GP-1101 - Transmission Pipe Asset Management Plan

Gas Plan

Document Number: GP-1101

August 1, 2016

Document Owner: George Karkazis

Document Approver: Sumeet Singh

Table of Contents

Tables

Figures

1. Executive Summary

This asset management plan provides an assessment of condition and risk of the Transmission Pipe asset family and includes a program plan detailing risk mitigations based on strategic objectives and asset maintenance, applied over the life cycle of the assets.

The plan is developed with a 5-year planning horizon to align with the Gas Operations 5-year financial outlook and is updated annually. It describes the physical assets included in this asset family, the current condition and desired future state of the assets, the key risks associated with the asset family, and the investments planned or in progress to mitigate and reduce these risks. Beyond the physical assets, the plan considers the impact on support areas such as training and guidance documents.

This asset management plan is consistent with the Strategic Asset Management Plan, the guidance document for the development of asset management plans.

1.1 Asset Overview

The Transmission Pipe asset family currently consists of approximately 6,600 miles of pipeline and its associated major components, including transmission valves, which transport gas from receipt points into PG&E's natural gas transmission system until the pipe arrives at a distribution center, a storage facility or a large customer (not downstream of a distribution center). The average age of transmission pipe is approximately 45 years, with current geographic and other component data held on a Geographic Information System (GIS).

During preparation for PAS 55 certification, PG&E reviewed the categorization of our distribution and transmission assets using 49 Code of Federal Regulations (CFR) 192.3 and recent Pipeline and Hazardous Materials Safety Administration (U.S. Department of Transportation) (PHMSA) interpretation letters. As a result, PG&E reclassified approximately 830 miles of distribution main as transmission pipe[1]. This will increase the overall total of transmission pipeline to approximately 6,600 miles. For PG&E, the main change in this categorization revolves around the physical location of the "distribution center" where the function changes from transporting gas to distributing it for two or more customers[2]. The change means that newly classified transmission segments will be included in the transmission maintenance and inspection schedule and, depending on the density and types of buildings in close proximity to these segments, may qualify for inclusion in the Transmission Integrity Management Program (TIMP), which is covered in the Transmission Pipe Asset Family Management Plan.

1.2 Strategic Objectives

Gas Operations sets annual corporate Line of Sight (LoS) goals that cascade throughout the organization. Asset Family objectives are created using these LoS goals as a framework and developed both from a bottom-up and top-down approach. After analyzing asset risk and condition within the LoS framework, the 2016 Transmission Pipe strategic asset objectives are as follows:

1. Apply integrity management principles to pipelines covering 100% of the population living along transmission pipelines by 2030

[1] Approximately 830 miles were deducted from the total miles of distribution gas pipeline and added to the Transmission Pipe asset family effective January 1, 2016.
[2] Utility Bulletin TD-4001B-004, currently in draft form

2. Evaluate the scope of and assess for Stress Corrosion Cracking (SCC) and Internal Corrosion (IC) risks based on improved data by 2019
3. Improve system data to enhance threat and risk analysis by executing the activities laid out in the Data Quality Improvement roadmap by 2020
4. Proactively manage assets by planning integrity assessments 3 years in advance by 2017
5. Improve system capacity, reliability, and improve employee safety by meeting 100% of design day conditions, eliminating high risk manual operations, and reducing medium risk manual operation in abnormal peak day (APD) conditions by 2019
6. Update PG&E's gas transmission SCADA assets and technology to improve recognition and response to significant transmission events by 2021
7. Maintain a first quartile Damage Prevention program to further reduce transmission dig-ins.

1.3 Asset and Data Condition

While significant asset characteristic data is held (and is being continuously updated) in the GIS, there is limited consistent monitoring of the system wide asset condition indicators. Asset data that is managed outside of GIS also provides insights on asset condition; however this data has inconsistent levels of availability, accessibility, and quality. As a result of these inconsistencies, the Transmission Pipe Asset Family uses output from the Transmission Integrity Management Program (TIMP) risk management calculations, integrity assessments, and subject matter judgement to understand asset condition.

1.4 Key Risks

This asset management plan takes a risk-based approach to managing the assets to reduce risk. Proposed programs of work are risk scored with a process for prioritization across all asset families in an effort to implement an investment plan that is driven by risk and considers constraints.

Gas Operations identifies risks for each asset family. For each threat (as defined in ASME B31.8S), risk drivers and risks are identified and assessed for each asset family based on available data and SME input. The result of this process is a set of Gas Operations risks as shown in

Figure 1. For this effort, risk is defined as the potential for an adverse event that can impact the company's ability to achieve its objectives. Risk drivers are defined as factor(s) that could cause risk to occur. These risks are defined with a significant degree of granularity. From an asset family basis, risks are defined and discussed in the Asset Management Plans based on the risks defined here.

PG&E Enterprise Operational Risk Management (EORM) also defines risks at the enterprise level. The enterprise level assessment ensures that all lines of business have risks defined at a consistent basis for enterprise level decision-making. Furthermore, due to Gas Operations' level of granularity, the risk drivers were aggregated or "rolled up" to allow for consistent calibration with all PG&E lines of business. The rolled up risks incorporate multiple "risk drivers" from the Gas Operations risk register. Additional details regarding the roll up methodology can be found in the Strategic Asset Management Plan. The development of the Gas Operations enterprise risks is performed by treating the Gas Operations risks as "risk drivers" to develop higher level enterprise risks. Therefore, the enterprise risks incorporate many of the "risk drivers" (or risks from the Gas Operations histogram). Additional details regarding the roll up methodology can be found in the Strategic Asset Management Plan (GP-1100).

This asset management plan is based on the risks developed for this asset family within Gas Operations. The enterprise risk for this asset family is shown below:

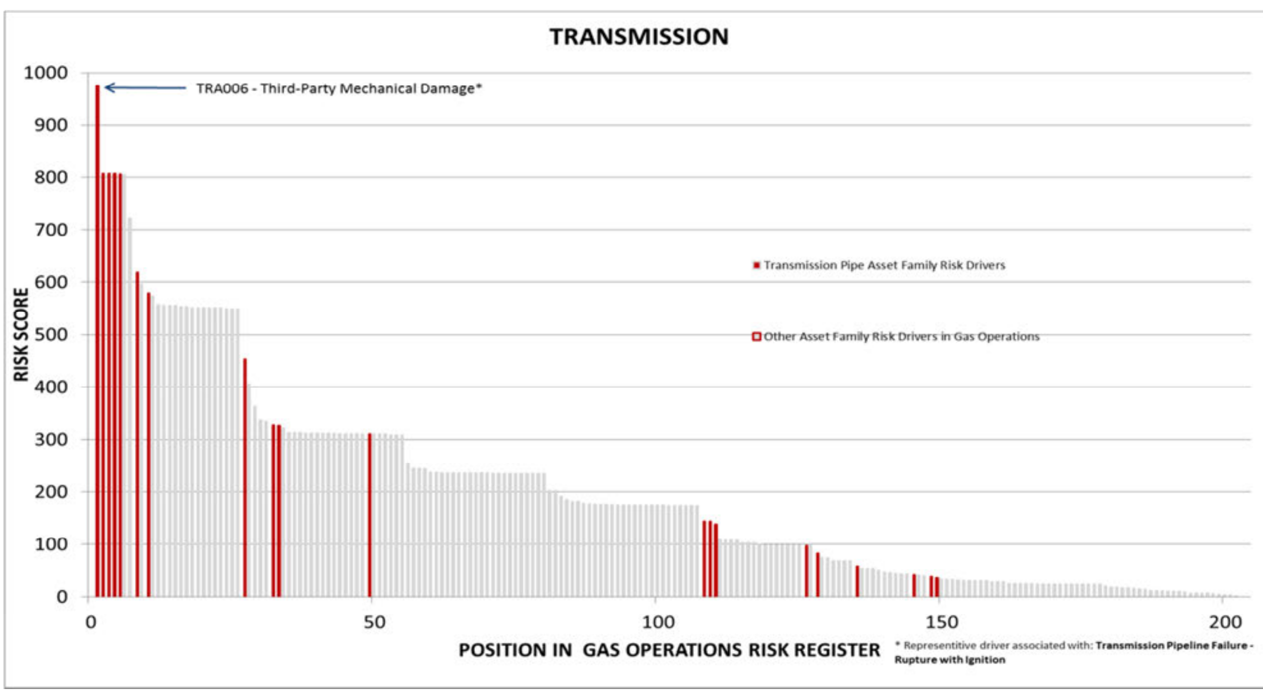
Table 1 – Enterprise Risk for Transmission Pipe Asset Family

Enterprise Risk	Risk Drivers
Transmission Pipeline Failure – Rupture with Ignition	TRA6 – Catastrophic Pipeline Failure - Third-Party / Mechanical Damage
	TRA4 – Catastrophic Pipeline Failure – Manufacturing Related Defects
	TRA8 – Catastrophic Pipeline Failure – Internal Corrosion
	TRA1 – Catastrophic Pipeline Failure – External Corrosion
	TRA3 - Catastrophic Pipeline Failure - Welding / Fabrication Related - Girth Weld & Pre-1962 Construction with Land Movement
	TRA11 – Incorrect Operations – Over Pressure Event
	TRA12 – Catastrophic Pipeline Failure – Weather Related & Outside Forces – Land Movement
	TRA30 - Construction/Fabrication Related - Branch Connections
	TRA16 – Equipment Related – Over Pressure Event
	TRA9 – Stress Corrosion Cracking
	TRA19 - Mechanical Damage - Electric Substation Damage
	TRA21 - Material Traceability
	TRA26 - Equipment Related - Component Failure (Drips, Fittings)
	TRA14 - Mechanical Damage - First & Second Party Damage
	TRA23 - Third-Party / Mechanical Damage - Vandalism
	TRA20 - Weather Related & Outside Forces - Tree Damage
	TRA10 - Weather-Related Outside Force - Pipe Span Damage
	TRA29 - Weather Related Outside Force - Pipe Buoyancy

The histogram below in

Figure 1 displays the position of the Transmission Pipe asset family risks (red) within the Gas Operations risk register. Of all the Gas Operations Risks, the highest Transmission risk (TRA6) is ranked 1.

Figure 1 - Gas Operations Risk Histogram



The key identified Transmission Pipe risks, briefly described in Table 2, are derived based on a risk score that considers the likelihood and consequence of failure. The risks highlighted below are the highest among multiple threats that have been identified across the Transmission Pipe assets. The full extent of risks identified is addressed in detail in Appendix C.

1.5 High Level Program Overview

The asset management plan focuses on managing and reducing risk in the most efficient and effective manner possible. As the plan matures, focus on optimizing risks, performance and costs will continue to be strengthened. Proposed programs involve both capital and expense funding and in some cases address more than one area of risk. Detailed description of the scope of select programs is found in Section 4. The pace, trajectory, scope and anticipated budgets for these proposed programs align with the submittals included in the 2015 Gas Transmission and Storage Rate Case for transmission assets.

The primary mitigations used to reduce risk are shown in Table 2 along with a metric to track progress toward reducing risk.

Table 2 - Key Transmission Pipe Threats, Risks, Related Mitigations, and Metrics

Threat	Risk ID	Risk Description	Primary Mitigation	Mitigation Metric (Status)
External Corrosion	TRA001	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage.	In-Line Inspection (ILI)	System Piggability: 24%[3]
Welding/Fabrication Related – Pre-1962 Construction with Land Movement	TRA003	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Vintage Pipe Replacement	Miles with vintage construction interacting with land movement replaced: 33 miles

[3] Metric value shows negative progress due to the increase in total Transmission miles. Over 120 miles of transmission pipe were made piggable in 2015 and in the first half of 2016.

Threat	Risk ID	Risk Description	Primary Mitigation	Mitigation Metric (Status)
Internal Corrosion	TRA008	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	In-Line Inspection (ILI)	System Piggability: 24%[4]
Manufacturing Related Defects	TRA004	Longitudinal rupture of transmission pipe may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Hydrostatic Testing	% of miles with manufacturing related defect threat hydrostatically tested: 80% in HCAs and Class 3 and 4
Weather Related & Outside Forces – Land Movement	TRA012	Pipeline failure due to land movement associated with seismic activity, flooding, or other geo-hazards (e.g., subsidence, soil creep, fault creep, liquefaction) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	In-Line Inspection (ILI)	System Piggability: 24%[5]
Incorrect Operation	TRA011	Over pressurization, pipeline failure due to incorrect operations by PG&E's staff or contractors may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds, property damage.	SCADA / Network Visibility	% System visibility: 84% (backbone) 37% (local)

[4] Metric value shows negative progress due to the increase in total Transmission miles. Over 120 miles of transmission pipe were made piggable in 2015 and in the first half of 2016.

[5] Metric value shows negative progress due to the increase in total Transmission miles. Over 120 miles of transmission pipe were made piggable in 2015 and in the first half of 2016.

Threat	Risk ID	Risk Description	Primary Mitigation	Mitigation Metric (Status)
Stress Corrosion Cracking	TRA009	Rupture of transmission pipeline due to stress corrosion cracking (SCC) may result in the uncontrolled flow of gas that can lead to significant impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds and additional SCC-related investigations that would occur post-incident, property damage.	Stress Corrosion Cracking Direct Assessment (SCCDA)	% of miles with SCC threat inspected: <1%
Equipment Related – Over-Pressure Event	TRA016	Equipment related defect resulting to an OP event downstream causing loss of Containment at a customer facility	SCADA / Network Visibility	Number of Large Overpressure Events: 3 YTD
Third-Party / Mechanical Damage	TRA006	Rupture of transmission pipe due to mechanical damage by 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	Locate and Mark	Dig-in reductions: The number of third-party gas dig-ins per 1,000 Underground Service Alert tags/tickets for gas: 1.73
Mechanical Damage - First & Second Party Damage	TRA014	Failure from transmission pipe resulting from mechanical damage by PG&E (1st and 2nd party damage) may result in the uncontrolled flow of gas that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Locate and Mark	Dig-in reductions: The number of third-party gas dig-ins per 1,000 Underground Service Alert tags/tickets for gas: 1.73
Construction/Fabrication Related - Branch Connections	TRA030	Rupture of pipe at branch connection (saddle type) caused by external loading (including soil subsidence, inadequate pipe support, etc.) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages	Vintage Pipe Replacement	Miles with vintage construction interacting with land movement replaced: 33 miles

2. Asset Inventory and Condition Overview

2.1 Asset Overview

The Transmission Pipe asset family consists of line pipe used in transporting natural gas as well as related major components, such as valves, fittings, casings, Supervisory Control and Data Acquisition (SCADA) systems, cathodic protection monitoring points, and drips, and transports gas from receipt points into PG&E's natural gas transmission system until the gas is delivered into PG&E's natural gas distribution system. It includes natural gas pipeline owned and operated by PG&E and the Standard Pacific transmission pipeline system.

Table 3 describes the different asset types that comprise the Transmission Pipe asset family.

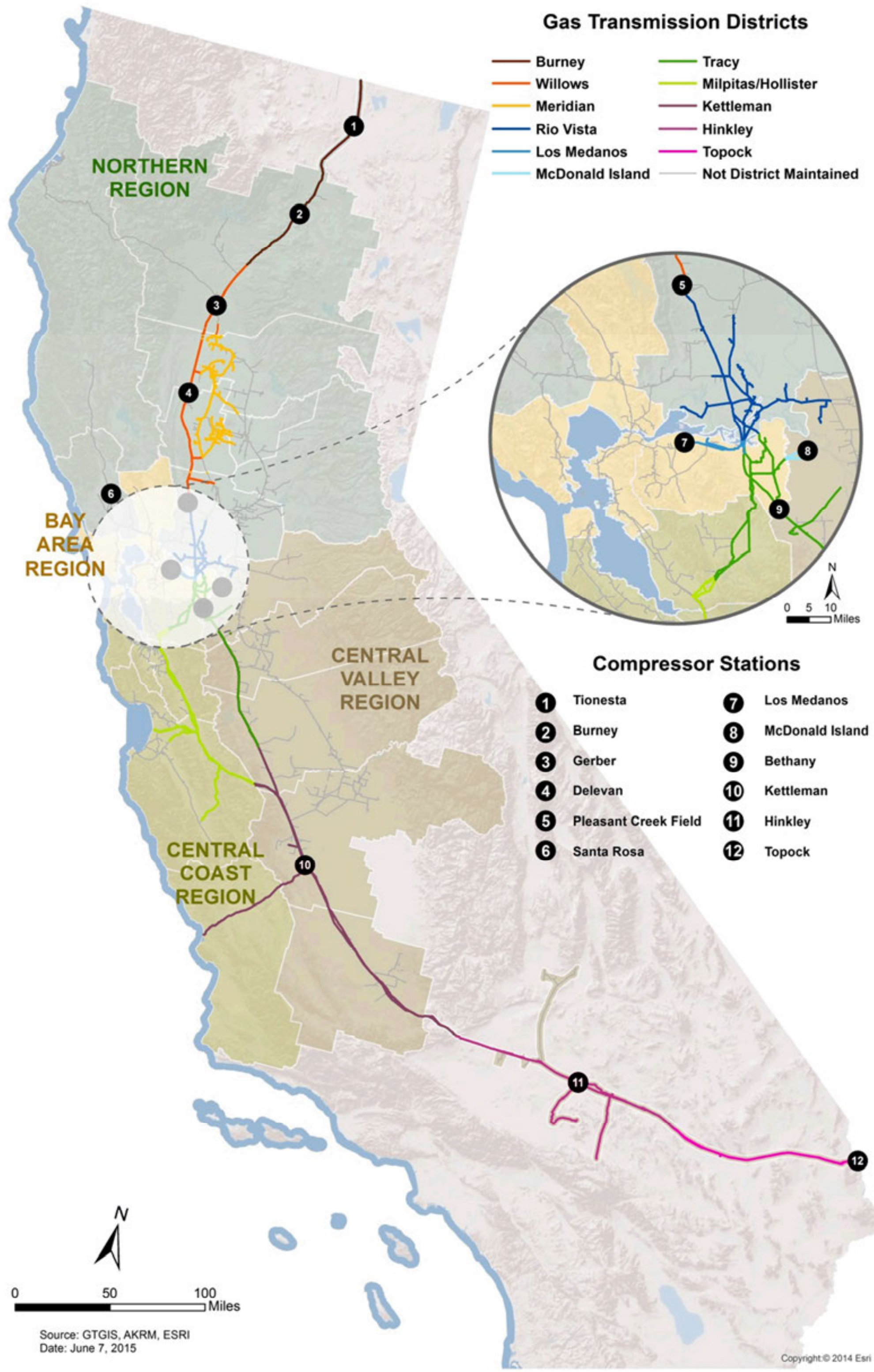
Table 3 - Transmission Pipe Asset Type Overview

Asset Type	Description
Pipe	Transmission pipe transports gas from PG&E's interconnects at Malin, Oregon and Topock, Arizona as well as gas storage fields within California to Distribution Centers or Farm Taps, where gas enters the Distribution system. In addition to Transmission pipe, PG&E also maintains Gas Gathering pipe, which transports gas from small, individually-operated gathering fields to PG&E's Transmission system.
Valves	Valves restrict flow of natural gas through transmission pipe and its appurtenances. Types of valves included in this asset family include: • Relief Valves • Control Valves • Tap Valves • Manually operated mainline valves (not included in Measurement & Control asset family)
Fittings	Fittings are connectors between pipe segments. Types of fittings include: • Elbows • Tees • Bends • Reducers • Caps • Mechanical Couplings
Casings	Casings are larger diameter pipe or concrete cylinders into which smaller diameter pipe is inserted for additional protection. Casings are typically found when pipe is constructed under railroads or roadways.
SCADA Systems	Supervisory Control and Data Acquisition (SCADA) monitors pressure at various locations in the transmission system.

Asset Type	Description
Cathodic Protection Monitoring Points	Cathodic protection (CP) equipment is used to protect metallic pipe from corrosion. Types of equipment include: • Rectifiers • Anode Beds & Anodes • Electrolysis Test Stations (ETS) • CP Monitoring Points
Drips	Drips are appurtenances found on transmission pipe, typically at low points in the system. Drips serve as liquid collection points to prevent liquids from remaining in the transmission system and contributing to internal corrosion and equipment failure.

Figure 2 provides a map of where the transmission pipe facilities are located within the service territory.

Figure 2 - Map of Transmission Pipe Asset Family



The primary asset type of the Transmission Pipe asset family is steel pipe[6], which is characterized by four key factors:

1. Pipe diameter
2. Coating type
3. Seam type
4. Pipe vintage

2.2 Asset Inventory and Condition

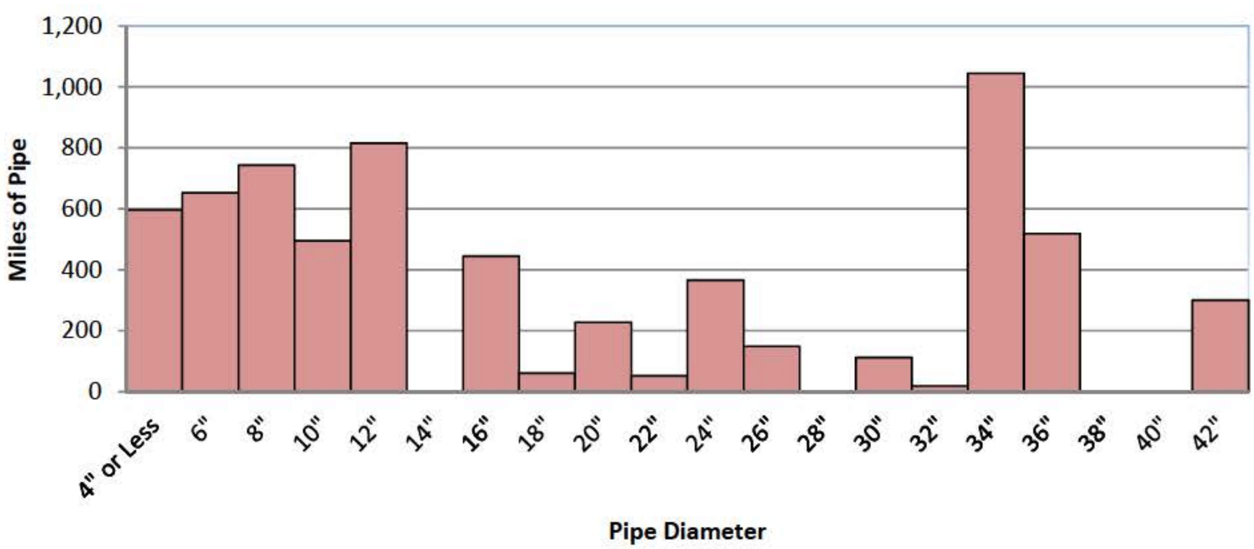
The availability of asset condition data varies within the Transmission Pipe asset family. A comprehensive effort is underway to improve data collection and condition assessment data via the TIMP Data Quality Improvement effort. Asset inventory is detailed by asset characteristic in the following sections.

2.2.1 Pipe Diameter

Pipe in the transmission system ranges from less than 4 inches to 42 inches (3.5 feet) in diameter. 50% of the pipe network by mileage is a foot or less in diameter; the most common diameter of pipe within the system is 34 inches. Additionally, the pipelines are configured with multiple diameters of pipe and with varied operating pressures between segments.

Figure 3 - Transmission Pipe Diameter

Source: 2015 PHMSA 7100 Reports



[6] The Storage Asset Family also includes 14 miles of transmission pipe. These 14 miles of transmission pipe are not included in the Transmission Pipe Asset Family. Refer to GP-1108 for more information on the Storage Asset Family.

2.2.2 Coating Type

The coating type covering the transmission pipe and fittings can be seen as a leading indicator of potential asset condition – particularly related to the resistance of the asset to the external corrosion threat. About one half of the transmission pipe in the network is coated with Hot Applied Asphalt and a variety of other coatings comprise the remainder, including 1,025 miles (15% of the total) for which the coating type is unknown.

Table 4 - Coating Type of Transmission Pipe (includes pipe and fitting features)

Source: Pipeline Features List (May 2016)

Coating types	Miles of pipe	% of total
Hot Applied Asphalt	3,102	47%
Polyethylene Tape	1,033	16%
Fusion Bonded Epoxy	833	13%
Somastic Asphalt	399	6%
Unknown	1,025	15%
Other[7]	218	3%

[7] "Other" coating types include concrete, Powercrete, unspecified epoxies, paint, armor coating, etc.

2.2.3 Seam Type

The longitudinal seam welding process used to seam the pipe during manufacturing can also be seen as a leading indicator of asset condition, related to the vulnerability of the pipe to the manufacturing threat. Table 5 below shows the ratios of weld seam types across the Transmission Pipe asset family.

Table 5 - Seam Type of Transmission Pipe (includes only pipe features)

Source: Pipeline Features List (May 2016)

Seam type	Miles of pipe[8]	% of total
Double-Submerged Arc Welded	2,577	39%
Electric Resistance Welded	2,199	33%
Seamless	751	11%
Single Submerged Arc Weld (SSAW)		
➢ A.O. Smith[9]	76	1%
➢ Other SSAW	88	1%
Other	59	1%
Unknown	847	13%

2.2.4 Pipe Vintage

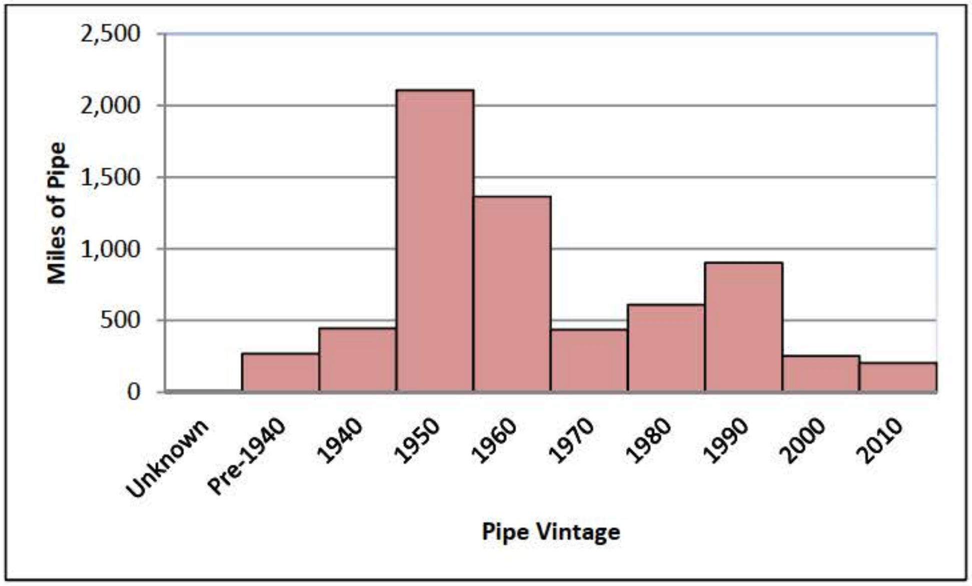
The transmission pipeline system was constructed predominantly in the 1950s and 1960s, but spans in age from pre-1940s to 2010s. Approximately 10% of PG&E's pipeline shares the characteristics that define "vintage pipe." These characteristics include:

- Low-frequency Electric Resistance Weld (ERW) pipe manufactured before 1970,
- Pipe manufactured by AO Smith,
- Pipe welded together using lap welds, flash welds, and butt welds,
- Pre-1990 spiral weld pipe, and
- Pipe that is constructed with wrinkle bends, coupled pipe, and miter bends.

[8] Includes miles for which seam type is known based on traceable, verifiable, and complete records and miles for which the seam type is assumed based on conservative assumptions, as documented in TD-4199-01, revised March 20, 2014.
[9] A.O. Smith manufactured pipe is potentially susceptible to manufacturing defects such as bond-line lack of fusion and hook cracks.

Figure 4 - Transmission Pipe Vintage

Source: 2015 PHMSA 7100 Reports



While advanced age of the asset is not, by itself, an indicator of poor asset health, the original installation year of transmission pipe assets is a useful indicator of construction practices and technologies used in the manufacture and construction of the particular pipeline segment. Installation year therefore can be used to assist in assessment of potential risk when combined with other pipe manufacturing, construction or maintenance characteristics. Pipe vintage is an input directly or indirectly into a number of risk assessment criteria (within Integrity Management and beyond). A number of factors beyond age will determine the need to inspect and potentially renew a particular asset (including physical location, operation, poor design standards, and construction practices).

2.2.5 Data

Currently Available Condition Data

Outlined below are the key data sources used in risk analysis and in establishing the condition of the Transmission Pipe asset family. The data sources have varying levels of availability, quality, and accessibility, as shown below by the Maturity. Data availability was determined by calculating the percentage of times conservative assumptions were used in place of actual data in the Transmission Integrity Management (TIMP)[10] risk algorithm. Data quality and accessibility were evaluated by gathering feedback from data users. The average maturity score for these data sources is 2. Note that the maturity scores have not been re-assessed since mid-2015.

Table 6 - Transmission Pipe Key Data Sources

Maturity Key

0	Data not collected
1	Not all data collected and data warehouse is Excel, manually pulled, or similar
2	Either all data collected or data populated in SAP/GTGIS/PODS/IRAS, not both
3	All data collected and data populated in SAP/GTGIS/PODS/IRAS with no process for regular updates
4	All data collected in one place and data populated in SAP/GTGIS/PODS, with process for regular updates

Source	Maturity	Desired Data Fields
A-Form	2	Multiple data fields
Audit Data	2	Notices of Violation (NOV), Areas of Concern (AOC), and Observations
Corrective Action Program (CAP)	4	Historical Incorrect Operations
Close Interval Survey (CIS) Final Reports	1	Corrosion Survey Criteria, ECDA Assessment Information
Corrosion Data	1	Multiple data fields
Direct Assessment (DA) Final Reports	2	Multiple data fields
External Data	3	Crossings, Seismic Area, Unstable Soil, Heavy Rains & Floods, Lightning, Frost
GIS (Gas Map)	1	Excavation Frequency, Compressor Proximity, Internal coating
H-Form	2	Multiple data fields
ILI Final Reports	2	Multiple data fields
Liquids Sample Lab Results	1	Liquids
MAOP 086868 (MAOP Catalogue)	2	Operating Stress
NHAP Hazard Data	3	Heavy Rains & Floods
Patrol Reports	3	Multiple data fields
Pipeline Features List (PFL)	4	Pipe Attributes

[10] Further discussion on TIMP can be found in Section 3.2 of this plan.

Public Awareness Report	2	Public Education
Root Cause Analysis (RCA) Reports	2	Incorrect Operation Leak History
SCADA Citech	3	Gas Source and Monitoring
USA Tickets	4	Ground Breaking

One step toward improving asset data maturity was the completion of the Asset Maintenance – Backbone & Stations (AMBBS) project. This project migrated the backbone transmission, stations, and storage asset information from multiple systems and platforms into SAP, as a single system of record.

The Transmission Pipe Asset Family also uses the results of Process Hazard Analyses (PHAs) to inform the asset condition.

Gaps in the Current Condition Data

In addition to the data sources listed above, there are several data fields that are not collected in any existing system, which would enhance risk analysis. The TIMP Data Quality Improvement effort is underway to improve all data sources that provide input to the TIMP risk algorithm, upon which the asset family's understanding of asset condition is based.

3. Threats and Risks

Risks are tracked in an enterprise-wide risk register, a central repository where risk names, descriptions and scores (as determined by utilization of EORM's risk criteria) along with other pertinent information are documented. The risk register is updated and refined as additional information is obtained and evaluated.

The risk management framework is fully integrated into PG&E's Integrated Planning process (IPP). This framework complements risk assessment processes already in place via integrity management programs. Additional information about the integrated planning process can be found in the Strategic Asset Management Plan, GP-1100.

While the formal IPP (annual planning cycle) is employed as described above, risks are also identified and addressed continuously as new information is discovered either from working with transmission pipe assets, or from experience elsewhere in industry.

3.1 Threat and Risk Identification

To identify the portfolio of Transmission Pipe risks, the Asset Family Owner (AFO) works with their team and subject matter experts to identify asset threats. The AFO relies on American Society of Mechanical Engineers (ASME) Standard B31.8S and 49 Code of Federal Regulations (CFR) Part 192, Subpart O ("Code") as the basis for categorizing and evaluating the threats, as seen in Table 7.

Table 7 - Transmission Pipe Threat Categories

Threat Category	Description	Specific Threats
Time-dependent	Potentially increase over time	• External Corrosion • Internal Corrosion • Stress Corrosion Cracking
Stable or "Resident"	Present, or potentially inherent in the pipeline, but do not grow over time or pose a threat unless influenced by another condition or failure mechanism	• Manufacturing • Construction/Fabrication • Equipment threats
Time-Independent	Not influenced by time	• Third Party Damage • Incorrect Operation • Weather and Outside Forces

In addition to these Code threats, PG&E recognizes risks related to its obligation to serve, both in terms of ensuring reliable delivery of natural gas and increasing capacity to meet demand, as well as risks posed by an inadequate response to and recovery from emergencies. The Transmission Pipe asset family also considers interactive threats, such as land movement interacting with the presence of construction defects, which is an industry best practice.

After identifying various applicable threats, available data sources and Subject Matter Experts (SMEs) are consulted to determine the relative risk, including impact and frequency levels, associated with each threat. Transmission Pipe risks are calibrated across both Gas Operations and enterprise-wide.

3.1.1 Primary Threats and Mitigations

The threat matrix in Appendix B lists the primary threats that are deemed applicable to the Transmission Pipe asset family. These threats guide the identification of the risks contained in the Transmission Pipe Risk Register.

3.1.2 Key Transmission Pipe Risks

Using the identified threats from the threat matrix, risks have been identified and annually updated for the transmission pipe asset family, and prioritized for both Gas Operations (addressing risks across asset families) and within the asset family (as part of the risk and compliance process).
The Transmission Pipe asset family identified 24 risks drivers in 2016. The highest Transmission Pipe risk (TRA6 - Transmission Pipeline Failure - Rupture with Ignition: Third-Party/Mechanical Damage) ranked first among the risks in Gas Operations.

Table 8 - Key Transmission Pipe Risks

This table includes all risks with a score of 200 or higher as a result of the 2016 Session D process. Risks are listed in order from highest to lowest. For all Transmission Pipe risks see Appendix C.

Risk ID	Risk	Threat
TRA6	Rupture of transmission pipe due to mechanical damage by 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	Third Party / Mechanical Damage
TRA4	Longitudinal rupture of transmission pipe may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Manufacturing Related Defects
TRA8	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	Internal Corrosion
TRA1	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage.	External Corrosion
TRA3	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Welding/Fabrication Related – Pre-1962 Construction with Land Movement

Risk ID	Risk	Threat
TRA11	Over pressurization, pipeline failure due to incorrect operations by PG&E's staff or contractors may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds, property damage.	Incorrect Operation
TRA12	Pipeline failure due to land movement associated with seismic activity, flooding, or other geo-hazards (e.g., subsidence, soil creep, fault creep, liquefaction) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages	Weather Related & Outside Forces – Land Movement
TRA30	Rupture of pipe at branch connection (saddle type) caused by external loading (including soil subsidence, inadequate pipe support, etc.) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages	Construction/Fabrication Related – Branch Connections
TRA16	Equipment related defect resulting to an OP event downstream causing loss of Containment at a customer facility	Equipment Related - Over-Pressure Event
TRA9	Rupture of transmission pipeline due to stress corrosion cracking (SCC) may result in the uncontrolled flow of gas that can lead to significant impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds and additional SCC-related investigations that would occur post-incident, property damage.	Stress Corrosion Cracking

3.2 Integrity Management Programs

In addition to EORM, the Transmission Pipe asset family leverages information from related integrity management programs to identify asset level risks.

Transmission Integrity Management Program (TIMP)
The TIMP is a mature, well-defined program for assessing the risk related to different segments of pipe on the system and taking action to prevent or mitigate these risks. The approach for assessing risk is based on an assessment of likelihood and consequence of a leak or rupture, and uses the nine threats listed in the threat matrix to identify high-risk segments. While the TIMP risk management process contains many elements that overlap with risk assessment processes within the risk register, it is a separate process that considers threats to individual segments of pipe as opposed to the system as a whole.

4. Desired State, Strategic Objectives, Programs and Risk Mitigations

The long term vision for the Transmission Pipe asset family is to improve the overall safety and reliability of the assets through a combination of asset condition understanding, infrastructure improvements, and promotion of a culture that focuses on the long term safety and reliability of the assets. Goals supporting this vision include:

- 66% system piggable by 2026
- Corrosion control practices and cathodic protection in place validated and effective for 100% of system
- No untested pipe in system
- 100% SCADA Visibility
- Automatic shutoff valves in all HCA and Class 3 locations
- Accessible records that are traceable, verifiable, complete and clearly linked to original information about a pipeline segment or facility.
- Quantitative risk model down to segment level which is able to quantify risk reduction
- Risk managed by addressing pipelines covering 100% of the population prioritized via quantitative risk model
- Properly qualified personnel performing all functions as required by Code of Federal Regulations (CFR) Title 49, § 192, Subpart N—Qualification of Pipeline Personnel

Note that the content of and the timelines for both the strategic objectives and desired end states may be affected by rule makings and rate cases and other external and internal factors.

The Transmission Pipe asset family's strategic objectives are developed to optimize asset life cycle by maintaining and improving asset condition and adequately mitigating risks and threats. These strategic objectives, which support Gas Operations' Line of Sight (LoS) goals, have been established to align investment in the asset family with the Asset Management Strategy, reduce risks, and ultimately realize Gas Operations' corporate vision.

Using these inputs, a long-term plan has been defined to meet Transmission Pipe Asset Management and corporate objectives.

The Transmission Pipe strategic asset objectives and associated metrics as they correspond to Gas Operations' LoS goals are detailed in

Table 9 below:

Table 9 - Strategic Objectives Mapped to Gas Operations Line of Sight (LoS) Goals

Gas Operations Objectives	Strategic Objective	Metric
Public Safety / Compliance & Risk	Apply integrity management principles to pipelines covering 100% of the population living along pipelines by 2030	% population associated with pipelines where Integrity Management principles have been applied
Public Safety / Compliance & Risk	Evaluate scope of and assess for Stress Corrosion Cracking (SCC) and Internal Corrosion (IC) risks based on improved data by 2019	% of segments assessed for SCC & IC (where these threats apply)
Compliance & Risk	Improve system data to enhance threat and risk analysis by executing the activities laid out in the Data Quality Improvement roadmap by 2020	Data Quality Improvement Roadmap implementation (% complete)
Compliance & Risk / Affordability	Manage assets proactively by planning integrity assessments 3 years in advance by 2018	Number of integrity assessments planned 3 years in advance
Employee & Contractor Safety / Reliability / Customer Satisfaction	Improve system capacity, reliability, meet 100% of design day conditions, and eliminate high risk manual operations and reduce medium risk manual operation in APD conditions by 2019	Number of high risk manual operations Number of medium risk manual operations Number of large transmission overpressure events
Public Safety / Reliability / Customer Satisfaction	Update PG&E's gas transmission assets and technology to improve recognition and response to significant transmission events by 2021	Execution of backbone transmission SCADA visibility improvements (% complete) Execution of local transmission SCADA visibility improvements (% complete)
Public Safety / Reliability / Compliance & Risk	Maintain a first quartile Damage Prevention program to further reduce transmission dig-ins	Dig-in reductions: The number of third-party gas dig-ins per 1,000 Underground Service Alert tags/tickets for gas

4.1 Strategic Objectives, Programs and Mitigations Alignment

PG&E has developed the following programs to meet these strategic objectives, using the aforementioned risk-based investment strategy to address both enterprise and asset level risks, meet compliance requirements, and maintain asset condition.

Table 10 - Programs, Mitigations, and Strategic Objectives

Programs & Mitigations	Apply Integrity Management Principles	Evaluate SCC & ICC	Improve System Data	Plan Integrity Assessments 3 Years in Advance	Improve System Capacity, Reliability	Recognize & Respond to Transmission Events	Damage Prevention Program
Cathodic Protection	X	X	X				
In-Line Inspection (ILI)	X	X	X	X			
Direct Assessment (DA)	X	X	X	X			
Pressure Test	X	X	X	X			
Leak Survey & Repair	X		X				X
Damage Prevention	X		X				X
Vintage Pipe Replacement	X						
Patrols / Continuing Surveillance	X		X				X
Shallow Pipe Program	X		X				X
SCADA / Network Visibility					X	X	
Atmospheric Corrosion Inspection Program	X	X	X				
Valve Automation	X					X	

4.2 Programs & Mitigations Overview

The following is additional information on some of the key programs and mitigations in place to reduce risk to transmission pipe assets. The timeframes for the following programs and mitigations are based on the proposed 2015 GT&S rate case targets as of the publish date of this Asset Management Plan.

Note that ownership of programs may be owned or executed from many different parts of PG&E outside of TIMP. See Figure 9 - Stakeholder Roles and Responsibility Matrix for additional detail.

Also, note that metrics are found in Table 25 - Transmission Pipe Asset Family Metrics and Corresponding Threat.

Program:	Cathodic Protection (CP)
Scope/Program Description: As part of this program, PG&E plans to enhance cathodic protection levels by adopting a more conservative protection criterion of -850 mV "off" as described in the National Association of Corrosion Engineers (NACE) Standard Practice 0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." PG&E currently uses the -850 mV "on" criteria and transitioning to the "off" criteria will provide a more accurate indicator of system protection levels because it considers the soil IR voltage drop between pipe and reference cell when recording a pipe-to-soil potential. Including voltage drop can yield less conservative pipe-to-soil readings and potentially mask areas with inadequate levels of CP.	
Desired State:	• Establish internal engineering team including expert corrosion engineer, program manager, associate engineers, and data analyst to develop a program methodology, manage the program and provide engineering analysis and remedial CP System designs and upgrades to achieve 850 Off transmission pipeline CP levels. • Establish team of field engineers to survey the 6750 miles of transmission pipeline within a 4 year period for CP status and collect the data necessary to support the Engineering recommendations to meet 850 Off criteria for all transmission pipelines. • Eliminated notifications and Notices of Violations (NOVs) for inadequate CP • Improved compliance for bi-monthly and annual CP reads
Risks Addressed:	TRA001, TRA009
Timeframe:	2019: Ongoing
Responsible Organization:	Corrosion Engineering

Program:	In-Line Inspection (ILI)
Scope/Program Description: ILI is the most reliable pipeline integrity assessment tool currently available to natural gas pipeline operators to assess the internal and external condition of transmission line pipe. ILI enables a pipeline operator to learn about the condition of its pipelines and to predict the integrity of those pipelines into the future to address time dependent as well as other threats to pipeline integrity. It involves running technologically advanced inspection tools, often called "smart pigs," through the inside of the pipeline to collect data about the pipe, and then using that data to identify anomalies that may require further investigation or repair.	
Desired State:	• Targeting 66 percent system piggable by 2026 • Apply both short and long-term recommendations from the McKinsey Capital Productivity Effort • Complete development and testing of custom ILI tools from ROSEN including 12"x16", 10"x12", and 24"x30", including full API 1163 qualification for each • Improve ILI run success rate to 90% for first-time ILI and 95% for ILI re-inspections
Risks Addressed:	TRA001, TRA002, TRA003, TRA004, TRA006, TRA007, TRA008, TRA010, TRA012, TRA014, TRA015, TRA019, TRA020
Timeframe:	2026: Ongoing
Responsible Organization:	Transmission Integrity Management
Program:	Direct Assessment (DA)
Scope/Program Description: DA is used to evaluate the possibility of time dependent threats of external corrosion, internal corrosion, and stress corrosion cracking. Each evaluation methodology is designed to proactively address the pipeline threat of corrosion and is meant to discover and prevent anomalies from growing to a size that affects the structural integrity of the pipeline. Application of DA involves applying a four-step process consisting of: (1) Pre-Assessment; (2) Indirect Inspection; (3) Direct Examination; and (4) Post Assessment.	
Desired State:	• Top decile procedures • No corrosion failures after DA projects • No NOVs • Implement 100 percent digital documentation
Risks Addressed:	TRA001, TRA002, TRA008, TRA009, TRA015
Timeframe:	2017: Ongoing
Responsible Organization:	Transmission Integrity Management

Program:	Pressure Test
Scope/Program Description: The objective of the Pressure Test program is to validate the integrity and assure a margin of safety for those gas transmission pipelines that lack a documented strength test record. This program identifies stable/resident threats by evaluating the yield strength of segments of pipe for the presence of manufacturing defects, which is then followed by implementation of mitigation measures.	
Desired State:	All pipe with traceable, verifiable, and complete pressure test records
Risks Addressed:	TRA001, TRA002, TRA004, TRA005, TRA008, TRA015
Timeframe:	2023: Ongoing
Responsible Organization:	Transmission Integrity Management
Program:	Vintage Pipeline Replacement
Scope/Program Description: PG&E considers vintage construction and fabrication threats interacting with land movement as one of the top risks facing the transmission pipe asset and the Vintage Pipeline Replacement Program will significantly reduce that risk. PG&E's vision for its Vintage Pipeline Replacement program is to replace all known pipe segments containing vintage fabrication and construction threats that are subject to the threat of land movement that are in proximity to population by the end of 2030.	
Desired State:	• Targeting reducing risk to the population toward the 90% goal as soon as possible (2025). • Expected Completion Date – Based off remaining miles from program snapshot from current year if 15 miles/year is the execution rate. • Primary focus is to reduce the risk to the impacted population (that is within the vicinity of our pipelines) by 2030. • Incorporate Light Detection and Ranging (LiDAR) data to improve identification of land movement threats as managed through the geo-hazard identification program. • Incorporate Inertial Mapping Unit (IMU) data from ILI to determine bending stresses in the pipeline, verifying land movement concerns.
Risks Addressed:	TRA003
Timeframe:	2025
Responsible Organization:	Transmission Integrity Management

Program:	Patrolling / Continuing Surveillance
Scope/Program Description: The Pipeline Patrol Program is a means of preemptive threat identification and can observe a myriad of potential threats, ranging from construction activity, landslides, ground movement, vegetation encroachments, right-of-way (ROW) encroachments, leaks, corrosion, missing markers, etc. If left unidentified and unmitigated, many of these threats could result in a failure/rupture of company assets. These patrols are conducted to achieve compliance with 49 CFR Part 192.705 and to fulfill commitments to the California Public Utilities Commission (CPUC).	
Desired State:	• Increased patrolling of areas with high risk of dig-ins, such as agricultural areas, high consequence areas (HCAs), Class 3 locations, and targeted distribution pipelines • Acquire seven (7) additional centralized ground patrol personnel to assist with vegetative cover patrols, landslide patrols, and ground investigations • Light Detection and Ranging (LiDAR) technology under consideration for patrolling vegetative cover areas, identification of new construction, and historic earth disturbance change detection
Risks Addressed:	TRA006, TRA007, TRA010, TRA012, TRA014, TRA023
Timeframe:	2016; Ongoing
Responsible Organization:	Gas Transmission and Distribution Operations
Program:	Shallow Pipeline Replacement
Scope/Program Description: The purpose of this program is to identify, prioritize and mitigate locations that have insufficient cover and is vulnerable to exposure from third parties. Capital remediation options include: replacement or relocation of the pipeline at an acceptable depth of cover in parallel, or along an alternate route and retirement of the shallow location and retirement of those shallow pipelines not necessary for operations. Expense remediation options include: excavation along the length of the pipeline to allow lowering to an acceptable depth of cover (only an option if the required depth of cover can be met without adding excessive external stresses to the pipeline) and protection of the pipeline by installing additional cover, concrete cap, or permanent bridging structure over the shallow location.	
Desired State:	• 3 year cyclical monitoring plan for continual surveillance established. • Primary focus is to reduce the risks at locations of agriculture/farming, external loading concerns on pipe, and erosion leading to exposure of pipeline. • Continued performance of public awareness.
Risks Addressed:	TRA006, TRA007, TRA014
Timeframe:	2017: Ongoing
Responsible Organization:	Transmission Integrity Management

<table>
<tr><td>Program:</td><td>Atmospheric Corrosion Inspection Program</td></tr>
<tr><td colspan="2">Scope/Program Description: 2 major aspects of the program are:
• Improve our current procedures and trainings to ensure our atmospheric corrosion inspections are performed correctly and uniformly through-out the company, by improving the training materials and procedures. As well as creating new automated processes and procedure for when remediation are required to ensure they are completed within the compliance window.
• Review our existing records and to find existing deficiencies and prioritize the remediation based risk. This includes a review of all our system of record (PLM, SAP, and paper), inspecting for issues, and creating remediation projects.</td></tr>
<tr><td>Desired State:</td><td>• Developed new inspection procedures and training, reduce and simplify forms.
• Improved our system of record across different asset types (spans, vaulted assets, etc.)
• Implemented mobile solution to facilitate quicker turn-around of field inspection results.
• Over two thirds of station projects completed.
• Over two thirds of span projects completed.</td></tr>
<tr><td>Risks Addressed:</td><td>TRA001, TRA002</td></tr>
<tr><td>Timeframe:</td><td>2021: Ongoing</td></tr>
<tr><td>Responsible Organization:</td><td>Corrosion Engineering</td></tr>
<tr><td colspan="2"></td></tr>
<tr><td>Program:</td><td>Valve Automation</td></tr>
<tr><td colspan="2">Scope/Program Description: PG&E's Valve Automation Program is designed to enhance emergency response in the event of a gas transmission pipeline rupture. This installation of automated isolation capability on major pipelines in heavily populated areas increases emergency preparedness, and may reduce property damage and the danger to emergency personnel and the public in the event of a pipeline rupture.</td></tr>
<tr><td>Desired State:</td><td>Install automated valves at all Class 3 HCA and Class 3 non-HCA locations with potential impact radius of greater than 200 feet</td></tr>
<tr><td>Risks Addressed:</td><td>Major Emergency or Disaster</td></tr>
<tr><td>Timeframe:</td><td>2020: Ongoing</td></tr>
<tr><td>Responsible Organization:</td><td>Transmission Engineering Design</td></tr>
<tr><td colspan="2"></td></tr>
</table>

Program:	Damage Prevention
Scope/Program Description: The damage prevention program manages the risks associated with excavation around PG&E facilities. This program focuses on educating third parties as well as the public in the "Call before you dig" or 811 program and monitors contractor performance via the repeat offender program.	
Desired State:	First quartile Damage Prevention program to further reduce transmission dig-ins
Risks Addressed:	TRA006, TRA007, TRA014
Timeframe:	Ongoing
Responsible Organization:	Gas T & D Compliance Programs
Program:	SCADA / Network Visibility
Scope/Program Description: The Gas Transmission Control Center (GTCC) SCADA system is designed to provide greater visibility to the gas system operators and increased situational awareness, which means faster detection of abnormal conditions, and more robust response. The system can accommodate advanced applications such as the real-time line break detection application, improved control room management including improved audit documentation, emergency response tools, and other applications.	
Desired State:	100% system visibility
Risks Addressed:	TRA011, TRA022
Timeframe:	2021
Responsible Organization:	Gas Control Strategy & Support

The latest program investment plan information can be found at the following links or by contacting Investment Planning:

- Transmission S1: 2015 GT S1 file
- Transmission S2: 2015 GT S2 file.

5. Areas for Continuous Improvement

There are some areas in the asset management plans that have not been fully built out at this stage; these are highlighted in Table 11 below. These are areas that will continue to evolve and improve as more thorough data sets and understanding of asset condition are developed over time.

Table 11 - Areas for Continuous Improvement

Areas for Continuous Improvement
Data • Improve data quality issue visibility to ensure data users understand the quality of data used for risk analyses and understand the process(es) underway to address data quality issues • Work toward migrating all Transmission data into enterprise data management systems that can be accessed by all data users, including data that is currently in paper form • Implement Transmission Data Quality roadmap
Session D • Consider the effect of current mitigations in potentially creating additional risks • Continue to work toward integrating TIMP risk evaluation results with Transmission Pipe risk register • Fully integrate interactive threats into Transmission Pipe risk register, as appropriate
Asset Management Plan • Continue to work with other asset families to develop consistency in plan content • Ensure asset management plan is the primary source of asset family information and incorporates information from the Threat Matrices, Risk & Compliance Committee meetings, and Session D • Improve criteria for identifying mitigation program status, including benchmarking criteria, program effectiveness metrics, and funding fulfilment
Personnel Implications • Additional personnel/hours will be needed to develop and implement data quality issues resolution process • Additional or supplemental personnel may be needed to perform proactive risk, asset, and process safety management activities • Identify development plans for subject matter experts to ensure their skills/expertise remain current • Identify succession plans for subject matter experts and begin skill/expertise development for successor • Continue developing skills of Asset Management Principals and supplement team with additional analysts, as necessary

APPENDICES

A. Related Documents

The following table lists documents associated with this asset management plan.

Table 12 - Related Documents

Related document	Document Number / Description	Link
Transmission Pipe Risk Register	The risk register captures all risks outlined in this plan at the date of publish	http://gasrisk/
Asset family investment planning forecast	Retained by Investment Planning for S1 and S2 planning purposes.	
Enterprise and Operational Risk Management Standard and Procedures	RISK-5001S, RISK-5001P-01, RISK-5001P-02, RISK-5001P-03	http://pgeatwork/Guidance/RiskCompliance/Pages/default.aspx
Gas Asset Management Policy	TD-01	TD-01
Gas Operations Risk and Compliance Committee Charter	GOV-1021S	http://pgeatwork/Guidance/Governance/Pages/default.aspx
Strategic Asset Management Plan	GP-1100	http://www/techlib/default.asp?body=gas_plans.htm
Distribution Mains and Services Asset Management Plan	GP-1102	
Customer Connected Equipment Asset Management Plan	GP-1103	
Measurement and Control Asset Management Plan	GP-1104	
Compression and Processing Asset Management Plan	GP-1105	
LNG/CNG Portable Supplies Asset Management Plan	GP-1106	
CNG Station Asset Management Plan	GP-1107	
Gas Storage Asset Management Plan	GP-1108	

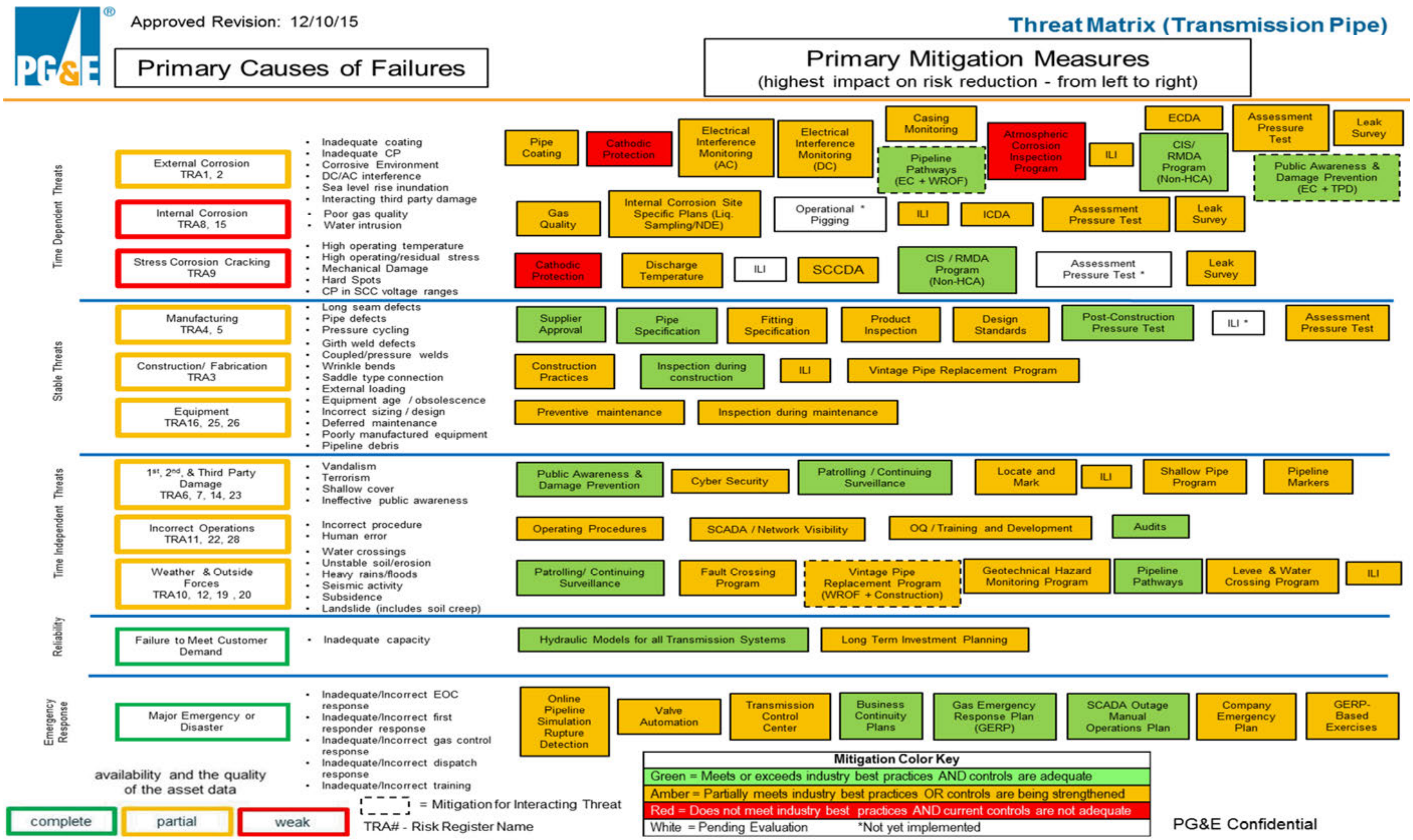
B. Threat Matrix and Key Threats

Threat Matrix

The threat matrix below displays threats, drivers, and mitigations associated with this asset family. The threats are outlined with a red, amber, or green status denoting the current availability and quality of asset data. The mitigations are color coded with white, red, amber, or green status to display how it currently compares to industry best practices as well as the strength of the controls. The color coding is assigned based on three factors:

1. Compliance Performance (e.g., has PG&E experienced any Notices of Violation (NOVs) or self-reports related to this mitigation?)
2. Benchmarking (e.g., does the mitigation meet or exceed industry best practices?)
3. Pace (e.g., is the mitigation funded to address the risk at an adequate pace?)

Figure 5 - Transmission Pipe Threat Matrix



Key Threats

In order to identify key threats to the Transmission Pipe asset family, national and PG&E data was evaluated. Following are summaries of incidents in US gas transmission pipeline systems as well as PG&E's gas transmission system from the past six years, organized by primary cause.

Table 13 - Industry and PG&E Reported Pipeline Incidents by Cause, Onshore Natural Gas Transmission (2010-Present)

Source: PHMSA Significant Incident Files, May 13, 2016

Incident Cause	% Industry Incidents	% PG&E Incidents
External Corrosion	7%	9%
Internal Corrosion	6%	0%
Stress Corrosion Cracking	2%	0%
Excavation Damage	16%	49%
Equipment	29%	14%
Manufacturing	3%	3%
Construction	8%	6%
Weather-Related Outside Force	16%	9%
Incorrect Operation	5%	9%
Other/Unknown	8%	3%

Figure 6 - All Reported Pipeline Incidents by Cause, National Gas Transmission Onshore – Number of Incidents (2010-Present)

Source: PHMSA Significant Incident Files, May 13, 2016

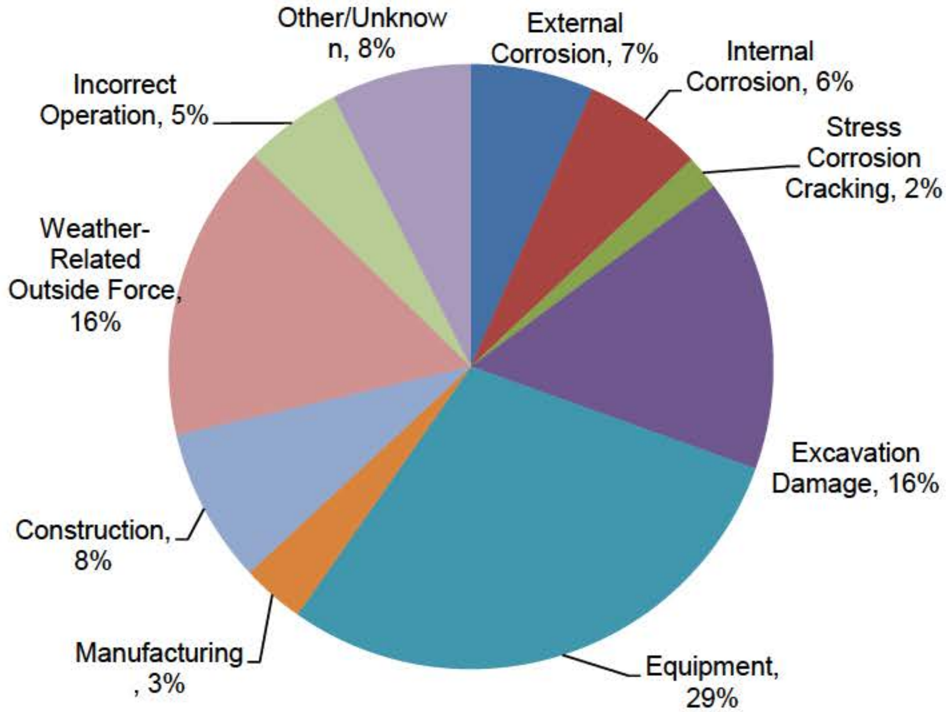
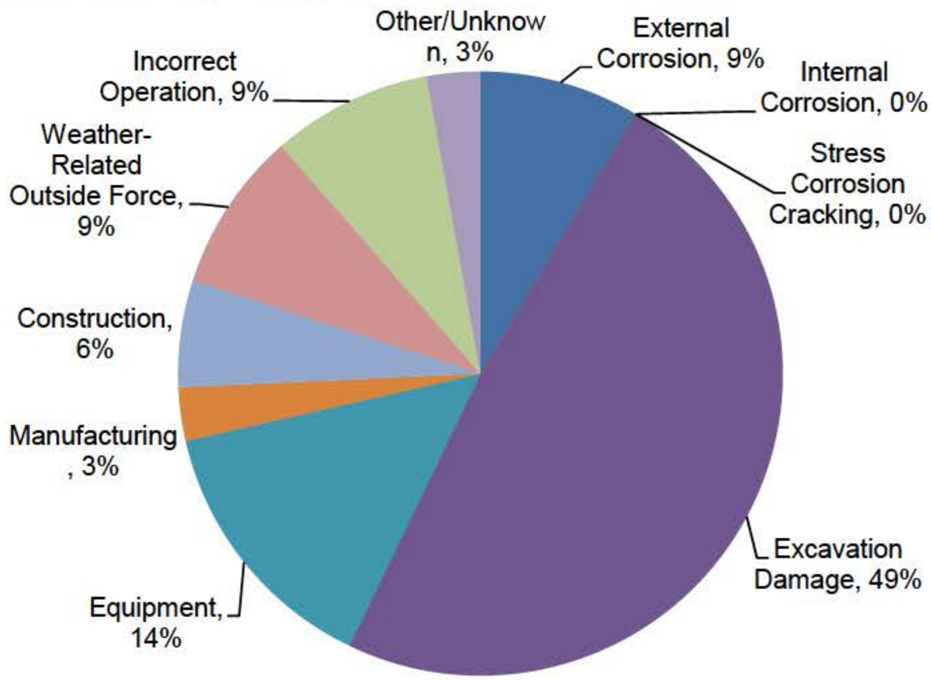


Figure 7 - PG&E Pipeline Incidents by Cause, National Gas Transmission Onshore – Number of Incidents (2010-Present)

Source: PHMSA Flagged Incident Files, June 1, 2015



These charts indicate the importance of considering both PG&E data along with national data when evaluating threats and risks to the Transmission Pipe asset family.

External Corrosion

External corrosion is driven by the nature of conditions on the outside of the pipe, such as the long-term chemical reaction between the exterior of the pipeline and the surrounding soil and manifests itself in the oxidation or 'rusting' of the pipe.

External corrosion can, over time, reduce the wall thickness of the pipe and subsequently the strength of the pipe. The reduction in 'as-built' pipe strength could result in leakage or rupture of the pipeline unless the corrosion is repaired, the affected pipeline section is replaced, or the operating pressure of the pipeline is reduced.

External pipeline corrosion creates weaknesses at points in the pipe, which in turn makes the pipe more susceptible to third party damage, overpressure events, etc. (i.e., corrosion doesn't necessarily need to cause the leak or rupture in order to increase the risk of leak or rupture).

All Transmission pipe in PG&E's system is potentially vulnerable to the external corrosion threat. Key known drivers of the external corrosion threat are degradation of the pipe coating and inadequate cathodic protection.

Internal Corrosion

Corrosion of the internal wall of transmission pipelines occurs following exposure to water and/or contaminants in the gas. The extent of the corrosion damage that may occur and the

threat this creates will depend on the operating conditions of the pipeline as well as the particular combinations of these various corrosive constituents within the pipe. For example, gas temperature and pressure in the pipeline will play a major role in determining if internal corrosion damage can occur. A particular gas composition in the presence of liquid water (e.g. particularly sour gas) may cause corrosion under some operating conditions but not others. Accumulated liquid water in the pipe may also represent an internal corrosion threat.
At present, the Transmission Integrity Management Risk Management team estimates that approximately 79% of the system is potentially vulnerable to the internal corrosion threat.

Stress Corrosion Cracking
Stress Corrosion Cracking (SCC) is a cracking mechanism that requires elevated stresses combined with a favorable environment to drive crack growth. This threat is often discussed in terms of high pH SCC and near-neutral pH SCC. At present, the Transmission Integrity Management Risk Management team estimates that approximately 3% of the system is potentially vulnerable to high pH stress corrosion cracking while approximately 25% of the system is potentially vulnerable to near-neutral pH stress corrosion cracking.

Manufacturing-Related
Manufacturing related threats manifest themselves in a number of ways, including:

Longitudinal Seam Defects
Seam defects are caused by errors in the welding of the pipe seam and can cause leaks or ruptures, particularly in over-pressure situations or in the presence of interacting threats. Nonetheless, seam weld related defects can be considered stable in the transmission pipe as long as sufficient pressure testing is performed, the pipe is operated correctly (see Incorrect Operation threat), and interacting threats (e.g. land movement) do not drive the growth of such defects. The Transmission Integrity Management Risk Management team estimates that approximately 36% of the system is potentially vulnerable to the unstable long-seam defect threat.

Pipe Defects
Pipe defects in the pipe wall can be generated by various steel impurities that are possible from earlier vintage (pre-1962) steel making practices. The Transmission Integrity Management Risk Management team estimates that approximately 50% of the system is potentially vulnerable to manufacturing pipe defects threat.

Construction
Construction threats are any weakness in the pipe resulting from the segment of manufactured pipe being connected into its neighboring segments or corresponding components. The key areas affected by construction threats are girth welds, coupled pipe, wrinkle bends, miter bends and branch connections. These defects make the pipe segments more susceptible and likely to rupture when interacting with a land movement. At present, the Transmission Integrity Management Risk Management team estimates that approximately 17% of the system is potentially vulnerable to construction threats.

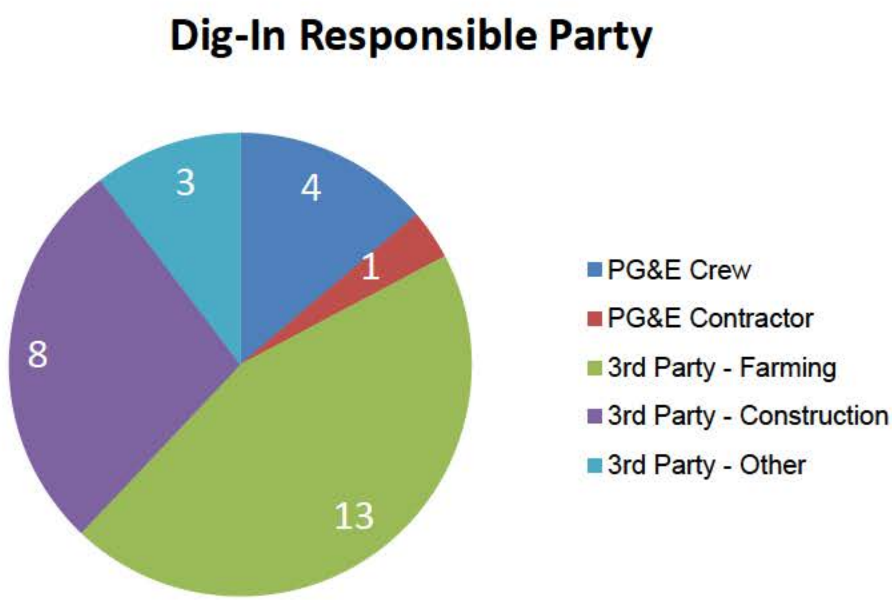
Equipment-Related
Equipment-related issues such as age or maintenance may lead to equipment failures that may lead to over-pressure excursions, which may produce failure of downstream assets, or under-

pressure excursions, which may result in customer outages. Due to the compliance requirements associated with valve maintenance, equipment-related issues typically only result in small leaks attributable to these components. The Transmission Integrity Management Risk Management team categorizes this threat as high, medium, or low threat level in accordance with Risk Management Procedure 16 (RMP-16). Equipment-related risk is subsequently calculated for segments of pipe categorized as High threat level. Currently, TIMP estimates that none of the system is highly vulnerable to equipment failure threats.

Mechanical / Excavation Damage
Excavation damage happens when the pipeline is inadvertently ruptured or dented through digging. Excavation damage can be caused by PG&E employees and contractors, other companies or members of the public, as seen below.

Figure 8 – Number of instances of excavation damage on PG&E's transmission system (2002 - 2016) by responsible party

Source: PG&E Dig-In Data Requests



Farming activity caused the largest number of excavation damage since 2002, with ripping or ploughing of fields being the primary activity causing damage to transmission pipeline. Also included in this threat category is the cyber security threat, which includes third parties infiltrating the SCADA system by bypassing PG&E's cyber security systems and potentially causing pressure fluctuations that could result in system damage.

Currently, all of the PG&E system is potentially vulnerable to the mechanical damage threats.

Incorrect Operations

Incorrect Operations threats include human error and incorrect procedures. These threats may lead to over-pressure events or under-pressure events due to incorrect manual valve operation. These threats may also lead to myriad safety hazards when procedures are not followed or when improperly trained or untrained personnel perform work on the transmission system. The Transmission Integrity Management Risk Management team categorizes this threat as high, medium, or low threat level in accordance with Risk Management Procedure 16 (RMP-16). Incorrect operations risk is subsequently calculated for segments of pipe categorized as High threat level. Currently, TIMP estimates that approximately 77% of the system is highly vulnerable to incorrect operation threats.

Weather and Outside Force

Weather and outside force damage may be caused by a wide range of factors:

- Water crossings
- Unstable soil / erosion
- Heavy rains / floods
- Seismic activity

PG&E has a well-established and advanced program for identification of potential damage due to earthquake through the automated process of email communications whenever an earthquake affects a pipeline area through the Dynamic Automated Seismic Hazard (DASH) automated reporting system. DASH was developed by the Geoscience Department, and integrates US Geological Survey (USGS) ShakeMaps and digital geohazard maps. DASH estimates shaking and damages at PG&E facilities and prioritizes emergency response. Additionally, PG&E annually reviews geohazard data, such as data from USGS, and updates a database layer that is incorporated into PG&E's GIS system. The layer identifies areas with known and potential liquefaction and landslide, and also has clearly identified locations of known fault crossings. At present, the Transmission Integrity Management Risk Management team estimates that approximately 78% of the system is potentially vulnerable to weather-related or outside force threats.

In 2014, PG&E began the process of surveying its entire transmission system using LiDAR, which informs the process for identification of geohazards, specifically soil creep and landslides. As a result of this completed survey, locations identified as high potential for erosion and landslides were field investigated by PG&E (Geosciences, TIMP Geotechnical consultants). The field reconnaissance activities inform whether or not more in-depth evaluations or mitigation are necessary.

Other Threats

As part of the Transmission definition change, approximately 7 miles of plastic pipe are now classified as Transmission. Plastic pipe is subject to a different set of threats than steel pipe. Therefore, additional threats and risks will be evaluated in accordance with ASME B31.8S and, if appropriate, added to the Transmission Pipe risk register. If any of the Transmission plastic pipe is located in high consequence areas, these segments will be subject to regulations in 49 CFR, Part 192.

C. Asset Family Risks

The Transmission Pipe asset family risks below are sorted below by Risk ID number. Also, interdependencies are listed for risks related to other Storage (STO), Transmission Pipe (TRA), Compression & Processing (CP), and Measurement & Controls (MC) asset family risks.

Table 14 - Transmission Pipe Risks and Interdependencies

Risk ID	Threat	Risk	Related Risks
TRA6	Third Party / Mechanical Damage	Rupture of transmission pipe due to mechanical damage by 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	Calibrated with STO30,19 Related to TRA7
TRA4	Manufacturing Related Defects	Longitudinal rupture of transmission pipe may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Calibrated with STO20 Related to TRA5
TRA8	Internal Corrosion	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	Calibrated with STO16 Related to TRA15
TRA1	External Corrosion	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage.	Calibrated with STO17 Related to TRA2
TRA3	Welding/Fabrication Related – Pre-1962 Construction with Land Movement	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Calibrated with STO21

Risk ID	Threat	Risk	Related Risks
TRA11	Incorrect Operation	Over pressurization, pipeline failure due to incorrect operations by PG&E's staff or contractors may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds, property damage.	Related toTRA22
TRA12	Weather Related & Outside Forces – Land Movement	Pipeline failure due to land movement associated with seismic activity, flooding, or other geo-hazards (e.g., subsidence, soil creep, fault creep, liquefaction) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages	Calibrated with STO23,22
TRA30	Construction/Fabrication Related – Branch Connections	Rupture of pipe at branch connection (saddle type) caused by external loading (including soil subsidence, inadequate pipe support, etc.) may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages	N/A
TRA16	Equipment Related - Over-Pressure Event	Equipment related defect resulting to an OP event downstream causing loss of Containment at a customer facility	N/A
TRA9	Stress Corrosion Cracking	Rupture of transmission pipeline due to stress corrosion cracking (SCC) may result in the uncontrolled flow of gas that can lead to significant impact on public or employee safety, prolonged outages due to lack of redundancy on radial feeds and additional SCC-related investigations that would occur post-incident, property damage.	Calibrated with STO31
TRA19	Mechanical Damage – Electric Substation Damage	Failure of transmission pipe located at or near electric substations due to operations and incidents at electric substations may result in unsafe work environment (electrified pipe) or loss of containment that can lead to impact on public and employee safety, outages, property damage.	N/A

Risk ID	Threat	Risk	Related Risks
TRA21	Material Traceability	The inability to have a systemic process to trace or disseminate information on recalled or obsolete materials for removal or remediation may lead to safety impact.	N/A
TRA26	Equipment Related – Component Failure (Drips, Fittings)	Leak on Transmission component, including drips and fittings that may result in impact on public or employee safety, minor outages and requires valve replacement.	N/A
TRA14	Mechanical Damage – First & Second Party Damage	Failure from transmission pipe resulting from mechanical damage by PG&E (1st and 2nd party damage) may result in the uncontrolled flow of gas that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	Calibrated with STO30
TRA23	Third Party / Mechanical Damage – Vandalism	Vandalism and/or vehicular damage on above ground pipeline/equipment, including illegal/nefarious valve operation, may result in damage, over-pressurization, and/or loss of containment that may lead to impact on public or employee safety, minor outages, property damage.	Calibrated with STO29
TRA22	Incorrect Operations	Failures of transmission pipe due to PG&E employees or contractors not following work procedures may result in loss of containment that can lead to impact on public or employee safety, outages, property damages.	Related to TRA11
TRA20	Weather Related & Outside Forces – Tree Damage	Failure of transmission pipe due to trees damaging the pipe may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	N/A
TRA10	Weather Related & Outside Forces – Pipe Span Damage	Failure of pipeline spans (either intentional or unintentional) due to outside force damage (e.g., flood, tsunami, wind) may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public or employee safety, property damage, outages.	N/A

Risk ID	Threat	Risk	Related Risks
TRA25	Equipment Related – Inoperable Valves	Leak on transmission main line valve and/or inability to operate valve due to equipment failure may result in impact on public or employee safety, minor outages and requires valve replacement.	N/A
TRA29	Weather Related Outside Force – Pipe Buoyancy	Failure of pipeline due to buoyancy forces resulting from sea level rise or seasonal flooding may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public or employee safety, property damage, outages.	N/A
TRA2	External Corrosion (P50)	Leak in transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to minor impact on public safety, minor property damage, brief/no outages and/or minor environmental damage. (P50)	Calibrated with STO17.1 Related to TRA1
TRA7	Third Party / Mechanical Damage (P50)	Leak in transmission pipe resulting from mechanical damage by a 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to impact on public safety, minor property damage, brief/no outages. (P50)	Calibrated with STO30.1 Related to TRA6
TRA15	Internal Corrosion (P50)	Leak in transmission pipeline due to internal corrosion may result in the uncontrolled flow of gas that can lead to minor impact on public or employee safety, minor/no outages, property damages. (P50)	Calibrated with STO16.1 Related to TRA8
TRA5	Manufacturing Related Defects (P50)	Leak at longitudinal weld of transmission pipe may result in loss of containment and/or uncontrolled gas flow that can lead to negligible impact on public safety and negligible property damage.	Calibrated with STO20.1 Related to TRA4

D. Stakeholder Roles and Responsibilities Matrix

The key contacts are stakeholders who are involved in each phase of the asset lifecycle, managing and operating the assets to operate as planned.

Figure 9 - Stakeholder Roles and Responsibility Matrix

Stakeholder Group	Primary Contact	Creation / Enhancement				Utilization	Maintenance	Decommission / Dispose
		Conception	Design	Procure	Construct/ Start-up			
Compliance	Director	X	X	X	X	X	X	X
Transmission Engineering & Design	Director	X	X	X	X			X
Project Management	Director	X	X	X	X			X
Backbone Planning	Manager	X	X			X		X
Local Transmission Planning	Manager	X	X			X		X
Gas Transmission Control Center	Manager	X			X	X	X	X
Gas Control Strategy & Support	Director	X	X					X
Transmission Operations & Maintenance	Director		X		X		X	X
Wholesale Marketing & Business Development	Director	X						X
General Construction	Senior Director				X			X
Transmission and Distribution Operations	Vice President		X		X		X	X

E. Summary of Integrated Programs

The table below summarizes the programs of work contained within this asset management plan that are relevant to and documented in other asset family asset management plans. The table highlights which programs are applicable to multiple asset families and which plan has included forecast costs. This also ensures there is no duplication in forecasted program costs.

Figure 10 - Programs Relevant to Multiple Asset Families

Programs of Work	Transmission Pipe	Gas Storage	M&C	C&P	Other
Locate & Mark	X	X			
Gas transmission routine pipeline maintenance & monitoring	X	X			
Gas transmission routine pipeline reliability & expense projects	X	X			
Corrosion control	X	X	X	X	
ILI assessments	X	X			
ILI upgrades	X	X			
ILI anomalies rectification	X	X			
ILI inspected by other means	X	X			
ECDA	X	X			
ICDA	X	X			
SCCDA	X	X			
Close Interval Surveys (CIS)	X	X			
Stress corrosion cracking	X	X			
Pressure testing	X	X			
Shallow pipe	X	X			
Class location program	X	X			

Programs of Work	Transmission Pipe	Gas Storage	M&C	C&P	Other
Valve automation	X	X	X		
Public awareness	X	X			
Inoperable & Hard-to-Turn Valves	X	X	X	X	
Preventative maintenance program	X	X	X	X	X
Guidance documents	X	X	X	X	X
Training	X	X	X	X	X
Process safety	X	X	X	X	X
Cyber security	X	X	X	X	X
Physical security	X	X	X	X	

F. Glossary of Acronyms and Abbreviations

The following is a glossary of acronyms and abbreviations used in this asset management plan and related documents.

Table 15 - Acronyms and Abbreviations

Acronym	Meaning
AC	Alternating Current
AC	Atmospheric Corrosion
AF	Asset Family
AFO	Asset Family Owner
AHS	Asset Health Scorecard
AMP	Asset Management Plan
ANSI	American National Standards Institute
APD	Abnormal Peak Day
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
C&P	Compression & Processing
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CIS	Close Interval Survey
CM	Corrective Maintenance
CNG	Compressed Natural Gas
CoF	Consequence of Failure
CP	Cathodic Protection
CPUC	California Public Utilities Commission
CWD	Cold Winter Day
DC	Direct Current
DOT	Department of Transportation
ECA	Engineering Critical Assessment
ECDA	External Corrosion Direct Assessment
EORM	Enterprise and Operational Risk Management
ERM	Enterprise Risk Management
ERW	Electric Resistance Welded
ETS	Electrolysis Test Station
GIS	Geographic Information System
GSE	Gas Safety Excellence
GSR	Gas Service Representative
GT	Gas Transmission
GT&S	Gas Transmission and Storage
HCA	High Consequence Area
HP	High Pressure
IC	Internal Corrosion
ICDA	Internal Corrosion Direct Assessment
IGIS	Integrated Gas Information System

Acronym	Meaning
ILI	In-Line Inspection
IM	Integrity Management
KPI	Key Performance Indicator
LNG	Liquefied Natural Gas
LOB	Line of Business
LoF	Likelihood of Failure
M&C	Measurement and Control
M&O	Maintenance and Operations
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic Flux Leakage
MIC	Microbiologically Induced Corrosion
MOP	Maximum Operating Pressure
MPR	Material Problem Reporting
NDE	Non-Destructive Examination
NOV	Notice of Violation
PG&E	Pacific Gas and Electric
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	Potential Impact Radius
PM	Preventive Maintenance
PMC	Periodic Meter Change
PS	Portable Supply
psig	Pounds per Square Inch Gauge
RMP	Risk Management Procedure
SAP	Systems, Applications, Products
SCADA	Supervisory Control and Data Acquisition
SCC	Stress Corrosion Cracking
SCCDA	Stress Corrosion Cracking Direct Assessment
SME	Subject Matter Expert
SMYS	Specified Minimum Yield Strength
STPR	Strength Test Pressure Report
TIMP	Transmission Integrity Management Program
USA	Underground Service Alert
USGS	United States Geological Survey
WRO	Work Requested by Others

G. Change Log

The following table summarizes revisions since the previous publication of GP-1101: Transmission Pipe Asset Management Plan, Revision 2, which was published 8/12/2015.

Table 16 - Asset Management Plan Change Log

Section	Change	Reason for Change	Implication of Change
Entire Asset Management Plan	Updated asset family statistics, including asset and metric information	2015 data available	None
Sections 1.2 & 4.1	Added new strategic objective "Maintain a first quartile Damage Prevention program to further reduce transmission dig-ins"	Ensure continued focus on reducing highest asset risk	Work with Gas T&D Compliance Programs organization to monitor first quartile performance
Sections 1.4, 3.1, and Appendix C	Update list of risks to reflect 2016 Session D risk ranks	Consistent view of risks based on ranking	None
Section 4	Added discussion of desired state for Transmission Pipe asset family and key mitigation programs to address asset family risks	Ensure continued focus on improving the asset family and reducing asset risks	Work with various program owners to ensure desired state and timeframes for achieving desired state are kept up to date in this AMP
Section 4.2	Added Responsible Organization to each of the key mitigations included in this AMP	Ensure accountability in executing key mitigations to reduce asset risks	Work with various responsible organizations to ensure accurate program ownership information is kept up to date in this AMP

H. Session D Summaries for Highest Risks

The following summaries were prepared for five of the highest Transmission Pipe Asset Family risks to facilitate discussions during risk calibration. In addition to the workshops mentioned below workshops were held with other asset families to calibrate against M&C, C&P, and Storage risks.

The Transmission Pipe Asset Family also facilitated a third-party external review. Mark Hereth of Process Improvement Consultants, LLC was obtained to conduct a third party review of the Transmission Pipe Risk Register. Mark has over 30 years of experience in the energy, chemical and environmental industries as well as the oil and gas insurance industry. He has worked in the areas of risk management, management system development, pipeline operations, project management, process plant design and environmental and pipeline safety legislation and regulations. Mark presently serves as a board member for the Interstate Natural Gas Association of America Foundation and is on the Faculty at the Transportation Center at Northwestern University.

Mark was provided the relevant data and meeting materials related to the 2016 Transmission Pipe risk register, including: the Transmission Pipe risk register, Transmission Pipe risk workshop presentation materials and meeting notes etc. Mark was asked to review these materials, identify any gaps in terms of (1) risks included in risk register and (2) risk drivers for each risk included in risk register, and determine if the risk scores and rankings make sense, given his knowledge and experience in the industry.

Mark’s findings included the following:

“I agree with the change in Third Party Mechanical Damage (TRA006). Certainly the frequency is supported by the experience of line strike in Fresno, and the more recent line strike in Bakersfield. I believe this frequency is also warranted as there likely remains some risk of a late ticket(s) which could result in a line strike. I recognize that late tickets have been an area of directed effort but this frequency and the overall score should maintain a keen focus on prevention of third party mechanical damage. The fact that third party mechanical damage as the highest transmission score is consistent with other operators with systems in heavily congested urban areas. It should not be viewed as reflecting negatively on your damage prevention program. That program from our perspective is very strong. But it will likely ensure that you maintain continuing vigilance. I believe that the QA group that you had making random checks around the system is an exemplary practice. First it has the potential and in fact did find instances of where excavation was occurring without use of One Call and secondly, it sends a message that PG&E will be out in the community, working to protect its assets and in so doing will also protect the people that it serves. I am impressed and commend the group for its flexibility and its move to change scoring to reflect actual experience.”

In addition Gas Operations calibration sessions were held on November 9th and November 19th with asset family owners, SMEs and members of Gas Operations senior leadership. Enterprise calibration sessions with all lines of business were also held by PG&E, however these calibrations did not result in changes to any of the Transmission Pipe risk scores.

TRA6 – Third-Party / Mechanical Damage

Table 17 – TRA6 Risk Summary

Risk Name	Risk Description	2015 Score	2016 Score
TRA6 - Third-Party / Mechanical Damage	Rupture of transmission pipe due to mechanical damage by 3rd party may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	310	975

Process & Findings

The following were considered through the risk refresh process for TRA6:

WORKSHOP(S):

- Topics Covered:
  - All mechanical damage risks calibrated with one another
  - Industry and PG&E data
- Attendees:
  - Transmission Integrity Management (TIMP)
  - Damage Prevention
  - Pipeline Patrols
  - T&D Operations

SCENARIO:

- Heavy equipment dig-in causing line rupture
- Many fatalities
- Industry Example(s): Fresno and Bakersfield, CA, 2015

CONSEQUENCE:

- Safety consequence increased from a 6 to 7 as a result of changing scenario from single farmer to multiple people on site of failure causing significant increase in scores from 2015 to 2016

FREQUENCY:

No significant changes affecting frequency of failure from 2015 to 2016.

TRA1 – External Corrosion

Table 18 – TRA1 Risk Summary

Risk Name	Risk Description	2015 Score	2016 Score
TRA1 – Catastrophic Pipeline Failure – External Corrosion	Rupture of transmission pipeline due to external corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damages and/or significant environmental damage.	807	807

Process & Findings
The following were considered through the risk refresh process for TRA1:

WORKSHOP(S):

- Topics Covered:
    - All time-dependent risks (IC, EC, SCC) calibrated with one another
    - Industry and PG&E data
- Attendees:
    - Lead Subject Matter Expert: Bennie Barnes
    - Corrosion Engineering
    - Transmission Integrity Management (TIMP)
    - Pipeline Services
    - T&D Operations

SCENARIO:

- High consequence area (HCA) or Class 3 or 4 location
- Many fatalities
- Industry Example(s): Columbia Gas Company external corrosion rupture event in Sissonville, West Virginia, 2012

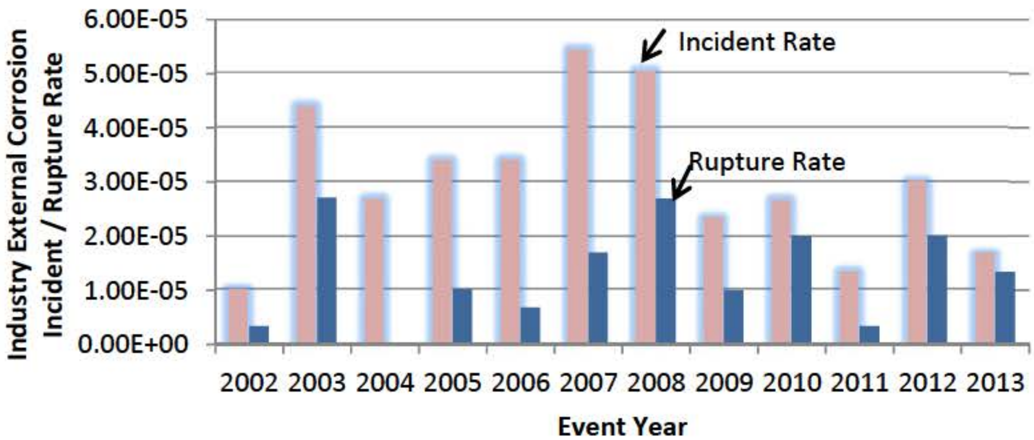
CONSEQUENCE:

- No significant changes affecting consequence of failure scores from 2015 to 2016

FREQUENCY:

- No significant changes affecting frequency of failure from 2015 to 2016.

Figure 11 - Industry External Corrosion Incident/Rupture Rate



Source: PHMSA Incident Database

- leak rate (2015)
  - PG&E = 0.0010701 external corrosion leak rate per mile
  - Industry = 0.0011089 external corrosion leak rate per mile

- In-line inspection (ILI)
  - PG&E's transmission system = 24% piggable
  - Industry = 68% piggable

Figure 12 - Number of ILI Repairs (by cause) per Mile Inspected

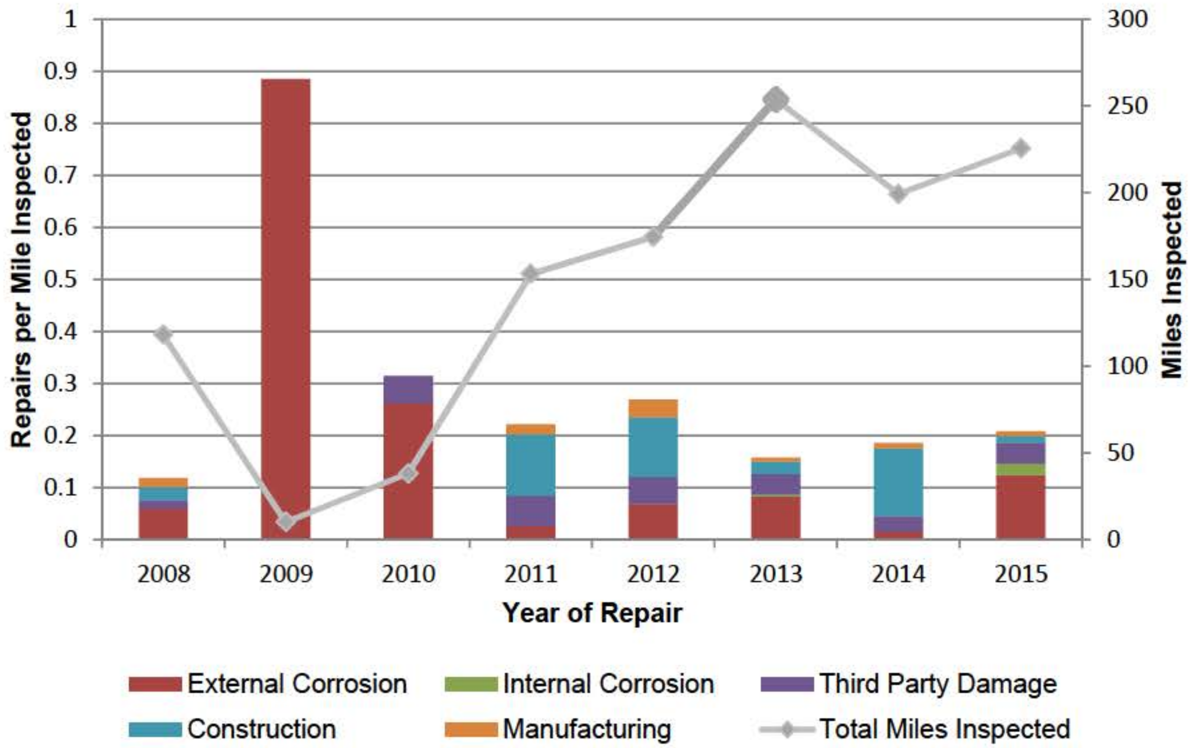


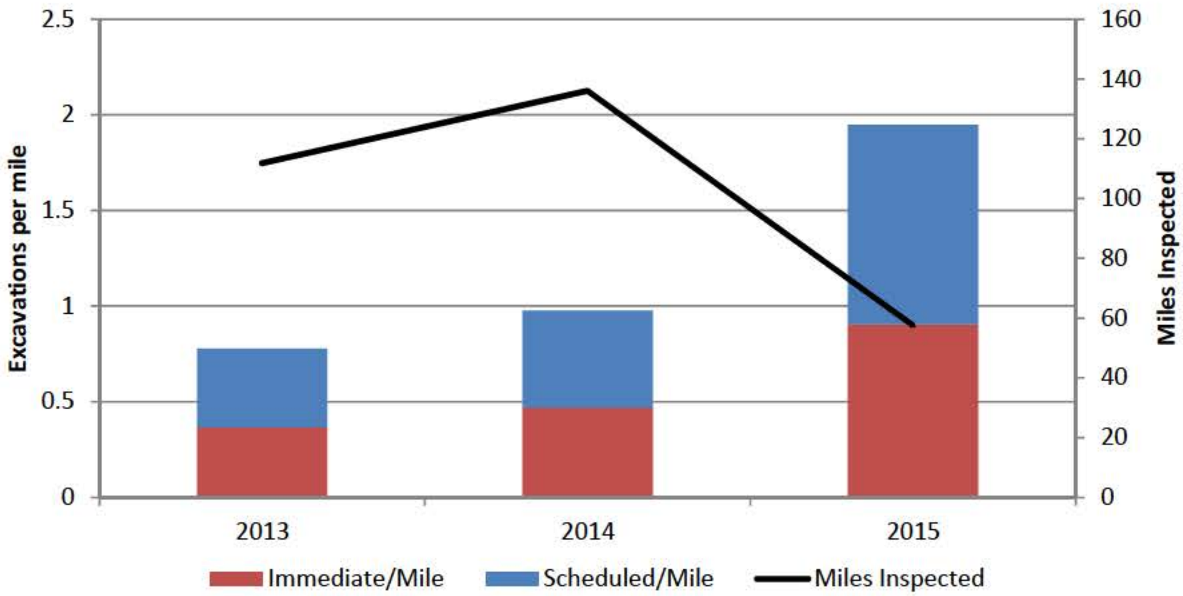
Table 19 - Total Number of ILI External Corrosion Anomalies

Year	2008	2009	2010	2011	2012	2013	2014	2015
# of Immediate	1	7	3	0	5	3	2	3
# of Scheduled	2	0	1	0	2	0	0	1
# of Non-Prioritized	4	2	6	4	16	37	6	11

NOTE: PHMSA annual report data is not structured to allow PG&E to compare its ILI repair statistics with industry by cause (e.g., external corrosion).

- PG&E's total anomaly findings from ILI are over two times industry average anomalies per mile (based on data from 2010-2015)
    - PG&E = 0.81 anomalies per 100 miles inspected
    - Industry = 0.29 anomalies per 100 miles inspected
- 2010 – 2015 External Corrosion Direct Assessment (ECDA) Anomalies per 100 Miles
    - PG&E = 3.30 external corrosion anomaly rate
    - Industry = 33.91 external corrosion anomaly rate

Figure 13 - Rate of ECDA Indications per Mile Inspected



- PG&E Transmission Corrosion Program Data:
  - 335 Contacted casings - 77 casings mitigated in 2015, 136 planned for 2016 and 122 in 2017. An additional 350 casings were identified in 2016 and planned for next rate case cycle.
  - Atmospheric corrosion mitigation required for 641 locations per 2012 self-report, 433 spans mitigated to date which includes backbone and local transmission
  - Low Reads - 180 items identified in 2012, 490 items in 2013, and 720 items in 2015 not meeting compliance criteria.
    - 904 of the 1,390 locations have been mitigated to date
    - Total of 1,390 low reads not meeting compliance and not mitigated within 12 months not to exceed 15 month window.
  - Alternating Current Interference
    - 7,040 potential locations with alternating current (AC) interference (2,784 locations investigated to date, 9 mitigation jobs completed).

- Given the information presented (known data), including
  - PG&E's lack of external corrosion rupture history and
  - PG&E's relatively low external corrosion leak and anomaly rate (compared to industry),

  Frequency scores 1 (once every 100+ years) and 2 (once every 30-100 years) were considered.

- Given the discussions around the strength of the Corrosion Program as well as unknowns due to current system piggability, the SMEs scored the Likelihood of Failure (LoF) for this risk at a Frequency of 2 (once every 30-100 years).

- Additional information that was not discussed during the workshop, but may have implications for the Frequency includes:
  Community Pipeline Safety Initiative (CPSI) Data:
  - Of the 300,322 right-of-way encroachments identified,
    - 7,315 have been deemed high risk
    - 20,302 have been deemed medium risk
    - 70,601 have been deemed low-medium risk
    - 202,104 have been deemed low risk and can stay within the right-of-way.
  - Of the high risk encroachments that have been reviewed, 97 locations require additional indirect inspections

TRA3 – Pre-1962 Construction with Land Movement

Table 20 - TRA3 Risk Summary

Risk Name	Risk Description	2015 Score	2016 Score
TRA3 – Catastrophic Pipeline Failure – Pre-1962 Construction with Land Movement	Circumferential rupture of vintage construction pipe (pre-radiographic pre-1962 girth welds, wrinkle bends, dresser couplings, miter bends, etc.) in known regions of geo-hazards and localized landslide zones may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	806	806

Process & Findings

The following were considered through the risk refresh process for TRA3:

WORKSHOP(S):

- Topics Covered:
  - All manufacturing and construction risks calibrated with one another
  - Industry and PG&E data
- Attendees:
  - Lead Subject Matter Expert: Bennie Barnes
  - Transmission Integrity Management (TIMP)
  - T&D Operations

SCENARIO:

- High consequence area (HCA) or Class 3 or 4 location
- Many fatalities
- Industry Example: Tennessee Gas Pipeline Company; Vintage construction and land movement rupture; Southern Ohio; 2011

CONSEQUENCE:

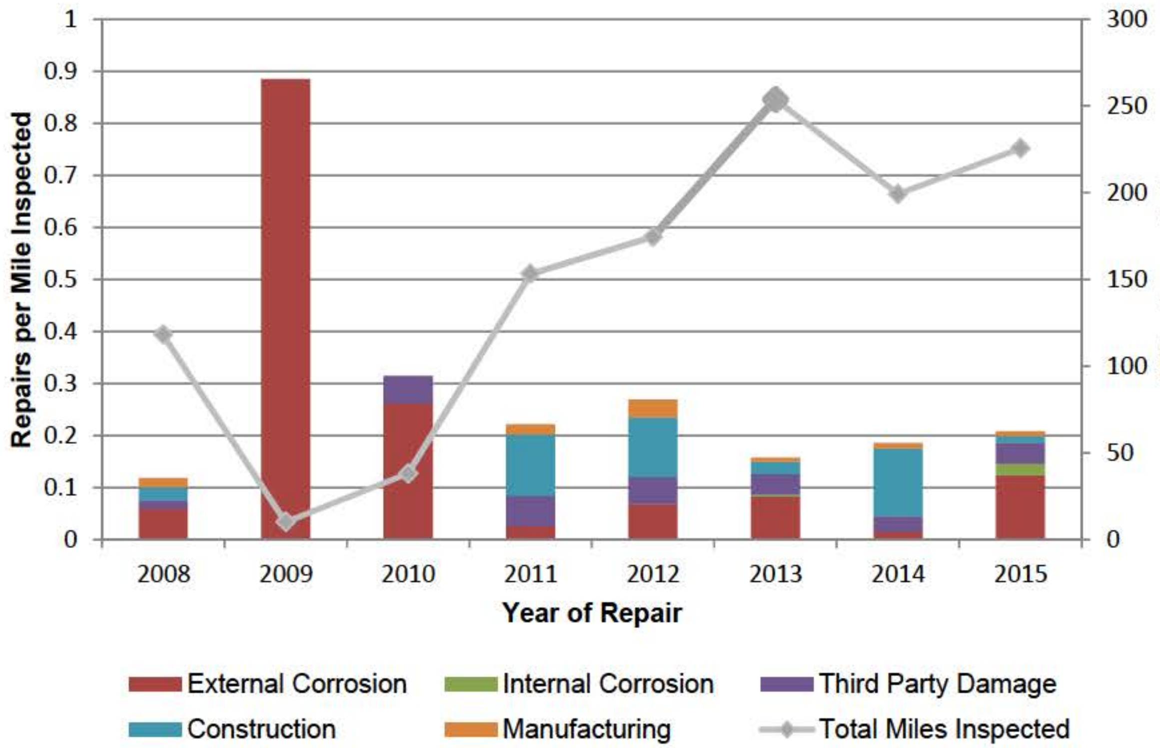
- No significant changes affecting consequence of failure scores from 2015 to 2016

FREQUENCY:

- No significant changes affecting frequency of failure from 2015 to 2016.

- In-line inspection (ILI)
  - PG&E's transmission system = 24% piggable
  - Industry = 68% piggable

Figure 14 - Number of ILI Repairs (by cause) per Mile Inspected



NOTE: PHMSA annual report data is not structured to allow PG&E to compare its ILI repair statistics with industry by cause (e.g., external corrosion).

- PG&E's total anomaly findings from ILI are approximately two to three times industry average anomalies per mile (based on data from 2010-2013)
  - PG&E = 0.92 anomalies per 100 miles inspected
  - Industry = 0.33 anomalies per 100 miles inspected

Given the information presented (known data) and discussions around the Vintage Pipe Replacement Program as well as unknowns due to current system piggability, the SMEs scored the Likelihood of Failure (LoF) for this risk at a Frequency of 2 (once every 30-100 years).

TRA8 – Internal Corrosion

Table 21 - TRA8 Risk Summary

Risk Name	Risk Description	2015 Score	2016 Score
TRA8 – Catastrophic Pipeline Failure – Internal Corrosion	Rupture of transmission pipeline due to internal corrosion may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public or employee safety, prolonged outages, property damage.	807	807

Process & Findings

The following were considered through the risk refresh process for TRA8:

WORKSHOP(S):

- Topics Covered:
  - All time-dependent risks (IC, EC, SCC) calibrated with one another
  - Industry and PG&E data
- Attendees:
  - Lead Subject Matter Expert: Bennie Barnes
  - Corrosion Engineering
  - Transmission Integrity Management (TIMP)
  - Pipeline Services
  - T&D Operations

SCENARIO:

- High consequence area (HCA) or Class 3 or 4 location
- Many fatalities
- Industry Example(s): El Paso Natural Gas pipeline internal corrosion rupture event in Carlsbad, New Mexico, 2000

CONSEQUENCE:

- No significant changes affecting consequence of failure scores from 2015 to 2016

FREQUENCY:

- No significant change in frequency score from 2015 to 2016

- In-line inspection (ILI)
  - PG&E's transmission system = 24% piggable
  - Industry = 68% piggable

Figure 15 - Number of ILI Repairs (by cause) per Mile Inspected

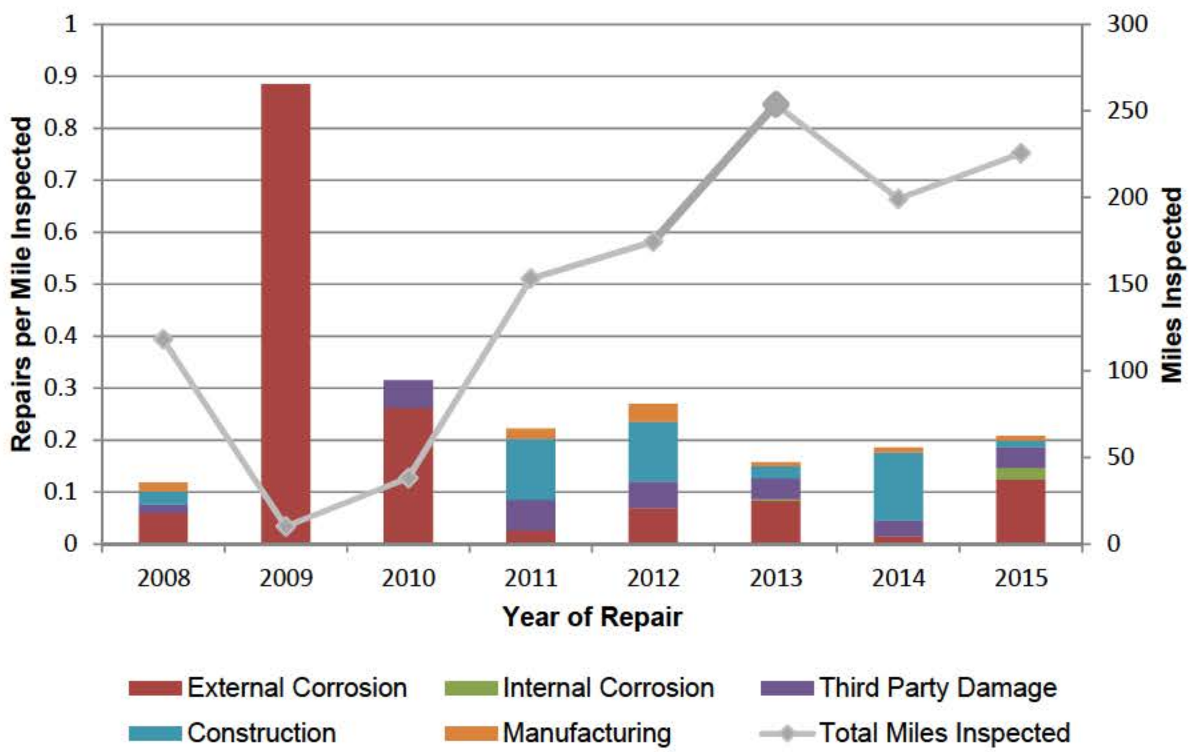


Table 22 - Total Number of ILI Internal Corrosion Anomalies

Year	2008	2009	2010	2011	2012	2013	2014	2015
# of Immediate	0	0	0	0	0	0	0	0
# of Scheduled	0	0	0	0	0	0	0	0
# of Non-Prioritized	0	0	0	0	1	7	4	0

NOTE: PHMSA annual report data is not structured to allow PG&E to compare its ILI repair statistics with industry by cause (e.g., internal corrosion).

- PG&E's total anomaly findings from ILI are over two times industry average anomalies per mile (based on data from 2010-2015)
  - PG&E = 0.81 anomalies per 100 miles inspected
  - Industry = 0.29 anomalies per 100 miles inspected
- 2010-2015 Internal Corrosion Direct Assessment (ICDA)
  - PG&E = 0.28 internal corrosion anomaly rate
  - Industry = 2.17 internal corrosion anomaly rate

- PG&E Transmission Corrosion Program Data:
    - Working with DNV to benchmark other utilities' internal corrosion processes and build best practices into PG&E procedures
    - Began Internal Corrosion Site Specific Plan investigations on gathering lines in 2015

- Given the information presented (known data) and discussions around the strength of the Corrosion Program as well as unknowns due to current system piggability, historic gas flow, and historic wet gas, the SMEs scored the Likelihood of Failure (LoF) for this risk at a Frequency of 2 (once every 30-100 years).

TRA4 – Manufacturing Related Defects

Table 23 - TRA4 Risk Summary

Risk Name	Risk Description	2015 Score	2016 Score
TRA4 – Catastrophic Pipeline Failure – Manufacturing Related Defects	Longitudinal rupture of transmission pipe may result in loss of containment and/or uncontrolled gas flow that can lead to significant impact on public safety, significant property damage, wide-scale/prolonged outages.	807	807

<u>Process & Findings</u>
The following were considered through the risk refresh process for TRA4:

WORKSHOP(S):
- Topics Covered:
  - All manufacturing and construction risks calibrated with one another
  - Industry and PG&E data
- Attendees:
  - Lead Subject Matter Expert: Bennie Barnes
  - Pipeline Services
  - Transmission Integrity Management (TIMP)
  - Data Delivery & Quantitative Analysis

SCENARIO:
- High consequence area (HCA) or Class 3 or 4 location
- Many fatalities
- Industry Example: Spectra Energy longitudinal seam weld rupture, Buick, British Columbia, 2012

CONSEQUENCE:
- No significant changes affecting consequence of failure scores from 2015 to 2016

FREQUENCY:
- No significant change in frequency of failure score from 2015 to 2016. Risk frequency is 2 (once every 30-100 years).

- Hydrostatic Testing
  - Of the 1,805 miles included in the scope of this risk, 5,853[11] miles have been tested to at least 1.25xMAOP (assessed for manufacturing threat)

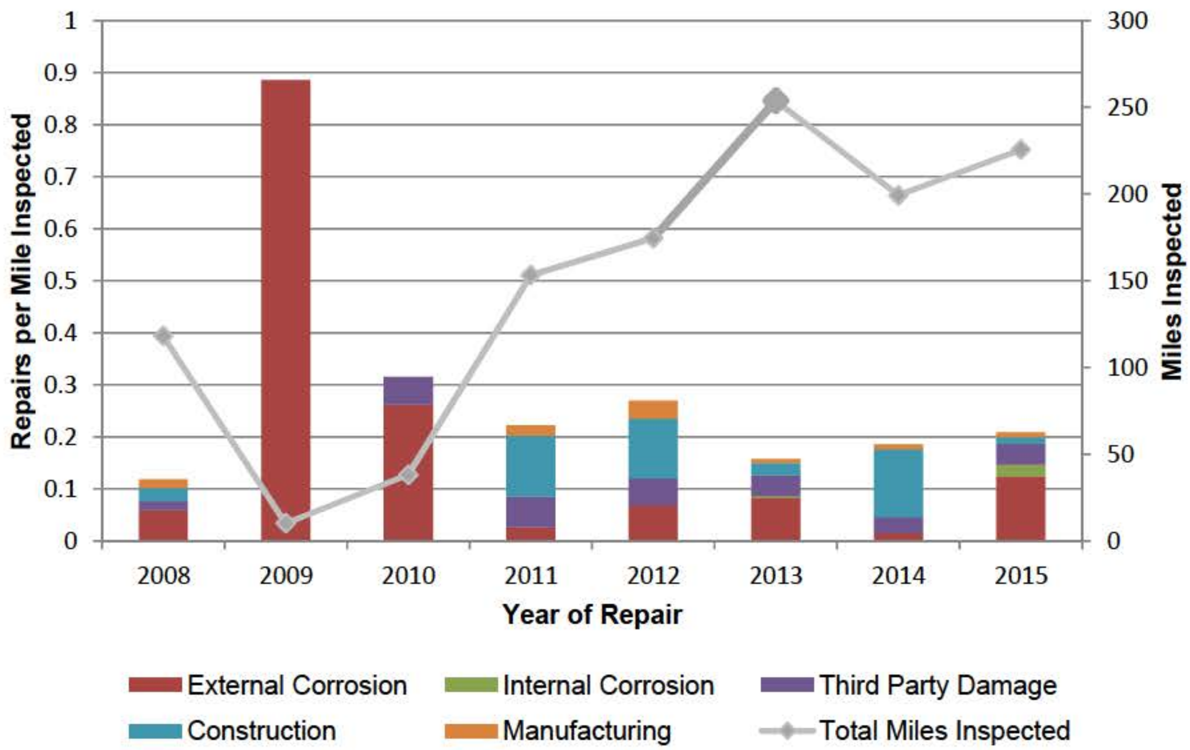
[11] Total Hydrotest miles complete are actual mileages from 2011-2015 and forecast for 2016

- Approximately 952 miles remain to be assessed for manufacturing threat (this includes all remaining HCA and non-HCA untested pipe)

- Fatigue Analysis
  - 1,039 miles included in scope of analysis (all HCA miles identified in 2011)
  - Completed fatigue analysis on 990[12] of these miles

- In-line inspection (ILI)
  - PG&E's transmission system = 24% piggable
  - Industry = 68% piggable
  - PG&E is beginning to use ILI technologies capable of identifying manufacturing defects (e.g., EMAT)

Figure 16 - Number of ILI Repairs (by cause) per Mile Inspected



[12] Additional miles were analyzed in 2016, but completion of analysis has not yet been verified and is not included in this figure.

Table 24 - Total Number of ILI Manufacturing Defect Anomalies

Year	2008	2009	2010	2011	2012	2013	2014	2015
# of Immediate	0	0	0	0	0	0	1	1
# of Scheduled	0	0	0	0	0	0	0	0
# of Non-Prioritized	2	0	0	2	7	14	7	0

NOTE: PHMSA annual report data is not structured to allow PG&E to compare its ILI repair statistics with industry by cause (e.g., manufacturing defects).

- PG&E's total anomaly findings from ILI are approximately two to three times industry average anomalies per mile (based on data from 2010-2013)
    - PG&E = 0.92 anomalies per 100 miles inspected
    - Industry = 0.33 anomalies per 100 miles inspected

- Given the information presented (known data), including
    - 153 miles remaining to be strength tested
    - 90+ miles remaining for fatigue analysis,

  Frequency scores 1 (once every 100+ years) and 2 (once every 30-100 years) were considered.

- Given the unknowns due to current system piggability, the SMEs confirmed the Likelihood of Failure (LoF) score for this risk at a Frequency of 2 (once every 30-100 years).

I. Performance Indicators

The metrics described in this section represent those currently being tracked by PG&E. Data is available or is becoming available to support these metrics. The metric along with related objective, current value, and future target values are presented in Table 25. Current Performance Indicators were identified since they provide the business with feedback for decision-making and prioritized since data was generally already available. The majority of metrics relate to leak performance as this has been and will continue to be a key indicator of asset condition and risk.

Table 25 - Transmission Pipe Asset Family Metrics and Corresponding Threat

Threat	Metric	Leading/Lagging	Indicator	YTD
External Corrosion	# of ILI and DA repairs completed as a result of the integrity management inspection program/miles inspected	Leading	lower is better	6
	# of leaks	Lagging	lower is better	3
	# of hydrostatic test failures	Leading	lower is better	0
Internal Corrosion	# of ILI and DA repairs completed as a result of the integrity management inspection program/miles inspected	Leading	lower is better	0
	# of leaks	Lagging	lower is better	0
	# of hydrostatic test failures	Leading	lower is better	0
Stress Corrosion Cracking	# of leaks	Lagging	lower is better	0
	# of hydrostatic test failures			0
	# of repair replacements		lower is better	0
Manufacturing	# of leaks	Lagging	lower is better	0
	# of hydrostatic test failures	Leading	lower is better	0
Construction	# of leaks	Lagging	lower is better	0

Threat	Metric	Leading/Lagging	Indicator	YTD
	# of girth welds/couplings reinforced/removed	Leading	lower is better	2642
	# of welds inspected/repaired/removed			17
Equipment	# of leaks	Lagging	lower is better	16
	# of equipment failures (regulator and relief valves, gasket or o-ring, and other)	Lagging	lower is better	10
Mechanical/Excavation Damage	# of ILI and DA repairs completed as a result of the integrity management inspection program/miles inspected	Leading	lower is better	0
	# of leaks	Lagging	lower is better	0
Incorrect Operations	# of leaks	Lagging	lower is better	0
Weather and Outside	# of leaks	Lagging	lower is better	0
	# of repair, replacement, or relocation actions	Lagging	lower is better	21
Other	# of ILI and DA repairs completed as a result of the integrity management inspection program/miles inspected	Leading	lower is better	4
	# of hydrostatic test failures	Leading	lower is better	0