Risk Assessment and Mitigation Phase
Risk Mitigation Plan

Catastrophic Damage Involving a Medium-Pressure Pipeline Failure
(Chapter SCG-10)

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Executive Summary

The Catastrophic Damage Involving a Medium-Pressure Pipeline Failure (Medium-Pressure Pipeline Failure) risk relates to the public safety and property impacts that can result from failure of medium-pressure pipelines.

To assess this risk, SoCalGas first identified a reasonable worst case scenario, and scored the scenario against five residual impact categories (e.g., Health, Safety, Environmental; Operational & Reliability, etc., discussed in Section 4). Then, SoCalGas considered as a baseline, the SoCalGas mitigation in place as of 2015 for Medium-Pressure Pipeline Failure and estimated the costs (baseline mitigations are discussed in Section 5, and costs are discussed in Section 7). SoCalGas identified the controls that comply with Code of Federal Regulations Part 192 and General Order 112. The 2015 baseline controls include:

- Maintenance
- Qualifications of Pipeline Personnel
- Requirements for Corrosion Control
- Operations
- Gas Distribution Pipeline Integrity Management

These 2015 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.

Based on the foregoing assessment, SoCalGas proposed future mitigations (discussed in Section 6) for the Medium-Pressure Pipeline Failure risk. SoCalGas will continue the controls, identified above, and proposes to accelerate the activity of Distribution Integrity Management Programs (DIMP) Distribution Risk Evaluation and Monitoring System (DREAMS), a program included in the Gas Distribution Pipeline Integrity Management baseline control.

Finally, SoCalGas developed the risk spend efficiency for Medium-Pressure Pipeline Failure. The risk spend efficiency is a new tool that SoCalGas developed to attempt to quantify how the proposed mitigations will incrementally reduce risk. The five mitigations were grouped into four for purposes of calculating the risk spend efficiency. The metric used to determine the risk spend efficiency of the mitigations was based on data relating to medium pressure pipelines, including data from PHMSA and asset data. Based on a benefit-cost assessment (i.e. risk spend efficiency), the four mitigations for this risk can be prioritized as follows, from highest risk spend efficiency to lowest:

1. Compliance activities
2. Technical training
3. DIMP/Distribution integrity
4. Expanded Integrity activities

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

Risk: Catastrophic Damage Involving Medium-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 damage caused by a medium-pressure pipeline (Maximum Allowable Operating Pressure [MAOP] at or lower than 60 psig) failure event, which results in catastrophic consequences (referred to herein as Medium-Pressure Pipeline Failure). This risk concerns a gas public safety event on a medium-pressure distribution pipeline or gas facility, and focuses on routine maintenance and pipeline replacement mitigations consistent with industry standard medium pressure pipeline operations of state of the art polyethylene pipelines and cathodically protected steel pipelines.[1]

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 as a base year for mitigation planning purposes, risk management has been occurring, successfully, for many years within the Company. San Diego Gas & Electric (SDG&E) and SoCalGas (collectively, the utilities) take compliance and managing risks seriously, as can be seen by the number of actions taken to mitigate each risk. This is the first time, however, that the utilities have presented a Risk Assessment Mitigation Phase (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 utilities do not currently track expenditures in this way, so the baseline amounts are the best effort of each 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.[2] 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 utilities 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, 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.

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[1] Mitigation activities addressing damage to gas infrastructure caused by third parties, also referred to as dig-ins, is not addressed in this chapter, but rather discussed in the Risk Assessment Mitigation Phase chapter of Catastrophic Damage Involving Gas Infrastructure (Dig-Ins).
[2] 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 potential range for the future GRC filing. This range will be refined with supporting testimony in the GRC. Although some risks have overlapping costs, the utilities have made efforts to identify those costs.

2 Background

Typically, medium-pressure distribution systems use a series of mains, larger diameter pipe, to feed service lines. The service lines are smaller diameter pipes which feed customer homes, businesses, and some commercial applications. Medium-pressure pipelines are comprised of steel or plastic material.

For safety and compliance purposes, the Code of Federal Regulations (CFR) Part 192 and General Order (GO) 112 are the leading sources, among other legal and regulatory provisions, of requirements for SoCalGas' medium-pressure pipeline. CFR Part 192 prescribes minimum safety requirements for pipeline facilities and the transportation of gas and GO 112 complements and enhances the requirements set forth on a federal level at a state level.

With regard to medium pressure lines, the Company operates over 100,000 miles of medium pressure mains and services lines. Over 50,000 miles of medium-pressure main with nearly 24,000 miles being plastic and over 26,000 being steel along with nearly 32,000 miles of plastic services lines and over 18,000 miles of steel services lines (see Table 1 below). These medium-pressure pipelines serve over 21.4 million SoCalGas consumers.

Table 1: Medium-Pressure Pipelines

Medium-Pressure Pipelines	SoCalGas Mains	SoCalGas Service Lines	Total
Miles of Steel	26,191	18,131	44,322
Miles of Plastic	23,990	31,971	55,961
Total Miles Medium-Pressure Pipelines	50,181	50,102	100,283

Various causes and events can lead to medium pressure pipeline failures. Factors can range from improper installation techniques or material defects, aging/environmental factors such as corrosion and fatigue, and inadequate operations or maintenance of the pipeline infrastructure. However, for the purposes of this chapter, the Medium-Pressure Pipeline Failure risk focuses on the more serious results of failures that lead to a release of natural gas with a potential hazard to life and property.

3 Risk Information

As stated in the testimony of Jorge M. DaSilva in the Safety Model Assessment Proceeding (S-MAP) Application (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." 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. This includes identifying leading indicators of risk. Sections 3 through 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 Medium-Pressure Pipeline Failure risk.

3.1 Risk Classification

Consistent with the taxonomy presented by SoCalGas and SDG&E in A.15-05-004, SoCalGas classifies this risk as an operational gas risk as shown in Table 2.

Table 2: Risk Classification per Taxonomy

Risk Type	Asset/Function Category	Asset/Function Type
OPERATIONAL	GAS	MEDIUM AND LOW-PRESSURE (<=60 PSI)

3.2 Potential Drivers[3]

When performing the risk assessment for Medium-Pressure Pipeline Failure, SoCalGas identified potential indicators of risk, referred to as potential drivers. The potential drivers for this risk are derived from the listing of cause categories from the Pipeline and Hazardous Materials Safety Administration (PHMSA) database, along with historical events and credible scenarios developed by Subject Matter Experts (SMEs). The potential drivers considered include, but are not limited to:

1. **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.[4]

[3] An indication that a risk could occur. It does not reflect actual or threatened conditions.
[4] Corrosion Basics, An Introduction, L.S. Van Delinder, ed. (Houston, TX: NACE, 1984).

2. **Natural Forces** attributable to causes not involving humans, such as earth movement, earthquakes, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds
3. **Other Outside Force Damage** is 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.
4. **Pipe, Weld or Joint Failure** is 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.
5. **Equipment Failure** is attributable to malfunction of component including but not limited to regulators, valves, meters, flanges, gaskets, collars, couples, etc.
6. **Incorrect Operations** can include a pipeline incident attributed to insufficient or incorrect operating procedures or the failure to follow a procedure.

In accordance with the taxonomy of SoCalGas, the potential drivers above can be classified as an asset failure, employee incident, contractor incident, public incident, or force of nature. Table 3 below maps the potential risk drivers of Medium-Pressure Pipeline Failure to SoCalGas' taxonomy.

Table 3: Potential Operational Risk Drivers

Potential Driver Category	Potential Medium-Pressure Pipeline Failure Driver(s)
Asset Failure	• Corrosion • Pipe, Weld, or Joint Failure • Equipment Failure
Asset-Related Information Technology Failure	Not applicable
Employee Incident	• Other Outside Forces • Incorrect Operation • Pipe, Weld, or Joint Failure
Contractor Incident	• Other Outside Forces • Incorrect Operation
Public Incident	• Other Outside Forces
Force of Nature	• Natural Forces

3.3 Potential Consequences

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

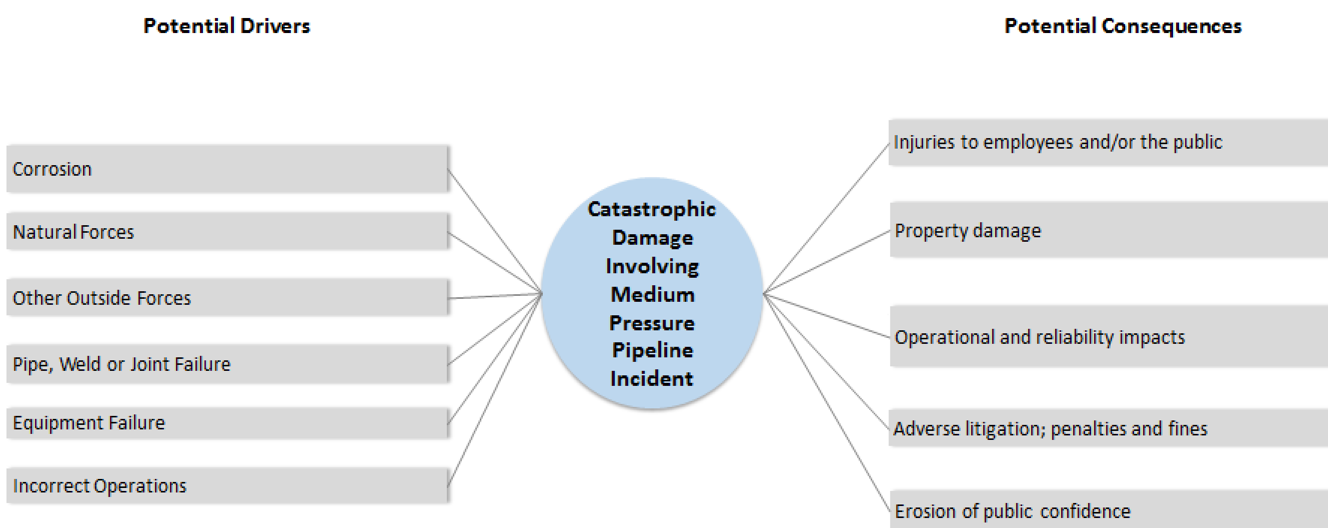
- Injuries to employees and/or the public.
- Property damage.
- Operational and reliability impacts.
- Adverse litigation and resulting financial consequences.
- Increased regulatory scrutiny.
- Erosion of public confidence.

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

3.4 Risk Bow Tie

The risk "bow tie," shown in Figure 1, is a commonly-used tool for risk analysis. The left side of the bow tie illustrates 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 1: 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 Medium-Pressure Pipeline Failure as one of the enterprise risks. During the development of the risk register, SMEs assigned a score to this risk, based on empirical data to the extent it is available and/or using their expertise, following the process discussed in this section.

4.1 Risk Scenario – Reasonable Worst Case

For purposes of scoring this risk, SMEs 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 SMEs selected a reasonable worst case scenario to develop a risk score for Medium-Pressure Pipeline Failure, which was:

- A medium pressure pipeline failure due to a control device malfunction, which results in uncontrolled gas release causing injuries to employees and the public. This also results in over 1,000 customers without gas supply for at least 24 hours.

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

4.2 2015 Risk Assessment

Using this scenario, SMEs 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.[5] Using the levels defined in the REF, the SMEs 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 Medium-Pressure Pipeline 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.

Table 4: Risk Score

Residual Impact				Residual Frequency	Residual Risk Score
Health, Safety, Environmental (40%)	Operational & Reliability (20%)	Regulatory, Legal, Compliance (20%)	Financial (20%)		
5	3	3	3	3	2,344

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

4.3 Explanation of Health, Safety, and Environmental Score

The Company scored this risk a 5 (extensive) in the Health, Safety, and Environmental impact area due to the potential of an event resulting in serious injuries to the public or employees, as well as environmental impacts. For example, from 2010-2016 there have been 37 material failure/weld/fitting incidents in the United States on distribution mains, causing 2 fatalities and approximately 40 injuries.[6] On the other hand, fatalities are rarer for these types of incidents compared to other risk events such as dig-ins or failures on high-pressure pipelines. Accordingly, SoCalGas determined that a score of 6 (severe) was not appropriate.

4.4 Explanation of Other Impact Scores

Based on the selected reasonable worst case risk scenario, SoCalGas scored the other residual impact areas in the following manner:

- Operational and Reliability: A score of 3 (moderate) was given in this impact category. A risk score of 3 is defined in the 7X7 matrix as greater than 1,000 customers affected, impacts a single critical location or customer, or disruption of service for one day. Based on the risk scenario, a significant customer disruption may occur in which a whole street, several homes, or a whole block loses gas service depending if the damages involved medium pressure gas main or service lines.
- Regulatory, Legal, and Compliance: SoCalGas scored this impact category as a 3 (moderate). SoCalGas scored in this manner because of potential for lawsuits and resulting financial impacts. The most common legal issue associated with this risk scenario typically involves lawsuits.
- Financial: The Company could suffer financial repercussions as a result of the other risk areas. Potential litigation and penalties from the CPUC and PHMSA are prime examples of the costs associated with the medium-pressure pipeline system failing. Though the exact cost of litigation and other potential financial consequences can vary depending on the type of incident, if a failure were to occur, the potential losses could be between $1 million and $10 million. The risk score of a 3 (moderate) is assigned due to the fact that all incidents are collateral damages of the first risk area, health, safety, and environment assigning it a secondary type of risk.

4.5 Explanation of Frequency Score

The frequency of an event occurring was assumed to be once every 10-30 years; a risk score of 3 (infrequent). According to PHMSA, between 1996-2015, the number of fatalities that have occurred associated with medium-pressure failures in California are nine (9) persons. See below.

[1]http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=fdd2dfa122a1d110VgnVCM1000009ed07898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print.

PHMSA Pipeline Incidents: (1996-2015)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** CALIFORNIA

Calendar Year	Number	Fatalities	Injuries
1996	1	0	3
1997	1	1	2
1998	3	0	4
1999	3	0	3
2000	2	0	2
2001			
2002	1	1	0
2003	3	1	2
2004			
2005	1	0	1
2006	1	0	1
2007	4	0	5
2008	4	1	5
2009			
2010			
2011			
2012	2	3	1
2013			
2014	2	2	1
2015	1	0	2
Grand Total	**29**	**9**	**32**

Therefore, the risk score is a reasonable estimate of how frequently these types of events happen.

5 Baseline Risk Mitigation Plan

As stated above, Medium-Pressure Pipeline Failure risk potentially impacts the public and/or property damage. The 2015 baseline mitigations discussed below includes the 2015 evolution of the utilities' risk management of this risk. The baseline mitigations have been developed over many years to address this risk and they include activities to comply with applicable laws. SoCalGas' baseline mitigation plan for this risk consists of controls based on CFR Part 192 and GO 112-E.

The primary areas highlighted in the risk registry are:

1. CFR 192 Subpart M – Maintenance
2. CFR 192 Subpart N – Qualifications of Pipeline Personnel
3. CFR 192 Subpart I – Requirements for Corrosion Control
4. CFR 192 Subpart L – Operations
5. CFR 192 Subpart P – Gas Distribution Pipeline Integrity Management

These controls focus on safety-related impacts[7] (i.e., Health, Safety, and Environment) per guidance provided by the Commission in D.16-08-018[8] as well as controls and mitigations that may address reliability.[9] Accordingly, the controls and mitigations described in this section and in Section 6 address safety-related impacts primarily. Note that the controls and mitigations in the baseline and proposed risk mitigation plans are intended to address various events related to Medium-Pressure Pipeline Failure and are not limited to the reasonable worst case risk scenario used for the Risk Score.

1. <u>CFR 49 Part 192 Subpart M – Maintenance</u>

   Federally mandated activities provide the minimum safety requirements for medium-pressure pipelines. These activities include performing pipeline patrol, bridge and span inspections and meter set assemblies, valve and regulator inspection and maintenance on a 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. The activities include but are not limited to:

   - Inspections of natural gas pipeline over bridges and land crossings at least once every 2 calendar years, but with intervals not exceeding 27 months
   - Each 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.
   - Each valve must be checked and serviced at intervals not exceeding 15 months, but at least once each calendar year. (CFR 192.747).
     - Prompt remedial action must be taken to repair an inoperable valve unless an alternative valve is used to divert gas.
   - Region operations may perform tests and inspections at times other than the compliance period but cannot be substituted for federally mandated valve inspection in CFR 192.747.

2. <u>CFR 49 Part 192 Subpart N – Qualifications of Pipeline Personnel</u>

   The training, set forth in CFR 49, Part 192, Subpart N, requires a qualification program on covered tasks, recordkeeping, and evaluation. Each covered task is attached to a gas standard which contains a full description of what the employee/contractor will have to perform. For distribution programs, the following training subsets are the most prominent:

   1. Distribution construction technician training
   2. Energy technician distribution training

[7] The Baseline and Proposed Risk Mitigation Plans may include mandated, compliance-driven mitigations.
[8] 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."
[9] Reliability typically has an impact on safety. Accordingly, it is difficult to separate reliability and safety.

3. Distribution Lead construction technician
4. Distribution system protection specialist
5. Distribution lead system protection specialist

By properly training employees and contractors through the distribution technician training, the frequency of potential accidents can be lowered because the training educates the employees and contractors on proper safety techniques and standards. After a prescribed amount of years, SoCalGas employees are evaluated and requalified to reflect any changes in Company or federal standards.

3. <u>CFR 49 Part 192 Subpart I –Requirements for Corrosion Control Operations</u>

   As prescribed by CFR 192 Subpart I, the minimum safety requirements include monitoring of cathodic protection (CP) 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 corrosion both external and internal. The following summarizes the required intervals for completing these preventative measures:

   - 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 two and a half months, to insure that it is operating.

4. <u>CFR 49 Part 192 Subpart L – Operations</u>

   The minimum safety requirements prescribed by CFR 192 Subpart L – Operations include locate and mark, emergency preparedness and odorization. These activities are intended to address threats as identified by PHMSA. Locate and mark activities are specific to third party damage while emergency preparedness and odorization are intended to address all threats. The following provides 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. <u>CFR 49 Part 192 Subpart P – Gas Distribution Pipeline Integrity Management</u>

   PHMSA established Distribution Integrity Management Programs (DIMP) requirements to enhance pipeline safety by having operators identify and reduce pipeline integrity risks for distribution pipelines, as required under the Pipeline Integrity, Protection, Enforcement and Safety Act of 2006. SoCalGas has implemented various Programs and Activities to Address Risk (PAARs) to address potential drivers such as corrosion, other outside forces and equipment failure, and some of the PAARs specific to this risk are discussed below.

(a) The DREAMS PAAR prioritizes certain early-vintage steel (pre-1960) and plastic (pre-1986), including Aldyl-A, for replacement. With regard to plastic, PHMSA Advisory Bulletin ADB-07-01 states that “the number and similarity of plastic pipe accident and non-accident failures indicate past standards used to rate the long-term strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking for much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s.” Within the SoCalGas system, there are approximately 20,000 miles of early-vintage pipe in the distribution system. SoCalGas has implemented a risk evaluation system to accelerate replacements on a targeted basis. The risk evaluation considers the leakage history, cathodic protection (for steel), vintage of the pipe and the location using E-GIS.
   - SoCalGas mitigation includes the replacement of 17 miles

(b) The Gas Infrastructure Protection Program (GIPP) PAAR addresses potential vehicular damage associated with above-ground distribution facilities. To address vehicular damage to Company facilities, SoCalGas has identified, evaluated and implemented a damage prevention solution that includes a collection of mitigation measures to address this threat. The collection of mitigation measures includes: construction of barriers (bollards or block wall); relocation of the facility; or installation of an Excess Flow Valve. This program is responsive to PHMSA guidance indicating that operators should address low frequency, but potentially high consequence, events through the DIMP.
   - SoCalGas mitigation includes the inspection of 7,764 assets

(c) The Sewer Lateral Inspection Program (SLIP) PAAR addresses an emerging issue concerning pipeline damage associated with sewer laterals. The integrity threat comes from the use of trenchless technology during installation of pipelines. Trenchless technology provides a means of installing a pipeline without having to excavate a trench along the entire length of the pipeline. Instead of excavating a trench along the entire length of a pipeline, the operator can use advanced boring or directional drilling technology to install the pipeline from a single point of entry. An auger, or drill, is affixed to the tip of the pipeline segment and is used to bore or drill the pipeline through existing terrain.
   - SoCalGas mitigation includes 35,157 sewer lateral inspections per year and review of installation records

(d) The Distribution Riser Inspection Program (DRIP) PAAR addresses the potential failures of anodeless risers. Anodeless risers are service line components that could fail before the end of their useful lives. The anodeless riser issue has a potential consequence because they are attached to a meter set assembly (MSA), which is usually located next to a residence. There are approximately 2,600,000 anodeless riser units in SoCalGas’ territory.
   - SoCalGas mitigation includes inspection and repair/replacement of 100,000 anodeless risers.

6 Proposed Risk Mitigation Plan

SoCalGas is proposing to continue with its baseline activities described in Section 5 above. In addition, SoCalGas is proposing to expand and add new mitigations to further address the risk of medium pressure pipeline incident through an incremental replacement rate of early vintage steel. The proposed activities and costs are for controls that are primarily based on the Code of Federal Regulation Part 192 and General Order 112-F state requirements.

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 primary areas highlighted in the risk registry are:

1. CFR 192 Subpart M – Maintenance: Patrolling, Leak Survey, Pressure Limiting and Regulator Station Inspections and Maintenance, Valve Maintenance intended to address Equipment Failure and Natural Forces
2. CFR 192 Subpart N – Qualifications of Pipeline Personnel: Training and procedures intended to address Incorrect Operations
3. CFR 192 Subpart I – Requirements for Corrosion Control: Corrosion control and monitoring intended to address corrosion
4. CFR 192 Subpart L – Operations: Locate and Mark, Odorization, Emergency Preparedness, Continual Surveillance intended to address Equipment Failure, Incorrect Operations and Natural Forces
5. CFR 192 Subpart P – Gas Distribution Pipeline Integrity Management: Threat Evaluation, Risk Analysis, and Program and Activities to Address Risk of all threats

According to the 2015 end of year Department of Transportation (DOT) report, there are a total of approximately 8,000 miles of unprotected steel mains in the SoCalGas system. SoCalGas proposes to modify its DIMP DREAMS program to target a population of 2,200 miles of unprotected steel mains that have historical records of three or more leak repairs in the last 10 years. In addition, SoCalGas proposes to accelerate the current effort by replacing three times the mileage of priority pipe totaling 150 miles per year. This plan will require a step up period in which the cost will increase from a projected $61 - 65 million in 2017-2018, and increase to about $168 - 180 million in the year 2019. The acceleration of DIMP DREAMS aims to reduce the frequency of a potential event occurring related to this risk.

7 Summary of Mitigations

Table 5 summarizes the 2015 baseline risk mitigation plan, the risk driver(s) addressed, and the 2015 baseline costs for Medium-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 or 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 SMEs and available accounting data.

Table 5: Baseline Risk Mitigation Plan Overview[10]
(Direct 2015 $000)[11]

ID	Mitigation	Potential Risk Drivers Addressed	Capital[12]	O&M	Control Total[13]	GRC Total[14]
1	Maintenance*	• Asset Failure • Force of Nature • Public Incident	$2,110	$14,290	$16,400	$16,400
2	Qualifications of Pipeline Personnel*	• Contractor Incident • Employee Incident • Human Error	n/a	3,100	3,100	3,100
3	Requirements for Corrosion Control*	• Asset Failure • Force of Nature • Public Incident	3,640	10,240	13,880	13,880
4	Operations*	• Asset Failure • Contractor Incident • Employee Incident • Public Incident	10	1,310	1,320	1,320
5	Gas Distribution Pipeline Integrity Management*	• Asset Failure • Public Incident	60,090	14,530	74,620	74,620
	TOTAL COST		$65,850	$43,470	$109,320	$109,320

***** Includes one or more mandated activities

[10] Recorded costs were rounded to the nearest $10,000.
[11] The figures provided in Tables 5 and 6 are direct charges and do not include Company loaders, with the exception of vacation and sick. This is consistent with the presentation in previously GRCs. The costs are also in 2015 dollars and have not been escalated to 2016 amounts.
[12] 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.
[13] 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).
[14] The GRC Total column shows costs typically presented in a GRC.

In developing costs, SoCalGas utilized accounting data, where available, and SMEs' high level assumptions. Generally, SoCalGas does not account for costs by activity, but rather, by cost center and capital budget code. Specifically, as it relates to training, SoCalGas does not track its employees' and contractors' labor in a manner that distinguishes when and how long an employee or contractor attended training compared to when they were performing their "typical" job function. Accordingly, for training, assumptions were used based on the known number of students that attended the safety-related distribution training, the duration of the training and a derived labor rate. Training materials and instructor costs were also included in the cost of the Qualifications of Pipeline Personnel control.

Table 6 summarizes SoCalGas' proposed mitigation plan and 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. As set forth in Table 6, the utilities are using a 2019 forecast provided in ranges based on 2015 dollars.

Table 6: Proposed Risk Mitigation Plan Overview[15]
(Direct 2015 $000)

ID	Mitigation	Potential Risk Drivers Addressed	2017-2019 Capital[16]	2019 O&M	Mitigation Total[17]	GRC Total[18]
1	Maintenance *	• Asset Failure • Force of Nature • Public Incident	$6,500 - 8,220	$21,050 - 23,260	$27,550 - 31,480	$27,550 - 31,480
2	Qualifications of Pipeline Personnel*	• Contractor Incident • Employee Incident • Human Error	n/a	4,050 - 4,470	4,050 - 4,470	4,050 - 4,470
3	Requirements for Corrosion Control *	• Asset Failure • Force of Nature • Public Incident	12,900 - 16,290	19,240 - 21,270	32,140 - 37,560	32,140 - 37,560
4	Operations*	• Asset Failure • Contractor Incident • Employee Incident • Public Incident	30 - 40	1,610 - 1,780	1,640 - 1,820	1,640 - 1,820
5	Gas Distribution Pipeline	• Asset Failure • Public	356,940 - 468,240	33,390 - 41,080	390,330 - 509,320	390,330 - 509,320

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[15] Ranges of costs were rounded to the nearest $10,000.
[16] 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.
[17] The Mitigation Total column includes GRC items as well as any applicable non-GRC items.
[18] The GRC Total column shows costs typically represented in a GRC.

	Integrity Management*	Incident				
	TOTAL COST		$376,370 - 492,790	$79,340 - 91,860	$455,710 - 584,650	$455,710 - 584,650

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

Costs for the acceleration of the DIMP programs were calculated using a zero based approach which varied from year to year. The amount of inspections, repairs, replacements, etc. are generated by the respective project manager and approved by a director. Based on previous GRC testimony as well as available resources, that number will typically be lower or higher in the cost projection in 2017-2019. For a small group, other costs in the risk mitigation template, a variation of linear regressions and averages were used based on the historical cost found in 2011-2015. For programs that did not show wide variations in expenditures year to year such as training, the cost is based on a three or five year average, whichever has a more linear behavior. For other costs not zero based, averaged, or linear trended, a cubic spline approach was used to capture varying peaks and troughs of the graph. By using costs in 2017-2019 as a point constraint, the curve was adjusted to follow the trend of the historical years 2011-2015 and ultimately "flattening" in 2019 to stabilize and reach a more linear trend.

While all the mitigations and costs presented in Tables 5 and 6 mitigate the Medium-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 Medium-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 utilities 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."[19] 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.[20]

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 RSE 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.

[19] D.16-08-018 Ordering Paragraph 8.
[20] D.14-12-025 also refers to this as "estimated mitigation costs in relation to risk mitigation benefits."

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.[21] 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.

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 2: 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 Medium 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 five mitigations in its proposed plan:

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

1. Maintenance
2. Qualifications of Pipeline Personnel
3. Requirements for Corrosion Control
4. Operations
5. Gas Distribution Pipeline Integrity Management

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

(a) DIMP/Distribution integrity (current controls)
(b) Technical training (current controls)
(c) Regulatory compliance activities (current controls)
(d) Expanded Integrity activities (incremental mitigations)

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 Medium Pressure Pipeline Failure 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.

- ***Distribution Integrity***

The RSE modeling approach for distribution integrity programs was 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 the program not be funded, then performance would deteriorate to at best the 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 programs in place.

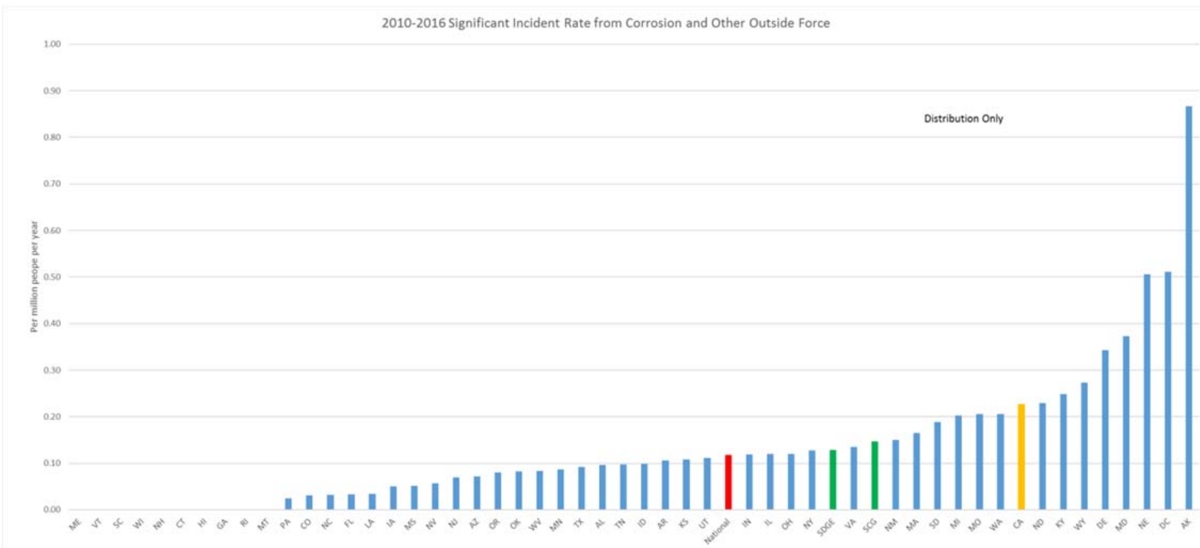
The potential drivers associated with a medium pressure pipeline incident were corrosion, and other outside forces for the DIMP programs, and corrosion and material failure of pipe or weld for the unprotected steel program. This was compared to the incident rate due to all potential drivers so as to attain the projected deterioration 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 was prorated proportionally comparing the number of assets remediated to the total assets.

Additionally, to take into account that the worst of the poor-performing assets are targeted for replacement first, an effectiveness factor was applied that reflects the relative impact of replaced assets versus the average condition of targeted poor-performing assets.

Once the new risk score is calculated, a true-up factor is applied to account for the fact that SoCalGas’ risk exposure is 6 times greater than SDG&E’s exposure due to its significantly larger gas distribution system. This factor was necessary in order to compare to the SDG&E risk and score.

The chart shown below applies to the DIMP programs, and contains the pipeline failure incident rates of all 50 states, in addition to SoCalGas and the national average. SoCalGas has a rate of 0.147 incidents per million people per year, and the worst-performing state is Alaska at a rate of 0.867. Using SoCalGas' service population of 21.6 million people, the incident rates can be converted to an incident expectation, given by the following calculation:

$$\begin{aligned}&Expected\ Incident\ Rate = \Delta(Incident\ Rate) * Service\ Population\\ &= (0.867 - 0.147)\ incidents\ per\ million\ people\ per\ year * 21.6\ million\ people\\ &= 15.5\ incidents\ per\ year\end{aligned}$$



When the calculation is repeated for the unprotected steel program the number of incidents per year comes out to be 4.8.

The average number of SoCalGas incidents per year from all potential drivers for the same time period is 4.3[22], the proportion of targeted miles being addressed is 7.8%, and the assumed replacement effectiveness is 5. Putting it all together, the residual risk multiplier for the bundled set of distribution integrity programs is given by the following calculation:

$$\begin{aligned}&Residual\ Risk\ Multiplier\\ &\qquad = Projected\ deterioration\ factor * Proportion\ of\ Remediated\ Assets\\ &\qquad * Effectiveness\end{aligned}$$

$$Residual\ Risk\ Multiplier = \frac{15.5 + 4.8\ incidents\ per\ year}{4.3\ incidents\ per\ year} * 7.8\% * 5$$

$$Residual\ Risk\ Multiplier = 1.8$$

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

= 0.1987 incidents per year per million people * 21.6 million people

= 4.3 incidents per year

After applying the factor to this residual risk multiplier to align it with the SDG&E risk and score, the new multiplier becomes 11.5. Therefore, if the mitigation is not funded, the projected risk is 11.5 times the current residual risk.

- **Technical Training**

The RSE modeling approach for these programs was the same as that used for distribution 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 worst state performance level. The potential drivers considered as applicable to this category were: incorrect operations. The second difference was that there is no secondary adjustment for the percentage of targeted assets and no effectiveness factor, but it was assumed that the effect of structured training takes time to fade as time and turn over increase, up to a decade. The fading effect is accounted for by dividing by 3.

For this category of projects, the residual risk multiplier is (5.5 / 4.3) X (100%) X (1) / (3) = 0.4. After applying the true-up factor to this residual risk multiplier, the new multiplier becomes 2.7. Therefore, if the mitigation is not funded, the projected risk is 2.7 times the current residual risk.

- **Regulatory Compliance Systems**

The RSE modeling approach for these programs was the same as that used for distribution 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. The potential drivers considered as applicable to this category were: all causes. The second exception was that there is no secondary adjustment for the percentage of targeted assets and no effectiveness factor.

For this category of projects, the residual risk multiplier is (21.2 / 4.3) X (100%) X (1) = 4.9. After applying the true-up factor to this residual risk multiplier, the new multiplier becomes 30.7. Therefore, if the mitigation is not funded, the projected risk is 30.7 times the current residual risk.

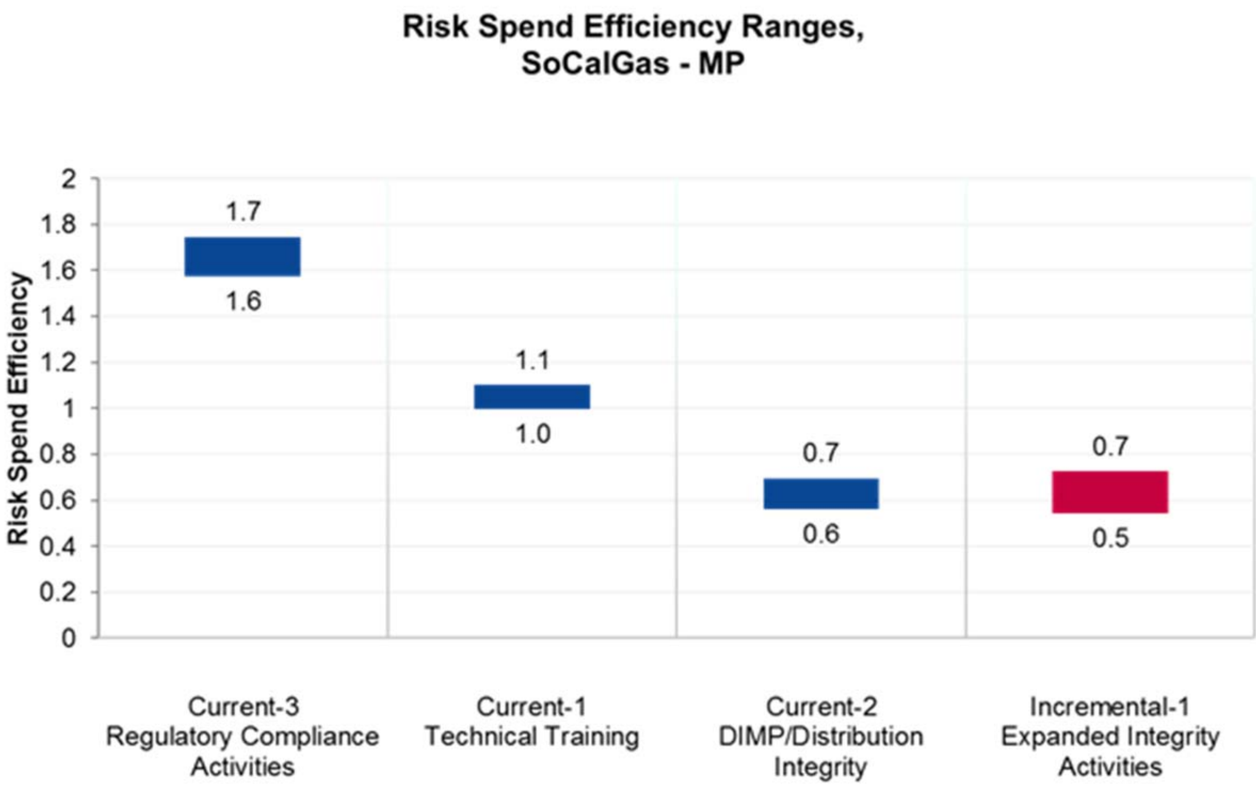
8.3 Risk Spend Efficiency Results

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. DIMP/Distribution integrity (current controls)
4. Expanded Integrity activities (incremental mitigations).

Figure displays the range[23] of RSEs for each of the SoCalGas Medium Pressure Pipeline Incident risk mitigation groupings, arrayed in descending order.[24] That is, the more efficient mitigations, in terms of risk reduction per spend, are on the left side of the chart.

Figure 3: Risk Spend Efficiency



9 Alternatives Analysis

SoCalGas considered alternatives when developing its proposed plan for this risk. After consideration, these alternatives were dismissed in favor of the proposed plan, as described below.

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[23] Based on the low and high cost ranges provided in Table 6 of this chapter.
[24] It is important to note that the risk mitigation prioritization shown in this Report is not comparable across other risks in this Report.

9.1 Alternative 1 – Further Acceleration of Unprotected Steel Mains Work

SoCalGas considered an acceleration of the current program or status quo. This alternative would target all 8,000 miles of DOT reported unprotected steel mains. The project would be completed in an estimated 20 years while replacing over 400 miles/year and targeting the districts with the highest concentration of bare, unprotected steel mains. This program involves the creation of a very large capital intensive program as it would need a multitude of resources to accommodate an aggressive ramp up period. Based on the current replacement cost, each year the program would *require over $600 million per year* to operate and reach the aforementioned target. Due to the fact that a large percentage of non-state-of-the-art pipes are still functioning well in the system, this plan was not selected because of its less-focused approach (relative to proposed incremental activities), the amount of resources needed to implement, and the lack of focus on assets with a greater risk profile. SoCalGas believes that its proposed plan, which proposes to target certain unprotected steel pipe, balances affordability and risk reduction.

9.2 Alternative 2 – Acceleration of Pipeline Replacement

SoCalGas considered an alternative that involved further accelerating the replacement of aging steel pipelines under cathodic protection to address the medium pressure risk. In general, the more time that steel pipelines have been installed/buried, the more susceptible they are to corrosion even when cathodic protection is applied. This is due to a variety of factors which may include vintage coating types and their degradation over time, vintage methods of pipe preparation and coating application, localized soil stresses on pipe, and local soil corrosivity and resistivity being some of the more common. Due to these and other factors, over time, certain pipelines become more susceptible to corrosion. This in turn requires significant increases in operation and maintenance time and money to maintain necessary cathodic protection levels. This alternative would target steel mains where the utility is experiencing increased and ongoing performance issues with the pipeline and the applied cathodic protection system. To address these pipelines, one alternative that was considered was to replace specific identified pipelines with new plastic pipelines, thus providing a benefit to the system and reducing the risk of a medium pressure failure. This program, however, would involve creating an additional capital program. Importantly, these pipelines are still functioning well in the system despite their challenges. Although this option is viable, this plan was not selected because this replacement strategy would not appreciably advance pipeline performance-based approaches already in place via the SoCalGas DIMP strategy.