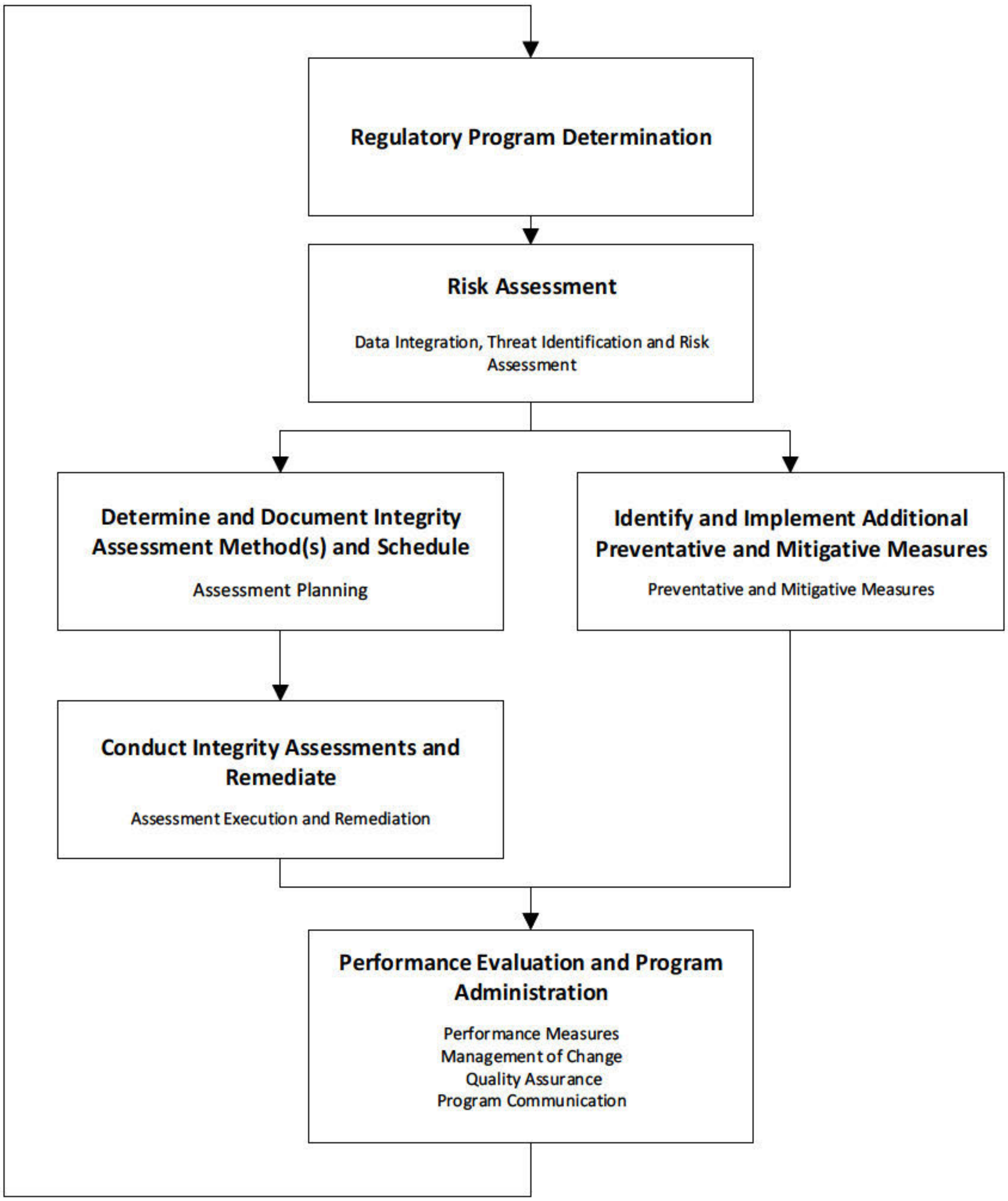
Pipeline Integrity Management Program
49 CFR §192 - Subpart O

Natural Gas Pipelines
Pipeline Integrity Department
Kinder Morgan, Inc.
Effective: February 1, 2002
Updated: July 1, 2020

NTSB INCIDENT #PLD21FR003
EPNG LINE 2000-0005945

Attachment A – Sub-Program Overview



3. Data Integration, Threat Identification and Risk Assessment

3.1. Introduction

In conformance with 49 CFR §192.917, ASME B31.8S[2] (*Managing System Integrity of Gas Pipelines)* and TRRC 16 TAC 8.101, KM integrates data, identifies threats and assesses risk for each route within the KM Pipeline Open Database Standard (PODS) database (DB). Risk assessment results are then employed to determine assessment methods and prioritize assessment schedules.

3.1.2. Process Overview

KM has established an annual cycle for evaluating risk on the pipeline system. Data for the physical pipeline and immediate surroundings is continually gathered, verified, and updated in specified data repositories. Analysis of the data is conducted through the use of a Risk Assessment Software (Risk Tool). The risk results are validated by Subject Matter Experts (SMEs) and communicated to stakeholders. Prioritized results are then employed in directing the remaining analyses and processes of the IMP. A detailed workflow is presented in Figure 3.1 - Risk Assessment Process Workflow (following page).

[2] All references to B31.8S are for the version incorporated by reference in 49 CFR 192.7

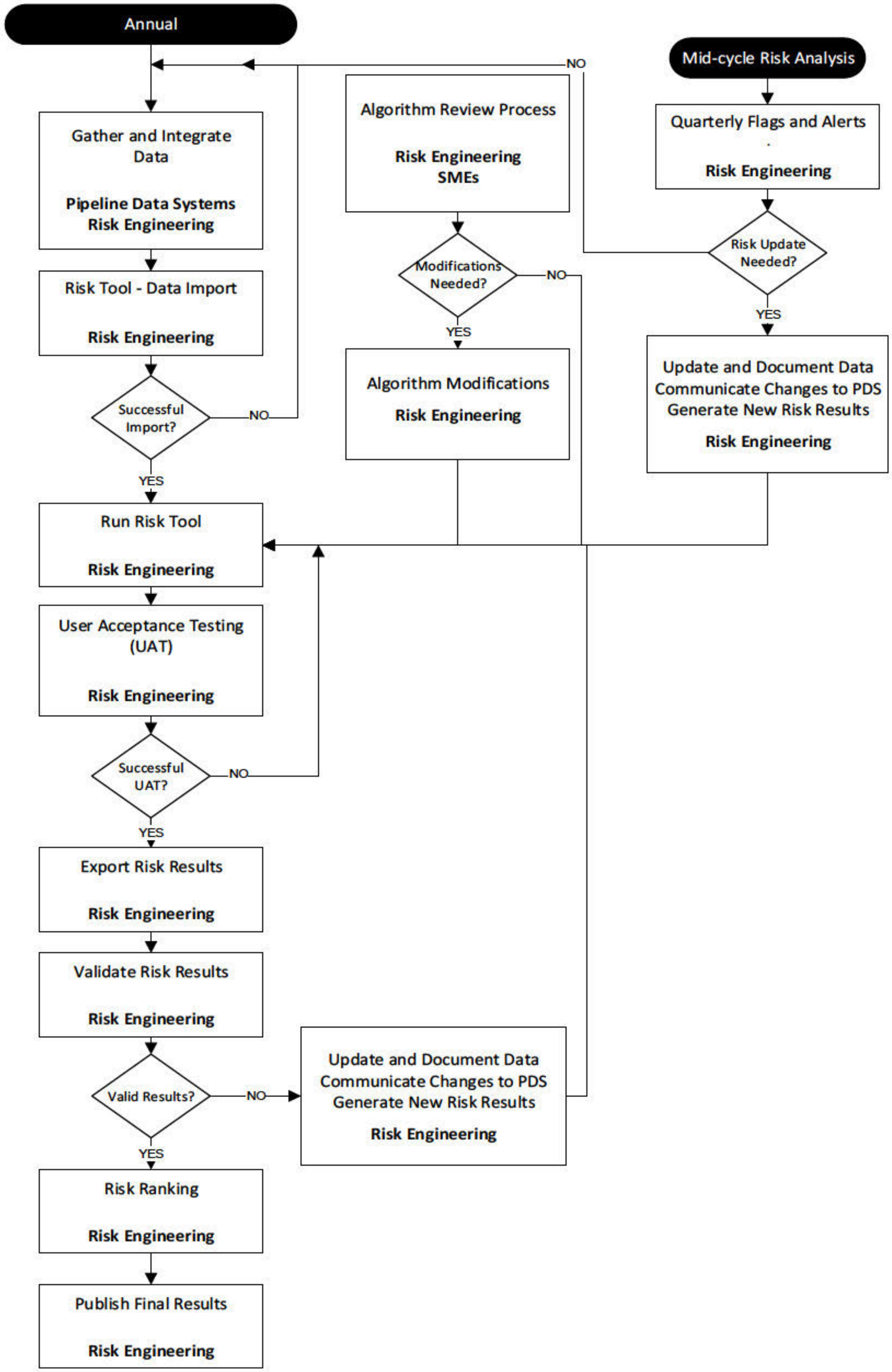


Figure 3.1 - Risk Assessment Process Workflow

3.1.3. Process Triggers

KM updates risk results through an annual risk determination process in addition to monitoring for changes that could trigger additional risk analysis.

3.1.3.1. Annual Risk Determination

In order to determine asset risks, KM conducts an annual risk analysis process as described in this section. This annually executed process includes the following considerations:

- Data integration and risk assessment information
- Past and present risk assessment results
- SME input

Risk results are finalized by the end of each calendar year. A typical schedule for Risk Determination is as follows:

- Algorithm Modifications – Continuous/Ongoing
- Data Gathering and Integration – Continuous/Ongoing
- User Acceptance Testing (UAT)/Validation of Risk Results – November 15th
- Publish Final Risk Rankings/Results – December 31st

3.1.3.2. Mid-Cycle Risk Determination

For newly identified HCAs, changes to existing HCAs, and Flags and Alerts, a mid-cycle risk assessment may be conducted. Flags and Alerts are identified for any of the following items:

- Leaks/Ruptures
- Pressure test failures
- Pipe Examination Reports (PERs) indicating presence of unexpected threats
- Completion of additional data gathering and validation
- MAOP Exceedances
- Hits and Near Misses

A mid-cycle risk analysis may be conducted on pipelines identified in this section on a case-by-case basis.

3.2. Risk Algorithm

KM employs a qualitative risk-based model to determine threats and potential consequences associated with pipeline segment failure. The Risk Tool is used to execute KM's risk analysis and assigns risk to segments. Risk of failure associated with a pipeline segment is a function of the likelihood of an event or condition that could lead to a release and the resulting consequences of that release. The total risk score (Risk) is the product of the Failure Likelihood Score (p_f) and the Consequence Score (C) and is represented by the following general equation:

Risk = p_f x C

Conservative assumptions are employed in risk analysis by threat and segment. If data is not available for a particular threat, the most conservative attribute value is assigned. A threat can be removed from a segment only if there is sufficient technical basis, documented by an SME, for the removal of that threat. Specific algorithm calculations are detailed in **Risk Algorithm Document**.

3.2.1. Failure Likelihood Analysis [§192.917(a) & (e)]

Failure Likelihood, as it relates to pipeline integrity, is the relative measure of the likelihood of the pipeline failing. Likelihood is calculated as a function of industry-accepted threats and their interactions. **Risk Engineering** monitors pipelines for new and changing conditions that could introduce additional threats or interactions.

3.2.1.1. Threat Identification [§192.917(a) & (e)]

The Risk Tool identifies and assigns risk scores to known threats to pipeline integrity. Threats are further delineated by three categories: 'Time Dependent', 'Time Independent', and 'Stable Threats'. In conformance with ASME B31.8S, Managing System Integrity of Gas Pipelines, **Risk Engineering** considers the threats shown in Table 3.1 - Threat Categories (follows), including cyclic fatigue, other loading conditions, and all other potential threats. Specific threat considerations are detailed in Threat Specific Considerations subsection.

Threats		
Time Dependent	**Time Independent**	**Stable**
External Corrosion	Third Party/Mechanical Damage • Damage inflicted by first, second, or third parties (instantaneous/immediate failure) • Previously damaged pipe (delayed failure mode) • Vandalism	Manufacturing Defects • Defective pipe seam (i.e. ERW, Lap weld, Flash weld, Butt weld, Hammer weld) • Defective pipe
Internal Corrosion	Incorrect Operations • Incorrect operational procedure	Construction Threats • Defective pipe girth weld • Defective fabrication weld • Wrinkle bend or buckle • Stripped threads/broken pipe/coupling failure
Stress Corrosion Cracking	Weather and Outside Force (Geotechnical) • Cold weather • Lightning • Heavy rains or floods • Earth movements • Geology • Seismicity	Equipment Failure • Gasket O-ring failure • Control/relief equipment malfunction • Seal/pump packing failure • Miscellaneous

Table 3.1 - Threat Categories

3.2.2. Consequence Analysis

The Consequence calculation, as defined in Section 4 of **Risk Algorithm Document**, provides a prioritized ranking of consequences of failure based on the following three areas of concern:

- Safety
- Environmental loss
- Economic loss

3.2.3.4. Interactive Threats [ASME B31.8S]

ASME B31.8S, Managing System Integrity of Gas Pipelines defines interactive threats as “more than one threat occurring on a section of pipeline at the same time”. During review and validation of the risk analysis output, **Risk Engineering** considers the following threat interactions:

- Manufacturing defects and land movement involving unstable slope susceptibility or slope movement hazard
- Manufacturing defects and selective seam weld corrosion
- Construction threat and land movement involving unstable slope susceptibility or slope movement hazard
- Manufacturing defects and degraded coating to identify hard spot susceptibility

Interaction analysis specifics are defined in the **Risk Algorithm Document**.

3.3. Data Gathering and Integration [§192.917(b)]

In order to facilitate the risk analysis process, data, and information pertaining to the pipeline is gathered and integrated. Consistent with Appendix A of ASME B31.8S, *Managing System Integrity of Gas Pipelines*, **Risk Engineering** considers past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records, in-line inspection records, remediation records, and other conditions specific to each pipeline. Data attributes used in risk analysis are provided in the **Risk Algorithm Document**.

3.3.1. Data Gathering

To determine risk attributed to a pipeline segment, **Risk Engineering** obtains input information from the PODS DB.

On a continual basis, **Pipeline Data Systems (PDS)** is responsible for pipeline data gathering, validation, and DB updates.

Additional data beyond standard PODS data structure may be needed to conduct a complete risk assessment. **Risk Engineering** may coordinate additional data discovery and subsequent PODS updates with **PDS** where data is missing or suspected to be inaccurate. Until processes have been built to incorporate these additional datasets into **PDS** operations, **Risk Engineering** is responsible for gathering and verifying this data and communicating with **PDS** for incorporation into PODS.

3.4. Risk Assessment [§192.917(c)]

Once data import is successfully completed, risk assessment is conducted. **Risk Engineering** runs the Risk Tool, ensures that the tool is functioning properly, and exports final results. This section further details each process step.

3.6. Risk Ranking

Risk Engineering ranks total risk score from highest to lowest for all segments across the KM natural gas transmission system (by company) to generate a prioritized list. **Risk Engineering** generates a ranked list of Regulatory Program segments through the following general steps:

1) Total risk scores are ranked from highest to lowest
2) Regulatory Program segments are assigned a risk rank number
3) Risk ranking is finalized and officially documented

3.8. Quarterly Flags and Alerts

Risk Engineering conducts a quarterly review of threat Flags and Alerts. Flags and Alerts are identified as any of the following:

- Leaks/Ruptures
- Pressure test failures
- Pipe Examination Reports (PERs) indicating presence of unexpected threats
- Completion of additional data gathering and validation
- MAOP Exceedances
- Hits and Near Misses

Should a mid-cycle risk analysis be necessary for pipeline(s) identified in this review, steps detailed in the Risk Assessment subsection are completed. For any leak resulting from external corrosion, internal corrosion, or stress corrosion cracking reassessment intervals are reconfirmed and documented as detailed in IMP Section 4 – Assessment Planning. **Risk Engineering** documents meeting date, attendees, flags and alerts, and rationale for any mid-cycle risk analysis and reassessment interval redetermination within INTEGRA.

Method Selection Guide	Integrity Assessment Methods[4]		
Threat Categories	**Option #1**	**Option #2**	**Option #3**
[redacted]			
Stress Corrosion Cracking (Near Neutral pH)	EMAT	SPT	DE
Stress Corrosion Cracking (High pH)	EMAT	SPT	SCCDA / DE
[redacted]			

Table 4.1 - Method Selection Guide

[redacted]

5. ILI – Residual Field MFL technology currently available for 16-48” single diameter and for select dual-diameters

4.3.1. In-Line Inspection (ILI) Technologies [§192.921(a)(1), §192.937(c)(1)]

Risk Engineering identifies an acceptable ILI technology for assessing the identified threat(s) on the pipe segment. The **ILI Manager** maintains a list of approved vendors and selects an appropriate tool for each integrity assessment as specified in **O&M Procedure 916 – In-Line Inspections**. The following list is a brief description of the most commonly used technologies:

Caliper

A geometry/deformation technology is an electronic, in-line configuration caliper pig designed to provide pipeline integrity information. Specifically, these tools record indications and features such as dents, flat spots, wrinkles, ovality (out of roundness), bend radius and angle, deformation, wall thickness changes, girth welds, defect orientation, and other pipe data. This type of tool can be used to discern deformation severity and overall shape aspects of the deformation. For internal corrosion, external corrosion, or third party damage this tool is often used in combination with MFL-A or MFL-C.

Axial Magnetic Flux Leakage (MFL-A)

This technology provides detection of metal loss and certain manufacturing defects. KM utilizes high-resolution digital metal loss tools. MFL-A tools apply an axial magnetic field designed to primarily detect circular and circumferentially oriented metal loss. For internal corrosion, external corrosion, or third party damage these tools are often used in combination with the Caliper. MFL-A can also be configured for Residual Field MFL hard spot detection.

Circumferential Magnetic Flux Leakage (MFL-C)

This technology provides detection of metal loss and certain manufacturing defects. KM utilizes high-resolution digital metal loss tools. MFL-C tools apply a circumferential magnetic field designed to primarily detect circular and axially oriented metal loss. These axially oriented anomalies include: manufacturing defects in the longitudinal seam weld, selective seam weld corrosion and narrow axial corrosion. For internal corrosion, external corrosion, or third party damage these tools are often used in combination with the Caliper.

Electro Magnetic Acoustic Transducer (EMAT)

The EMAT tool is a technology primarily used to identify and quantify axial oriented cracking associated with long seams or due to stress corrosion cracking. The technology does not require a liquid filled pipeline or slug of coupling material that is needed for a Shear-Wave Ultrasonic inspection survey used to find the same axial cracks.

Inertial Measurement Unit (IMU)

An IMU is an electronic device combined with a GPS transmitter that measures and reports the orientation and position of the tool through the use of latitude and longitude coordinates. This device is typically used in conjunction with other tool type runs to spatialize and orient pipeline appurtenances to known coordinate locations.

4.3.2. Pressure Test (PT) [§192.921(a)(2), §192.929(b)(2), §192.937(c)(2), ASME B31.8S Sec. 5, Table 3]

Pressure testing is an accepted method for evaluating pipeline integrity. Pressure testing is effective for addressing time-dependent threats (external corrosion and internal corrosion), construction-related threats, and manufacturing-related threats. Pressure testing identifies defects with failure pressures less than the test pressure.

To ensure that pressure tests are valid evaluations of pipeline integrity, **Risk Engineering** determines the following pressure testing assessment criteria:

Minimum Test Limits:

Begin and end station locations of a pressure test are defined by two methods:

1. Test the entire covered segment if this is the only assessment method determined for that assessment period
2. If done in combination with other assessment methods, test only the pipe with the applicable threat to the pressure test assessment method

Minimum Test Pressure and Hold Time:

If assessing for external corrosion and internal corrosion threats, the minimum test pressure is determined using Table 4.3 - Integrity Assessment Intervals – Time Dependent Threats [ASME B31.8S, Table 3] and depends on the operating percent SMYS of the pipeline. The hold time is determined consistent with 49 CFR 192 Subpart J.

If assessing for manufacturing and construction threats, the covered segment must be pressure tested in accordance with 49 CFR §192, Subpart J to at least 1.25 times Maximum Allowable Operating Pressure (MAOP).

4.3.3. Spike Pressure Test (SPT) [§192.506, §192.921(a)(3), §192.929(b)(2), §192.937(c)(3)]

The use of SPT is appropriate for threats such as stress corrosion cracking, selective seam weld corrosion, manufacturing defects (including defective pipe and pipe seams) and other forms of defect or damage involving cracks or crack like defects. SPT are conducted in accordance with §192.506. Minimum test pressures and hold times for spike tests are also described in **O&M Procedure/Construction Standard 1600/C1135 – Strength and Leak Testing**.

4.3.4. Excavation and *in situ* Direct Examination (DE) [§192.921(a)(4), §192.937(c)(4)]

DE is conducted by means of visual examination, direct measurement, and recorded non-destructive examination results and data needed to assess all threats. Based upon the threat assessed, examples of appropriate non-destructive examination methods include, but are not limited to: ultrasonic testing (UT), phased array ultrasonic testing (PAUT), inverse wave field extrapolation (IWEX), radiography, and magnetic particle inspection (MPI). DE processes are further described in IMP Section 5 – Assessment Execution and Remediation, **O&M Procedure 920 – External Corrosion Direct Assessment, O&M Procedure 921 – Internal Corrosion Direct Assessment and O&M Procedure 919 – SCC Direct Assessment.**

4.5. Threat Review [§192.917(c), §192.937]

If an additional threat(s) is found, **Risk Engineering** reviews the current CAP to determine if the additional threat(s) is addressed under the current proposed assessment method. If the threat(s) is not addressed, **Risk Engineering** selects a new or additional assessment method detailed in the Assessment Method Selection subsection.

6.3. Automatic Shutoff Valves or Remote Control Valves Action Criteria Evaluations [§192.935(c)]

Every seven years, **Risk Engineering** conducts a study based on risk analysis to determine whether an automatic shutoff valve (ASV) or remote control valve (RCV) would be an efficient means of adding protection to a HCA in the event of a gas release. The review includes, at a minimum: swiftness of leak detection, speed and pipe shutdown capabilities, the type of gas transported, operating pressure, rate of potential release, pipeline profile, potential for ignition, and nearest response personnel location. Valve studies encompass a variety of pipeline locations, design specifications, and operating conditions to determine which unique characteristics are conducive to more efficient protection through added valves. Study results and completion date are stored within INTEGRA. To date, KM concludes that the application of ASVs or RCVs will not significantly reduce the damage impact of a pipeline rupture or provide an efficient means of additional safety.

Attachment A - Preventative and Mitigative Measures Selection Criteria

	Consequence	External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Manufacturing	Construction	Equipment	Third Party Damage, Mechanical Damage, Previously Damaged Pipe, Vandalism	Incorrect Operations	Weather and Outside Forces	Required Third Party	Required Outside Force	Required for pipelines operating < 30% in Class 3, 4 and no HCA	Required for pipelines operating < 30% in HCA	Required Plastic Transmission Pipelines	Global Activity	Beyond 192 Requirements	Existing 192 Requirements
Line Relocation	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Increase Depth of Cover	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.317 §192.327
Weather readiness Business Resumption Plan	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 512)	Y	None
Annual Training reviews and/or conduct Emergency Response Drills (specify internal/external in Notes)	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 1900)	Y	§192.615
Install ASVs and/or RCVs	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.935(c)
Pressure Reduction (specify in Notes)	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.619 §192.703
Additional Operator Training (specify in Notes)	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Additional Leak Survey	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.706
Install Leak Detection and Monitoring System	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.935(a)
Increased Patrols (specify in Notes)	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.705(b)
Pipe Replacements	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.935(a)
Enhanced Materials Specification (specify in Notes)	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.103
Close Interval Survey On/Off	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.620(7)(i)
Recoat Pipe	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None

	Consequence	External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Manufacturing	Construction	Equipment	Third Party Damage, Mechanical Damage, Previously Damaged Pipe, Vandalism	Incorrect Operations	Weather and Outside Forces	Required Third Party	Required Outside Force	Required for pipelines operating < 30% in Class 3, 4 and no HCA	Required for pipelines operating < 30% in HCA	Required Plastic Transmission Pipelines	Global Activity	Beyond 192 Requirements	Existing 192 Requirements
Annual check of all impressed current rectifiers for proper operation	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 903)	Y	None
Increased CP Monitoring (specify in Notes)	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.465
Annual external corrosion control program review	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 903)	Y	None
Annual internal corrosion control program review	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 906)	Y	None
Install Moisture Reduction Equipment	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Monitor Gas Quality and/or Liquids Sampling	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 906)	N	§192.475 §192.477
Biocide/Inhibiting Injection	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Internal Corrosion Monitoring (Coupons)	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.475 §192.477
Internal Cleaning Pig Program	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
SCC Monitoring during Pipeline Inspections	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 917)	Y	None
SCC Mitigation CP Optimal Range	[redacted]	[redacted]	[redacted]	X	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Install Mechanical Barrier or External Protection (specify in Notes)	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	§192.317
Warning Tape Placement	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		Y	None
Excavate or conduct above ground surveys in areas of unmonitored encroachments	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Y (O&M 204)	N	§192.935(b)(1)(iv)

	Consequence	External Corrosion	Internal Corrosion	Stress Corrosion Cracking	Manufacturing	Construction	Equipment	Third Party Damage, Mechanical Damage, Previously Damaged Pipe, Vandalism	Incorrect Operations	Weather and Outside Forces	Required Third Party	Required Outside Force	Required for pipelines operating < 30% in Class 3, 4 and no HCA	Required for pipelines operating < 30% in HCA	Required Plastic Transmission Pipelines	Global Activity	Beyond 192 Requirements	Existing 192 Requirements
Monitoring of excavations	[redacted]				[redacted]											Y (O&M 204)	N	§192.935(b)(1)(iv)
Maintaining an excavation damage database	[redacted]				[redacted]											Y (O&M 204)	N	§192.935(b)(1)(ii)
Using Qualified Personnel for Marking, Locating, and Supervising Excavations, etc.	[redacted]				[redacted]											Y (O&M 204)	N	§192.935(b)(1)(i)
Increased Signage on ROW (specify in Notes)	[redacted]				[redacted]												Y	§192.707
Increased Public Awareness Communications (specify in Notes)	[redacted]				[redacted]												Y	§192.616
Member of One-Call System	[redacted]				[redacted]											Y (O&M 204)	N	§192.614(b) / §192.935(b)(1)(iii)
Compliance Audit	[redacted]				[redacted]												Y	None
Strain Measurement and Analysis	[redacted]				[redacted]												Y	None
Reduce External Stress	[redacted]				[redacted]												Y	§192.935(b)(2)
Visual/Mechanical Inspection	[redacted]			X	[redacted]												Y	§192.613
Bending Strain Analysis (ILI w/ IMU and Caliper inspection)	[redacted]				[redacted]												Y	§192.935(b)(2)

Note:
[1] Select at least one measure from list

7.1.3. Process Triggers

KM establishes performance measures and evaluates IMP performance on an annual basis. The Performance Measure Analysis Period covers performance from January 1 – December 31, and data collection and evaluation are completed by June 1. The performance measure analysis is reviewed during the Annual IMP Meeting.

Performance goals are established and measures are updated annually (completed during the Annual IMP Meeting). Detailed metric review occurs primarily for the processes being reviewed in the Internal Quality Audit for that calendar year. A typical schedule for Annual Performance Measure Process is as follows:

- Collection and Validation of Data – Continuous
- Data Compilation – March-May
- PHMSA Annual Report Metrics – March 15th
- Annual IMP Meeting – May
- Confrim Goals and Identify new Metrics – During Annual IMP Meeting/Ongoing

7.1.4. Responsibilities

The **Risk Engineering Manager** is responsible for the development, implementation, and oversight of the processes and procedures contained in this section, including but not limited to:

- Oversight of Annual Performance Measures Evaluation and documentation
- Communication of findings to key stakeholders according to IMP Section 9 – Quality Assurance

The following also have responsibilities in the Performance Measures process:

- **Risk Engineering**
- **Pipeline Data Systems**
- **Subject Matter Experts (SMEs)**

7.1.5. Associated KM Procedures

The following KM O&M Procedures and documents are referenced in this section and have been incorporated into this program:

- **O&M Procedure 155 – Management of Change**

7.2. Safety Performance Goals

KM establishes specific Safety Performance Goals to:

- Full compliance with regulatory integrity management requirements, both inside and outside of High Consequence Areas
- Exceed regulatory integrity management requirements, both inside and outside of High Consequence Areas, through the application of Operations and Maintenance procedures
- Outperform industry peers, and reduce our own 5-year average, on unintentional product releases

7.3. Performance Metrics

Performance measures are used to evaluate effectiveness of the IMP and are broken into two categories:

- **Leading Indicators** – Measure the accomplishment and effectiveness of operator programs and activities to control risk.
- **Lagging Indicators** – Measure the outcomes of programs and activities to manage risk. They provide documented success or failure of these activities (results).

Performance metrics are further categorized as general (programmatic) or threat-specific. General metrics measure effectiveness of individual program elements and processes used in the IM program. Threat-specific metrics provide an indication as to whether significant threats are being effectively managed.

7.3.1. Identification of Required Performance Metrics

Pipeline Integrity Management Regulations specify certain metrics that operators are required to measure, track, and/or report to PHMSA. In conformance with 49 CFR §192.911(i), §192.945, and §191.17, Kinder Morgan collects metrics listed in Table 7.1 - Required Performance Metrics.

The performance metrics in this section are not to be reported to PHMSA for Special Permit Segments and Areas. Special Permit Segments and Areas are to be treated as HCA's, but not included in the annual report.

Overall or Threat-Specific	**Metric**	**Required by**
Overall	Number of miles of pipeline inspected versus program requirements	ASME B31.8S, 9.4 - *Performance Measurement: Intrasystem*, Reported: 49 CFR 191.17(a), PHMSA form 7100.2-1 - *Gas Transmission and Gathering Systems Annual Report*
	Number of immediate repairs completed as a result of the integrity management inspection program as defined by 49 CRF §192.933(d)(1)	
	Number of scheduled repairs completed as a result of the integrity management inspection program as defined in 49 CFR §192.933(d)(2)	
	Number of leaks, failures, and incidents (classified by cause)	
External Corrosion	Number of hydrostatic test failures caused by external corrosion	ASME B31.8S, Table 9 - *Performance Metrics* Not Reported
	Number of repair actions taken due to in-line inspection results	
	Number of repair actions taken due to direct assessment results	
	Number of external corrosion leaks	
Internal Corrosion	Number of hydrostatic test failures caused by internal corrosion	
	Number of repair actions taken due to in-line inspection results	
	Number of repair actions taken due to direct assessment results	
	Number of internal corrosion leaks	
	Number of in ervice leak or failure due to SCC	

Overall or Threat-Specific	Metric	Required by
Stress Corrosion Cracking	Number of repair replacements due to SCC	
	Number of hydrostatic test failures due to SCC	
Manufacturing	Number of hydrostatic test failures caused by manufacturing defects	
	Number of leaks due to manufacturing defects	
Construction	Number of leaks or failures due to construction defects	
	Number of girth welds/couplings reinforced/removed	
	Number of wrinkle bends removed	
	Number of wrinkle bends inspected	
	Number of fabrication welds repaired/removed	
Equipment	Number of regulator valve failures	
	Number of relief valve failures	
	Number of gasket or O-ring failures	
	Number of leaks due to equipment failures	
Third-Party Damage	Number of leaks or failures caused by third-party damage	
	Number of leaks or failures caused by previously damaged pipe	
	Number of leaks or failures caused by vandalism	
	Number of repairs implemented as a result of third-party damage prior to a leak or failure	
Incorrect Operations	Number of leaks or failures caused by incorrect operations	
	Number of audits/reviews conducted	
	Number of findings per audit/review, classified by severity	
	Number of changes to procedures due to audits/reviews	
Weather-Related and Outside Forces	Number of leaks that are weather related or due to outside force	
	Number of repair, replacement, or relocation actions due to weather-related or outside-force threats	

Table 7.1 - Required Performance Metrics

Annual reports are compiled and submitted to PHMSA for the period ending December 31st of each year as detailed in **O&M Procedure 219 - DOT and State Pipeline Reports**. **Risk Engineering** assists in annual reports preparation and **Codes & Standards** submits the annual reports.

7.3.2. Selection of Additional Meaningful Metrics

In accordance with program effectiveness requirements established by 49 CFR §192.945, KM employs additional metrics beyond those required (defined in Identification of Required Performance Metrics subsection).

Effective performance indicators (metrics) are easily and reliably measured and provide consistent, repeatable, and meaningful results. They are relevant to the objective being measured and comparable to other similar indicators over time, across the company, and/or across the industry. Selected metrics are a combination of general (programmatic) and threat-based metrics from each indicator category (Leading and Lagging), and address previous program or operational inadequacies, if identified.

Performance metrics are reviewed and updated annually to address any improvements identified by program evaluation and updated safety performance goals; non-useful metrics are eliminated. **Risk Engineering** with SME input selects performance metrics that provide consistent, repeatable, and meaningful results. **Risk Engineering** assigns responsibility for collection and monitoring of each metric. Affected stakeholders and those responsible for collecting information are notified of the new performance metrics selected.

7.5. Metric Trending, Analysis, and Goals Comparison

Risk Engineering analyzes metrics data to identify trends over time, across operational areas or companies. **Risk Engineering** evaluates performance against goals established for each metric and documents the success or failure to meet the goal in the **Performance Metric Spreadsheet**. In cases where a goal was not met, **Risk Engineering** or SMEs identify and document root causes or obstacles to success. Following completion of trending and analysis of performance metrics, current year goals are reviewed and modified if necessary using process in Safety Performance Goals subsection.

7.6. Identify Continuous Improvement Initiatives

Kinder Morgan identifies continuous improvement initiatives response to failure in goal achievement, identification of a negative trend, or incident reviews showing failure to track performance of an activity (i.e., something happened that we do not have a way of measuring). Continuous improvement initiatives could comprise the following:

- Risk reduction measures to address negative trends
- Organizational or programmatic changes to address deficiencies (e.g., updating IMP)
- Changes to metrics and goals to correspond to areas of concern and/or areas of improvement

Once identified, continuous improvement initiatives are documented with current year goals, tracked to completion by **Risk Engineering** or responsible SME(s) in the **Continuous Improvement Initiatives Spreadsheet**. Continuous improvement initiatives resulting in significant technical, physical, procedural, or organizational changes are coordinated through the eMOC process detailed in **O&M Procedure 155 – Management of Change**. The **Risk Engineering Manager** ensures that continuous improvement initiatives are monitored in future program evaluations to assess effectiveness of the actions taken.

9.2.2. Program Audits

To validate IMP effectiveness and verify conformance with all applicable regulation requirements KM conducts annual internal quality audits.

Annually, the **Engineering Manager** assigns an internal audit team to audit and review the IMP**.** To ensure a comprehensive program audit in intervals not to exceed 36 months, KM implements a rotating audit schedule detailed in Table 9.1 - Annual Audit Program Review Schedule (follows). The internal audit team reports any audit findings at the next management review meeting.

External (third party) audits may also be scheduled to validate internal audit results or in the event that an internal audit is impracticable.

The **Risk Engineering Manager** is responsible for monitoring audit findings through INTEGRA.

Audit Report Year			
1	2	3	IMP Section
1	1	X	2 - Regulatory Program Determination
X			3 - Data Integration, Threat Identification and Risk Assessment
X	1	1	4 - Assessment Planning
	X		5 - Assessment Execution and Remediation
	X		6 - Preventive and Mitigative Measures
		X	7 - Performance Measures
1	X	1	8 - Management of Change
		X	9 - Quality Assurance
		X	10 - Program Communications

Table 9.1 - Annual Audit Program Review Schedule

Notes:

1. Items marked with an 'X' require a full audit of the IMP Section/Chapter and associated documentation. Items marked with a "1" require a review of the documentation only
2. The audit years are a rolling three years