Guidance[1] for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics

[1] This document is to provide guidance describing methods to evaluate and measure IM program effectiveness. This document is not a regulation and creates no new legal obligations.

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Guidance for Strengthening Pipeline Safety through Rigorous Program Evaluation and Meaningful Metrics

1. Purpose

This document provides guidance on the elements and characteristics of a mature program evaluation approach utilizing processes created to define, collect and analyze meaningful performance metrics. This guidance uses the basic requirements and processes previously developed and documented in ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, API Standard 1160, Managing System Integrity for Liquid Pipelines, ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition and the Part 192 and 195 Integrity Management (IM) rules.

The guidance builds on this foundation to provide more detailed and comprehensive descriptions of the activities / steps involved in program evaluation as well as in the selection of meaningful performance metrics to support this evaluation. It clarifies and expands the Pipeline and Hazardous Materials Safety Administration's (PHMSA's) expectations for operator requirements to measure IM program effectiveness. In addition to the rule requirements and the noted standards, PHMSA inspectors will rely upon this guidance to assure operators are developing sound program evaluation processes and applying a robust and meaningful set of performance metrics in their program evaluation process.

2. Background

PHMSA has long recognized and communicated the critical importance of operator self-evaluation as part of an effective safety program. PHMSA has promoted and required the development, implementation and documentation of processes to perform program evaluations, including the regular monitoring and reporting of meaningful metrics to assess operator performance. PHMSA emphasizes the importance of the operator's management responsibility to fully understand and acknowledge the implications of these program evaluations and to take the necessary steps to address deficiencies and make necessary program improvements.

PHMSA's pipeline IM regulations require operators to establish processes to evaluate the effectiveness of their IM programs. Program evaluation is one of the key required program elements established in the IM rules. Additionally, operator senior management is required to certify the IM program performance information submitted annually to PHMSA.

Specific sections in the Federal IM regulations that directly require operator program evaluation and the use of meaningful performance metrics include the following:

- For hazardous liquid pipelines, §§195.452(f)(7) and 195.452(k) require methods to measure program effectiveness. Appendix C to 49CFR195 provides more specific guidance on establishing performance metrics to support the understanding and analysis of integrity threats to each pipeline segment. API Standard 1160, Managing Integrity for Hazardous Liquid Pipelines, also provides additional guidance on the program evaluation process in which the analysis of these metrics is used to improve performance.
- For gas transmission pipelines, §§192.911(i) and 192.945 define the requirements for establishing performance metrics and evaluating IM program performance. The gas

requirements invoke ASME B31.8S-2004, Managing System Integrity of Gas Pipelines. Section 9 of this standard provides guidance on the selection of performance metrics.

- For gas distribution systems, §192.1007(e) requires development and monitoring of performance measures to evaluate the effectiveness of IM programs. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. The guidance from ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition and ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, Section 9 can be used for the selection of performance metrics that can be applied to gas distribution systems.
- Advisory Bulletin ADB–2012–10 was published in the Federal Register on December 5, 2012, to remind operators of their responsibilities under current regulations to perform evaluations of their IM programs using meaningful metrics.

3. Overview of Process for Rigorous Program Evaluation

Program evaluation is an ongoing process to measure, assess and evaluate program and piping system performance using both leading and lagging performance metrics. Effective corrective actions addressing the evaluation outcomes should be taken to improve both programmatic activity and pipeline system performance and integrity. Leading and lagging indicators are defined as:

- Leading indicators measure the accomplishment and effectiveness of operator programs and activities to control risk. They provide insight into how well the operator is implementing the various elements of its IM or safety management program.
- Lagging metrics measure the outcomes of the programs and activities to manage risk. They provide the documented success or failure of these activities (results).

The program evaluation process should be formally controlled through, and be an integral part of, the pipeline operator's quality control / quality assurance program. The formal process should include management's commitment to monitor and evaluate performance measures. The program evaluation process is most effective when utilizing the four-step Deming Cycle activities of "planning, "doing," "checking" and "acting". Specifically, program evaluation is the fundamental process of an organization's efforts to facilitate continuous improvement

- PLAN: establish the objectives and processes necessary to deliver results in accordance with the organization’s policies and the expected output (goals). By establishing output expectations, the completeness and accuracy of the process is also a part of the targeted improvement.
- DO: implement / execute the processes and collect information / data for analysis as part of the “CHECK” and “ACT” steps.
- CHECK: analyze the information / data against policies, objectives and requirements; report the results to determine if objectives and expected results are being achieved; look for trends and deviations in implementation from the goals of the plan; and analyze the differences to determine their root causes and what corrective actions may be implemented to improve the process or the results.
- ACT: identify and implement the corrective actions where significant differences between actual and planned results have been identified. These corrective actions may apply to the completeness and accuracy of the procedures and process as part of the targeted improvement.

Specifically, program evaluation is the fundamental process of an organization's efforts to achieve a continuous improvement process. The following diagram, Figure 3.1, highlights the elements of an expected program evaluation process.

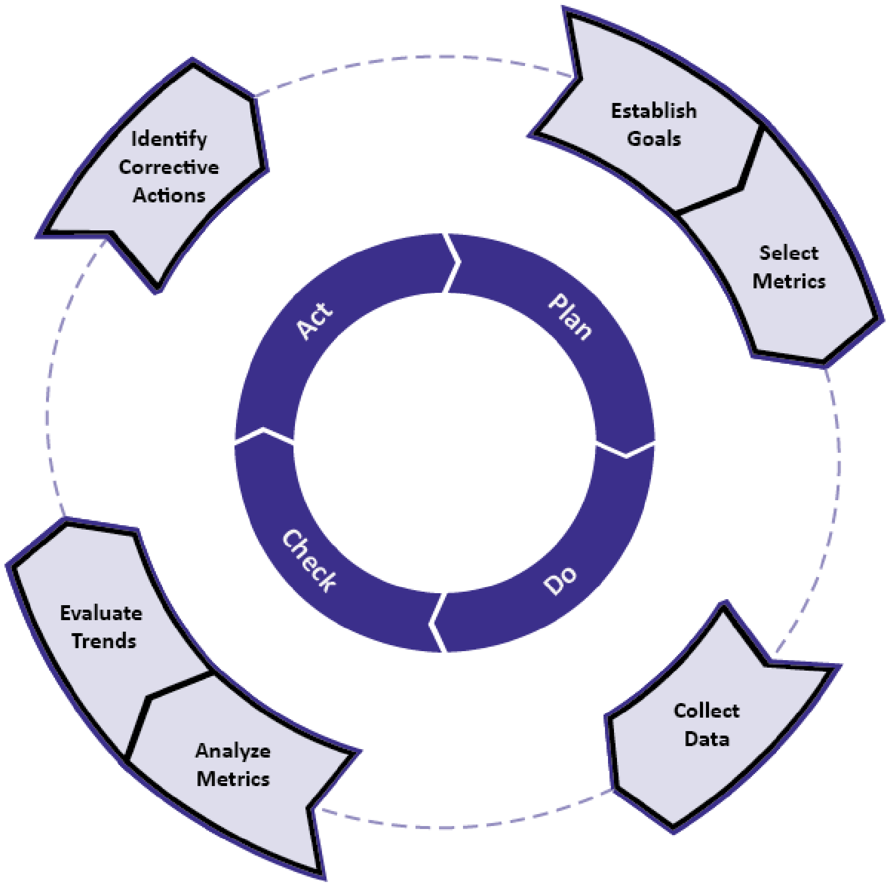

Figure 3.1, Elements of a Program Evaluation Process

Guidance related to these program evaluation elements is discussed in the following sections and is diagramed in Appendix A, Elements of a Mature Program Evaluation Process:

Section 4. Establish Safety Performance Goals
Section 5. Identification of Required Performance Metrics
Section 6. Selection of Additional Meaningful Metrics
Section 7. Performance Metrics Collection and Recording
Section 8. Program Evaluation Using Metrics
Section 9. Definitions

4. Establish Safety Performance Goals

Pipeline operators should establish their company's specific IM goals and objectives. The following sections outline the steps for selection, documentation, and communication of safety performance goals.

4.1. Safety Performance Goals - Safety performance goals should be documented and reviewed periodically, typically annually, as part of an operator's required program evaluation. These goals should support both the operator's short and long-term organizational objectives. The basis for their selection should be documented. Examples are:

- Documented program implementation - Who, What, When, Where and Why.
- On time implementations (e.g., scheduled integrity management assessments, preventive and mitigative measures).
- Reduction in the number of unintended releases or leaks (e.g., expressed as a reduction in the number of releases by "x"% with an ultimate goal of zero).
- Reduction in the volume of spills and leaks.
- Reduction in the number of "legacy" pipe failures.
- Reduction in the number of operator error events.
- Reduction in the number of public pipeline encroachments.
- Percentage of IM activities completed versus those scheduled during the evaluation period.
- Improved effectiveness of community outreach activities.

Safety performance goals should be established as appropriate at the operator / company / business unit levels that can be supported by performance metrics.

4.2. System Specific Safety Performance Goals - Additional safety performance goals should be established for any unique system configurations or situations. Unique system applications could include:

- Piping systems transporting products differing from the operator's primary product (e.g., highly volatile liquids, corrosive gas, CO_2).
- Piping systems having unique operating parameters (e.g., piping system that is susceptible to liquid entrainment).
- Piping systems having unique threat profiles (e.g., piping system susceptible to stress corrosion cracking, located in areas having high population density, industrial, or construction activity).

4.3. Senior Management Commitment - Senior management should be engaged in the development and review of the safety performance goals. Management provides input to the development of these goals. Management is expected to approve and endorse the final goals and to take an active role in communicating the goals to the appropriate levels of the organization. Senior management is also responsible for providing the necessary resources to make identified improvements, taking corrective actions and to ensure other company goals are consistent with safety goals.

4.4. Safety Performance Goal Communication - Safety performance goals should be routinely communicated within the operator's organization. An assessment of the organization's success, or failure, in meeting those goals should be communicated following each program evaluation, or at least annually. Typically, communication of the safety performance goals is implemented through:

- Company-wide e-mail communications.
- Documented discussions in staff and / or safety meetings.
- Documented tailgate safety meetings in the field prior to commencing work activities.
- Posters placed in prominent locations within the work place.
- Company internal web sites.
- Documented dissemination with contractor personnel who perform work.

4.5. Safety Performance Goal Review - Safety performance goals should be established or reaffirmed on a periodic basis. The operator reviews the appropriateness of its defined safety performance goals. The existing goals should be affirmed as appropriate for the operator's mission or refined / revised as needed to meet current conditions. Following the annual establishment or affirmation of safety performance goals, the goals should be communicated within the organization consistent with Section 4.4, Safety Performance Goal Communication.

5. Identification of Required Performance Metrics

Pipeline IM regulations specify performance metrics that are to be measured, tracked, and in certain cases, reported to PHMSA. These performance measures are valid meaningful performance metrics that should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics. Sections 5.1, Required IM Metrics, and 5.2, Other Required Metrics, identify those required performance metrics that all operators are required to measure, track, and report to PHMSA.

5.1. Required IM Metrics - Table 1, Calendar Year IM Program-Related Metrics from the Annual Reports, lists the Required IM Performance Metrics measured and reported to PHMSA by operators each calendar year.

- Gas Transmission Annual Report IM performance metrics are included in the Annual Reports required by §191.17 and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.
- Hazardous Liquid Annual Report IM performance metrics are included in the Annual Reports required by §195.49 and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.
- Gas Distribution System Annual Report IM performance metrics are included in the Annual Reports required by §192.1007(g) and are submitted on the Annual Report Form. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

5.2. Other Required Metrics - Other Metrics Required by §§192.911(i), 192.945, & ASME B31.8S Section 9 (GT); §§195.452(f), 195.452(k), 195 Appendix C & API-1160 Section 12 (HL); and §192.1007(e) (GD)

- 49CFR192.911(i) requires the establishment of a performance plan as outlined in ASME / ANSI B31.8S, Section 9 that includes performance measures meeting the requirements of §192.945. These additional threat specific metrics for gas transmission systems are included in Table 2, Other Required Metrics for Gas Transmission and Distribution Systems. These metrics are to be considered where applicable in the operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

- 49CFR195.452(k) requires measurement of hazardous liquid IM program effectiveness. The rule does not specify what methods are required to be used but provides example metrics in 195 Appendix C that could be used for performance measurement. The example metrics from this guidance are included, along with other examples in Table 3, IM Programmatic Performance Metrics, and Table 4, System and Threat-Specific Performance Measurement, and should be considered for selection under the process discussed in Section 6, Selection of Additional Meaningful Metrics.

- 49CFR192.1007(e) for gas distribution systems requires development and monitoring of performance measures to evaluate the effectiveness of IM programs. An operator must consider the results of its performance monitoring in periodically re-evaluating the threats and risks. Two performance metrics are required beyond those reported to PHMSA in the Annual Reports. These two addition metrics are included in Table 2, Other Required Metrics for Gas Transmission and Distribution Systems. These metrics should be included in an operator's annual program evaluation following the guidelines in Section 8, Program Evaluation Using Metrics.

6. Selection of Additional Meaningful Metrics

To fully comply with measurement of IM program effectiveness requirements established by §§192.945, 192.1007(e) and 195.452(k), operators must effectively measure the performance of their IM programs. Operators may need to consider additional metrics beyond those required metrics defined by Section 5, Identification of Required Performance Metrics, to enable a better understanding of the program implementation and the performance of specific systems or segments within systems. This is particularly important for the threat-specific metrics. It is also important to specify leading indicator metrics to identify potential organizational or programmatic inadequacies or failures that often contribute to a pipeline incident / accident. Operators should select metrics to effectively monitor and measure the company's methodology to achieve the safety performance goals established under Section 4, Establish Safety Performance Goals, of this guidance. They should also document the basis for the metrics selection. A description of the characteristics of effective performance indicators (metrics) is provided in Section 6.5, Characteristics of Effective Indicators (Metrics).

6.1. IM Program Element Implementation Metrics - Program implementation leading indicator metrics are used to identify potential organizational or programmatic inadequacies or failures that may contribute to a pipeline incident / accident. Operators should define performance metrics to effectively monitor and measure the company's program implementation. They should also document the basis for those metrics utilized. Table 3, IM Programmatic Performance Metrics, provides guidance for selection of these metrics. The suggested metrics may be applied to gas transmission, hazardous liquid transmission and gas distribution (where appropriate) and includes guidance for selecting process/operational activity, operational deterioration and failure metrics.

6.2. Operational Implementation Metrics – Operational implementation leading indicator metrics are used to identify potential operational activity inadequacies or failures (such as failure to follow procedure) that may contribute to a pipeline incident / accident. Operators should define performance metrics to effectively monitor and measure the activities associated with the safety programs including code-based requirements. They should also document the basis for those metrics utilized. Table 3, IM Programmatic Performance Metrics, provides guidance for selection of these metrics. The suggested metrics may be applied to gas transmission, hazardous liquid transmission and gas distribution pipelines where appropriate.

6.3. System Specific Metrics - Operators should establish system-specific performance metrics for any systems having unique operations, hazards or threats. System specific performance metrics may be required due to:

- Unique nature of product transported - CO_2, HVLs, bio-fuels, sour crude oil, etc.
- Unique hazards other company systems are not susceptible to - population growth in area of pipeline, unusual number of encroachments, electrical current.
- Unique threats other company systems are not susceptible to - stress corrosion cracking, selective seam corrosion, geological, environmental conditions in the pipeline area, bare pipe, etc.
- The presence of interacting threats (more than one threat occurring on a section of pipeline at the same time) that a company's system is susceptible to (e.g., corrosion at a location that has third party damage).
- Company systems with insufficient data on material attributes necessary to determine MOP / MAOP.

Metrics may also be useful to examine the performance of specific types of equipment and assets (e.g., facilities, breakout tanks, valves, pumps / compressors).

6.4. Threat Specific Metrics - Threat-Specific performance metrics are important to an effective program evaluation program. Table 4, System and Threat-Specific Performance Measurement, provides guidance for developing metrics that evaluate operator program effectiveness in managing the different transmission and distribution pipeline safety threats. This table is constructed similar to the example used in API 1160 with the threat guidance from ANSI / GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, 2012 Edition included.

An appropriate mix of performance metrics includes the following metric categories:

- Process /operational activity metrics monitor the surveillance and preventive activities undertaken by the operator. These are typically leading indicators of potential issues.
- Operational deterioration metrics are operational and maintenance trends that indicate when the integrity of the system is reduced despite preventive measures. These may be either leading or lagging indicators.
- Failure measures indicate the ultimate objective of the program has not yet been achieved, but hopefully will indicate progress towards goals (e.g., fewer spills, less damage, faster response, more effective cleanup). These are lagging indicators that undesirable outcomes have occurred.

6.5. Characteristics of Effective Indicators (Metrics) - Characteristics of effective performance indicators (metrics) are provided below. These characteristics are from ANSI/API RP 754-2010, Process Safety Performance Indicators for the Refining and Petrochemical Industries:

- Reliable: They are measurable using an objective or unbiased scale. To be measurable, an indicator needs to be specific and discrete.
- Repeatable: Similar conditions will produce similar results and different trained personnel measuring the same event or data point will obtain the same result.
- Consistent: The units and definitions are consistent across the company. This is particularly important when indicators from one area of the company will be compared with those of another.
- Independent of Outside Influences: The indicator leads to correct conclusions and is independent of pressure to achieve a specific outcome.
- Relevant: The indicator is relevant to the operating discipline or management system being measured; they have a purpose and lead to actionable response when outside the desired range.
- Comparable: The indicator is comparable with other similar indicators. Comparability may be over time, across a company, or across an industry.
- Meaningful: The indicator includes sufficient data to measure positive or negative change.
- Appropriate for the Intended Audience: The data and indicators reported will vary depending upon the needs of a given audience. Information for senior management and public reporting usually contains aggregated or normalized data and trends, and is provided on a periodic basis (e.g. quarterly or annually). Information for employees and employee representatives is usually more detailed and is reported more frequently.
- Timely: The indicator provides information when needed based upon the purpose of the indicator and the needs of the intended audience.
- Easy to Use: Indicators that are hard to measure or derive are less likely to be measured or less likely to be measured correctly.
- Auditable: Indicators should be auditable to ensure they meet the above expectations.

7. Performance Metrics Data Collection and Recording

Operators should have formalized processes to control and document collection of programmatic, operational and threat-specific performance measures.

7.1. Performance Metrics Collection – The details associated with the collection of performance metric data must be included in written plans or procedures which are managed through defined management systems and should include:

- Organizational responsibility for collection of information / data.
- Qualifications of personnel gathering and processing the metric data.
- Timing for collection of information / data.
- Data sources for metric data.
- How metric data is recorded.
- How raw metric data is processed, such as methods to normalize data by pipeline mileage, timeframe, or quantity of product transported.
- Technical review / validation of collected metric data to identify potential errors, including identification of measurement uncertainty, accuracy, and completeness.

7.2. Metrics Records Management - The written program should address records management requirements for maintaining measure data, analysis results and corrective actions taken. A mature program should have controlled systems or databases for retention, retrieval, and analysis of the performance maintained in an easily retrievable format and system.

8. Program Evaluation Using Metrics

As required by the IM rules, operators must implement processes to measure the effectiveness of their programs. The objective of these processes is to determine whether the program meets its intended objective of improving the safety and integrity of pipeline systems. Program evaluations support better management decision-making in support of continual improvement. These evaluations are to gauge the level to which an operator’s performance is meeting its identified safety performance goals.

Program and other evaluations may be conducted at different levels including the company or corporate level, at a system level to gauge one pipeline system's performance against that of other systems within the organization, or for selected assets with similar characteristics. Effective program evaluations should include all aspects of an operator’s organization, not just the integrity group.

Incident / accident investigations, abnormal operations and root cause analysis frequently reveal that management systems and organizational program deficiencies or failures are important contributors to pipeline accidents. For this reason, it is important that program evaluations also identify and correct potential organizational or programmatic deficiencies and failures that could have the potential to lead to pipeline incidents / accidents.

An effective operator program should have the characteristics identified below.

8.1. Assessment of Program Effectiveness - Periodic self-assessments, internal and/or external audits, management reviews, or other self-critical evaluations are used to assess program effectiveness. For the methods used, documented procedures or plans describe the:

- Scope, objectives, and frequency of program evaluations.
- Program evaluation process steps and documentation requirements.
- Responsibility, by organizational group or title, for both conducting the audits and implementing the required corrective actions.
- Evaluation of performance measures and the success in meeting safety, performance and integrity goals.
- Communication of evaluation results within the operator's organization.
- Management review and approval authority of program evaluation results.

8.2. Metric Trends - Program effectiveness is determined through the analysis of the performance measures selected under Section 5, Identification of Required Performance Metrics, and Section 6, Selection of Additional Meaningful Metrics. Performance metrics are reviewed to identify trends in the data collected for individual performance metrics. Positive and negative trends are documented. Risk reduction measures to address any negative trends are identified and documented. The performance metrics review includes an assessment of the success in meeting the safety performance goals described in Section 4, Establish Safety Performance Goals.

8.3. Program Evaluation Reviews - Program evaluation reviews should be conducted by the appropriate operator organizational groups to validate conclusions and the appropriateness of recommended corrective actions, including preventive or mitigative measures. Senior management should approve program evaluations and provide resources to address adverse performance trends identified by the program evaluation.

8.4. Performance Feedback - Performance feedback to the appropriate personnel and organizations responsible for the different aspects of the IM program should be provided. This feedback includes lessons learned, insights from the performance metric analysis, and best practices. Recommendations and action items should be communicated to the responsible managers in the organization.

8.5. Corrective Actions - Corrective actions should be formally tracked until completion. Documentation of corrective actions should be maintained for the life of the pipeline. Corrective actions should be monitored in future program evaluations to assess effectiveness of the actions taken. Corrective actions resulting in significant technical, physical, procedural, and organizational changes should be coordinated through the operator's management of change processes. Corrective actions should be implemented within designated timeframes commensurate with the action's importance to safety.

8.6. Threat Identification and Risk Analysis Updates - Periodic updates to the IM threat identification and risk analysis process consider the program evaluation outcomes, insights, and identified trends. This helps assure that the risk analysis tools used to support future safety and integrity decisions accurately reflect the operational history, asset condition, and program experience.

8.7. Program Evaluation Process Reviews - The program evaluation process itself should be reviewed at least annually to identify opportunities for improvement. Examples of opportunities for program improvement could include:

- Application of additional resources for performing program evaluations.
- Improvements to data validation processes.
- Improvements in the data collection and recording process.
- Streamlining of databases for data input, querying, and reporting.
- Revisions to program evaluation procedures.

8.8. Safety Performance Goal Confirmation - New safety performance goals should be established or the current set reaffirmed annually, based on the results of the program evaluation. The operator should review the appropriateness of their defined safety performance goals. The existing goals should be affirmed as appropriate for the operator's safety and IM programs or refined/revised as needed to meet current conditions.

8.9. Metric Updates - Metrics should be updated to address any improvements identified by the program evaluation and updated safety performance goals. The operator should eliminate non-useful metrics.

9. Definitions

9.1. **Deterioration Metrics** - Operation and maintenance non-release data trends that indicate when the integrity of the system is weakening despite operational programs and preventive measures. This category of performance metrics may indicate that the system condition is deteriorating despite well-executed preventive activities. These may be leading or lagging indicators and provide signals that improvement may be warranted. (API 1160-2001; §195 Appendix C, V.B(2))

9.2. **Failure Metrics** - Failure data reflecting whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure undesired outcomes such as the number of releases, the volume released, etc. (API 1160-2001; §195 Appendix C, V.B(3))

9.3. **Performance Analysis -** The comparison of the performance measures against objectives / goals to determine effectiveness.

9.4. **Program Evaluation** - Individual assessments to determine how well a program is working. Program evaluations support management decisions makers to implement continual process improvement. Program evaluations may be conducted at the company/corporate level or conducted at a unique system level to gauge one system's performance against that of other systems within the organization. Program evaluations may include comparing internal performance with performance of other similar external organizations (e.g., industry benchmarking).

9.5. **Performance Measurement** - Regularly monitoring and reporting on a program's progress and accomplishments using pre-selected performance measures or metrics. By establishing program metrics, an organization can gauge whether its program is meeting goals and objectives and can identify where changes in the program are warranted.

9.6. **Performance Metrics** - The type of information or data to be utilized to determine if objectives are being met. This information or data are parameters or measures of quantitative assessment used for measurement, comparison or to track safety performance. Performance measures form a continuum from leading indicators (before releases or failures) to lagging (after releases or failures), and include process measures, measures of deterioration and measures of actual failures or releases. (API 1160-2001)

9.7. **Required Performance Metrics** - Those performance metrics that operators are required to measure and track in accordance with §§191.17, 195.49, 192.945, 192.1007(g) and Section 5 of this guidance document.

9.8. **Selected Process (Activity) Measures** - Metrics that monitor the surveillance and preventive activities undertaken by the operator. These measures indicate the level at which an operator is implementing the various elements of the IM program and are generally considered to be leading indicators. (e.g., API 1160-2001; §195 Appendix C, V.B(1))

9.9. **System Specific Performance Metrics** - Performance metrics that apply to a single system or set of similar systems with unique operations, hazards or threats. These performance metrics are a subset of the Metrics established by an operator and not required by §§191.17, 195.49, 192.911(i) or 192.1007(g).

PHMSA's annual reporting forms, "F 7100.2-1" for Gas Transmission and "F 7000-1.1" for Hazardous Liquid Transmission, which operators must submit per §§191.17 and 195.49, require that operators submit the following information:

1. MILEAGE INSPECTED USING ILI
    a. Corrosion or metal loss tools.
    b. Dent or deformation tools.
    c. Crack or long seam defect detection tools.
    d. Any other internal inspection tools.
    e. Total tool mileage inspected using ILI.

2. ACTIONS TAKEN ON ILI
    a. Total number of anomalies excavated because they met the operator's criteria for excavation.
    b. Total number of anomalies repaired both within and outside HCA.
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT:
        i. Immediate repair conditions.
        ii. One-year conditions [HL: 60-day].
        iii. Monitored conditions [HL: 180-day].
        iv. Other Scheduled conditions [HL: This item is NA].

3. MILEAGE INSPECTED AND ACTIONS TAKEN BASED ON PRESSURE TESTING
    a. Total mileage inspected by pressure testing in calendar year.
    b. Total number of pressure test failures (ruptures and leaks) repaired, both within and outside HCA.
    c. Total number of pressure test ruptures (complete failure of pipe wall) repaired WITHIN AN HCA SEGMENT.
    d. Total number of pressure test leaks (less than complete wall failure but including escape of test medium) repaired WITHIN AN HCA SEGMENT.

4. MILEAGE INSPECTED AND ACTIONS TAKEN IN CALENDAR YEAR BASED ON DA (Direct Assessment methods)
    a. Total mileage inspected by each DA method in calendar year:
        i. ECDA
        ii. ICDA [HL: This item is NA]
        iii. SCCDA [HL: This item is NA]

    b. Total number of anomalies identified by each DA method and repaired based on the operator's criteria, both within and outside HCA:
        i. ECDA
        ii. ICDA [HL: This item is NA]
        iii. SCCDA [HL: This item is NA]

    c. Total number of conditions repaired in calendar year WITHIN AN HCA SEGMENT meeting the definition of:
        i. Immediate repair conditions
        ii. One-year conditions [HL: 60-day]
        iii. Monitored conditions [HL: 180-day]
        iv. Other Scheduled conditions [HL: This item is NA]

5. MILEAGE INSPECTED AND ACTIONS TAKEN BASED ON OTHER INSPECTION TECHNIQUES
    a. Total mileage inspected by inspection techniques other than those listed above.
    b. Total number of anomalies identified by other inspection techniques and repaired based on the operator's criteria, both within and outside HCA .
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT meeting the definition of:
        i. Immediate repair conditions
        ii. One-year conditions [HL: 60-day]
        iii. Monitored conditions [HL: 180-day]
        iv. Other Scheduled conditions [HL: This item is NA]

6. TOTAL MILEAGE INSPECTED (ALL METHODS) AND ACTIONS TAKEN IN CALENDAR YEAR
    a. Total mileage inspected .
    b. Total number of anomalies repaired both within and outside HCA.
    c. Total number of conditions repaired WITHIN AN HCA SEGMENT.

7. MILES OF BASELINE ASSESSMENTS AND REASSESSMENTS (HCA Segment miles ONLY)
    a. Baseline assessment miles completed during the calendar year.
    b. Reassessment miles completed during the calendar year.
    c. Total assessment and reassessment miles completed during the calendar year.

8. [Gas Only] Leaks, failures, and incidents during calendar year [Incident and Leak data breakdown not currently required for HL annual report]
    a. Breakdown by HCA and Non-HCA.
    b. Breakdown by transmission and gathering.
    c. Breakdown by the nine B31.8S cause categories (Table 2, Other Required Metrics for Gas Transmission and Distribution Systems).

PHMSA's annual reporting form, "F 7100.1-1" for Gas Distribution systems, which operators must submit per §192.1007(g), requires that operators submit the following information:

1. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by cause: corrosion, natural forces, excavation damage, materials or welds, equipment, incorrect operations, other.

2. Number of excavation damages.

3. Number of excavation tickets (receipt of information by the underground facility operator from the notification center).

4. Total number of leaks either eliminated or repaired, categorized by cause: corrosion, natural forces, excavation damage, materials or welds, equipment, incorrect operations, other.

Table 2 - Other Required Metrics for Gas Transmission and Distribution Systems

Required by §192.945 and ASME B31.8S-2004, Table 9 for Gas Transmission Pipelines:

Threat	Performance Metrics for Prescriptive Programs
External corrosion	Number of hydrostatic test failures caused by external corrosion
	Number of repair actions taken due to in-line inspection results
	Number of repair actions taken due to direct integrity 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 integrity assessment results
	Number of internal corrosion leaks
Stress corrosion cracking	Number of in-service leaks or failures due to SCC
	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

Required by §192.1007(g) for Gas Distribution systems, but not required to be reported on PHMSA's annual reporting form, "F 7100.1-1" for Gas Distribution systems:

1. Number of hazardous leaks either eliminated or repaired as required by §192.703(c) (or total number of leaks if all leaks are repaired when found), categorized by material.
2. Any additional measures the operator determines are needed to evaluate the effectiveness of the operator's IM program in controlling each identified threat.

Table 3 - IM Programmatic Performance Metrics

This table provides guidance for operators and inspectors to identify meaningful metrics to help understand and measure the effectiveness of the individual program elements and processes used in an IM program. The table lists required IM program elements and some candidate metrics that might be developed. The metrics for each program element are examples and do not represent a complete list. Operators may find that metrics other than those listed here are best suited for their operations and IM program. Operators may also have other important processes that are critical to managing integrity on their assets that are not listed here. In these situations, metrics to indicate the effectiveness of those activities should be developed.

Operators are not necessarily expected to develop and track metrics in all of the areas listed below. However, they should select a set of meaningful metrics that indicates whether the elements of its IM program are functioning as intended. The first 12 program elements apply to gas transmission and hazardous liquid transmission. Gas distribution could also address some of these program elements. The last program element, “Knowledge”, specifically applies to gas distribution systems.

Following a structure similar to that in API-1160 and ASME B31.8S, this table features three different types of performance metrics.

1. IM Process, Operational or Activity Metrics. These are metrics that reflect the implementation of the IM program elements, demonstrating that the program is being implemented as designed. These are typically leading indicators.
2. Operational Deterioration Indicators. These are metrics that indicate when the operator’s IM program processes and activities might be degrading despite the implementation of the processes noted in item 1.
3. Failure or Direct Integrity Metrics. These are clear, generally lagging, indicators that the IM program element’s objective of release prevention has not been achieved, but that over time may show trends toward improving safety.

Although this table does identify a number of specific metrics, an operator must tailor the specific metrics it uses to the design of its IM program, the specifics of the assets being managed, as well as the operator’s unique organizational needs. This table includes performance measurement opportunities for gas transmission, hazardous liquid transmission and gas distribution pipelines that are useful for identification of both programmatic and organizational deficiencies.

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators--*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
1. Identification of pipeline segments that could impact HCAs	● Frequency of updates to segment identification analysis ● Frequency and nature of reviews conducted to identify new HCAs ● Frequency of field district surveys or ROW inspections identifying new HCAs – or segments that could affect HCAs ● Frequency and nature of review of procedures and assumptions made in identifying segments that could affect HCAs ● Frequency of updates to aerial photography used for HCA segment analysis ● Frequency of contacts with public safety officials and others having local knowledge for information on potential "identified sites" or could affect segments	● No. of newly acquired or newly identified assets not incorporated within the IMP within the required timeframe ● No. of previously mis-identified HCAs identified as HCAs in updates to the segment identification analysis ● No. of PIR calculations using an inappropriate formula for product transported (Gas Trans) ● No. of new HCAs or could affect segments identified due to changing conditions (pipeline modifications, new public construction, change in public use of existing buildings, etc.) ● No. of abnormal weather conditions (e.g., stream flow rate) that exceed assumptions used in HCA or could affect segment identification	● No. of releases which reached an HCA from pipe that was not determined to be a "could affect" segment (Haz Liq) ● No. of releases with adverse impacts beyond the PIR (Gas Trans) ● No. of releases which had different impacts to HCAs than determined by the "could affect" analysis ● No. of releases which reached different HCAs than determined by the "could affect" analysis ● No. of releases that exceeded the highest estimated volume that could be released in a segment (Haz Liq)
2. Threat Identification and Risk Assessment	● Threat identification program ● Identification of interacting threats ● Frequency and nature of reviews for previously unidentified threats ● Processes to account for "missing data" ● Conformance with operator's risk assessment process procedures and practices ● Frequency and nature of risk assessment algorithm and / or model reviews ● Frequency of updates for data used in risk assessment; incorporation of new information in a timely manner ● Progress in addressing situations where documentation and records are absent. ● Timely integration of integrity assessment (e.g., ILI) results / insights into risk assessment ● Comprehensiveness of data sources ● Potential threat identified for monitoring or actions	● No. of mitigation activities for interacting threats (e.g., cyclic fatigue interaction with SCC) ● No. of mitigation activities for unstable threats ● Correlation of threat-specific deterioration and failure metrics with risk analysis results (i.e., are the metrics indicative of the most problematic technical areas consistent with the predictions of the risk model) ● No. of revisions or modifications to the threat identification process or tools as a result of IM Program evaluations ● No. of revisions or modifications to the risk assessment process or tools as a result of IM Program evaluations ● Destructive or non-destructive test results which indicate inaccuracies in material or component records – diameter, wall thickness, grade, seam type, toughness, coating type, etc.	● No. of releases involving a previously unidentified threat ● No. of releases involving an underestimated or misunderstood threat ● No. of releases involving two or more interacting threats. ● No. of releases in segments not identified as high risk ● No. of releases where lack of integration of information and / or data was a contributing factor ● No. of releases where the appropriate ILI tool or integrity assessment methodology was not employed ● No. of releases that exceeded the consequences considered in the risk analysis ● No. of failures of an expected stable manufacturing defect
3. Direct Assessment	● Conformance with operator's direct assessment procedures and practices ○ ECDA ○ ICDA ○ SCCDA ○ CDA	● Integrity assessment frequency ●Time remaining until next scheduled integrity assessment ● Time passed since most recent integrity assessment ● No. of revisions or modifications to the DA process as a result of IM Program evaluations	● Releases following direct examination and repair ● Releases that occurred at locations where direct examination was not conducted: ○ Mischaracterized indication severity ○ No indication was identified by DA tools / methods chosen ○ Defect growth rate underestimated
4. Repair	● Repair method selection criteria ● Development of prioritized remediation schedule ● Pipe replacement criteria ● Amount of pipe replaced on schedule ● Weld repair criteria ● Criteria for temporary pressure reductions	● Moving average of repairs by threat / cause category ● Moving average of repairs by integrity assessment method ● Moving average of repairs by HCA / non-HCA ● Trends in the type of repairs made ● No. of repairs not completed within the required timeframe ● No. of temporary pressure reductions	● Releases following integrity assessment and repair by detectable cause

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators--*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
5. In-line Inspection	● Amount of baseline and reassessment miles by integrity assessment type ● Integrity assessment frequency determination process ● Integrity assessment tool selection process ● Time passed since most recent integrity assessment ● Interaction criteria ● Tool accuracy or other specs (e.g., % of system or miles of tool runs with accuracy > [insert criteria] … to track that operators are using the best available tools and most current technology ● Fraction of HCA-affecting pipe assessed for each type of threat	● Anomalies repaired by repair criteria ● Features requiring excavation and repair per mile for each type of integrity assessment ● Features requiring excavation and repair per mile by pipe age ● Number of immediate repair conditions discovered in the n^{th} integrity assessment versus the $(n-1)^{th}$ integrity assessment. ● Anomalies (number and size) remaining in pipe. If done properly, this in combination with tool specs could be combined to calculate probability of injurious defects remaining in pipe after integrity assessment ● No. of continuing integrity assessments not conducted within the required timeframe ● No. of revisions or modifications to the ILI selection and execution process as a result of IM Program evaluations ● Presence of interactive threats such as metal loss and cracking, dents and cracking, disbonded coating and SCC, etc.	● Number of leaks and ruptures in HCAs by cause ● Releases that occurred at locations where integrity assessment was not conducted ● Releases following integrity assessment and repair by detectable cause ● Releases following integrity assessment without repair: ○ Defect under-called – no plans to repair ○ Defect not identified because interacting threats were not considered ○ Tool accuracy not appropriately considered in making repair decision ○ Defect not identified by integrity assessment method ○ Failure occurred before defect repaired ○ Defect growth rate underestimated ○ ECA not performed for remaining defects ○ B31G / RSTRENG overestimated burst pressure ○ Poor, out-of-spec ILI tool performance (without validation digs to calibrate interpretation of ILI logs)
6. Pressure test	● Integrity assessment method selection and frequency process ● Spike test vs. standard hydro ○ 1.25 x MOP / MAOP ○ 1.39 x MOP / MAOP	● Selective Seam Corrosion, Stress Corrosion Cracking, or other crack defects identified by ILI following previous pressure test ● No. of revisions or modifications to the pressure test process as a result of IM Program evaluations ● Upward trend in pressure reversals indicating an increasing amount of near-critical manufacturing flaws present in line pipe	● Releases after successful integrity assessment by pressure test ● Pressure reversals indicating an increasing amount of near-critical manufacturing or other flaws present in line pipe ● Pressure test pipe failures
7. Preventive Measures	● Frequency and nature of preventive measure identification ● Use of risk analysis in identifying and evaluating preventive measures ● Criteria used to select measures (e.g., No. of safety improvements with benefit-to-cost ratios in excess of predefined criteria that are implemented) ● Employee safety improvement projects implemented ● Progress in implementing preventive measures – e.g., pipe replacement program, recoating program, depth of cover survey, etc.	● No. or quantitative measure of specific preventive measures taken: ○ Pipe replacement ○ Recoating ○ CIS ○ ACVG / DCVG ○ Added cover ○ Increased patrols ○ Product quality improvement ○ More frequent integrity assessments ○ Changes in internal corrosion monitoring program results ○ Inhibitor injection ○ Addition of separators ○ Deformation, geometry, or DA findings for dents or expansion ● No. of revisions or modifications to the prevention and mitigation process as a result of IM Program evaluations	● Failure rates per mile in HCA segments compared to non-HCA segments ● Failure rates pre- and post-IM ● Volumes released per incident / accident in HCA segments compared to non-HCA segments ● Release volumes per incident / accident pre- and post-IM ● No. of releases involving a previously employed or identified preventive measure which did not prevent the release ● No. of releases where the SCADA and / or Leak Detection system(s) did not function as designed or anticipated to prevent the volume of the release ● No. of releases where the Control Center procedures and actions did not function as designed or anticipated to prevent the release

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators--*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
8. Mitigative Measures	● Frequency and nature of mitigative measure identification ● Use of risk analysis in identifying and evaluating mitigative measures ● Criteria used to select mitigative measures (e.g., No. of safety improvements with benefit-to-cost ratios in excess of predefined criteria that are implemented) ● Update and re-evaluation of RCV / EFRD needs analysis ● Update and improvements to leak detection capability and enhancements analysis ● Progress in implementing mitigative measures – e.g., installation of RCV / EFRDs, leak detection improvements, emergency response procedures, etc.	● No. or quantitative measure of specific mitigative measures taken: ○ EFRD's (e.g., % of system with EFRDs deployed that meet [insert criteria based on Valve Study]) ○ Leak Detection (e.g., % of system with LD capability that meets [insert criteria based on LD study]) ● No. of revisions or modifications to the prevention and mitigation process as a result of IM Program evaluations	● Failure rates per mile in HCA segments compared to non-HCA segments ● Failure rates pre- and post-IM ● Volumes released per incident / accident in HCA segments compared to non-HCA segments ● Release volumes per incident / accident pre- and post-IM ● No. of releases involving a previously employed or identified mitigative measure which did not result in the full, desired mitigative effect ● No. of releases where the SCADA and / or Leak Detection system(s) did not function as designed or anticipated to mitigate the volume of the release ● No. of releases where the line segment or facility isolation did not function as designed or anticipated to mitigate the volume of the release ● No. of releases where the Control Center procedures and actions did not function as designed or anticipated to mitigate the release ● No. of releases on pipe segments evaluated as requiring EFRDs, but the EFRD has not yet been installed ● Volume of releases on pipe segments evaluated as requiring EFRDs, but the EFRD has not yet been installed
9. Internal and External Audits and Procedure Reviews	● Internal and external audit program procedures ● Frequency of internal and external audits ● Timeliness of corrective actions ● Level of management sponsorship ● Program reviews of operating and maintenance procedures ● Program reviews of integrity management procedures	● No. of findings of inadequacies or issues ● Effectiveness of corrective actions ● Corrective actions taken, planned, and outstanding based on annual review of operator's normal O&M procedures ● Corrective actions taken, planned, and outstanding based on review of response by operator personnel to abnormal operating conditions (AOCs) ● Corrective actions taken, planned, and outstanding based on post-incident / accident investigation(s) ● Corrective actions taken, planned, and outstanding based on response using emergency O&M procedures ● No. of reported / repaired damage without a release	● No. of releases that occurred prior to implementation of planned corrective actions
10. External Communications Plan	● Percentage of Landowners / Tenants along the ROW contacted by the operator ● Percent of public officials in municipalities and other local governments along the pipeline route contacted by the operator ● Indicators that audience is receiving and understanding pipeline safety message	● Attendance at operator sponsored events. ● 811 / safe digging awareness levels ● First / emergency responder participation in operator drills and exercises ● Operator participation in first / emergency responder drills and exercises ● KPIs from operator formal public awareness plans	● Incidents / accidents where landowners, public officials, or emergency responders did not behave as expected per the operator's communication plans. (e.g., a landowner not calling 811 prior to excavation, an emergency responder not utilizing information provided by the operator in responding to an event)
11. Internal Communication Plan	● Indicators that the internal communications plan is effective in communicating key IM program insights and results ● Periodic communication of IM program performance measures	● No. of employees who have not completed routine IM program refresher orientation / training ● Percentage of intended audience reached by internal communications plan	● Releases associated with ineffective or no routine IM program refresher orientation / training

Table 3 - IM Programmatic Performance Metrics

	Leading --Indicators--*Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
12. General release response	● No. of lines without leak detection systems ● No. of lines or facilities not continuously monitored via SCADA or Control Room ● No. of post-incident / accident investigations where process or procedural inadequacies or improvement areas were identified ● No. of post-incident / accident investigations where equipment additions or improvements were identified ● No. of failure investigations where improvements were noted	● Average volume released per accident for: ○ Corrosion ○ 3rd Party Excavation Damage ○ All failures ○ Tank bottom failures ○ Tank overfills ● Time to shutdown from identification of release or other upset ● Time to isolation from identification of release or other upset ● Percent of released volume recovered	● No. of incidents / accidents or upsets where release volume was not minimized to the extent possible with existing equipment and procedures ● No. of releases where release volume was not minimized to the extent possible due to availability and location of personnel
13. Knowledge (Gas Distribution)	● Identification of pipeline's design, operations and environmental factors ● Information gained from past design, operations and maintenance ● Plan to identify addition information needs over time ● Procedure to account for collection of "missing data" ● The capture and retention of data on new pipeline installations	● Percentage of system not having all required Knowledge elements	● No. of incidents / accidents on segments without documentation of relevant data

Table 4 - System and Threat-Specific Performance Measurement

This table provides guidance for operators and inspectors to identify meaningful threat-specific metrics that may be required to effectively measure the performance of gas transmission, hazardous liquid transmission and gas distribution pipeline IM programs. The table lists the major pipeline failure mechanisms and some candidate activities for which metrics might be developed. Operators are not expected to develop and track metrics in all of the areas listed below. However, they should select a meaningful set of metrics that provides indication as to whether the operator's significant threats are being effectively managed. While this list is lengthy, it is certainly not complete. Operators will typically have other activities important to preventing specific threats that are not listed here. In these situations, metrics to indicate the effectiveness of those activities should be developed.

Following a structure similar to that in API-1160 and ASME B31.8S, this table features three different categories for which performance metrics should be developed.

1. Process or Operational Activities for Threat Prevention or Management. These are the surveillance, maintenance, and other risk prevention / control activities or operator programs used by operators to address specific pipeline threats. Metrics that that reflect the implementation of these activities and their effectiveness can be useful leading indicators.
2. Operational Deterioration Indicators. These are operational or maintenance parameters that indicate when the integrity of the system might be degrading despite the presence of the risk control and prevention activities noted in item 1, and typically reveal themselves prior to an actual pipeline failure and / or release.
3. Failure or Direct Integrity Metrics. These are clear indicators that the objective of preventing releases from specific threats has not been achieved, but that over time may show trends toward improving safety.

For the most part, this table does not identify specific metrics. It identifies operator programs or activities for which metrics should be developed. This approach has been taken because meaningful metrics must be tailored to the actual nature and manifestation of the threat on the operator's system, as well as an operator's unique risk management activities and organizational needs. In many cases, critical facilities for which consequences of a release could be significant (for example, aboveground and below ground storage facilities, tanks, or spheres), will warrant their own set of monitored performance metrics.

This table includes performance measurement opportunities for gas transmission, hazardous liquid transmission and gas distribution pipelines.

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Mechanical Damage			
First-party (operator) and second-party (contractor) damage	● Operator procedures for excavation on or near its own pipeline ● Contractor procedures for excavation on or near the pipeline ● Use of current system / facility maps	● No. of improper locates ● No. of excavations outside locate area ● No. of incidents / accidents where procedures were not followed or where appropriate care was not exhibited ● No. of damages not reported ● No. of enforcement actions taken by enforcement authority ● Increase in frequency of damage	● Releases due to first or second party damage
Third-party excavation, construction or other work at the time of failure Excavation, construction or other work activity occurring at some time prior to failure	● Damage prevention program ● Public awareness program ● Active participation in appropriate one-call systems ● Notification of public and specific others on use of one-call system ● Identification of public and other stakeholders along the ROW and notification of pipeline location, threats, etc. ● Identification and education of contractors and excavators that normally engage in excavation in area of pipeline ● Locator training and qualification ● Inspection and monitoring program for high-risk excavations ● Patrolling to gather and record damage prevention information ● Line marking program to locate and replace line markers as needed ● Depth of cover program ● Alignment with “common ground” best practices ● Use of Damage Information Reporting Tool (DIRT) report data ● Incorporation and utilization of PIPA Recommended Practices ● Excavation practices ● Use of current system / facility maps ● 811 / call before you dig awareness measurement ● Analysis of damage data, to include root causes of damages ● Loading calculations for third party crossings or blasting ● Monitoring of construction activity in area of pipeline ● Location of systems in areas where excavation requires the use of explosives	● No. of ROW encroachments ● No. of one-call tickets (comparison of third-party damage to one call tickets) ● Timeliness of one-call notification ticket responses ● No. of improper and inaccurate locates or other inadequate one-call follow-up ● No. of unreported excavation damage ● No. of unmonitored excavations ● No. of excavations performed without calling for locates ● No. of excavation related near-miss incidents / accidents ● Increase in frequency of damage ● No. of damage incidents without release due to third party damage ● No. of excavations outside the locate area ● No. of excavations involving unsafe excavation practices, such as failure to hand-dig when required ● No. of high risk and other excavations monitored ● No. of inadequate participation in one-call system ● Incomplete and / or inaccurate identification of public and other stakeholders along the ROW ● Incomplete and / or inaccurate identification of contractors and excavators that normally engage in excavation in area of pipeline ● No. of affected stakeholders without adequate knowledge of pipeline location or threats ● Percentage of pipeline mileage whose ROW has been cleared consistent with operator’s clearing requirements. ● No. off aerial patrol reports with no one-call ● No. of pig runs with indicated mechanical damage ● No. of enforcement actions taken by enforcement authority	● Releases due to third-party damage ● Third-party damage from excavations that should have been monitored by operator but that were not ● Releases following targeted ILI tool run or pressure test ● Third party damage incidents / accidents without a release ● Cover increases causing load issues ● Occurrences of unmonitored blasting ● Releases experienced in areas where previous damage has occurred

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators--*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Other Third Party Damage, including vandalism, third-party vehicle contact with facility, interferences and other intentional or unintentional acts	● ROW and patrolling program ● Line marking program ● Training and OQ tasks ● Depth of Cover survey program ● Use of Damage Information Reporting Tool (DIRT) report data ● Public awareness program ● Physical protection of aboveground facilities	● No. of patrol reports that have not had necessary follow-up completed ● Reports by law enforcement agencies and first responder agencies ● No. of pig runs with indicated damage ● No. of sites lacking security fencing and / or cameras or other features ● No. of susceptible sites lacking vehicle impact barriers ● No. of aboveground facilities hit by vehicles ● No. of vandalism incidents without a release ● Incidents of damage due to underground inference with adjacent structures, utilities, etc.	● Releases due to third-party damage ● Releases due to prior excavation-related damage ● Releases due to prior non-excavation-related mechanical damage

Table 4 - System and Threat-Specific Performance Measurement

<table>
<tr><th></th><th colspan="3">Leading --Indicators---Lagging</th></tr>
<tr><th>Failure Mechanism</th><th>Selected Process or Operational Activities for Threat Prevention or Management</th><th>Deterioration Indicators</th><th>Failure or Direct Integrity Metrics</th></tr>
<tr><td colspan="4">Corrosion - Impact on bare steel pipe, cast iron pipe, coated and wrapped steel pipe, other metallic materials</td></tr>
<tr><td>External corrosion</td><td>● Cathodic protection system performance testing program
● Exposed pipe examination program
● Protective coating application program
● Electrical isolation program
● Interference current control and remediation program
● Training and OQ tasks
● Stray current surveys</td><td>● No. of pig runs or ECDA excavations with indicated corrosion
● No. of close interval surveys
● Trends in performance of external corrosion protection program
● No. of annual cathodic protection exception reports
● No. of ineffective impressed current system survey results
○ Insufficient number of anodes
○ Low CP current
○ High CP current
○ Failed rectifiers
○ Damaged test leads
○ Changes in soil resistivity
○ Consecutive low CP readings in same location (failure to correct deficiencies)
● No. of ineffective sacrificial anode system survey results
○ Insufficient number of anodes
○ Ineffective anodes
○ Changes in soil resistivity
● No. of damaged coatings as indicated by ACVG, DCVG, CIS, or PCM
● No. of disbonded coating as indicated by ECDA, ACVG / DCVG, ILI, Hydro, EMAT, or excavations
● No of interference currents / stray currents identified
○ Electrical surveys
○ Current sources
● No. of indications of MIC
○ Water samples from disbanded coating
○ Soil sample for bacteria
● No of exposed pipe inspections indicating external corrosion
● No of indications of atmospheric corrosion (in addition to coating / CP metrics)
○ Inspection reports
○ Splash zone locations
● Percentage of bare pipe in the system
● No. of cast iron or ductile iron components / fittings in the system</td><td>● Releases due to external corrosion
● Failures following targeted ILI tool run or pressure test
● Releases following targeted NDT
● Releases following targeted ECDA</td></tr>
</table>

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators--*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Internal corrosion	● Internal coupon monitoring program ● Product / commodity quality monitoring ● Separator performance monitoring ● Inhibitor injection program ● Dead leg monitoring program ● Training and OQ tasks	● Trends in performance of internal corrosion protection program ● No. of coupon tests ● No. of ER probes ● No. of electrochemical probes ● No. of metallurgical analyses completed ● No. of gas processing upsets ● No. of pig runs or ICDA excavations with indicated corrosion ● Time interval between scraper runs ● Time interval between inhibitor injection ● No of piping inspections indicating internal corrosion ● No. of product / commodity quality checks ○ Inhibitor quantity ○ Water content ○ H_2S content ○ CO_2 content ○ Microbe content ○ Sediment content ○ Low flow	● Releases due to internal corrosion ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Stress Corrosion Cracking	● SCC monitoring program and susceptibility criteria ○ Soil conditions ○ Operating pressure and temperature ○ Coating type ○ Process for coating application	● No. of pig runs or SCCDA excavations with indicated cracks or crack-like anomalies ● No. of times SCC identified during bell hole exam ● No. of hydrostatic test failures ● No. of times soil / water pH exceeds criteria ● No. of indications of disbonded coating discovered through ECDA, ACVG / DCVG, ILI, Hydro, EMAT, Excavations, other ● Upward trend in pressure reversals indicating an increasing amount of near-critical flaws present in line pipe	● Releases due to SCC ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Selective Seam Corrosion	Same as external corrosion plus ● Coating type ● Seam type – ERW, FW ● Disbonded coating	Same as external corrosion plus ● No. of indications of disbonded coating near the long seam discovered through ACVG / DCVG, ILI, Hydro, Excavations, other ● No. of pig runs with indications of corrosion metal loss, cracks, or crack-like anomalies near the long seam	● Releases due to SSC ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Material Failures			
Pipe materials, including pipe seam ● Year of manufacture ● Manufacturer ● Pipe type ● Seam type ● Material properties ● Manufacturing specifications ● Mill test results	● Pipeline replacement and rehabilitation to address the risks associated with specific pipe materials, seam type, manufacturer, vintage, etc. ● Integrity assessment and monitoring programs to address the risks associated with specific pipe materials, seam type, manufacturer, vintage, etc. ● No. of pipe segments with Legacy Pipe ● No. of pipe segments with Legacy Pipe which have not been appropriately assessed ● Design and construction controls ● Pre-operational testing ● Testing of new or replacement materials to ensure specifications meet requirements ● Usage of the following pipe materials: ○ Century Utility Products ○ Low-ductile inner wall Aldyl pipe manufactured by DuPont prior to 1973 ○ PE 3306	● ILI tool run results with tools capable of detecting pipe body defects (laminations, hard spots, hook cracks, blisters, etc.) ● No. of surveys indicating high CP ● No. of hydro-test failures ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity ● Destructive or non-destructive test results indicate inaccuracies in material or component records ● No. of manufacturing defects identified ● No. of failures due to workmanship defects	● Leak or rupture due to material defects ● Pressure reversals indicating an increasing amount of near-critical flaws present in line pipe ● Seam failures ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Release following targeted NDT ● In-service failure of expected stable manufacturing flaws
Construction girth welds, including repair welds	● Construction specifications ● Welding specifications ● Weld procedures and technique ● Welder qualification program ● Welding inspection / NDT program ● No. of pipe segments with Legacy Construction Techniques ● No. of pipe segments with Legacy Construction Techniques which have not been appropriately assessed	● No. of indications of weld fit-up errors / misalignment ● No. of indications of inadequate weld quality ● Percentage of initial NDT results indicating inadequate weld quality ● No. of hydro-test failures ● Trends in failures by repair type methodology (welded sleeves, composite, etc.) ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity ● Percentage of new pipeline construction monitored continuously by operator inspectors ● No. of failures due to workmanship defects	● Girth weld failures ● Failure of weld joints other than girth welds ● Repair weld failures ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT
Transportation and Construction damage	● Construction procedures ● Transportation procedures ● Field coating application procedures ● Wrinkle bends ● No. of pipe segments with Legacy Construction Techniques ● No. of pipe segments with Legacy Construction Techniques which have not been appropriately assessed	● No. of ILI indications of rock dents, wrinkle bends, or construction damage ● No. of indications of coating damage ● No. of indications of ineffective repair of damaged coating ● No. of hydro-test failures ● No. of pressure excursions > MAOP / MOP ● No. of indications of high cyclic loading ● No. of occurrences where the NOP / MOP(or MAOP) ratio approaches unity	● Releases due to construction damage ● Releases due to transportation damage ● No. of pressure excursions > 110% MAOP / MOP ● Releases following targeted ILI tool run or pressure test ● Releases following targeted NDT

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Equipment Failure			
Equipment malfunction or failure of non-pipe component	● Equipment specifications and materials ● Testing program and procedures for ○ Pumps ○ Control valves ○ High pressure shutdown devices ○ Relief valves ○ Block valves ● Maintenance and operations training ● Maintenance procedures ● Tank inspection program ● Tank corrosion control program ● Root cause failure analysis program for systemic problems ● Implementation of preventive maintenance program	● No. of API 653 inspections ● No. of API 570 inspections ● No. of relief valve malfunctions ● Mean time between failures (MTBF) ● No. of occurrences having excessive vibration ● No. of control malfunctions ● Percentage of safety-critical equipment that performs to specification when inspected or tested. ● Percentage of planned maintenance activities completed on time. ● Trends of equipment failures prior to the expected life cycle period ● Destructive or non-destructive test results indicate inaccuracies in material or component records ● No. of manufacturing defects identified	● Corrosion failure ● Releases due to gasket and packing failures ● Releases due to tank failure ● Sump tank leaks ● Failure of fittings, threaded connections, couplings, non-threaded connections, tubing, equipment body ● Pump and compressor failure ● Amount of gas released ● Barrels spilled ● Equipment failures prior to the expected life cycle ● Regulator or pressure control failure ● Over-pressure control failure ● Valve leak or failure
Operational Error			
Valve left or placed in wrong position	● Operating procedures ● Training and OQ program	● No. of relief valves operating ● No of relief valve failures ● No. of incorrect operations resulting in contamination ● No of pressure excursions > MAOP / MOP (percentage of events for which overpressure protection devices functioned as intended) ● Percentage of relief valves tested which function as intended ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Over pressure ● Releases ● Tank overflow ● Sump or other overflow
Incorrect start / stop of pump or compressor	● Operating procedures ● Training and OQ program	● No. of relief valves operating ● No. of incorrect operations resulting in contamination ● No. of pressure excursions > MAOP / MOP ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Relief valve failure ● Over pressure ● Releases ● Tank overflow
Tank overfilled	● Operating procedures ● Shipper schedule changes or unscheduled deliveries ● Alarm monitoring and testing program ● Training and OQ program	● No. of alarm failures or malfunctions ● No. of tanks without redundant overfill protection ● No. of tanks with inadequate diking ● No. of failures due to inadequate procedures / safety practices ● No. of failures due to a failure to follow procedures	● Tank overflow

Table 4 - System and Threat-Specific Performance Measurement

	Leading --Indicators---*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Other human errors	● Operator qualification audits ● CRM operator training and qualification audits ● Training and staff qualification program	● No. of relief valves operating ● No. of relief valve failures ● No. of errors resulting in contamination ● No of motor vehicle impacts ● No. of pressure excursions > MAOP / MOP ● No. of relief valves or shutdown devices inoperable for long periods of time ● No. of times that line pressure was not temporarily reduced when it was required ● Percentage of individuals who take the correct action in response to an abnormal operating condition or incident / accident ● No. of failures due to inadequate procedures ● No. of failures due to a failure to follow procedures	● Over pressurization of system ● Releases due to operator error ● Tank overflow ● Failure to shut down system, when appropriate
Natural Forces - Impact on steel pipe, plastic pipe, cast iron pipe			
Cold Weather	● Inspection program to identify frost heave	● Frost heave	● Releases due to frost heave ● Releases due to freezing conditions ● Damage due to increased loading from ice / snow
Heavy rains / flooding	● Water crossing inspection program ● Strain based design parameters	● No. of exposed pipe segments ● No. of indications of overstrained pipe ● No. of stream crossing washouts ● Damage without a release due to weather conditions	● Releases due to heavy rains / flooding
Lightning	● Lightning protection program ● Tank floating roof seal inspection program	● No. of station shutdowns due to ground faults ● No. of tanks lacking fire suppression systems ● No. of tanks lacking lightning arrestors	● Releases due to lightning
Earth movement	● Strain based design parameters ● Girth weld inspection program ● Identification of areas of known land subsidence, landslides. earthquake fault zones, and washouts	● No. of occurrences of earthquakes or seismic activity ● No. of occurrences of ground sloughing ● No. of occurrences of subsidence ● No. of ILI indications of overstrain	● Releases due to overstrain ● Girth weld failure due to soil movement ● Failure of weld joints other than girth welds due to soil movement

Appendix A - Elements of a Mature Program Evaluation Process