into the same five categories described above. The post-mitigation analysis demonstrates that the Companies' Alternative Portfolio 1, comprising only high-impact projects, is estimated to have a lower RSE than the Presented Portfolio when considering the RSE of the individual categories, as shown below. In addition, this portfolio does not provide enough risk reduction to address the increasing rate of cybersecurity risk. The effectiveness of the projects in this alternative portfolio is lower than the growth rate of the risk, as estimated by the Companies; hence, if we fund at this level, the cyber risk will increase.

The post-mitigation analyses for each of the five utility-focused operational cybersecurity categories are presented below. As stated above, these projects, when combined into an alternative portfolio, is lower than the Companies' Presented Portfolio provided in Sections V and VI.

1. Alternative Portfolio 1 – C1 (High-impact Perimeter Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0256**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1149.48	**1178.79**	1227.64
	RSE	122.26	**125.37**	130.57

2. Alternative Portfolio 1 – C2 (High-impact Internal Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	15.53	**15.93**	16.59

3. Alternative Portfolio 1 – C3 (High-impact Sensitive Data Protection)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0214**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	960.47	**984.96**	1025.78
	RSE	35.83	**36.74**	38.26

4. Alternative Portfolio 1 – C4 (High-impact OT Cybersecurity)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0276**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1237.68	**1269.24**	1321.84
	RSE	52.69	**54.03**	56.27

5. Alternative Portfolio 1 – C5 (High-impact Obsolete IT Infrastructure and Application Replacement)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0238**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1067.57	**1094.80**	1140.17
	RSE	65.03	**66.69**	69.46

C. Alternative Portfolio 2

Alternative Portfolio 2 consists of all cybersecurity projects under consideration (*i.e.,* high-impact, medium-impact and low-impact). Whereas the Companies' Presented Portfolio includes high- and medium-impact projects, and Alternative Portfolio 1 includes only high-impact projects, this Alternative Portfolio 2 presents all projects that the Companies have currently identified. Alternative Portfolio 2 has the highest cost, and the most risk reduction. Alternative Portfolio 2 has an RSE lower than the Presented Portfolio since the additional projects in the portfolio (the low-impact projects beyond those included in the Presented Portfolio) provide an incremental benefit; however, that incremental benefit is less effective relative to its incremental cost.

1. Alternative Portfolio 2 – C1 (High-, Medium-, and Low-impact Perimeter Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0277**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1243.98	**1275.70**	1328.57
	RSE	123.40	**126.55**	131.80

2. Alternative Portfolio 2 – C2 (High-, Medium-, and Low-impact Internal Defenses)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0262**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1174.68	**1204.63**	1254.56
	RSE	24.32	**24.94**	25.97

3. Alternative Portfolio 2 – C3 (High-, Medium-, and Low-impact Sensitive Data Protection)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0228**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1023.47	**1049.57**	1093.07
	RSE	58.13	**59.61**	62.08

4. Alternative Portfolio 2 – C4 (High-, Medium-, and Low-impact OT Cybersecurity)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0284**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1275.48	**1308.01**	1362.21
	RSE	51.60	**52.92**	55.11

5. Alternative Portfolio 2 – C5 (High-, Medium-, and Low-impact Obsolete IT Infrastructure and Application Replacement)

		Low Alternative	Single Point	High Alternative
Pre-Mitigation	LoRE		**0.020**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	897.47	**920.35**	958.50
Post-Mitigation	LoRE		**0.0242**	
	CoRE	44873.42	**46017.68**	47924.79
	Risk Score	1086.48	**1114.18**	1160.36
	RSE	66.06	**67.74**	70.55

APPENDIX A: SUMMARY OF ELEMENTS OF RISK BOW TIE ADDRESSED

Control ID	Control Name	Driver(s), Trigger(s) & Potential Consequences Addressed
SDG&E-10-C1 SCG-9-C1	Perimeter Defenses	DT.2, DT.4, DT.5, DT.6, DT.7 PC.4, PC.6
SDG&E-10-C2 SCG-9-C2	Internal Defenses	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.7, DT.8 PC.2, PC.3, PC.4, PC.6
SDG&E-10-C3 SCG-9-C3	Sensitive Data Protection	DT.1, DT.3, DT.5, DT.8, PC.2, PC.3, PC.4, PC.5, PC.6, PC.7
SDG&E-10-C4 SCG-9-C4	Operational Technology (OT) Cybersecurity	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, DT.8 PC.1, PC.2, PC.5, PC.6, PC.7
SDG&E-10-C5 SCG-9-C5	Obsolete Information Technology (IT) Infrastructure and Application Replacement	DT.1, DT.2, DT.3, DT.4, DT.5, DT.6, PC.1, PC.2, PC.3, PC.4, PC.6