Risk Assessment and Mitigation Phase
Risk Mitigation Plan

Catastrophic Damage Involving a High-Pressure Gas Pipeline Failure
(Chapter SCG-4)

November 30, 2016

310329

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Executive Summary

The Catastrophic Damage Involving a High-Pressure Gas Pipeline Failure (High-Pressure Pipeline Failure) risk relates to the potential public safety and property impacts that may result from the failure of high-pressure pipelines.

To assess this risk, Southern California Gas Company (SoCalGas) first identified a reasonable worst case scenario, and scored the scenario against four residual impact and residual frequency categories. Then, SoCalGas considered the 2015 baseline mitigations in place for High-Pressure Pipeline Failure. The 2015 controls are primarily based on Code of Federal Regulation (CFR) Part 192; General Order (GO) 112 state requirements; and Public Utility Code Sections 957 and 958, and include the following: (1) Maintenance (e.g., Patrolling, Leak Survey, etc.); (2) Qualifications of Pipeline Personnel (Training); (3) Requirements for Corrosion Control; (4) Operations (e.g., Odorization, etc.); (5) Pipeline Integrity (e.g., Threat Evaluation, etc.); and, (6) PSEP (e.g., Pressure testing and pipeline replacement, and valve automation and replacement).

These controls focus on safety-related impacts (e.g., Health, Safety, and Environment) 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 2015 baseline controls. In addition, based on the foregoing assessment, SoCalGas proposes to expand its mitigations for the following categories:

1. Maintenance: SoCalGas proposes to expand class location activity to be able to identify areas of growth and strategically pressure test, replace, or derate pipeline segments.
2. Operations: SoCalGas proposes for example, to expand efforts 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.
3. PSEP: Continuation and expansion of PSEP activities associated with work in less populated areas and pressure testing and replacement.

Next, SoCalGas developed the risk spend efficiency (sometimes referred to as RSE). The risk spend efficiency is a new tool that SoCalGas developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. The RSE was determined using the proposed mitigations and resulted in prioritizing mitigation activities.

Finally, SoCalGas considered two alternatives to the proposed mitigations for the High-Pressure Pipeline Failure risk, and summarizes the reasons that the two alternatives were not selected as a proposed mitigation.

Risk: Catastrophic Damage Involving a High-Pressure Pipeline Failure

1 Purpose

The purpose of this chapter is to present the mitigation plan of the Southern California Gas Company (SoCalGas or Company) for the risk of catastrophic damage involving a high pressure asset (namely, pipelines and related components, referred to herein as "High-Pressure Pipeline Failure"). An asset is considered high pressure when it is operating at a pressure greater than 60 psig. These high pressure assets are operated by Transmission, Distribution and Storage.

The medium pressure assets operating at a pressure of 60 psig and less are included in the Risk Assessment Mitigation Phase (RAMP) chapter of Catastrophic Damage Involving Medium-Pressure Pipeline Failure. Similarly, events caused by third party damage are included in the RAMP chapter of Catastrophic Damage Involving Gas Infrastructure (Dig-Ins).

This risk is a product of SoCalGas' September 2015 annual risk registry assessment cycle. Any events that occurred after that time were not considered in determining the 2015 risk assessment, in preparation for this Report. Note that while 2015 is used a base year for mitigation planning, risk management has been occurring, successfully, for many years within the Company. SoCalGas and San Diego Gas & Electric Company (SDG&E) (collectively, the Companies) take compliance and managing risks seriously, as can be seen by the amount of actions taken to mitigate each risk. This is the first time, however, that the Companies have presented a RAMP Report, so it is important to consider the data presented in this plan in that context. The baseline mitigations are determined based on the relative expenditures during 2015; however, the Companies do not currently track expenditures in this way, so the baseline amounts are the best effort of the utility to benchmark both capital and operations and maintenance (O&M) costs during that year. The level of precision in process and outcomes is expected to evolve through work with the California Public Utilities Commission (Commission or CPUC) and other stakeholders over the next several General Rate Case (GRC) cycles.

The Commission has ordered that RAMP be focused on safety related risks and mitigating those risks.[1] In 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 the Companies take those activities very seriously. In all cases, the 2015 baseline mitigations include activities and amounts necessary to comply with the laws in place at that time. Laws rapidly evolve, however, so the RAMP baseline has not taken into account any new laws that have been passed since September 2015. Some proposed mitigations, however, do take into account those new laws.

[1] Commission Decision (D.) 14-12-025 at p. 31.

The purpose of RAMP is not to request funding. Any funding requests will be made in the GRC. The forecasts for mitigation are not for funding purposes, but are rather to provide a range for the future GRC filing. This range will be refined with supporting testimony in the GRC. Although some risks have overlapping costs, the Companies have made efforts to identify those costs.

2 Background

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 6,741 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 Table 1:

Table 1: SoCalGas High Pressure Pipelines (>60 psig)

Operating Unit	Total High-Pressure Miles (>60psig)	Number of High Consequence Area Miles
Transmission	2,955	917
Distribution	3,741	178
Storage	45	5
Total	6,741	1,100

The U.S. Department of Transportation Pipeline and Hazardous Materials and Safety Administration (PHMSA) and ASME B31.8S, "*Managing System Integrity of Gas Pipelines*" categorizes nine 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
9) Third Party Damage[2]

These factors, also known as potential risk drivers, can work independently, interactively together, or in combination with fatigue.

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 may cause little-to-no risk from a safety standpoint, but it may have other impacts to the environment depending on the magnitude of the release. Risk to the public and employees can occur 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. Safety 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 function as intended in the transport of gas, and therefore is not considered a failure using the definition defined by ASME B31.8S.

However, in some instances a pipeline may be weakened to the extent that the pipe can overload and will "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 be catastrophic in nature, releasing a high level of energy, and sometimes igniting, resulting in damage to the surrounding area, injury and potentially 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 catastrophic 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. Applying mitigative measures as outlined in 192.935 such as increased inspections and assessments, additional maintenance, participation in a one-call system,

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[2] This threat has been removed from this risk plan and is being addressed under a standalone risk and mitigation plan. In the RAMP, this risk chapter is Catastrophic Damage Involving Gas Infrastructure (Dig-Ins).

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.

2.1 Safety Model Assessment Proceeding

SoCalGas also presented how it models and assesses its risk on its transmission pipelines system, specifically with regard to its Transmission Integrity Management Program (TIMP), in the Safety Model Assessment Proceeding (S-MAP). On May 1, 2015, SoCalGas submitted its Application (A.) 15-05-004 and the supporting testimony of Mari Shironishi. Ms. Shironishi's testimony addressed the SoCalGas relative risk model that accounted for 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 the origination of the Transmission Integrity Management Program. As mentioned in Ms. Shironishi's testimony "since the fundamental inputs of the Relative Assessment do not change significantly for year to year, the primary driver for the subsequent integrity assessments is the requirements set by Subpart O, which requires a minimum reassessment interval of seven years."[3] These Subpart O requirements are the primary basis for the scheduling of the assessment and remediation cost presented within this RAMP chapter. SoCalGas continues to strive towards enhancing its TIMP risk model to the best of its ability to manage and mitigate risk.

3 Risk Information

As stated in the testimony of Jorge M. DaSilva in A.15-05-004, "SoCalGas is moving towards a more structured approach to classifying risks and mitigations through the development of its new risk taxonomy. The purpose of the risk taxonomy is to define a rational, logical and common framework that can be used to understand analyze and categorize risks."[4] The Enterprise Risk Management (ERM) process and lexicon that SoCalGas has put in place was built on the internationally-accepted IS0 31000 risk management standard. In the application and evolution of this process, the Company is committed to increasing the use of quantification within its evaluation and prioritization of risks.[5] This includes identifying leading indicators of risk. Sections 3 – 9 of this plan describe the key outputs of the ERM process and resultant risk mitigations.

In accordance with the ERM process, this section describes the risk classification, potential drivers and potential consequences of the High-Pressure Pipeline Incident risk.

[3] A.15-05-004, Testimony of Mari Shironishi, at p. MS-6.
[4] A.15-05-004, filed May 1, 2015, at p. JMD-7.
[5] Testimony of Diana Day submitted on November 14, 2014 in A.14-11-003.

3.1 Risk Classification

Consistent with the taxonomy presented by SoCalGas and SDG&E in the S-MAP, SoCalGas classifies this as an operational, gas risk. The risk classification is provided in Table 2.

Table 2: Risk Classification per Taxonomy

Risk Type	Asset/Function Category	Asset/Function Type
OPERATIONAL	GAS	HIGH PRESSURE (>60 psig)

3.2 Potential Drivers[6]

When performing the risk assessment for High-Pressure Pipeline Failure, SoCalGas identified potential indicators of risk, referred to as potential drivers. These include, but are not limited to:

- **Corrosion (external corrosion, internal corrosion, and stress corrosion cracking)**

  This category includes internal, external and stress corrosion cracking. Corrosion is a degradation of a material due to a reaction to its environment.

- **Manufacturing Threat**

  This category includes the potential for a latent manufacturing anomaly in the body or the seam of a pipe that could affect the integrity of a pipe. These types of latent anomalies can often be deemed "stable" unless changes in pressure cycling or other interactive mechanisms cause anomaly growth to an injurious condition. According to PHMSA's "Significant Incident 20 year Trend," approximately 4.4% of all incidents are a result of material, weld, or equipment failure.[7]

- **Construction/Fabrication**

  This category includes the potential for construction errors to occur on installation as well as the potential risk from legacy construction practices such as the installation of miters, wrinkle bends and oxy-acetylene welds.

- **Outside Forces**

  This category includes both natural forces and those from external sources. Examples of natural forces includes: ground movement from earthquakes, floods, landslides, subsidence, and

[6] An indication that a risk could occur. It does not reflect actual or threatened conditions.
[7] http://phmsa.dot.gov/pipeline/library/data-stats/pipelineincidenttrends.

lightning. Some of the outside forces are addressed in the Risk Assessment Mitigation Phase (RAMP) chapter of Climate Change Adaptation. Other external outside forces include vandalism, sabotage, vehicular damage, fire and other damages caused by external sources (excluding excavating equipment).

Within the Outside Force damage cause, vehicular damage is responsible for 75% of the incidents.[8]

- **Incorrect Operation**

  This category includes a variety of operational and procedural processes that could lead to human error or incorrect operation of a pipeline. Areas where incorrect operations can occur include, but are not limited to: inadequate inspection or monitoring, inadequate records, inadequate maintenance and construction practices.

- **Equipment**

  This category includes equipment related incidents. This includes: o-ring /gasket failure, seal, packing failure, and malfunction of control equipment).

Table 3 maps the potential drivers of High-Pressure Pipeline Failure to SoCalGas' risk taxonomy.

Table 3: Potential Operational Risk Drivers

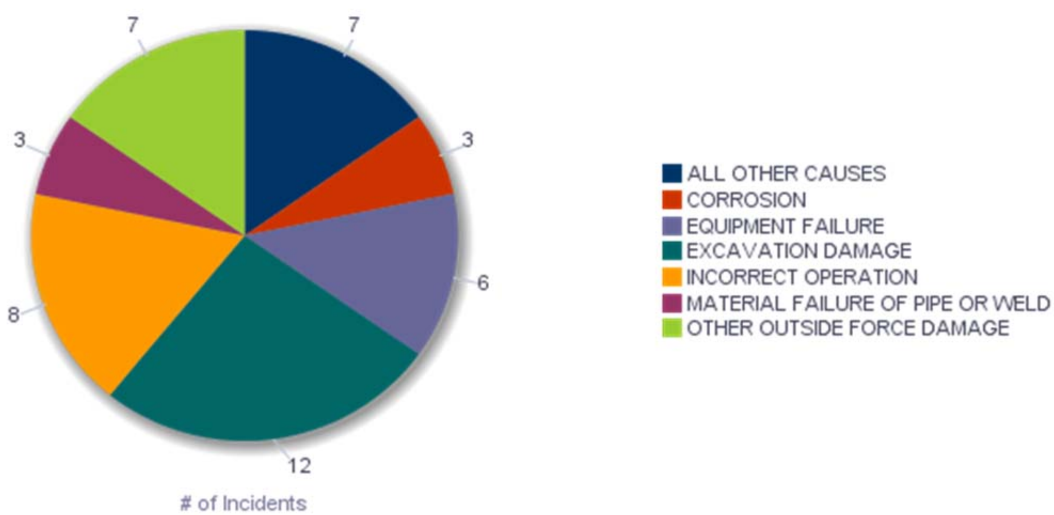
Potential Driver Category	Potential High-Pressure Pipeline Failure Driver(s)
Asset Failure	• Corrosion • Manufacturing Threat • Construction/Fabrication • Equipment
Asset-Related Information Technology Failure	Not applicable
Employee Incident	• Construction/Fabrication • Outside Forces

[8] https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages&NQUser=PDM_WEB_USER&NQPassword=Public_Web_User1&PortalPath=%2Fshared%2FPDM%20Public%20Website%2F_portal%2FGT%20Performance%20Measures.

Potential Driver Category	Potential High-Pressure Pipeline Failure Driver(s)
	• Incorrect Operation
Contractor Incident	• Construction/Fabrication • Outside Forces • Incorrect Operation
Public Incident	• Outside Forces
Force of Nature	• Outside Forces

Figure 1 below, provided by PHSMA, demonstrates the leading causes of incidents related to high-pressure pipelines. This depicts the seriousness of this risk through the potential drivers and number of incidents, safety-related events.

Figure 1: Gas Transmission Serious Incident Cause 2005-2015[9]



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[9] Figure from online metrics published by PHMSA on https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages as 10/4/2016. Serious incidents include a fatality or injury requiring overnight, in-patient hospitalization.

3.3 Potential Consequences

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

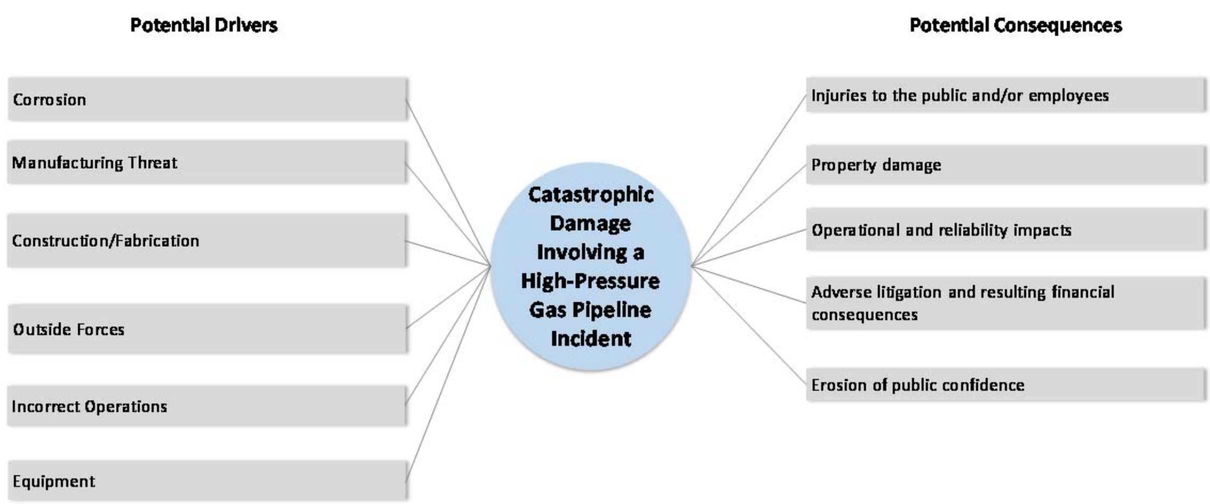
- Injuries to employees and/or the public.
- Property damage.
- Operational and reliability impacts.
- Adverse litigation and resulting financial consequences.
- Increased regulatory scrutiny.
- Erosion of public confidence.

These potential consequences were used in the scoring of High-Pressure Pipeline Failure that occurred during the SoCalGas' 2015 risk registry process. See Section 4 for more detail.

3.4 Risk Bow Tie

The risk "bow tie," shown in Figure 2, is a commonly-used tool for risk analysis. The left side of the bow tie illustrates the potential 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.

Figure 2: Risk Bow Tie



4 Risk Score

The SDG&E and SoCalGas ERM organization facilitated the 2015 risk registry process, which resulted in the inclusion of High-Pressure Pipeline Incident as one of the enterprise risks. During the development of the risk register, subject matter experts assigned a score to this risk, based on empirical data to the extent it is available and/or using their expertise, following the process outlined in this section.

4.1 Risk Scenario – Reasonable Worst Case

There are many possible ways in which a high-pressure pipeline incident can occur. For purposes of scoring this risk, subject matter experts used a reasonable worst case scenario to assess the impact and frequency. The scenario represented a situation that could happen, within a reasonable timeframe, and lead to a relatively significant adverse outcome. These types of scenarios are sometimes referred to as low frequency, high consequence events. The subject matter experts selected a reasonable worst case scenario to develop a risk score for High-Pressure Pipeline Failure:

- A natural gas high pressure pipeline failure in a populated residential area resulting in fatalities, injuries, and property damage. The incident resulted in reliability concerns in the surrounding gas network threatening curtailments and loss of core customers.

Note that the following narrative and scores are based on this scenario; they do not address all consequences that can happen if the risk occurs.

4.2 2015 Risk Assessment

Using this scenario, subject matter experts then evaluated the frequency of occurrence and potential impact of the risk using SoCalGas' 7X7 Risk Evaluation Framework (REF). The framework (also called a matrix) includes criteria to assess levels of impact ranging from Insignificant to Catastrophic and levels of frequency ranging from Remote to Common. The 7X7 framework includes one or more criteria to distinguish one level from another. The Commission adopted the REF as a valid method to assess risks for purposes of this RAMP.[10] Using the levels defined in the REF, the subject matter experts applied empirical data to the extent it is available and/or their expertise to determine a score for each of four residual impact areas and the frequency of occurrence of the risk.

Table 4 provides a summary of the High-Pressure Gas Failure risk score in 2015. This risk has a score of 4 or above in the Health, Safety, and Environmental impact area and, therefore, was included in the RAMP. These are residual scores because they reflect the risk remaining after existing controls are in place. For additional information regarding the REF, please refer to the RAMP Risk Management Framework chapter within this Report.

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[10] D.16-08-018 Ordering Paragraph 9.

Table 4: Risk Score

Residual Impact				Residual Frequency	Residual Risk Score
Health, Safety, Environmental (40%)	Operational & Reliability (20%)	Regulatory, Legal, Compliance (20%)	Financial (20%)		
6	5	5	6	3	36,950

4.3 Explanation of Health, Safety, and Environmental Impact Score

A score of 6 (severe) was given in 2015 in the impact area of Healthy, Safety, and Environmental. The basis for the score is that a fatality or serious injuries to employees and/or the public is a potential consequence for this risk due to the possibility of a failure of high-pressure pipelines located in populated areas. Furthermore, there is potential for a few fatalities to occur from a single incident.

4.4 Explanation of Other Impact Scores

Based on the selected reasonable worst case risk scenario, the following scores were assigned to the remaining residual risk categories.

- **Operational and Reliability**: A score of 5 (extensive) was given in the Operational and Reliability impact category. A risk score of 5 is defined in the 7X7 matrix as greater than 50,000 customers affected, impacts a single critical location or customers, or disruption of service for greater than 10 days. Based on the risk scenario, it is probable that there would be significant customer disruption which can include a whole street, several homes, or a whole city losing gas service depending if the damages involved high pressure gas lines.
- **Regulatory, Legal and Compliance**: A score of 5 (extensive) was given in this impact category. Similar risk events over the past 20 years have resulted in new regulations and compliance requirements such as the California Public Utility Code 958, the Notice of Proposed Rulemaking (NPRM), and modifications to GO 112. Additionally, litigation could result from the risk scenario.
- **Financial**: The Company could suffer various financial repercussions as a result of the other risk areas. Potential litigation and other financial consequences from the Commission and PHMSA are prime examples of the costs associated with the high-pressure pipeline system failing. Though the exact cost can vary depending on the type of incident, if a failure were to occur, these could have the potential financial impact loss of $1 billion to $3 billion consistent with a score of 6 (severe) defined in SoCalGas' 7X7 matrix.

4.5 Explanation of Frequency Score

A frequency score of 3 (infrequent), indicating the likelihood of this event being once every 10-30 years, was chosen taking into account industry-wide data combined with the current state of the Company's system and operations. The lack of an incident at the Company must be tempered by the fact that, according to PHMSA, the number of fatalities that have occurred due to high-pressure failures in California are 10 persons.[11]

5 Baseline Risk Mitigation Plan[12]

As stated above, High-Pressure Pipeline Failure entails a pipeline failure event resulting in fatality/injuries to the public or damage to property and/or environmental damage. The 2015 baseline mitigations discussed below include the current evolution of the Companies' risk management of this risk. The baseline mitigations have been developed over many years to address this risk. They include the amount to comply with laws that were in effect at that time.

These controls focus on safety-related impacts[13] (i.e., Health, Safety, and Environment) per guidance provided by the Commission in D.16-08-018[14] as well as controls and mitigations that may address reliability.[15] Accordingly, the controls and mitigations described in Sections 5 and 6 address safety-related impacts primarily. Note that the controls and mitigations in the baseline and proposed plans are intended to address various events related to High-Pressure Pipeline Failure, not just the scenario used for purposes of risk scoring.

The 2015 controls are primarily based on the Code of Federal Regulation (CFR) Part 192, General Order (GO) 112-E state requirements and Public Utility Code (PUC) §957 and §958. The CFR Part 192 prescribes minimum safety requirements for pipeline facilities and the transportation of gas and GO 112-E complements and enhances the requirements set forth on a federal level on a state level. In addition, PUC §957 and §958 required gas corporations to prepare and submit to the Commission a proposed comprehensive valve plan and plan to pressure test or replace transmission pipelines that lack sufficient record of a pressure test. The Company complied with these statutes through the filing of the Pipeline Safety Enhancement Plan (PSEP) in 2011. PSEP is continuing and the next stages of PSEP work will be incorporated into the Test Year 2019 GRC proceeding. SoCalGas engages in compliance activities in order to mitigate this risk and to comply with applicable laws.

The primary areas highlighted in the risk registry are:

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[11] https://hip.phmsa.dot.gov/analyticsSOAP/saw.dll?Portalpages.
[12] As of 2015, which is the base year for purposes of this Report.
[13] The Baseline and Proposed Risk Mitigation Plans may include mandated, compliance-driven mitigations.
[14] D.16-08-018 at p. 146 states "Overall, the utility should show how it will use its expertise and budget to improve its safety record" and the goal is to "make California safer by identifying the mitigations that can optimize safety."
[15] Reliability typically has an impact on safety. Accordingly, it is difficult to separate reliability and safety.

1. Maintenance: Patrolling, Leak Survey, Pressure Limiting and Regulator Station Inspections and Maintenance, Valve Maintenance
2. Qualifications of Pipeline Personnel (Training)
3. Requirements for Corrosion Control: Corrosion Control, Monitoring and Remedial Measures
4. Operations: Odorization, Emergency Preparedness, Continual Surveillance
5. Pipeline Integrity: Threat Evaluation, Risk Analysis, Pipeline Assessments and P&M
6. PSEP: Pressure Testing and Replacement, and Valve Automation and Replacement

1. Maintenance

The minimum safety requirements prescribed by CFR 192 Subpart M – Maintenance include performing pipeline patrol, bridge and span inspections and meter set assemblies, valve and regulator inspection and maintenance on regular basis throughout the year. These activities are intended to address threats as identified by PHMSA specifically outside forces (vandalism, fault lines, liquefaction, etc.), equipment failure (pipeline facilities and components) and corrosion. These preventive measures provide an opportunity to address issues that otherwise could lead to an incident or failure. The following details the required intervals for completing the preventative measures per CFR 192 Subpart M:

- Bridge and Span inspections are required at least once every two calendar years, but with intervals not exceeding 27 months.
- Pressure limiting station, relief device, signaling device, and pressure regulating station and its equipment must be inspected and tested at intervals not exceeding 15 months, but at least once each calendar year.
- Valve must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year.
- The frequency of patrols is determined by the size of the line, the operating pressures, the class location, terrain, weather, and other relevant factors and range from one to four times per calendar year.

2. Training

The minimum safety training and qualification requirements of field personnel that perform Cathodic Protection, Construction and other activity on the pipeline are prescribed by CFR 192 Subpart N – Qualification of Pipeline Personnel. The prescribed training is intended to address Incorrect Operations as identified by PHMSA, which includes incorrect operating procedures or failure to follow a procedure that could lead to a serious incident or failure. The training and qualifications are intended to increase the safety of the personnel and public by focusing on understanding and proficiency of the concepts through testing.

3. Requirements for Corrosion Control

The minimum safety requirements prescribed by CFR 192 Subpart I – Requirements for Corrosion Control Operations 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 and internal corrosion. These preventive measures provide an opportunity to address issues that otherwise could lead to a serious incident or a failure. The following details the required intervals for completing these preventative measures as prescribed in 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 insure that it is operating.

4. Operations

The minimum safety requirements prescribed by CFR 192 Subpart L – Operations include emergency preparedness and odorization. These activities are intended to address threats as identified by PHMSA. Emergency preparedness and odorization are intended to address all threats. These preventive measures provide an opportunity to address issues that otherwise could lead to a failure. The following details the required intervals for completing these preventative measures as prescribed in Subpart L:

- To assure the proper concentration of odorant in accordance with this section, each operator must conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable.

5. Pipeline Integrity

The minimum safety requirements for assessment of transmission pipelines within high consequence areas are prescribed by CFR 192 Subpart O – Gas TIMP and include threat identification, risk analysis, assessment, remediation, preventative, and mitigative measures. These activities are intended to address all threats as identified by PHMSA as applicable to each pipelines. This program provides an opportunity to address issues that otherwise could lead to a serious incident or failure.

- An operator must establish a reassessment interval for each covered segment in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years.

6. PSEP

Commission Decision (D.) 11-06-017 found that "natural gas transmission pipelines in service in California must be brought into compliance with modern standards for safety" and ordered all California natural gas transmission pipeline operators "to prepare and file a comprehensive Implementation Plan to replace or pressure test all natural gas transmission pipelines in California that has not been tested or for which reliable records are not available."[16] The Commission required that the plans "also address retrofitting pipeline to allow for in-line inspection tools and, where appropriate, automated or remote controlled shut off valves."[17] Many of the requirements of D.11-06-017 were later codified into California Public Utilities Code Sections 957 and 958.

On August 26, 2011, the Company filed their PSEP. The PSEP encompasses the following four objectives:

- Enhance public safety
- Comply with the Commission's directives
- Minimize customer impacts
- Maximize cost effectiveness

The PSEP identifies pipeline sections without sufficient record of a pressure test and, through the Decision Tree process, recommends either pressure testing or replacement. PSEP also includes a Valve Enhancement Program to enhance system safety by installing and upgrading valve infrastructure to support the automatic and remote isolation and depressurization of the transmission pipeline system in 30 minutes or less in the event of a pipeline rupture.

In June 2014, the Commission issued D.14-06-007 which approved SoCalGas' and SDG&E's proposed PSEP and set forth a process for reviewing and approving PSEP Phase 1 implementation costs after-the-fact through Reasonableness Reviews. In D.16-08-003, the Commission authorized the tracking of PSEP Phase 2 costs and directed PSEP to transition to the General Rate Case beginning in the 2019 Test Year.

6 Proposed Risk Mitigation Plan

The 2015 baseline mitigations outlined in Section 5 will continue to be performed in the proposed plan to, in most cases, maintain the current residual risk level. In addition, SoCalGas is proposing to expand mitigations to further address the risk of High-Pressure Pipeline Failure. The proposed activities are for mitigations that are primarily based on the CFR Part 192, GO 112-F state requirements and PUC §957

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[16] D.11-06-017, mimeo., at 18-19.
[17] D.11-06-017, mimeo., at 21.

and §958. The additional mitigation not specifically prescribed in CFR 192 and GO 112-F are intended to enhance the prescribed minimum requirements in areas identified as contributing to potential risk drivers.

It should be noted that the proposed activities do not account for the Notice of Proposed Rule Making (NPRM) issued by PHMSA on Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines which may expand the integrity requirements beyond HCAs, require the verification of Maximum Allowable Operating Pressure (MAOP), and records requirements among other items. The expanded requirements of General Order 112-F have been included, which include a change in leak survey from annual to semi-annual.

The baseline mitigations below are maintaining their current levels in the proposed plan. These mitigations are needed to keep the risk from increasing.

1. Qualifications of Pipeline Personnel (Training)
2. Requirements for Corrosion Control: Corrosion Control, Monitoring and Remedial Measures
3. Pipeline Integrity: Threat Evaluation, Risk Analysis, Pipeline Assessments and P&M

SoCalGas proposes to expand the following baseline mitigations, as further described below.

4. Maintenance: Patrolling, Leak Survey, Pressure Limiting and Regulator Station Inspections and Maintenance, Valve Maintenance
5. Operations: Odorization, Emergency Preparedness, Continual Surveillance
6. PSEP: Continuation of PSEP activities will be addressed in the Test Year 2019 GRC in accordance with D.16-03-003

1. <u>Maintenance</u>

As part of pipeline patrol, construction activity and growth is monitored to identify the need for class location studies. In certain instances, these class location studies indicate sufficient growth in the area to require a class location change, which could lead to the transmission pipeline being replaced, pressure tested, or the pipeline's pressure being de-rated.[18] In order to address class location changes driven by population growth and construction activity in SoCalGas' service territory, SoCalGas is proposing to expand this activity to be able to identify areas of growth and strategically pressure test, replace, or derate pipeline segments. Taking action to pressure test, replace, or derate the pipeline mitigates catastrophic damage involving a high pressure asset by validating the pipeline's integrity (pressure test), replacing a pipeline with a new modern pipeline (replace), or increase the pipeline's safety margin by lowering the operating pressure (derate).

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[18] See 49 CFR 192.611.

2. Operations

As part of SoCalGas' efforts to continually survey and maintain Company's Right of Way (ROW), SoCalGas proposes to increase span painting, pipeline maintenance, storm damage repair, removal of previously abandoned pipelines, vegetation removal, and right of way maintenance. Incremental efforts to survey and maintain SoCalGas' ROWs reduces risks associated with high pressure pipelines and enhances employee, contractor, and public safety by repairing pipeline and related infrastructure, improving pipeline and line marker visibility, and increasing pipeline accessibility.

In addition to the maintenance of the ROW itself, maintenance of access roads allows SoCalGas personnel to access ROWs, enables pipelines to be accessed in a timely manner, minimizes third party pipeline damages, prevents of wild fire damages, and improves the overall general safety of employees and the public.

Finally, upcoming changes to GO 112 through implementation of GO 112-F will require instrumented leak survey of all Transmission pipelines. Currently, instrument leak survey is only required where pipelines are operating in a Class 3 or Class 4 locations, which means, currently, 900 miles of Transmission pipeline are required to be leak surveyed. GO 112-F requires an additional 1,800 miles of Transmission pipeline to be instrument leak surveyed in Class 1 and 2 locations. GO 112-F does, however, allow difficult to access pipelines operating in a Class 1 and Class 2 locations to be patrolled by aircraft. Accordingly, this activity is being expanded to comply with revisions to GO-112-F.

3. PSEP

PSEP is transitioning into the GRC process as directed by D.16-08-003. The mitigation activities in the proposed plan for PSEP are primarily associated with work in less populated areas, and pressure testing and replacement included in Phase 2A. D.16-08-003 also authorized SoCalGas to file a Forecast Application to request approval for some Phase 2A work to commence prior to GRC approval. The increased activities reflect the anticipated regulatory approval timeframes for the GRC and Forecast Application, which will result in construction commencing in 2019.

7 Summary of Mitigations

Table 5 summarizes the 2015 baseline risk mitigation plan, the risk driver(s) a control addresses, and the 2015 baseline costs for High-Pressure Pipeline Failure. While control or mitigation activities may address both potential risk drivers and potential consequences, potential risk drivers link to the likelihood of a risk event. Thus, potential risk drivers are specifically highlighted in the summary tables.

SoCalGas does not account for and track costs by activity, but rather, by cost center and capital budget code. So, the costs shown in Table 5 were estimated using assumptions provided by Subject Matter Experts (SMEs) and available accounting data.

Table 5: Baseline Risk Mitigation Plan[19]
(Direct 2015 $000)[20]

ID	Mitigation	Potential Risk Drivers Addressed	Capital[21]	O&M	Control Total[22]	GRC Total[23]
1	CFR 192 Subpart M – Maintenance*	• Outside Forces • Equipment • Corrosion	$12,890	$ 7,670	$20,560	$20,560
2	CFR 192 Subpart N – Qualifications of Pipeline Personnel*	• Incorrect Operations	n/a	400	400	400
3	CFR 192 Subpart I – Requirements for Corrosion Control*	• Corrosion	500	330	830	830
4	CFR 192 Subpart L – Operations*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect Operations	8,010	3,700	11,710	11,710
5	CFR Part 192 Subpart O – Gas Transmission Pipeline Integrity Management*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect	42,990	31,960	74,950	74,950

[19] Recorded costs were rounded to the nearest $10,000.
[20] The figures provided in Tables 5 and 6 are direct charges and do not include Company overhead loaders, with the exception of vacation and sick. The costs are also in 2015 dollars and have not been escalated to 2016 amounts.
[21] Pursuant to D.14-12-025 and D.16-08-018, the Company is providing the "baseline" costs associated with the current controls, which include the 2015 capital amounts. The 2015 mitigation capital amounts are for illustrative purposes only. Because projects generally span several years, considering only one year of capital may not represent the entire mitigation.
[22] The Control Total column includes GRC items as well as any applicable non-GRC jurisdictional items. Non-GRC items may include those addressed in separate regulatory filings or under the jurisdiction of the Federal Energy Regulatory Commission (FERC).
[23] The GRC Total column shows costs typically presented in a GRC.

ID	Mitigation	Potential Risk Drivers Addressed	Capital[21]	O&M	Control Total[22]	GRC Total[23]
		Operations				
6	PUC 957 & 958 – PSEP: High Pressure Testing and Replacement, Valve Automation and Replacement*	• Manufacturing • Construction • Outside Forces	389,720	60,950	450,670	0
	TOTAL COST		$454,110	$105,010	$559,120	$108,450

* Includes one or more mandated activities

Table 6 summarizes SoCalGas's proposed mitigation plan, associated projected ranges of estimated O&M expenses for 2019, and projected ranges of estimated capital costs for the years 2017-2019. It is important to note that SoCalGas is identifying potential ranges of costs in this plan, and is not requesting funding approval. SoCalGas will request approval of funding, in its next GRC. There are non-CPUC jurisdictional mitigation activities addressed in RAMP; the costs associated with these will not be carried over to the GRC. As set forth in Table 6 the Companies are using a 2019 forecast provided in ranges based on 2015 dollars.

Southern California Gas Company
A Sempra Energy utility

Table 6: Proposed Risk Mitigation Plan[24]
(Direct 2015 $000)

ID	Mitigation	Potential Risk Drivers Addressed	2017-2019 Capital[25]	2019 O&M	Mitigation Total[26]	GRC Total[27]
1	CFR 192 Subpart M – Maintenance*	• Outside Forces • Equipment • Corrosion	$38,930 - 43,020	$7,690 - 8,500	$46,620 - 51,520	$46,620 - 51,520
2	CFR 192 Subpart N – Qualifications of Pipeline Personnel*	• Incorrect Operations	n/a	400 - 440	400 - 440	400 - 440
3	CFR 192 Subpart I – Requirements for Corrosion Control *	• Corrosion	2,920 - 3,780	520 - 1,140	3,440 - 4,920	3,440 - 4,920
4	CFR 192 Subpart L – Operations*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect Operations	14,280 - 15,780	18,120 - 20,030	32,400 - 35,810	32,400 - 35,810
5	CFR Part 192 Subpart O – Gas Transmission Pipeline Integrity Management*	• Corrosion • Manufacturing • Construction • Equipment • Incorrect Operations	124,920 - 187,120	44,930 - 49,650	169,850 - 236,770	169,850 - 236,770
6	PUC 957 & 958 – PSEP:	• Manufacturing • Construction	365,250 - 608,750	13,500 - 110,000	378,750 - 718,750	133,750 - 321,750

[24] Ranges of costs were rounded to the nearest $10,000.
[25] The capital presented is the sum of the years 2017, 2018, and 2019 or a three-year total. Years 2017, 2018 and 2019 are the forecast years for SoCalGas' Test Year 2019 GRC Application.
[26] The Mitigation Total column includes GRC items as well as any applicable non-GRC items.
[27] The GRC Total column shows costs typically represented in a GRC.

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	High Pressure Testing and Replacement, Valve Automation and Replacement*	• Outside Forces				
	TOTAL COST		$546,300 - 858,450	$85,160 - 189,760	$631,460 - 1,048,210	$386,460 - 651,210

☐	Status quo is maintained
☐ (shaded)	Expanded or new activity
*	Includes one or more mandated activities

While all the mitigations and costs presented in Tables 5 and 6 mitigate the High-Pressure Pipeline Failure risk, some of the activities also mitigate other risks presented in this RAMP Report, including: Catastrophic Damage Involving Third Party Dig-Ins (Dig-Ins) and Employee, Contractor, Customer and Public Safety. Because these activities mitigate High-Pressure Pipeline Failure as well as these aforementioned risks, both the costs and risk reduction benefits are included in all applicable RAMP chapters.

8 Risk Spend Efficiency

Pursuant to D.16-08-018, the Companies are required in this Report to "explicitly include a calculation of risk reduction and a ranking of mitigations based on risk reduction per dollar spent." For the purposes of this Section, Risk Spend Efficiency (RSE) is a ratio developed to quantify and compare the effectiveness of a mitigation at reducing risk to other mitigations for the same risk. It is synonymous with "risk reduction per dollar spent" required in D.16-08-018.

As discussed in greater detail in the RAMP Approach chapter within this Report, to calculate the RSE the Company first quantified the amount of Risk Reduction attributable to a mitigation, then applied the Risk Reduction to the Mitigation Costs (discussed in Section 7). The Company applied this calculation to each of the mitigations or mitigation groupings, then ranked the proposed mitigations in accordance with the RSE result.

8.1 General Overview of Risk Spend Efficiency Methodology

This subsection describes, in general terms, the methods used to quantify the *Risk Reduction*. The quantification process was intended to accommodate the variety of mitigations and accessibility to applicable data pertinent to calculating risk reductions. Importantly, it should be noted that the analysis described in this chapter uses ranges of estimates of costs, risk scores and RSE. Given the newness of

RAMP and its associated requirements, the level of precision in the numbers and figures cannot and should not be assumed.

8.1.1 Calculating Risk Reduction

The Company's SMEs followed these steps to calculate the Risk Reduction for each mitigation:

1. **Group mitigations for analysis:** The Company "grouped" the proposed mitigations in one of three ways in order to determine the risk reduction: (1) Use the same groupings as shown in the Proposed Risk Mitigation Plan; (2) Group the mitigations by current controls or future mitigations, and similarities in potential drivers, potential consequences, assets, or dependencies (e.g., purchase of software and training on the software); or (3) Analyze the proposed mitigations as one group (i.e., to cover a range of activities associated with the risk).
2. **Identify mitigation groupings as either current controls or incremental mitigations:** The Company identified the groupings by either current controls, which refer to controls that are already in place, or incremental mitigations, which refer to significantly new or expanded mitigations.
3. **Identify a methodology to quantify the impact of each mitigation grouping:** The Company identified the most pertinent methodology to quantify the potential risk reduction resulting from a mitigation grouping's impact by considering a spectrum of data, including empirical data to the extent available, supplemented with the knowledge and experience of subject matter experts. Sources of data included existing Company data and studies, outputs from data modeling, industry studies, and other third-party data and research.
4. **Calculate the risk reduction (change in the risk score):** Using the methodology in Step 3, the Company determined the change in the risk score by using one of the following two approaches to calculate a Potential Risk Score: (1) for current controls, a Potential Risk Score was calculated that represents the increased risk score if the current control was not in place; (2) for incremental mitigations, a Potential Risk Score was calculated that represents the new risk score if the incremental mitigation is put into place. Next, the Company calculated the risk reduction by taking the residual risk score (See Table 4 in this chapter.) and subtracting the Potential Risk Score. For current controls, the analysis assesses how much the risk might increase (i.e., what the potential risk score would be) if that control was removed.[28] For incremental mitigations, the analysis assesses the anticipated reduction of the risk if the new mitigations are implemented. The change in risk score is the risk reduction attributable to each mitigation.

[28] For purposes of this analysis, the risk event used is the reasonable worst case scenario, described in the Risk Information section of this chapter.

8.1.2 Calculating Risk Spend Efficiency

The Company SMEs then incorporated the mitigation costs from Section 7. They multiplied the risk reduction developed in subsection 8.1.1 by the number of years of risk reduction expected to be realized by the expenditure, and divided it by the total expenditure on the mitigation (capital and O&M). The result is a ratio of risk reduction per dollar, or RSE. This number can be used to measure the relative efficiency of each mitigation to another.

Figure shows the RSE calculation.

Figure 3: Formula for Calculating RSE

$$Risk\ Spend\ Efficiency = \frac{Risk\ Reduction * Number\ of\ Years\ of\ Expected\ Risk\ Reduction}{Total\ Mitigation\ Cost\ (in\ thousands)}$$

The RSE is presented in this Report as a range, bounded by the low and high cost estimates shown in Table 6 of this chapter. The resulting RSE scores, in units of risk reduction per dollar, can be used to compare mitigations within a risk, as is shown for each risk in this Report.

8.2 Risk Spend Efficiency Applied to This Risk

SoCalGas analysts used the general approach discussed in Section 8.1 above, in order to assess the RSE for the High Pressure Pipeline Incident risk. The RAMP Approach chapter in this Report, provides a more detailed example of the calculation used by the Company.

To calculate the RSE, SoCalGas began with the six mitigations in its proposed plan:

1. Qualifications of Pipeline Personnel (Training)
2. Requirements for Corrosion Control
3. Pipeline Integrity (TIMP)
4. Maintenance
5. Operations
6. PSEP

SoCalGas then analyzed and arranged these mitigations into common groupings that address similar potential drivers or consequences, for purposes of analysis:

(a) Transmission integrity (current controls)
(b) PSEP (current controls)
(c) Technical training (current controls)
(d) Regulatory compliance activities (current controls)

For the High-Pressure Pipeline Failure risk in particular, there were limited new or expanded activities in the proposed plan. Accordingly, only the four groups listed above, with no incremental activities, were analyzed.

For each of the four mitigation groupings used for the RSE, SoCalGas determined the preferred methodology for quantifying the RSE. The primary assumption for the RSE for the High-Pressure Pipeline Fail ure risk was that performance would deteriorate in absence of the mitigation. Data from the PHMSA and asset data, where applicable, was used to model the deterioration boundaries. The appropriate data was selected based on the judgment of SMEs.

- **Transmission Integrity**

The modeling approach for transmission integrity programs is to find the level of possible performance deterioration if these programs did not exist, which would represent the baseline, inherent risk level. It is assumed that should these programs were not to be funded, then performance would deteriorate to at best the pipeline failure incident rate of the worst state in the nation. The term "at best" is used because even the worst-performing states are assumed to have some similar programs in place.

The potential drivers associated with a high-pressure pipeline failure are corrosion and material failure of weld or pipe. This was compared to the incident rate due to all causes to attain the residual risk multiplier, which is the ratio of future to current performance.

Not all targeted assets will be remediated within the time period of interest. To account for this, the residual risk multiplier will be adjusted proportionally to the proportion of remediated assets to all high pressure assets.

The chart shown below contains the pipeline failure incident rates of all 50 states, in addition to SoCalGas and the national average. SoCalGas is among the entries with zero incidents per million people per year, and the worst-performing state is Louisiana at 1.120 incidents per million people per year. Using SoCalGas' service population of 21.6 million people, the incident rates can be converted to an incident expectation, given by the following calculation:

$$Expected\ Incident\ Rate = \Delta(Incident\ Rate) * Service\ Population$$
$$= (1.120 - 0)\ incidents\ per\ million\ people\ per\ year * 21.6\ million\ people$$
$$= 24.2\ incidents\ per\ year$$

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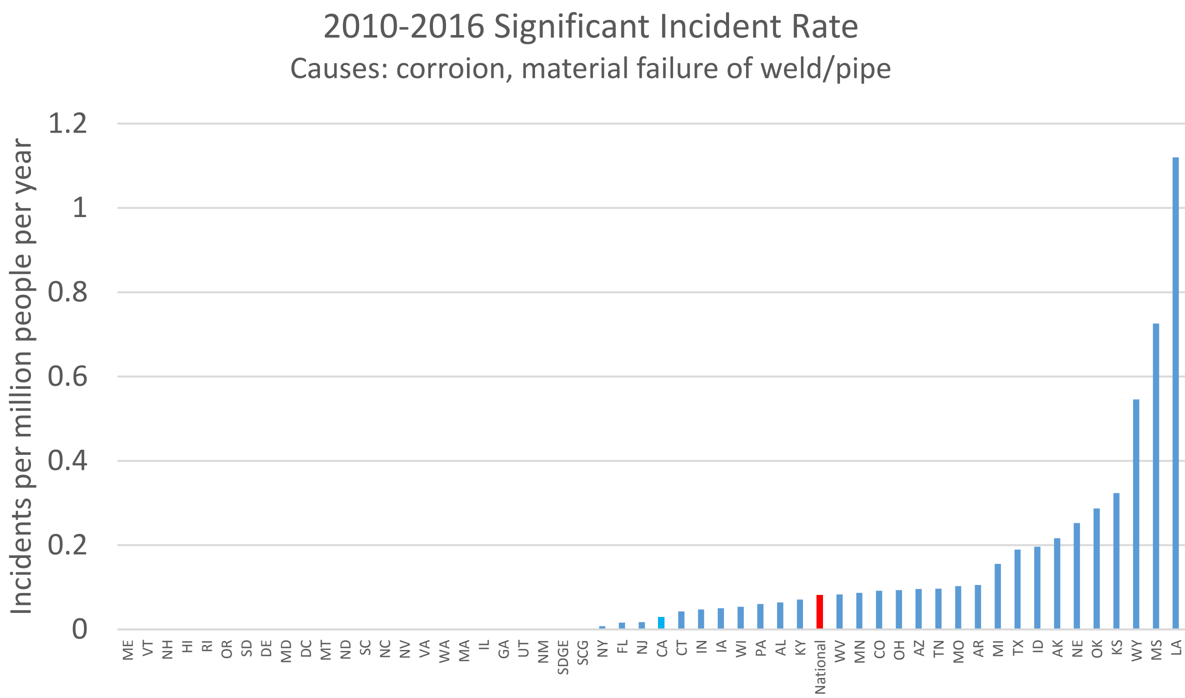

The average number of incidents per year from all causes for the same time period is 1.1[29] and the proportion of targeted miles being addressed is 43%. Putting it all together, the residual risk multiplier is given by the following calculation:

$$\begin{aligned} &\mathit{Residual\ Risk\ Multiplier} \\ &\qquad = \frac{\mathit{Incident\ Rate\ from\ select\ Causes}}{\mathit{Incident\ Rate\ from\ all\ Causes}} * \mathit{Proportion\ of\ Remediated\ Assets} \end{aligned}$$

$$\mathit{Residual\ Risk\ Multiplier} = \frac{24.2\ \mathit{incidents\ per\ year}}{1.1\ \mathit{incidents\ per\ year}} * 43\%$$

$$\mathit{Residual\ Risk\ Multiplier} = 9.7$$

Therefore, if the mitigation is not funded, the projected risk is 9.7 times the current residual risk.

[29] Expected Incidents per year for All Causes for SCG = Current Incidents per year per million people * Service population

= 0.051 incidents per year per million people * 21.6 million people

= 1.1 incidents per year

- **PSEP**

The RSE modeling approach for these programs was the same as that used for transmission integrity programs with a couple of slight differences. The first difference was that a different set of potential incident drivers was used to establish the deteriorated performance level. Potential driver categories chosen as applicable to these programs were: corrosion, material failure of weld or pipe, equipment failure, and other[30]. The second difference was that the national average was used rather than the worst state performance, to account for the fact that the benefit of this mitigation has high chance of being duplicative with the other mitigations in place (e.g., compliance activities, TIMP). For this category of projects, the residual risk multiplier is (4.2 / 1.1) X (27.3%) = 1.1. Therefore, if the mitigation is not funded, the projected risk is 1.1 times the current residual risk.

- **Technical Training**

The modeling approach for these programs was the same as that used for transmission integrity programs with two exceptions. The first exception was that a different set of potential incident drivers was used to establish the worst state performance level. Potential drivers chosen as applicable to this category were: incorrect operations. The second exception was that there is no secondary adjustment for the percentage of targeted assets, but there was an adjustment for the fact that it takes some time for the effects of technical training to wear off.

For this category of projects, the residual risk multiplier is (3.0 / 1.1) X (33.3%) = 0.9. Therefore, if the mitigation is not funded, the projected risk is 0.9 times the current residual risk.

- **Regulatory Compliance Activities**

The modeling approach for these programs was the same as that used for transmission integrity programs with two exceptions. The first exception was that a different set of potential incident drivers was used to establish the worst state performance level. Potential drivers chosen as applicable to this category were: all causes with incorrect operations and natural and other forces excluded. The second exception was that there was no secondary adjustment for the percentage of targeted assets.

For this category of projects, the residual risk multiplier is (48.6 / 1.1) X (100%) = 45.1. Therefore, if the mitigation is not funded, the projected risk is 45.1 times the current residual risk.

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[30] The "other" potential drivers are derived from the PHMSA data base. They were grouped into an "other" category because these entries do not have any obvious relationship to another.

8.3 Risk Spend Efficiency Results

Based on the foregoing analysis, SoCalGas calculated the RSE ratio for each of the proposed mitigation groupings. Following is the ranking of the mitigation groupings from the highest to the lowest efficiency, as indicated by the RSE number:

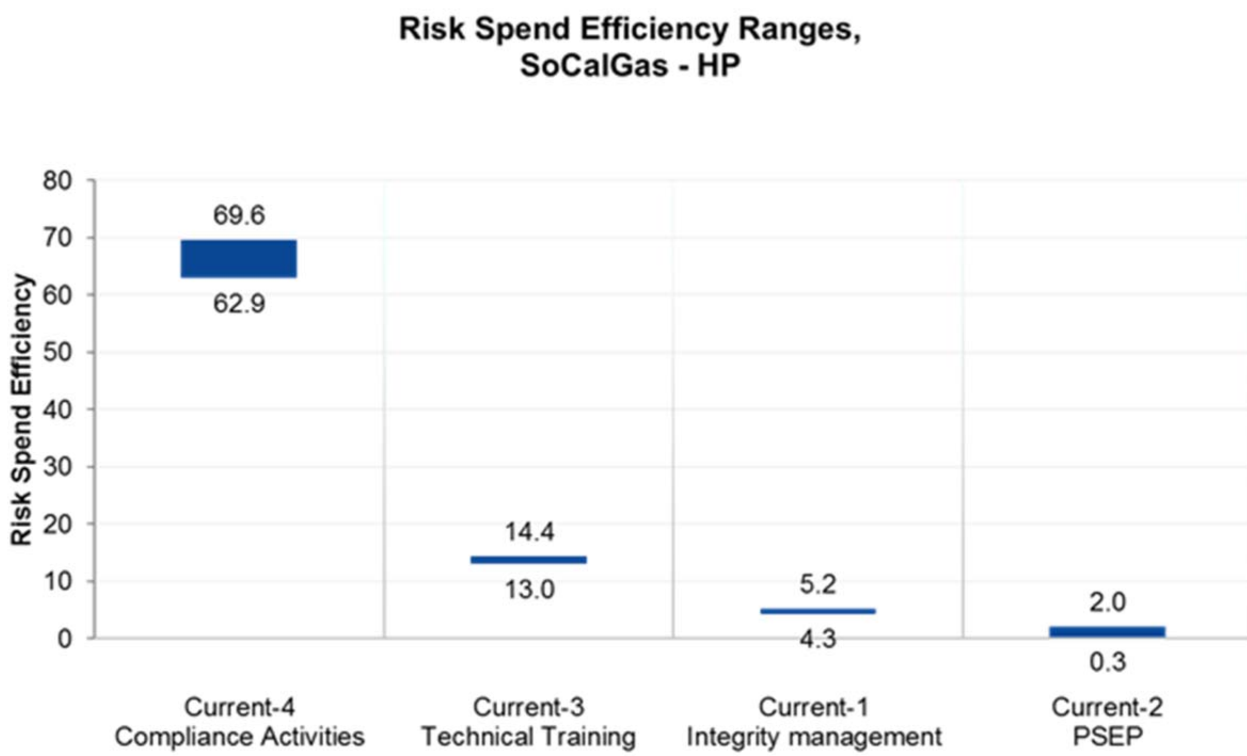
1. Regulatory compliance activities (current controls)
2. Technical training (current controls)
3. Transmission integrity (current controls)
4. PSEP (current controls)

Figure displays the range[31] of RSEs for each of the SoCalGas High Pressure Pipeline Incident risk mitigation groupings, arrayed in descending order.[32] That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

[31] Based on the low and high cost ranges provided in Table 6 of this chapter.

[32] It is important to note that the risk mitigation prioritization shown in this Report, is not comparable across other risks in this Report.

Figure 4: Risk Spend Efficiency



9 Alternatives Analysis

SoCalGas considered alternatives to the proposed mitigations as it developed the proposed mitigation plan for the High-Pressure Pipeline Failure risk. Typically, alternatives analysis occurs when implementing activities, and with vendor selection in particular, to obtain the best result or product for the cost. The alternatives analysis for this risk plan also took into account modifications to the proposed plan and constraints, such as budget and resources.

9.1 Alternative 1 – Acceleration of TIMP

SoCalGas considered expanding TIMP-related work as an alternative into non-HCA. However, this alternative was not selected due to the pending NPRM and in recognition that conflicts may arise with scheduling and resources. SoCalGas will continue to expand TIMP-related work into non-HCA as dictated by assessment results and overall system performance as part of Preventative and Mitigative measures.

9.2 Alternative 2 – Acceleration of PSEP

In addition, SoCalGas considered increasing the pace of PSEP-related work. Again, this would enhance safety more expeditiously, but would also require additional capital to accommodate the accelerated pace. Similar to the TIMP alternative, the proposed PSEP pace is preferred because it balances affordability, risk reduction and financial constraints with available resources.