MANAGING SYSTEM INTEGRITY OF GAS PIPELINES

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1 INTRODUCTION

1.1 Scope

This Code applies to onshore pipeline systems that are constructed with ferrous materials and transport gas. The principles and processes embodied in integrity management are applicable to all pipeline systems.

This Code is specifically designed to provide the operator (as defined in section 13) with the information necessary to develop and implement an effective integrity management program using proven industry practices and processes. The processes and approaches described within this Code are applicable to the entire pipeline.

1.2 Purpose and Objectives

Managing the integrity of a gas pipeline system is the primary goal of every pipeline system operator. Operators want to continue providing safe and reliable delivery of natural gas to their customers without adverse effects on employees, the public, customers, or the environment. Incident-free operation has been and continues to be the gas pipeline industry’s goal. The use of this Code as a supplement to ASME B31.8 will allow pipeline operators to move closer to that goal.

A comprehensive, systematic, and integrated integrity management program provides the means to improve the safety of pipeline systems. Such an integrity management program provides the information for an operator to effectively allocate resources for appropriate prevention, detection, and mitigation activities that will result in improved safety and a reduction in the number of incidents.

This Code describes a process that an operator of a pipeline system can use to assess and mitigate risks to reduce both the likelihood and the consequences of incidents. It covers both a prescriptive-based and a performance-based integrity management program.

The prescriptive process, when followed explicitly, will provide all the inspection, prevention, detection, and mitigation activities necessary to produce a satisfactory integrity management program. This does not preclude conformance with the requirements of ASME B31.8. The performance-based integrity management program alternative uses more data and more extensive risk analyses, which enable the operator to achieve a greater degree of flexibility to meet or exceed the requirements of this Code, specifically in the areas of inspection intervals and tools and mitigation techniques used. An operator cannot proceed with the performance-based integrity program until adequate inspections are performed that provide the information on the pipeline condition required by the prescriptive-based program. The level of assurance of a performance-based program or an alternative international standard must meet or exceed that of a prescriptive program.

The requirements for prescriptive-based and performance-based integrity management programs are provided in each of the sections in this Code. In addition, Nonmandatory Appendix A provides specific activities by threat categories that an operator shall follow to produce a satisfactory prescriptive integrity management program.

This Code is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. Typically, a team will include managers, engineers, operating personnel, technicians, and/or specialists with specific expertise in prevention, detection, and mitigation activities.

1.3 Integrity Management Principles

A set of principles is the basis for the intent and specific details of this Code. They are enumerated here so that the user of this Code can understand the breadth and depth to which integrity shall be an integral and continuing part of the safe operation of a pipeline system.

Functional requirements for integrity management shall be engineered into new pipeline systems from initial planning, design, material selection, and construction. Integrity management of a pipeline starts with sound design, material selection, and construction of the pipeline. Guidance for these activities is primarily provided in ASME B31.8. There are also a number of consensus standards that may be used, as well as pipeline jurisdictional safety regulations. If a new line is to become a part of an integrity management program, the functional requirements for the line, including prevention, detection, and mitigation activities, shall be considered to meet this Code. Complete records of material, design, and construction for the pipeline are essential for the initiation of a good integrity management program.

System integrity requires commitment by all operating personnel using comprehensive, systematic, and integrated processes to safely operate and maintain pipeline systems. To have an effective integrity management program, the program shall address the operator’s organization and processes and the physical system.
An integrity management program must be continuously evolving and must be flexible. An integrity management program should be customized to meet each operator's unique conditions. The program shall be periodically evaluated and modified to accommodate changes in pipeline operation, changes in the operating environment, and the influx of new data and information about the system. Periodic evaluation is required to ensure the program takes appropriate advantage of improved technologies and uses the best set of prevention, detection, and mitigation activities that are available for the conditions at that time. Additionally, as the integrity management program is implemented, the effectiveness of the activities shall be reassessed and modified to ensure the continuing effectiveness of the program and all its activities.

Information integration is a key component for managing system integrity. A key element of the integrity management framework is the integration of all pertinent information when performing risk assessments. Information that can affect an operator's understanding of the important risks to a pipeline system comes from a variety of sources. The operator is in the best position to gather and analyze this information. By analyzing all of the pertinent information, the operator can determine where the risks of an incident are the greatest and make prudent decisions to assess and reduce those risks.

Risk assessment is an analytical process by which an operator determines the types of adverse events or conditions that may affect pipeline integrity. Risk assessment also determines the likelihood or probability of those events or conditions that will lead to a loss of integrity and the nature and severity of the consequences that may occur following a failure. This analytical process involves the integration of design, construction, operations, maintenance, testing, inspection, and other information about a pipeline system. Risk assessments, which are the very foundation of an integrity management program, can vary in scope or complexity and use different methods or techniques. The ultimate goal of risk assessment is to identify the most significant risks so that an operator can develop an effective and prioritized prevention/detection/mitigation plan to address the risks.

Assessing risks to pipeline integrity is a continuous process. The operator shall periodically gather new or additional information and system operating experience. These shall become part of revised risk assessments and analyses that in turn may require adjustments to the system integrity plan.

New technology should be evaluated and implemented as appropriate. Pipeline system operators should avail themselves of new technology as it becomes proven and practical. New technologies may improve an operator's ability to prevent certain types of failures, detect risks more effectively, or improve the mitigation of risks.

Performance measurement of the system and the program itself is an integral part of a pipeline integrity management program. Each operator shall choose significant performance measures at the beginning of the program and then periodically evaluate the results of these measures to monitor and evaluate the effectiveness of the program. Periodic reports of the effectiveness of an operator's integrity management program shall be issued and evaluated to continuously improve the program.

Integrity management activities shall be communicated to the appropriate stakeholders. Each operator shall ensure that all appropriate stakeholders are given the opportunity to participate in the risk assessment process and that the results are communicated effectively.

1.4 Units of Measure

This Code states values in both U.S. Customary and International System (SI, also known as metric) units. Either set of units may be used. Local customary units may also be used to demonstrate compliance with this Code. Within the text, the SI units are shown in parentheses. The values stated in each system are not exact equivalents; therefore, each system of units should be used independently of the other. The equations in this Code may be used with any consistent system of units. It is the responsibility of the organization performing calculations to ensure that a consistent system of units is used. When necessary to convert from one system of units to another, conversion should be made by rounding the values to the number of significant digits of implied precision in the starting value.

2 INTEGRITY MANAGEMENT PROGRAM OVERVIEW

2.1 General

This section describes the required elements of an integrity management program. These program elements collectively provide the basis for a comprehensive, systematic, and integrated integrity management program. The program elements depicted in Figure 2.1-1 are required for all integrity management programs.

This Code requires that the operator document how its integrity management program will address the key program elements. This Code uses recognized industry practices for developing an integrity management program.

The process shown in Figure 2.1-2 provides a common basis to develop (and periodically reevaluate) an operator-specific program. In developing the program, a pipeline operator shall consider his company's specific integrity management goals and objectives, and then apply the processes to ensure that these goals are achieved. This Code details two approaches to integrity
management: a prescriptive method and a performance-based method.

The prescriptive integrity management method requires the least amount of data and analysis and can be successfully implemented by following the steps provided in this Code and Nonmandatory Appendix A. The prescriptive method incorporates expected worst-case indication growth to establish intervals between successive integrity assessments in exchange for reduced data requirements and less extensive analysis.

The performance-based integrity management method requires more knowledge of the pipeline, and consequently more data-intensive risk assessments and analyses can be completed. The resulting performance-based integrity management program can contain more options for inspection, inspection tools, mitigation, and prevention methods. The results of the performance-based method must meet or exceed the results of the prescriptive method. A performance-based program cannot be implemented until the operator has performed adequate integrity assessments that provide the data for a performance-based program. A performance-based integrity management program shall include the following in the integrity management plan:

(a) a description of the risk analysis method employed
(b) documentation of all of the applicable data for each segment and where it was obtained
(c) a documented analysis for determining integrity assessment intervals and mitigation (repair and prevention) methods
(d) a documented performance matrix that, in time, will confirm the performance-based options chosen by the operator

The processes for developing and implementing a performance-based integrity management program are included in this Code.

There is no single "best" approach that is applicable to all pipeline systems or equipment for all situations. This Code recognizes the importance of flexibility in designing integrity management programs and provides alternatives commensurate with this need. ASME PCC-3 provides guidance and information applicable to equipment or components that for practical reasons may be excluded from inspection activities normally conducted for the transportation piping and/or that may be subject to damage mechanisms that differ from those of the main pipeline. Operators may choose either a prescriptive-based or a performance-based approach for their entire system, individual lines, segments, or individual threats. The program elements shown in Figure 2.1-1 are required for all integrity management programs.

The process of managing integrity is an integrated and iterative process. Although the steps depicted in Figure 2.1-2 are shown sequentially for ease of illustration, there is a significant amount of information flow and interaction among the different steps. For example, the selection of a risk assessment approach depends in part on what integrity-related data and information are available. While performing a risk assessment, additional data needs may be identified to more accurately evaluate potential threats. Thus, the data gathering and risk assessment steps are tightly coupled and may require several iterations until an operator has confidence that a satisfactory assessment has been achieved.

A brief overview of the individual process steps is provided in section 2, as well as instructions to the more specific and detailed description of the individual elements that compose the remainder of this Code.
References to the specific detailed sections in this Code are shown in Figures 2.1-1 and 2.1-2.

2.2 Integrity Threat Classification

The first step in managing integrity is identifying potential threats to integrity. Threats to pipeline integrity shall be considered. Gas pipeline incident data have been analyzed and classified by the Pipeline Research Committee-International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed. One of the causes, reported by operators is “unknown”; that is, no root cause or causes were identified. The remaining 21 threats are grouped into nine categories of related failure types, according to their nature and growth characteristics, and further delineated by three time-related defect types. The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment, and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

(a) Time Dependent
   (1) external corrosion
   (2) internal corrosion
   (3) stress corrosion cracking

(b) Resident
   (1) manufacturing-related defects
      (-a) defective pipe seam
      (-b) defective pipe
   (2) welding/fabrication related
      (-a) defective pipe girth weld (circumferential)
         including branch and T-joints
         (-b) defective fabrication weld
         (-c) wrinkle bend or buckle
         (-d) stripped threads/broken pipe/coupling failure
      (3) equipment
         (-a) gasket O-ring failure
         (-b) control/relief equipment malfunction
         (-c) seal/pump packing failure
         (-d) miscellaneous

(c) Random or Time Independent
   (1) third-party/mechanical damage
      (-a) damage inflicted by first, second, or third parties (instantaneous/immediate failure)
      (-b) previously damaged pipe, such as dents and/or gouges (delayed failure mode)
      (-c) vandalism
   (2) incorrect operational procedure
   (3) weather-related and outside force
      (-a) excessive hot or cold weather (outside the design range)
      (-b) high wind
      (-c) hydrotechnical: water-related threats including, but not limited to, liquefactions, floodings, channeling, scouring, erosions, floatations, breaches, surges, inundations, tsunamis, ice jams, frost heaves, and avalanches

   (-d) geotechnical: earth movement threats including, but not limited to, subsidences, extreme surface loads, seismicity, earthquakes, fault movements, mining, and mud and landslides
   (-e) lightning

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third-party damage.

The operator shall consider each threat individually or in the nine categories when following the process selected for each pipeline system or segment. The prescriptive approach delineated in Nonmandatory Appendix A enables the operator to conduct the threat analysis in the context of the nine categories. All 21 threats shall be considered when applying the performance-based approach.

If different gases are transported, failure mode categories may require revision.

2.3 The Integrity Management Process

The integrity management process depicted in Figure 2.1-2 is described below.

2.3.1 Identifying Potential Pipeline Impact by Threat.

This program element involves the identification of potential threats to the pipeline, especially in areas of concern. Each identified pipeline segment shall have the threats considered individually or by the nine categories. See para. 2.2.

2.3.2 Gathering, Reviewing, and Integrating Data.

The first step in evaluating the potential threats for a pipeline system or segment is to define and gather the necessary data and information that characterize the segments and the potential threats to that segment. In this step, the operator performs the initial collection, review, and integration of relevant data and information needed to understand the condition of the pipe; identifies the location-specific threats to its integrity; and understands the public, environmental, and operational consequences of an incident. The types of data to support a risk assessment will vary depending on the threat being assessed. Information on the operation, maintenance, patrolling, design, operating history, and specific failures and concerns that are unique to each system and segment will be needed. Relevant data and information also include those conditions or actions that affect defect growth (e.g,
Paragraph 3.2 describes how to determine the area that is affected by a pipeline failure (potential impact area) to evaluate the potential consequences of such an event. The area impacted is a function of the pipeline diameter and pressure.

3.2 Potential Impact Area

3.2.1 Typical Natural Gas. The radius of impact for natural gas whose methane + inert constituents content is not less than 93%, whose initial pressure does not exceed 1,450 psig (10 MPa), and whose temperature is at least 32°F (0°C) is calculated using the following equation:

(U.S. Customary Units)

\[ r = 0.69 \cdot d \sqrt{p} \]  

(SI Units)

\[ r = 0.00315 \cdot d \sqrt{p} \]

where

\[ d = \text{outside diameter of the pipeline, in. (mm)} \]

Additional guidance for estimating the magnitude and dispersion of flammable and non-flammable gas discharges—may be found in:

(a) ASME IPC2022-87099
(b) ASME IPC2022-87217
(e) TTO Number 13, Integrity Management Program, Delivery Order DTRS56-02-D-70036, Potential Impact Radius Formulae for Flammable Gases Other Than Natural Gas Subject to 49 CFR 192
(f) TTO Number 14, Integrity Management Program, Delivery Order DTRS56-02-D-70036, Derivation of Potential Impact Radius Formulae for Vapor Cloud Dispersion Subject to 49 CFR 192

Example:

(1) A 30 in. diameter pipe with a maximum allowable operating pressure of 1,000 psig has a radius of impact of approximately 660 ft.

\[ r = \frac{115,920}{8} \cdot \mu \cdot \chi_g \cdot C_d \cdot H_C \cdot a_o \cdot p d^2 \cdot I_{th} \]

\[ m = \text{gas molecular weight, lbm/lb-mole (g/mole)} \]
\[ p = \text{live pressure, lbf/in}^2 \text{ (Pa)} \]
\[ Q = \text{flow factor} \]
\[ r = \frac{\gamma + 1}{2(\gamma - 1)} \]

The impact areas and potential consequences associated with other gases which may be heavier than air, non-combustible, toxic, asphyxiant, or an irritant, or combinations of these, shall be evaluated.

\[ \mu = \text{combustion efficiency factor} \]
\[ \chi_g = \text{emissivity factor} \]

Note: When performing these calculations, the user is advised to carefully observe the differentiation and use of pound mass (lbm) and pound force (lbf) units.

Additional guidance when considering the transported gases other than natural gas can be found in:

(a) ASME IPC2022-87099
(b) ASME IPC2022-87217
(e) TTO Number 13, Integrity Management Program, Delivery Order DTRS56-02-D-70036, Potential Impact Radius Formulae for Flammable Gases Other Than Natural Gas Subject to 49 CFR 192
(f) TTO Number 14, Integrity Management Program, Delivery Order DTRS56-02-D-70036, Derivation of Potential Impact Radius Formulae for Vapor Cloud Dispersion Subject to 49 CFR 192

3.2.2 Other Gases. Although a similar methodology may be used for other lighter-than-air flammable gases, the natural gas factor of 0.69 (0.00315) in para. 3.2.1 must be derived for the actual gas composition or range of compositions being transported. Depending on the gas composition, the factor may be significantly higher or lower than 0.69 (0.00315).

This methodology may not be applicable for nonflammable gases, toxic gases, heavier-than-air flammable gases, lighter-than-air flammable gases operating above 1,450 psig (10 MPa), gas mixtures subject to a phase change during decompression, or gases transported at low temperatures such as may be encountered in arctic conditions.

For gases outside the range of para. 3.2.1, the user must show the applicability of the methods and factors used in the determination of the potential impact area.

3.2.3 Performance-Based Programs — Other Considerations. In a performance-based program, the operator may consider alternate models that calculate impact areas and consider additional factors, such as depth of burial, that may reduce impact areas.

3.2.4 Ranking of Potential Impact Areas. The operator shall count the number of houses and individual units in buildings within the potential impact area. The potential impact area extends from the extremity of the first affected circle to the extremity of the last affected...
circle (see Figure 3.2.4-1). This housing unit count can then be used to help determine the relative consequences of a rupture of the pipeline segment.

The ranking of these areas is an important element of risk assessment. Determining the likelihood of failure is the other important element of risk assessment (see sections 4 and 5).

3.3 Consequence Factors to Consider

When evaluating the consequences of a failure within the impact zone, the operator shall consider at least the following:

(a) number and location of inhabited structures
(b) proximity of the population to the pipeline (including consideration of man-made or natural barriers that may provide some level of protection)
(c) proximity of populations with limited or impaired mobility (e.g., hospitals, schools, child-care centers, retirement facilities, prisons, recreation areas), particularly in unprotected outside areas
(d) property damage
(e) environmental damage
(f) effects of unignited gas releases
(g) security or reliability of gas supply (e.g., effects of interruption of service)
(h) public convenience and necessity
(i) potential for secondary failures
(j) duration of a failure event, including product depressurization and potential fire

Note that the consequences may vary based on the richness of the gas transported and as a result of how the gas depressurizes, flows, and decompresses. Consequences of failure may vary based on steel chemistry, distribution and sizing of pipeline anomalies, and gas properties, including composition, density, and decompression characteristics.

4 GATHERING, REVIEWING, AND INTEGRATING DATA

4.1 General

This section provides a systematic process for pipeline operators to collect and effectively use the data elements necessary for risk assessment. Comprehensive pipeline and facility knowledge is an essential component of a performance-based integrity management program. In addition, information on operational history, the environment around the pipeline, mitigation techniques employed, and process/procedure reviews is also necessary. Data are a key element in the decision-making process required for program implementation. When the operator lacks sufficient data or where data quality is below requirements, the operator shall follow the prescriptive-based processes as shown in Nonmandatory Appendix A.

Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential to obtain complete and accurate information needed for an integrity management program.

4.2 Data Requirements

The operator shall have a comprehensive plan for collecting all data sets. The operator must first collect the data required to perform a risk assessment (see section 5). Implementation of the integrity management program will drive the collection and prioritization of
additional data elements required to more fully understand and prevent/mitigate pipeline threats.

4.2.1 Prescriptive Integrity Management Programs.
Limited data sets shall be gathered to evaluate each threat for prescriptive integrity management program applications. These data lists are provided in Nonmandatory Appendix A for each threat and summarized in Table 4.2.1.1. All of the specified data elements shall be available for each threat to perform the risk assessment. If such data are not available, it shall be assumed that the particular threat applies to the pipeline segment being evaluated.

4.2.2 Performance-Based Integrity Management Programs.
There is no standard list of required data elements that apply to all pipeline systems for performance-based integrity management programs. However, the operator shall collect, at a minimum, those data elements specified in the prescriptive-based program requirements. The quantity and specific data elements will vary between operators and within a given pipeline system. Increasingly complex risk assessment methods applied in performance-based integrity management programs require more data elements than those listed in Nonmandatory Appendix A.

Initially, the focus shall be on collecting the data necessary to evaluate areas of concern and other specific areas of high risk. The operator will collect the data required to perform system-wide integrity assessments and any additional data required for general pipeline and facility risk assessments. These data are then integrated into the initial data. The volume and types of data will expand as the plan is implemented over years of operation.

4.3 Data Sources

The data needed for integrity management programs can be obtained from within the operating company and from external sources (e.g., industry-wide data). Typically, the documentation containing the required data elements is located in design and construction documentation, and current operational and maintenance records.

A survey of all potential locations that could house these records may be required to document what is available and its form (including the units or reference system), and to determine if significant data deficiencies exist. If deficiencies are found, action to obtain the data can be planned and begun relative to its importance. This may require additional inspections and field data collection efforts.

Existing management information system (MIS) or geographic information system (GIS) databases and the results of any prior risk or threat assessments are also useful data sources. Significant insight can also be obtained from subject matter experts and those involved in the risk assessment and integrity management program processes. Root cause analyses of previous failures are a
understanding of the nature and locations of risks along a pipeline or within a facility.

Risk assessment methods should not be completely relied upon to establish risk estimates or to address or mitigate known risks. Risk assessment methods should be used in conjunction with knowledgeable, experienced personnel (subject matter experts and people familiar with the facilities) who regularly review the data and documents. Such experience-based reviews should validate the data input, assumptions, and results of the risk assessment approach or mitigate known risks. Risk assessment processes and their results shall be documented.

An initial risk assessment shall incorporate facility reports and incorporate additional processes as required (see section 11).

5.5 Risk Assessment Approaches

(a) To organize integrity assessments for pipeline segments of concern, a risk priority shall be established. This risk value is composed of a number reflecting the overall likelihood of failure and a number reflecting the consequences. The risk analysis can be fairly simple, with values ranging from 1 to 3 (to reflect high, medium, and low likelihood and consequences), or can be more complex and involve a larger range to provide greater differentiation between pipeline segments. Multiplying the relative likelihood and consequence numbers together provides the operator with a relative risk for the segment and a relative priority for its assessment.

(b) An operator shall use one or more of the following risk assessment approaches consistent with the objectives of the integrity management program. These approaches are listed in a hierarchy of increasing complexity, sophistication, and data requirements. These risk assessment approaches are subject matter experts, relative assessments, scenario assessments, and probabilistic assessments. The following paragraphs describe risk assessment methods for the four listed approaches.

(1) Subject Matter Experts (SMEs). SMEs from the operating company or consultants, combined with information obtained from technical literature, can be used to provide a relative numeric value describing the likelihood of failure for each threat and the resulting consequences. The SMEs are used by the operator to analyze each pipeline segment, assign relative likelihood and consequence values, and calculate the relative risk.

(2) Relative Assessment Models. This type of assessment builds on pipeline-specific experience and more extensive data, and includes the development of risk models addressing the known threats that have historically affected pipeline operations. Such relative or data-based methods use models that identify and quantitatively weigh the major threats and consequences relevant to past pipeline operations. These approaches are considered relative risk models, since the risk results are compared with results generated from the same model. They provide a risk ranking for the integrity management decision process. These models use algorithms weighing the major threats and consequences, and provide sufficient data to meaningfully assess them. Relative assessment models are more complex and require more specific pipeline system data than SME-based risk assessment approaches. The relative risk assessment approach, the model, and the results obtained shall be documented in the integrity management program.

(3) Scenario-Based Models. This risk assessment approach creates models that generate a description of an event or series of events leading to a level of risk, and includes both the likelihood and consequences of such events. This method usually includes construction of event trees, decision trees, and fault trees. From these constructs, risk values are determined.

(4) Probabilistic Models. This approach is the most complex and demanding with respect to data requirements. The risk output is provided in a format that is compared to acceptable risk probabilities established by the operator, rather than using a comparative basis.

It is the operator's responsibility to apply the level of importance and risk analysis to their system. A thorough understanding of the strengths and limitations of each risk assessment method is necessary before a long-term strategy is adopted.

(c) All risk assessment approaches described above have the following common components:

(1) They identify potential events or conditions that could threaten system integrity.

(2) They evaluate likelihood of failure and consequences.

(3) They permit risk ranking and identification of specific threats that primarily influence or drive the risk.

(4) They lead to the identification of integrity assessment and/or mitigation options.

(5) They provide for a data feedback loop mechanism.

(6) They provide structure and continued updating for risk reassessments.

Some risk assessment approaches consider the likelihood and consequences of damage, but they do not consider whether failure occurs as a leak or rupture.
An overall risk value may be represented by a number reflecting the overall likelihood of failure multiplied by a number reflecting the severity of consequences. Likelihood of event(s) occurring may be represented qualitatively (e.g., low = 1, medium = 2, high = 3) or quantitatively (e.g., probabilistic models) with outputs in standard units (such as frequency). Similarly, the consequence(s) resulting from an event occurring may be represented qualitatively (e.g., minor = 1, moderate = 2, severe = 3) or quantitatively through detailed analyses of the scenarios following a failure. Operators shall determine the appropriate units of comparative measure for all inputs and outputs. Multiplying the event likelihood(s) by the estimated event consequence(s) increases the granularity of the relative risk for each segment and improves the discrimination that the risk estimate offers when prioritizing multiple segments for integrity (re-)assessment.
The integrity plan shall also provide for the elimination of any specific threat from the risk assessment. For a prescriptive integrity management program, the minimum data required and the criteria for risk assessment to eliminate a threat from further consideration are specified in Nonmandatory Appendix A. Performance-based integrity management programs that use more comprehensive analysis methods should consider the following to exclude a threat in a segment:

(a) There is no history of a threat impacting the particular segment or pipeline system.
(b) The threat is not supported by applicable industry data or experience.
(c) The threat is not implied by related data elements.
(d) The threat is not supported by like/similar analyses.
(e) The threat is not applicable to system or segment operating conditions.

More specifically, (c) considers the application of related data elements to provide an indication of a threat's presence when other data elements may not be available. As an example, for the external corrosion threat, multiple data elements such as soil type/moisture level, CP data, CIS data, CP current demand, and coating condition can all be used, or if one is unavailable a subset may be sufficient to determine whether the threat shall be considered for that segment. Subparagraph (d) considers the evaluation of pipeline segments with known and similar conditions that can be used as a basis for evaluating the existence of threats on pipelines with missing data. Subparagraph (e) allows for the fact that some pipeline systems or segments are not vulnerable to some threats. For instance, based on industry research and experience, pipelines operating at low stress levels do not develop SCC-related failures.

The unavailability of identified data elements is not a justification for exclusion of a threat from the integrity management program. Depending on the importance of the data, additional inspections or field data collection efforts may be required. In addition, a threat cannot be excluded without consideration given to the likelihood of interaction by other threats. For instance, cathodic protection shielding in rocky terrain where impressed current may not prevent corrosion in areas of damaged coating must be considered.

When considering threat exclusion, a cautionary note applies to threats classified as time dependent. Although such an event may not have occurred in any given pipeline segment, system, or facility, the fact that the threat is considered time dependent should require very strong justification for its exclusion. Some threats, such as internal corrosion and SCC, may not be immediately evident and can become a significant threat even after extended operating periods.

5.11 Integrity Assessment and Mitigation

The process begins with examining the nature of the most significant risks. The risk drivers for each high-risk segment should be considered in determining the most effective integrity assessment and/or mitigation option. Section 6 discusses integrity assessment and Section 7 discusses options that are commonly used to mitigate threats. A recalculation of each segment’s risk after integrity assessment and/or mitigation actions is required to ensure that the segment’s integrity can be maintained to the next inspection interval.

It is necessary to consider a variety of options or combinations of integrity assessments and mitigation actions that directly address the primary threat(s). It is also prudent to consider the possibility of using new technologies that can provide a more effective or comprehensive risk mitigation approach.

5.12 Validation

Validation of risk analysis results is one of the most important steps in any assessment process. This shall be done to ensure that the methods used have produced results that are usable and are consistent with the operator's and industry's experience. A reassessment of and modification to the risk assessment process shall be required if, as a result of maintenance or other activities, areas are found that were inaccurately represented by the risk assessment process. A risk validation process shall be identified and documented in the integrity management program.

Risk-result validations can be successfully performed by conducting inspections, examinations, and evaluations at locations that are indicated as either high risk or low risk to determine if the methods are correctly characterizing the risks. Validation can be achieved by considering another location’s information regarding the condition of a pipeline segment and the condition determined during maintenance action or prior remedial efforts. A special risk assessment performed using known data prior to the maintenance activity can indicate if meaningful results are being generated.

6 INTEGRITY ASSESSMENT

6.1 General

Based on the priorities determined by risk assessment, the operator shall conduct integrity assessments using the appropriate integrity assessment methods. The integrity assessment methods that can be used are in-line inspection, pressure testing, direct assessment, or other methodologies provided in para. 6.5. The integrity assessment method is based on the threats to which the segment is susceptible. More than one method and/or tool may be required to address all the threats in a pipeline segment. Conversely, inspection using any of the integrity
assessment methods may not be the appropriate action for the operator to take for certain threats. If permitted by the jurisdiction, ASME PCC-3 may be used for guidance concerning the use of inspection methods appropriate for threats to equipment that may not be included in inspection activities for the transportation piping or may be subject to damage mechanisms that differ from those of the main pipeline. Other actions, such as prevention, may provide better integrity management results.

Section 2 provides a listing of threats by three groups: time dependent, resident, and time independent. Time-dependent threats can typically be addressed by using any one of the integrity assessment methods discussed in this section. Resident threats, such as defects that occurred during manufacturing, can typically be addressed by pressure testing, while construction and equipment threats can typically be addressed by examination and evaluation of the specific piece of equipment, component, or pipe joint. Random threats typically cannot be addressed through use of any of the integrity assessment methods discussed in this section but are subject to the prevention measures discussed in section 7.

Use of a particular integrity assessment method may find indications of threats other than those that the assessment was intended to address. For example, the third-party damage threat is usually best addressed by implementation of prevention activities; however, an in-line inspection tool may indicate a dent in the top half of the pipe. Examination of the dent may be an appropriate action to determine if the pipe was damaged due to third-party activity.

It is important to note that some of the integrity assessment methods discussed in section 6 only provide indications of defects. Examination using visual inspection and a variety of nondestructive examination (NDE) techniques is required, followed by evaluation of these inspection results in order to characterize the defect. The operator may choose to go directly to examination and evaluation for the entire length of the pipeline segment being assessed, in lieu of conducting inspections. For example, the operator may wish to conduct visual examination of aboveground piping for the external corrosion threat. Since the pipe is accessible for this technique and external corrosion can be readily evaluated, performing in-line inspection is not necessary.

6.2 Pipeline In-Line Inspection

In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize indications, such as metal loss or deformation, in a pipeline. The effectiveness of the ILI depends on the condition of the specific pipeline section to be inspected and how well the ILI system matches the requirements set by the inspection objectives. API Std 1163 provides definitions and additional guidance on pipeline in-line inspection. Table 6.2-1 provides guidance for which types of ILI technologies have generally been proven successful for identifying pipeline features and helping manage the threats indicated in para. 2.2. ILI technologies not included in Table 6.2-1 may be used; the operator must retain documentation describing the rationale and justification for using such technologies to manage the intended threat(s). NACE SP0102 provides further guidance.

6.2.1 Special Considerations for the Use of In-Line Inspection Tools

(a) The following shall also be considered when selecting the appropriate tool:

(1) Detection Sensitivity. Minimum defect size specified for the ILI tool should be smaller than the size of the defect sought to be detected.

(2) Classification. Classification allows differentiation among types of anomalies.

(3) Sizing Accuracy. Sizing accuracy enables prioritization and is a key to a successful integrity management plan.

(4) Location Accuracy. Location accuracy enables location of anomalies by excavation.

(5) Requirements for Defect Assessment. Results of ILI have to be adequate for the specific operator's defect assessment program.

(b) Typically, pipeline operators provide answers to a questionnaire provided by the ILI vendor that should list all the significant parameters and characteristics of the pipeline section to be inspected. Some of the more important issues that should be considered are as follows:

(1) Pipeline Questionnaire. The questionnaire provides a review of pipe characteristics, such as steel grade, type of welds, length, diameter, wall thickness, elevation profiles, etc. Also, the questionnaire identifies any restrictions, bends, known ovalities, valves, unbarred tees, couplings, and chill rings the ILI tool may need to negotiate.

(2) Launchers and Receivers. These items should be reviewed for suitability, since ILI tools vary in overall length, complexity, geometry, and maneuverability.

(3) Pipe Cleanliness. The cleanliness can significantly affect data collection.

(4) Type of Fluid. The type of phase, gas or liquid, affects the possible choice of technologies.

(5) Flow Rate, Pressure, and Temperature. Flow rate of the gas will influence the speed of the ILI tool inspection. If speeds are outside of the normal ranges, resolution can be compromised. Total time of inspection is dictated by inspection speed but is limited by the total capacity of batteries and data storage available on the tool. High temperatures can affect tool operation quality and should be considered.

(6) Product Bypass/Supplement. Reduction of gas flow and speed reduction capability on the ILI tool may be a consideration in higher velocity lines.
### Table 6.2-1
Applicability of ILI Technologies

<table>
<thead>
<tr>
<th>Integrity Threat Classification</th>
<th>Metal Loss</th>
<th>Crack Detection</th>
<th>Inertial Tool/Mapping Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Magnetic Flux Leakage (MFL)</td>
<td>Ultrasonic</td>
<td>Ultrasonic</td>
</tr>
<tr>
<td>Time Dependent</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>External corrosion</td>
<td>●</td>
<td>●</td>
<td>○</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>●</td>
<td>●</td>
<td>○</td>
</tr>
<tr>
<td>Stress corrosion cracking</td>
<td>○</td>
<td>○</td>
<td>●</td>
</tr>
<tr>
<td>Resident</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Manufacturing related</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Defective pipe seam</td>
<td>●</td>
<td>○</td>
<td>●</td>
</tr>
<tr>
<td>Defective pipe</td>
<td>●</td>
<td>●</td>
<td>●</td>
</tr>
<tr>
<td>Welding / fabrication related</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Defective pipe girth weld (circumferential)</td>
<td>●</td>
<td>○</td>
<td>●</td>
</tr>
<tr>
<td>Defective fabrication weld</td>
<td>●</td>
<td>○</td>
<td>●</td>
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<tr>
<td>Wrinkle bend or buckle</td>
<td>●</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Stripped threads/broken pipe/coupling failure</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Equipment</td>
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<tr>
<td>Gasket O-ring failure</td>
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<tr>
<td>Control/relief equipment failure</td>
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<tr>
<td>Seal/pump packing failure</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Miscellaneous</td>
<td>○</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Random or Time Independent</td>
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<tr>
<td>Third party/ mechanical damage</td>
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<td></td>
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<tr>
<td>First, second, or third parties (instantaneous failure)</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Previously damaged pipe (e.g., dents and gouges)</td>
<td>●</td>
<td>●</td>
<td>●</td>
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<tr>
<td>Vandalism</td>
<td>●</td>
<td>●</td>
<td>●</td>
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<tr>
<td>Incorrect operational procedures</td>
<td>○</td>
<td>○</td>
<td>○</td>
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<tr>
<td>Weather-related and outside forces</td>
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<tr>
<td>Excessive hot or cold weather</td>
<td>○</td>
<td>○</td>
<td>○</td>
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<tr>
<td>High wind</td>
<td>○</td>
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<tr>
<td>Hydrotechnical</td>
<td>○</td>
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<tr>
<td>Geotechnical</td>
<td>○</td>
<td>○</td>
<td>○</td>
</tr>
<tr>
<td>Lightning</td>
<td>●</td>
<td>●</td>
<td>○</td>
</tr>
</tbody>
</table>

Legend:
- ● = Successfully used by operating companies to identify these types of features in pipelines. Verification of the applicability and capabilities of specific technology configurations offered by ILI vendors for the indicated threats must be confirmed with the vendors.
- ○ = Not typically used to identify these types of features in pipelines. Verification of the applicability and capabilities of specific technology configurations offered by ILI vendors for the indicated threats must be confirmed with the vendors.
Conversely, the availability of supplementary gas where the flow rate is too low shall be considered.

(c) The operator shall assess the general reliability of the ILI method by looking at the following:

1. confidence level of the ILI method (e.g., probability of detecting, classifying, and sizing the anomalies)
2. history of the ILI method/tool
3. success rate/fault surveys
4. ability of the tool to inspect the full length and full circumference of the section
5. ability to indicate the presence of multiple cause anomalies

Generally, representatives from the pipeline operator and the ILI service vendor should analyze the goal and objective of the inspection, and match significant factors known about the pipeline and expected anomalies with the capabilities and performance of the tool. Choice of tool will depend on the specifics of the pipeline section and the goal set for the inspection. The operator shall outline the process used in the integrity management plan for the selection and implementation of the ILI inspections.

6.2.2 Examination and Evaluation. Results of in-line inspection only provide indications of defects, with some characterization of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation. The time frame is discussed in section 7.

Examination consists of a variety of direct inspection techniques, including visual inspection, inspections using NDE equipment, and taking measurements, in order to characterize the defect in confirmatory excavations where anomalies are detected. Once the defect is characterized, the operator must evaluate the defect in order to determine the appropriate mitigation actions. Mitigation is discussed in section 7.

6.3 Pressure Testing

Pressure testing has long been an industry-accepted method for validating the integrity of pipelines. This integrity assessment method can be both a strength test and a leak test. Selection of this method shall be appropriate for the threats being assessed.

ASME B31.8 contains details on conducting pressure tests for both post-construction testing and for subsequent testing after a pipeline has been in service for a period of time. The Code specifies the test pressure to be attained and the test duration to address certain threats. It also specifies allowable test mediums and under what conditions the various test mediums can be used. Additional guidance can be found in API 1110.

The operator should consider the results of the risk assessment and the expected types of anomalies to determine when to conduct inspections using pressure testing.

6.3.1 Time-Dependent Threats. Pressure testing is appropriate for use when addressing time-dependent threats. Time-dependent threats are external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanisms.

6.3.2 Manufacturing and Related Defect Threats. Pressure testing is appropriate for use when addressing the pipe seam aspect of the manufacturing threat. Pressure testing shall comply with the requirements of ASME B31.8. This will define whether air or water shall be used. Seam issues have been known to exist for pipe with a longitudinal weld joint quality factor of less than 1.0 (e.g., lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is composed of low-frequency, electric-resistance welded (LRW) pipe or flash-welded pipe. References for determining if a specific pipe is susceptible to seam issues are Integrity Characteristics of Vintage Pipelines (The INGAA Foundation, Inc.) and History of Line Pipe Manufacturing in North America (ASME research report).

When raising the MAOP of a steel pipeline or when raising the operating pressure above the historical operating pressure (i.e., highest pressure recorded in 5 yr prior to the effective date of this Code), pressure testing must be performed to address the seam issue.

Pressure testing shall be in accordance with ASME B31.8, to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct tests for both post-construction and in-service pipelines.

6.3.3 All Other Threats. Pressure testing is typically not the appropriate integrity assessment method to use for all other threats listed in section 2.

6.4 Direct Assessment

Direct assessment is an integrity assessment method using a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation to determine the integrity.

6.4.1 External Corrosion Direct Assessment (ECDA) for the External Corrosion Threat. External corrosion direct assessment can be used for determining integrity for the external corrosion threat on pipeline segments. The operator may use NACE SP0502 to conduct ECDA. The ECDA process integrates facilities data and current and historical field inspections and tests with the physical characteristics of a pipeline. Nonintrusive (typically
### Table 7.1-1

**Acceptable Threat Prevention and Repair Methods (Cont’d)**

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<tbody>
<tr>
<td></td>
<td>TPD (IF)</td>
<td>PDP</td>
<td>Vand</td>
<td>Ext</td>
<td>Int</td>
<td>Gask/Oring</td>
<td>Strip/BP</td>
<td>Cont/Rel</td>
<td>Seal/Pack</td>
</tr>
<tr>
<td>Reduce moisture</td>
<td>...</td>
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<td>Biocide/inhibiting injection</td>
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<tr>
<td>Install thermal protection</td>
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</table>

**Repairs**

<table>
<thead>
<tr>
<th>Repairs</th>
<th>TPD (IF)</th>
<th>PDP</th>
<th>Vand</th>
<th>Ext</th>
<th>Int</th>
<th>Gask/Oring</th>
<th>Strip/BP</th>
<th>Cont/Rel</th>
<th>Seal/Pack</th>
<th>IO</th>
<th>CW</th>
<th>L</th>
<th>HR/F</th>
<th>Pipe</th>
<th>Seam</th>
<th>Pipe</th>
<th>Gweld</th>
<th>Fab Weld</th>
<th>Coup/Strip</th>
<th>WB/B</th>
<th>EM</th>
<th>SCC</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure reduction</td>
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<td>Replacement</td>
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<tr>
<td>ECA, recoat</td>
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<tr>
<td>Grind repair/ECA</td>
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<td>X</td>
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<tr>
<td>Direct deposition weld</td>
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<tr>
<td>Type B, pressurized sleeve</td>
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<td>X</td>
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<tr>
<td>Type A, reinforcing sleeve</td>
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<td>X</td>
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<td>X</td>
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<td>A/D</td>
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<tr>
<td>Composite sleeve</td>
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<tr>
<td>Epoxy-filled sleeve</td>
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<td>Annular filled saddle</td>
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<tr>
<td>Mechanical leak clamp</td>
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<td>X</td>
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</tbody>
</table>

**Legend:**

- **X** = acceptable
- **...** = unacceptable
- **A** = these may be used to repair straight pipe but may not be used to repair branch and T-joints.
- **B** = these may be used to repair branch and T-joints but may not be used to repair straight pipe.
- **C** = the materials, weld procedures, and pass sequences need to be properly designed and correctly applied to ensure cracking is avoided. Particular care must be exercised to ensure the safety of workers when welding on pressurized lines. Guidance can be found in publications by W. A. Bruce et al., IPC2002-27131, IPC2006-10299, and IPC2008-64353.
- **D** = this repair is not intended to restore axial pipe strength. It can only be used for damaged pipe where all the stress risers have been ground out and the missing wall is filled with uncompressible filler. Transitions at girth welds and fittings and to heavy wall pipe require additional care to ensure the hoop carrying capacity is effectively restored.

**GENERAL NOTE:** The abbreviations found in Table 7.1-1 relate to the 21 threats discussed in section 5. Explanations of the abbreviations are as follows:

- **Cont/Rel** = control/relief equipment malfunction
- **Coup/Strip** = failure of a mechanical coupling or stripped threads
- **CW** = cold weather
- **Direct deposition weld** = a very specialized repair technique that requires detailed materials information and procedure validation to avoid possible cracking on live lines
- **ECA** = engineering critical assessment
- **EM** = earth movement
- **Ext** = external corrosion
- **Fab Weld** = defective fabrication weld including branch and T-joints
- **Gask/Oring** = gasket or O-ring
- **Gweld** = defective pipe girth weld (circumferential)
When determining repair intervals, the operator should consider that certain threats to specific pipeline operating conditions may require a reduced examination and evaluation interval. This may include third-party damage or construction threats in pipelines subject to pressure cycling or external loading that may promote increased defect growth rates. For prescriptive-based programs, the inspection intervals are conservative for potential defects that could lead to a rupture; however, this does not alleviate operators of the responsibility to evaluate the specific conditions and changes in operating conditions to ensure the pipeline segment does not warrant special consideration (see GRI-01/0085).

If the analysis shows that the time to failure is too short in relation to the time scheduled for the repair, the operator shall apply temporary measures, such as pressure reduction, until a permanent repair is completed. In considering projected repair intervals and methods, the operator should consider potential delaying factors, such as access, environmental permit issues, and gas supply requirements.

7.2.5 Extending Response Times for Performance-Based Program. An engineering assessment (EA as defined in section 13) may be performed to determine an appropriate response, repair, or reinspection schedule for a performance-based program.

The operator’s integrity management program shall include documentation that describes grouping of specific defect types and the EA methods used for such analyses.

7.3 Responses to Pressure Testing

Any defect that fails a pressure test shall be promptly remediated by repair or removal.

7.3.1 External and Internal Corrosion Threats. The interval between tests for the external and internal corrosion threats shall be consistent with Table 5.6.1-1.

7.3.2 Stress Corrosion Cracking Threat. The interval between pressure tests for stress corrosion cracking shall be as follows:

(a) if no failures occurred due to SCC, the operator shall use one of the following options to address the long-term mitigation of SCC:

(1) a documented hydrostatic retest program with a technically justifiable interval, or

(2) an engineering critical assessment to evaluate the risk and identify further mitigation methods

(b) if a failure occurred due to SCC, the operator shall perform the following:

(1) implement a documented hydrostatic retest program for the subject segment

(2) technically justify the retest interval in the written retest program

7.3.3 Manufacturing and Related Defect Threats. A subsequent pressure test for the manufacturing threat is not required unless the MAOP of the pipeline has been raised or when the operating pressure has been raised above the historical operating pressure (highest pressure recorded in 5 yr prior to the effective date of this Supplement).

7.4 Responses to Direct Assessment Inspections

7.4.1 External Corrosion Direct Assessment (ECDa). For the ECDA prescriptive program for pipelines operating above 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspection and repairs all defects that could grow to failure in 10 yr, then the reinspection interval shall be 10 yr. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 5 yr, provided an analysis is performed to ensure all remaining defects will not grow to failure in 10 yr. The interval between determination and examination shall be consistent with Figure 7.2.1-1.

For the ECDA prescriptive program for pipeline segments operating up to but not exceeding 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspections and repair all defects that could grow to failure in 20 yr, the reinspection interval shall be 20 yr. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 10 yr, provided an analysis is performed to ensure all remaining defects will not grow to failure in 20 yr (at an 80% confidence level). The interval between determination and examination shall be consistent with Figure 7.2.1-1.

7.4.2 Internal Corrosion Direct Assessment (ICDA). For the ICDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 yr of selection. The interval between subsequent examinations shall be consistent with Figure 7.2.1-1.

7.4.3 Stress Corrosion Cracking Direct Assessment (SCCDa). For the SCCDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 yr of selection. ILI or pressure testing (hydrotesting) may not be warranted if significant and extensive cracking is not present on a pipeline system. The interval between subsequent examinations shall provide similar safe interval between periodic integrity assessments consistent with Figure 7.2.1-1 and Nonmandatory Appendix A, section A-4. Figure 7.2.1-1 and Nonmandatory Appendix A, section A-4 are applicable to prescriptive-based programs. The intervals may be extended for a performance-based program as provided in para. 7.2.5.
The mitigation element of the plan consists of two parts. The first part is the repair of the pipeline. Based on the results of the integrity assessments and the threat being addressed, appropriate repair activities shall be determined and conducted. These repairs shall be performed in accordance with accepted standards and operating practices. The second part of mitigation is prevention. Prevention can stop or slow down future deterioration of the pipeline. Prevention is also an appropriate activity for time-independent threats. All mitigation activities shall be prioritized and scheduled. The prioritization and schedule shall be modified as new information is obtained and shall be a real-time aspect of the plan (see section 7).

Tables 8.3.4-1, 8.3.4-2, and 8.3.4-3 provide examples of an integrity management plan in a spreadsheet format for a hypothetical pipeline segment (line 1, segment 3). This spreadsheet shows the segment data, the integrity assessment plan devised based on the risk assessment, and the reassessment interval.
Were all integrity management program objectives accomplished?

Were pipeline integrity and safety effectively improved through the integrity management program?

Table 8.3.4-2
Example of Integrity Management Plan for Hypothetical Pipeline Segment (Integrity Assessment Plan: Line 1, Segment 3)

<table>
<thead>
<tr>
<th>Threat</th>
<th>Criteria/Risk Assessment</th>
<th>Integrity Assessment</th>
<th>Mitigation</th>
<th>Interval, yr</th>
</tr>
</thead>
<tbody>
<tr>
<td>External corrosion</td>
<td>Some external corrosion history, no in-line inspection</td>
<td>Conduct hydrostatic test, perform in-line inspection, or perform direct assessment</td>
<td>Replace/repair locations where CFP below 1.25 times the MAOP</td>
<td>10</td>
</tr>
<tr>
<td>Internal corrosion</td>
<td>No history of IC issues, no in-line inspection</td>
<td>Conduct hydrostatic test, perform in-line inspection, or perform direct assessment</td>
<td>Replace/repair locations where CFP below 1.25 times the MAOP</td>
<td>10</td>
</tr>
<tr>
<td>SCC</td>
<td>Have found SCC of near critical dimension</td>
<td>Conduct hydrostatic test</td>
<td>Replace pipe at test failure locations</td>
<td>3–5</td>
</tr>
<tr>
<td>Manufacturing</td>
<td>EW pipe, longitudinal weld joint quality factor &lt;1.0, no hydrostatic test</td>
<td>Conduct hydrostatic test</td>
<td>Replace pipe at test failure locations</td>
<td>N/A</td>
</tr>
<tr>
<td>Construction/fabrication</td>
<td>No construction issues</td>
<td>None required</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Equipment</td>
<td>No equipment issues</td>
<td>None required</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Third-party damage</td>
<td>No third-party damage issues</td>
<td>None required</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Incorrect operations</td>
<td>No operations issues</td>
<td>None required</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Weather and outside force</td>
<td>No weather- or outside-force-related issues</td>
<td>None required</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

Table 8.3.4-3
Example of Integrity Management Plan for Hypothetical Pipeline Segment (Mitigation Plan: Line 1, Segment 3)

<table>
<thead>
<tr>
<th>Example</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Repair</td>
<td>Any hydrostatic test failure will be repaired by replacement of the entire joint of pipe.</td>
</tr>
<tr>
<td>Prevention</td>
<td>Prevention activities will include further monitoring for SCC at susceptible locations, review of the cathodic protection design and levels, and monitoring for selective seam corrosion when the pipeline is exposed.</td>
</tr>
<tr>
<td>Interval for reinspection</td>
<td>The interval for reinspection will be 3 yr if there was a failure caused by SCC. The interval will be 5 yr if the test was successful.</td>
</tr>
<tr>
<td>Data integration</td>
<td>Test failures for reasons other than external or internal corrosion, SCC, or seam defect must be considered when performing risk assessment for the associated threat.</td>
</tr>
</tbody>
</table>

GENERAL NOTE: For this pipeline segment, hydrostatic testing will be conducted. Selection of this method is appropriate due to its ability to address the internal and external corrosion threats as well as the manufacturing threat and the SCC threat. The test pressure will be at 1.39 times the MAOP.

9.2 Performance Measures Characteristics

Performance measures focus attention on the integrity management program results that show improved safety has been attained. The measures provide an indication of effectiveness but are not absolute. Performance measure evaluation and trending can also lead to recognition of unexpected results that may include the recognition of threats not previously identified. All performance measures shall be simple, measurable, attainable, relevant, and permit timely evaluations. Proper selection and evaluation of performance measures is an essential activity in determining integrity management program effectiveness.

Performance measures should be selected carefully to ensure that they are reasonable program effectiveness indicators. Change shall be monitored so the measures will remain effective over time as the plan matures. The time required to obtain sufficient data for analysis shall also be considered when selecting performance measures. Methods shall be implemented to permit both short- and long-term performance measure evaluations. Integrity management program performance measures can generally be categorized into groups.

9.2.1 Process or Activity Measures. Process or activity measures can be used to evaluate prevention or mitigation activities. These measures determine how well an operator is implementing various elements of the integrity management program. Measures relating to process or activity shall be selected carefully to permit performance evaluation within a realistic time frame.
measures that should be used to evaluate effectiveness in addition to other measures stipulated in the integrity management program. Recommendations for changes and/or improvements to the integrity management program shall be documented. The results, recommendations, and resultant changes made to the integrity management program shall be based on analysis of the performance and/or improvements to the integrity management program. Recommendations for changes should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel (technical, physical, procedural, and organizational) changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:

1. Identification of changes that could affect the integrity management program or integrity of the pipeline system
2. Reason for change(s)
3. Implementation actions and accountabilities
4. Analysis of implications
5. Whether the change(s) is temporary or permanent
6. Time limitations (e.g., timeframe for completing the change)
7. Authority for approving changes
8. Acquisition of required work permits
9. Communication of change(s) to appropriate internal and external stakeholders
10. Training and qualification of staff
11. Documentation demonstrating that all actions of the management of change process have been completed

(b) The operator shall recognize that system changes can require changes in the integrity management program and, conversely, results from the program can cause system changes. The following are examples that are gas-pipeline specific but are by no means all-inclusive:

1. If a change in land use would affect either the consequence of an incident, such as increases in population near the pipeline, or a change in likelihood of an incident, such as subsidence due to underground mining, the change must be reflected in the integrity management plan and the threats reevaluated accordingly.
2. If the results of an integrity management program inspection indicate the need for a change to the system, such as changes to the CP program or other than temporary reductions in operating pressure, these shall be communicated to operators and reflected in an updated integrity management program.

(3) If an operator decides to increase pressure in the system from its historical operating pressure to, or closer to, the allowable MAOP, that change shall be reflected in the integrity plan and the threats shall be reevaluated accordingly.

(4) If a line has been operating in a steady-state mode and a new load on the line changes the mode of operation to a more cyclical load (e.g., daily changes in operating pressure), fatigue shall be considered in each of the threats where it applies as an additional stress factor.

(c) Along with management, the review procedure should require the involvement of staff that can assess safety impact and, if necessary, suggest controls or modifications. The operator shall have the flexibility to maintain continuity of operation within established safe operating limits.

(d) Management of change ensures that the integrity management process remains viable and effective as changes to the system occur and/or new, revised, or corrected data becomes available. Any change to equipment or procedures has the potential to affect pipeline integrity. Most changes, however small, will have a consequence effect on another aspect of the system. For example, many equipment changes will require a corresponding technical or procedural change. All changes shall be identified and reviewed before implementation. Management of change procedures provides a means of maintaining order during periods of change in the system and helps to preserve confidence in the integrity of the pipeline.

(e) To ensure the integrity of a system, a documented record of changes should be developed and maintained. This information will provide a better understanding of the system and possible threats to its integrity. It should include the process and design information both before and after the changes were put into place.

(f) Communication of the changes carried out in the pipeline system to any affected parties is imperative to the safety of the system. As provided in section 10, communications regarding the integrity of the pipeline should be conducted periodically. Any changes to the system should be included in the information provided in communication from the pipeline operator to affected parties.

(g) System changes, particularly in equipment, may require qualification of personnel for the correct operation of the new equipment. In addition, refresher training should be provided to ensure that facility personnel understand and adhere to the facility’s current operating procedures.

(h) The application of new technologies in the integrity management program and the results of such applications should be documented and communicated to appropriate staff and stakeholders.
(5) If a line was designed for and has been operating in a single flow direction and changes in system operation require the line to change flow direction or become bi-directional, the changes in flow direction shall be reflected in the integrity plan and the threats shall be reevaluated accordingly. Specific consideration shall be given to the ability to run pipeline cleaning tools and in-line inspection tools, the ability to remove liquids from the pipeline, piping with no or low flow that may be subject to debris or liquid accumulation, and the potential impact of changes to operating temperatures and pressures.

(6) Changes in gas composition, such as increased water content, increased carbon dioxide content, change to sour gas, or hydrogen blending, shall be reflected in the integrity plan and the threats shall be reevaluated accordingly. The potential impact on the flow characteristics, corrosion, material degradation, and girth weld, seam or pipe body cracking shall be evaluated.

(7) If changes are made to the control system for a pipeline, such as a new or upgraded Supervisory Control and Data Acquisition (SCADA) system, changes to the SCADA software, changes to the SCADA communication system, changes to programmable logic controllers (PLC) used for pipeline control, etc., such changes shall be reflected in the integrity plan and the threats shall be reevaluated accordingly.

(8) If changes are made to procedures or practices for design, construction, operations and maintenance-related activities, such changes shall be reflected in the integrity plan and the threats shall be reevaluated accordingly.
carbon dioxide (CO₂): a heavier-than-air, odorless, colorless asphyxiant gas that does not support combustion, dissolves in water to form carbonic acid, and is toxic at high concentrations. Carbon dioxide occurs naturally or can be captured from processing. For the purposes of this Code, carbon dioxide and gaseous carbon dioxide are considered to be the same.

buckling: condition in which the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling in the pipe wall or excessive cross-sectional deformation caused by bending, axial, impact, and/or torsional loads acting alone or in combination with hydrostatic pressure.

butt joint: a joint between two members aligned approximately in the same plane. See AWS A3.0, Figures 1(A), 2(A), 3, 51(A), and 51(B).

butt weld: a nonstandard term for a weld in a butt joint.

calibration dig: exploratory excavation to validate findings of an in-line inspection tool with the purpose of improving data interpretation.

caliper tool: an instrumented in-line inspection tool designed to record conditions, such as dents, wrinkles, ovality, bend radius, and angle, by sensing the shape of the internal surface of the pipe.

cast iron: unqualified term “cast iron” shall apply to gray cast iron, which is a cast ferrous material in which a major part of the carbon content occurs as free carbon in the form of flakes interspersed throughout the metal.

cathodic protection (CP): technique to reduce the corrosion of a metal surface by making that surface the cathode of an electromechanical cell.

certification: written testimony of qualification.

characterize: to qualify the type, size, shape, orientation, and location of an anomaly.
**close interval survey (CIS):** inspection technique that includes a series of aboveground pipe-to-soil potential measurements taken at predetermined increments of a few to several feet (meters) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

**coating:** liquid, liquefiable, or mastic composition that, after application to a surface, is converted into a solid protective, decorative, or functional adherent film. Coating also includes tape wrap.

**coating system:** complete number and types of coats applied to a substrate in a predetermined order. (When used in a broader sense, surface preparation, pretreatments, dry film thickness, and manner of application are included.)

**component:** an individual item or element fitted in line with pipe in a pipeline system, such as, but not limited to, valves, elbows, tees, flanges, and closures.

**composite repair sleeve:** permanent repair method using composite sleeve material, which is applied with an adhesive.

**consequence:** impact that a pipeline failure could have on the public, employees, property, and the environment.

**corrosion:** deterioration of a material, usually a metal, that results from an electrochemical reaction with its environment.

**corrosion inhibitor:** chemical substance or combination of substances that, when present in the environment or on a surface, prevents or reduces corrosion.

**corrosion rate:** rate at which corrosion proceeds.

**crack:** very narrow, elongated defect caused by mechanical splitting into two parts.

**current:** flow of electric charge.

**data analysis:** the evaluation process by which inspection indications are classified and characterized.

**defect:** a physically examined anomaly with dimensions or characteristics that exceed acceptable limits. Inspection indications are classified and characterized.

**ductility:** measure of the capability of a material to be deformed plastically before fracturing.

**dye-penetrant test:** a non-destructive testing technique that involves applying a penetrant to the surface of a component, allowing it to seep into any flaws or discontinuities in the material, and then applying a penetrant developer that brings the penetrant to the surface of the component.

**dye-penetrant inspection:** a non-destructive testing method that involves the application of a penetrant to the surface of a component, allowing it to seep into any flaws or discontinuities in the material, and then applying a penetrant developer that brings the penetrant to the surface of the component.

**documented:** condition of being in written form.

**ductility:** measure of the capability of a material to be deformed plastically before fracturing.

**dry film thickness:** the measured thickness of a coating system after application to a surface, is converted into a solid protective, decorative, or functional adherent film.

**dimensions:** measurable wall loss indications are classified and characterized.

**direct-current voltage gradient (DCVG):** inspection technique that includes aboveground electrical measurements taken at predetermined increments along the pipeline and is used to provide information on the effectiveness of the coating system.

**discontinuity:** an interruption of the typical structure of a material, such as a lack of homogeneity in its mechanical, metallurgical, or physical characteristics. A discontinuity is not necessarily a defect.

**documented:** condition of being in written form.

**ductility:** measure of the capability of a material to be deformed plastically before fracturing.

**electric-induction welded pipe (EW):** pipe having one longitudinal (straight or helical) seam produced by low- or high-frequency electric welding. The process of forming a seam is done by electric-resistance welding, wherein the edges to be welded are mechanically pressed together and the heat for welding is generated by the resistance to flow of electric current applied by induction (no electric contact) or conduction. Typical specifications are ASTM A53, ASTM A135, ASTM A333, and API Spec 5L.

**high-frequency welded (HFW) pipe:** EW pipe produced with a welding current frequency equal to or greater than 70 kHz as stated in API Spec 5L.

**low-frequency welded (LFW) pipe:** EW pipe produced with a welding current frequency less than 70 kHz as stated in API Spec 5L.

**NOTE:** 360 Hz had been a common upper limit for LFW pipe manufactured prior to 1980.

**electric-resistance welded (ERW pipe):** see electric-induction welded pipe (EW).

**electrolyte:** medium containing ions that migrate in an electric field.

**electromagnetic acoustic transducer (EMAT):** a type of transducer that generates ultrasound in steel pipe without a liquid couplant, using magnets and coils for excitation of the pipe.

**engineering critical assessment:** an analytical procedure based on fracture mechanics that allows determination of the maximum tolerable sizes for imperfections and that is conducted by, or under the supervision of, a competent person with demonstrated understanding and experience in the application of the engineering and risk management principles related to the issue being assessed.

**engineering principles:** the application of the engineering and risk management principles related to the issue being assessed.
environment: surroundings or conditions (physical, chemical, mechanical) in which a material exists.

epoxy: type of resin formed by the reaction of aliphatic or aromatic polyols (like bisphenol) with epichlorohydrin and characterized by the presence of reactive oxirane end groups.

evaluation: a review following the characterization of an actionable anomaly to determine whether the anomaly meets specified acceptance criteria.

examination: direct physical inspection of a pipeline that may include the use of nondestructive examination (NDE) techniques or methods.

experience: work activities accomplished in a specific NDT method under the direction of qualified supervision including the performance of the NDT method and related activities but not including time spent in organized training programs.

failure: general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously to the point that it has become unreliable or unsafe for continued use.

fatigue: process of development of or enlargement of a crack as a result of repeated cycles of stress.

feature: any physical object detected by an in-line inspection system. Features may be anomalies, components, nearby metallic objects, welds, or some other item.

film: thin, not necessarily visible layer of material.

galvanic corrosion: accelerated corrosion of a metal and/or a more noble localized section of the metal or nonmetallic conductor in a corrosive electrolyte because of an electrical contact with nearby metallic objects, welds, or some other item.

gas: as used in this Code, any fluid transported by pipeline that is neither solid nor liquid at operating temperature and pressure.

gas distribution piping system: gas distribution piping system that operates at a pressure higher than the standard service pressure delivered to the customer. In such a system, a service regulator is required on each service line to control the pressure delivered to the customer.

hydrogen-induced damage: form of degradation of metals caused by exposure to environments (liquid or gas) that allows absorption of hydrogen into the material. Examples of hydrogen-induced damage are formation of internal cracks, blisters, or voids in steels; embrittlement (i.e., loss of ductility); and high-temperature hydrogen attack (i.e., surface decarburization and chemical reaction with hydrogen).

hydrogen sulfide (H₂S): toxic gaseous impurity found in some well gas streams. It also can be generated in situ as a result of microbiologic activity.

hydrostatic test: a pressure test using water as the test medium.

incident: unintentional release of gas due to the failure of a pipeline.

inclusion: nonmetallic phase such as an oxide, sulfide, or silicate particle in a metal pipeline.

indication: finding of a nondestructive testing technique or method that deviates from the expected. It may or may not be a defect.

inertial tool: an ILI system equipped with an inertial measurement unit (IMU) or other mapping technology.

in-line inspection (ILI): steel pipeline inspection technique that uses devices known in the industry as intelligent or smart pigs. These devices run inside the pipe and provide indications of metal loss, deformation, and other defects.

in-line inspection tools: any instrumented device or vehicle that records data and uses nondestructive test methods or other techniques to inspect the pipeline from the inside. These tools are also known as intelligent pigs or smart pigs.
in-service pipeline: defined herein as a pipeline that contains natural gas to be transported. The gas may or may not be flowing.

inspection: use of a nondestructive testing technique or method.

integrity: defined herein as the capability of the pipeline to withstand all anticipated loads (including hoop stress due to operating pressure) plus the margin of safety established by this section.

integrity assessment: process that includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, characterizing the evaluation by defect type and severity, and determining the resulting integrity of the pipeline through analysis.

launcher: pipeline facility used to insert a pig into a pressurized pipeline, sometimes referred to as a "pig trap."

leak: unintentional escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and nonpropagating, longitudinal, and circumferential), separation or pullout, and loose connections.

length: a piece of pipe of the length delivered from the mill. Each piece is called a length, regardless of its actual dimension. This is sometimes called a "joint," but "length" is preferred.

liquefied petroleum gas(es) (LPG): liquid petroleum gases composed predominantly of the following hydrocarbons, either by themselves or as mixtures: butane (normal butane or isobutane), butylene (including isomers), propane, propylene, and ethane. LPG can be stored as liquids under moderate pressures [approximately 80 psig to 250 psig (550 kPa to 1 720 kPa)] at ambient temperatures.

longitudinal weld joint quality factor: a value of 1.00 or less applicable to a straight or helical pipe seam weld, based on the type of welding process and relevant supplementary NDE requirements. This weld joint quality factor does not apply to girth welds.

low-pressure distribution system: gas distribution piping system in which the gas pressure in the mains and service lines is substantially the same as that delivered to the customer's appliances. In such a system, a service regulator is not required on the individual service lines.

low-stress pipeline: pipeline that is operated in its entirety at a hoop stress level of 20% or less of the specified minimum yield strength of the line pipe.

magnetic-flux leakage (MFL): an in-line inspection technique that induces a magnetic field in a pipe wall between two poles of a magnet. Sensors record status in leakage in this magnetic flux (flow) outside the pipe wall, which can be correlated to metal loss.

magnetic-particle inspection (MPI): a nondestructive test method using magnetic leakage fields and suitable indicating materials to disclose surface and near-surface discontinuity indications.

management of change: process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural, or organizational nature that can affect system integrity.

mapping technology: technology that allows features detected by an ILI tool to be correlated with GPS information.

maximum allowable operating pressure (MAOP): maximum pressure at which a pipeline system may be operated in accordance with the provisions of ASME B31.8.

may: used to denote permission, and is neither a requirement nor a recommendation.

mechanical damage: type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, puncturing, and residual stresses.

metal loss: types of anomalies in pipe in which metal has been removed from the pipe surface, usually due to corrosion or gouging.

microbiologically influenced corrosion (MIC): corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

mitigation: limitation or reduction of the probability of occurrence or expected consequence for a particular event.

municipality: city, county, or any other political subdivision of a state.

nominal outside diameter: see diameter.

nondestructive examination (NDE): testing method, such as radiography, ultrasonic, magnetic testing, liquid penetrant, visual, leak testing, eddy current, and acoustic emission, or a testing technique, such as magnetic-flux leakage, magnetic-particle inspection, shear-wave ultrasonic, and contact compression-wave ultrasonic.

nondestructive testing (NDT): see nondestructive examination (NDE).

operating stress: stress in a pipe or structural member under normal operating conditions.

operational pipe size (NPS): see diamètre nominal (DN).
operator: see operating company.

performance-based integrity management program: integrity management process that uses risk management principles and risk assessments to determine prevention, detection, and mitigation actions and their timing.

pig: device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.

pigging: use of any independent, self-contained device, tool, or vehicle that moves through the interior of the pipeline for inspecting, dimensioning, cleaning, or drying.

pipe: a tubular product, including tubing, made for sale as a production item, used primarily for conveying a fluid and sometimes for storage. Cylinders formed from plate during the fabrication of auxiliary equipment are not pipe as defined herein.

pipe grade: portion of the material specification for pipe, which includes specified minimum yield strength.

pipeline: all parts of physical facilities through which gas moves in transportation, including pipe, valves, fittings, flanges (including bolting and gaskets), regulators, pressure vessels, pulsation dampeners, relief valves, appurtenances attached to pipe, compressor units, metering facilities, pressure-regulating stations, pressure-limiting stations, pressure relief stations, and fabricated assemblies. Included within this definition are gas transmission and gathering lines, which transport gas from production facilities to onshore locations, and gas storage equipment of the closed-pipe type that is fabricated or forged from pipe or fabricated from pipe and fittings.

pipeline component: see component.

pipeline facility: new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

pipeline section: continuous run of pipe between adjacent compressor stations, between a compressor station and a block valve, or between adjacent block valves.

pipeline system: either the operator’s entire pipeline infrastructure or large portions of that infrastructure that have definable starting and stopping points.

pipe-to-soil potential: electric potential difference between the surface of a buried or submerged metallic structure and the electrolyte that is measured with reference to an electrode in contact with the electrolyte.

piping and instrumentation diagram (P&ID): drawing showing the piping and instrumentation for a pipeline or pipeline facility.

pitting: localized corrosion of a metal surface that is confined to a small area and takes the form of cavities called pits.

predicted failure pressure, \( P_f \): an internal pressure that is used to prioritize a defect as immediate, scheduled, or monitored. See the detailed explanation with Figure 7.2.1-1. The failure pressure is calculated using ASME B31G or similar method when the design factor, \( F \), is set to unity.

prescriptive integrity management program: integrity management process that follows preset conditions that result in fixed inspection and mitigation activities and timelines.

pressure: unless otherwise stated, pressure is expressed in pounds per square inch (kilopascals) above atmospheric pressure (i.e., gage pressure), and is abbreviated as psig (kPa).

pressure test: means by which the integrity of a piece of equipment (pipe) is assessed, in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.

probability: likelihood of an event occurring.

qualification: demonstration and documented knowledge, skills, and abilities, along with documented training and/or experience required for personnel to properly perform the duties of a specific job or task.

receiver: pipeline facility used for removing a pig from a pressurized pipeline; sometimes referred to as a “pig trap.”

resident threat: a manufacturing-, welding/fabrication-, or equipment-related imperfection that if not acted upon by a time-dependent or time-independent threat, remains dormant and does not deteriorate with time.

residual stress: stress present in an object in the absence of any external loading, typically resulting from manufacturing or construction processes.

resistivity:

(a) resistance per unit length of a substance with uniform cross section

(b) measure of the ability of an electrolyte (e.g., soil) to resist the flow of electric charge (e.g., cathodic protection current)

Resistivity data are used to design a groundbed for a cathodic protection system.

rich gas: gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane.

right-of-way (ROW): the strip of land on which pipelines, railroads, power lines, roads, highways, and other similar facilities are constructed. The ROW agreement secures the right to pass through property owned by others. ROW agreements generally allow the right of ingress and egress for the operation and maintenance of the facility, and the installation of the facility. The ROW width can vary with the construction and maintenance requirements of
the facility’s operator and is usually determined based on negotiation with the affected landowner, by legal action, or by permitting authority.

risk: measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

risk assessment: systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and can be performed at varying levels of detail depending on the operator’s objectives (see section 5).

risk management: overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

root cause analysis: family of processes implemented to determine the primary cause of an event. These processes all seek to examine a cause-and-effect relationship through the organization and analysis of data. Such processes are often used in failure analyses.

rupture: complete failure of any portion of the pipeline that allows the product to escape to the environment.

rust: corrosion product consisting of various iron oxides and hydrated iron oxides (this term properly applies only to iron and ferrous alloys).

seam weld: longitudinal (straight or helical) seam in pipe that is made in the pipe mill for the purpose of making a complete circular cross section.

segment: length of pipeline or part of the system that has unique characteristics in a specific geographic location.

sensors: devices that receive a response to a stimulus (e.g., an ultrasonic sensor detects ultrasound).

shall: used to denote a requirement.

shielding: preventing or diverting the flow of cathodic protection current from its natural path.

should: used to denote a recommendation.

sizing accuracy: given by the interval within which a fixed percentage of all metal-loss features will be sized. The fixed percentage is stated as the confidence level.

smart pig: see in-line inspection tools.

soil liquefaction: soil condition, typically caused by dynamic cyclic loading (e.g., earthquake, waves) where the effective shear strength of the soil is reduced such that the soil exhibits the properties of a liquid.

specified minimum yield strength (SMYS): expressed in pounds per square inch (psi) or megapascals (MPa); minimum yield strength prescribed by the specification under which the material is purchased from the manufacturer.

storage field: geographic field containing a well or wells that are completed for and dedicated to subsurface storage of large quantities of gas for later recovery, transmission, and end use.

strain: change in length of a material in response to an applied force, expressed on a unit length basis (e.g., inches per inch or millimeters per millimeter).

stress: internal resistance of a body to an external applied force, expressed in units of force per unit area (psi or MPa). It may also be termed “unit stress.”

stress corrosion cracking (SCC): form of environmental attack of the metal involving an interaction of local corrosive environment and tensile stresses in the metal, resulting in formation and growth of cracks.

stress level: level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

subject matter experts: individuals that have expertise in a specific area of operation or engineering.

submerged-arc welded (SAW) pipe: pipe that has been welded from one side or from both sides of a weld joint using the submerged-arc welding process. The pipe can have one or two straight seams or one helical seam. When it is welded from both sides, it is sometimes referred to as double submerged-arc welded (DSAW) pipe. The SAW process produces melting and coalescence of metals by heating them with an arc or arcs between a bare metal consumable electrode or electrodes and the work, wherein the arc and molten metal are shielded by a blanket of granular flux. Pressure is not used, and part or all of the filler metal is obtained from the electrodes. Typical specifications are ASTM A134, ASTM A139, ASTM A381, ASTM A671, ASTM A672, ASTM A691, and API Spec 5L.

submerged arc welding (SAW): arc welding process that uses an arc or arcs between a bare metal electrode or electrodes and the weld pool. The arc and molten metal are shielded by a blanket of granular flux on the workpieces. The process is used without pressure and with filler metal from the electrode and sometimes from a supplemental source (welding rod, flux, or metal granules).

survey: measurements, inspections, or observations intended to discover and identify events or conditions that indicate a departure from normal operation or undamaged condition of the pipeline.

system: see pipeline system.

temperature: expressed in degrees Fahrenheit (°F) or degrees Celsius (°C).

tensile stress: applied pulling force divided by the original cross-sectional area.

[psi] [megapascals (MPa)].
third-party damage: damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this Code, this also includes damage caused by the operator’s personnel or the operator’s contractors.

tool: generic term signifying any type of instrumented tool or pig.

training: organized program developed to impart the knowledge and skills necessary for qualification.

transmission line: segment of pipeline installed in a transmission system or between storage fields.

transmission system: one or more segments of pipeline, usually interconnected to form a network, that transports gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high- or low-pressure distribution system, a large-volume customer, or another storage field.

transportation of gas: gathering, transmission, or distribution of gas by pipeline or the storage of gas.

ultrasonic: high-frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

uprating: qualifying of an existing pipeline or main for a higher maximum allowable operating pressure.

weld: localized coalescence of metals or nonmetals produced by heating the materials to the welding temperature, with or without the application of pressure, or by the application of pressure alone with or without the use of filler material.

welding procedures: detailed methods and practices involved in the production of a weldment.

wrinkle bend: pipe bend produced by field machine or controlled process that may result in prominent localized wrinkles on the inner radius. The wrinkles are produced by heating the materials to the welding temperature, with or without the application of pressure, or by the application of pressure alone with or without the use of filler material.

wrinkle bend: pipe bend produced by field machine or controlled process that may result in prominent localized wrinkles on the inner radius. The wrinkles are produced by heating the materials to the welding temperature, with or without the application of pressure, or by the application of pressure alone with or without the use of filler material.

14 REFERENCES AND STANDARDS

The following is a list of publications that support or are referenced in this Code. The references shall be to the specific editions cited below, except the user may use the latest published edition of ANSI-approved standards unless specifically prohibited by this Code and provided the user has reviewed the latest edition of the Code to ensure that the integrity of the pipeline system is not compromised. If a newer or amended edition of a standard is not ANSI approved, then the user shall use the specific edition reference date shown herein. An asterisk (*) is used to indicate that the specific edition of the standard has been accepted as an American National Standard by the American National Standards Institute (ANSI).


*ANSI/GPTC-Z380.1 (2018, including Addenda 1 through 6), Guide for Gas Transmission, Distribution and Gathering Piping Systems

Publisher: American Gas Association (AGA), 400 North Capitol Street, NW, Suite 450, Washington, DC 20001 (www.aga.org)

*ANSI/ISO/ASQ Q9004-2009, Managing for the sustained success of an organization — A quality management approach

Juran’s Quality Handbook (seventh edition, 2016)

Publisher: American Society for Quality (ASQ), 600 North Plankinton Avenue, Milwaukee, WI 53203 (www.asq.org)

*API RP 1110 (sixth edition, February 2013, reaffirmed August 2018), Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide

*API RP 1160 (third edition, February 2019), Managing System Integrity for Hazardous Liquid Pipelines

*API Spec 5L (46th edition, April 2018, including Errata through May 2018), Line Pipe

*API Std 1163 (second edition, April 2013, reaffirmed August 2018), In-Line Inspection Systems Qualification

Publisher: American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001-5571 (www.api.org)

*ASME B31.8-2020, Gas Transmission and Distribution Piping Systems

*ASME B31G-2012 (R2017), Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping


ASME STP-PT-011, Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas (2008)


A-1 INTRODUCTION

This Appendix provides process charts and the essentials of a prescriptive integrity management plan for the nine categories of threats listed in the main body of this Code. The required activities and intervals are not applicable for severe conditions that the operator may encounter. In those instances, more rigorous analysis and more frequent inspection may be necessary.

A-2 EXTERNAL CORROSION THREAT

A-2.1 Scope

Section A-2 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, of external corrosion (see Figure A-2.1-1). External corrosion is defined in this context to include galvanic corrosion and microbiologically influenced corrosion (MIC).

This section outlines the integrity management process for external corrosion in general and also covers some specific issues. Pipeline incident analysis has identified external corrosion among the causes of past incidents.

A-2.2 Gathering, Reviewing, and Integrating Data

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. These data are collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring additional activities.

- (a) year of installation
- (b) coating type
- (c) coating condition
- (d) years with adequate cathodic protection
- (e) years with questionable cathodic protection
- (f) years without cathodic protection
- (g) soil characteristics
- (h) pipe inspection reports (bell hole)
- (i) MIC detected (yes, no, or unknown)
- (j) leak history
- (k) wall thickness
- (l) diameter
- (m) operating stress level (% SMYS)
- (n) past hydrostatic test information

For this threat, the data are used primarily for prioritization of integrity assessment and/or mitigation activities. Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

A-2.3 Criteria and Risk Assessment

For new pipelines or pipeline segments, the operator may wish to use the original material selection, design conditions, and construction inspections, as well as the current operating history, to establish the condition of the pipe. For this situation, the operator must determine that the construction inspections have an equal or greater rigor than that provided by the prescribed integrity assessment in this Code.

In no case shall the interval between construction and the first required reassessment of integrity exceed 10 yr for pipe operating above 60% SMYS, 13 yr for pipe operating above 50% SMYS and at or below 60% SMYS, 15 yr for pipe operating at or above 30% SMYS and at or below 50% SMYS, and 20 yr for pipe operating below 30% SMYS.

For all pipeline segments older than those stated above, integrity assessment shall be conducted using a methodology, within the specified response interval, as provided in para. A-2.5.

Previous integrity assessments can be considered as meeting these requirements, provided the inspections have equal or greater rigor than that provided by the prescribed inspections in this Code. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the interval stated in this Code.

A-2.4 Integrity Assessment

The operator has a choice of three integrity assessment methods: in-line inspection with a tool capable of detecting wall loss, such as an MFL tool; performing a pressure test; or conducting direct assessment.

(a) In-Line Inspection. The operator shall consult section 6, which defines the capability of various ILI devices and provides criteria for running the tool.
(c) Pressure Testing. The interval is dependent on the test pressure. If the test pressure is at least 1.39 times MAOP, the interval shall be 10 yr. If the test pressure is at least 1.25 times MAOP, the interval shall be 5 yr (see section 7).

If the actual operating pressure is less than MAOP, these factors can be applied to the actual operating pressure in lieu of MAOP for ensuring integrity at the reduced pressure only.

The operator shall select the appropriate repair methods as outlined in section 7.

The operator shall select the appropriate prevention practices as outlined in section 7.

A-2.6 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when conducting an ILI with an MFL tool, dents may be detected on the top half of the pipe. This may have been caused by third-party damage. This information will assist in prioritizing data for third-party damage.

A-2.7 Assessment Interval

The operator is required to assess integrity periodically. The interval for assessments is dependent on the responses taken as outlined in para. A-2.5. These intervals are maximum intervals. The operator must incorporate new data into the assessment as data becomes available and that may require more frequent integrity assessments. For example, a leak on the segment that may be caused by external corrosion should necessitate immediate reassessment.

Changes to the segment may also require reassessment. Change management is addressed in this Code in section 11.

A-2.8 Performance Measures

The following performance measures shall be documented for the external corrosion threat, to establish the effectiveness of the program and for confirmation of the integrity assessment interval:

(a) number of hydrostatic test failures caused by external corrosion

(b) number of repair actions taken due to in-line inspection results, immediate and scheduled

(c) number of repair actions taken due to direct assessment results, immediate and scheduled

(d) number of external corrosion leaks (for low-stress pipelines it may be beneficial to compile leaks by leak classification)

A-3 INTERNAL CORROSION THREAT

A-3.1 Scope

Section A-3 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, of internal corrosion. Internal corrosion is defined in this context to include chemical corrosion and internal microbiologically influenced corrosion (MIC; see Figure A-3.1-1).

Section A-3 provides a general overview of the integrity management process for internal corrosion in general and also covers some specific issues. Pipeline incident analysis has identified internal corrosion among the causes of past incidents.

A-3.2 Gathering, Reviewing, and Integrating Data

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. These data are collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring additional activities.

(a) year of installation

(b) pipe inspection reports (bell hole)

(c) leak history

(d) wall thickness

(e) diameter

(f) past hydrostatic test information

(g) gas, liquid, or solid analysis (particularly hydrogen sulfide, carbon dioxide, oxygen, free water, and chlorides)

(h) bacteria culture test results

(i) corrosion detection devices (coupons, probes, etc.)

(j) operating parameters (particularly pressure and flow velocity and especially periods where there is no flow)

(k) operating stress level (% SMYS)

For this threat, the data are used primarily for prioritization of integrity assessment and/or mitigation activities. Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

A-3.3 Criteria and Risk Assessment

For new pipelines or pipeline segments, the operator may wish to use the original material selection, design conditions, and construction inspections, as well as the current operating history, to establish the condition of the pipe. For this situation, the operator must determine that the construction inspections have an equal or greater rigor than that provided by the prescribed integrity assessments in this Code. In addition, the operator shall determine that a corrosive environment does not exist.
In no case may the interval between construction and the first required reassessment of integrity exceed 10 yr for pipe operating above 60% SMYS, 13 yr for pipe operating above 50% SMYS and at or below 60% SMYS, and 15 yr for pipe operating at or below 50% SMYS.

For all pipeline segments older than those stated above, integrity assessment shall be conducted using a methodology within the specified response interval, as provided in para. A-3.5.

Previous integrity assessments can be considered as meeting these requirements, provided the inspections have equal or greater rigor than that provided by the prescribed inspections in this Code. The interval between the previous integrity assessment and the next integrity assessment cannot exceed the interval stated in this Code.

A-3.4 Integrity Assessment

The operator has a choice of three integrity assessment methods: in-line inspection with a tool capable of detecting wall loss, such as an MFL tool; performing a pressure test; or conducting direct assessment.

(a) In-Line Inspection. For in-line inspection, the operator must consult section 6, which defines the capability of various ILI devices and provides criteria for running of the tool. The operator selects the appropriate tools and the operator or their representative performs the inspection.
A-4.2 Gathering, Reviewing, and Integrating Data

The following minimal data sets should be collected for each segment and reviewed before a threat assessment can be conducted. Additionally, these data are collected for special considerations, such as identifying severe situations requiring additional activities.

(a) age of pipe

NOTE: Age of pipe coating may be used if the pipeline segment has been assessed for SCC.

(b) operating stress level (% SMYS)

(c) operating temperature

(d) distance of the segment downstream from a compressor station

(e) coating type

(f) past hydrotest information

Where the operator is missing data, conservative assumptions shall be used when performing the risk analysis or, alternatively, the segment shall be prioritized higher.

A-4.3 Criteria and Threat Assessment

A-4.3.1 Possible Threat of Near-Neutral pH SCC. Each segment should be assessed for the possible threat of near-neutral pH SCC if all of the following criteria are present:

(a) operating stress level >60% SMYS

(b) age of pipe >10 yr

NOTE: Age of pipe coating may be used if the pipeline segment has been assessed for SCC.

(c) all corrosion coating systems other than plant-applied or field-applied fusion-bonded epoxy (FBE) or liquid epoxy (when abrasive surface preparation was used during field coating application). Field joint coating systems should also be considered for their susceptibility using the criteria in this section.

A-4.3.2 Possible Threat of High pH SCC. Each segment should be assessed for the possible threat of high pH SCC if the three criteria in para. A-4.3.1 are present and the following two criteria are also present:

(a) operating temperature >100°F (38°C)

(b) distance from compressor station discharge ≤20 mi (32 km)

A-4.3.3 Additional Considerations. In addition, each segment in which one or more service incidents or one or more hydrostatic test breaks or leaks have been caused by one of the two types of SCC shall be evaluated unless the conditions that led to the SCC have been corrected.

For this threat, the threat assessment consists of comparing the data elements to the criteria. If the conditions of the criteria are met or if the segment has a previous SCC history (i.e., bell hole inspection indicating the presence of SCC, hydrotest failures caused by SCC, in-service failures caused by SCC, or leaks caused by SCC), the pipe is considered to be at risk for the occurrence of SCC. Otherwise, if one of the conditions of the criteria is not met and if the segment does not have a history of SCC, no action is required.

A-4.4 Integrity Assessment

If conditions for SCC are present (i.e., meet the criteria in para. A-4.3), a written inspection, examination, and evaluation plan shall be prepared. The plan should give consideration to integrity assessment for other threats and prioritization among other segments that are at risk.

If the segment is a long segment that is a distance of the segment downstream from an exothermically welded attachment or foreign line crossings where the operator may need only to remove soil from the top portion of the pipe) are not subject to the MPI requirement as described unless there is a prior history of SCC in the segment. Coating condition should be assessed and documented. All SCC inspection activities shall be conducted using documented procedures. Any indications of SCC shall be addressed using guidance from Tables A-4.4-1 and A-4.4.1-1.

The response requirements applicable to the SCC crack severity categories are provided in Table A-4.4.1-1. The response requirements in Table A-4.4.1-1 incorporate conservative assumptions regarding remaining flaw sizes. Alternatively, an engineering critical assessment may be conducted to evaluate the threat.

A-4.4.1 Bell Hole Examination and Evaluation Method. Magnetic-particle inspection methods (MPI), or other equivalent nondestructive evaluation methods, shall be used when disbonded coating or bare pipe is encountered during integrity-related excavation of pipeline segments susceptible to SCC. Excavations where the pipe is not completely exposed (e.g., encroachments, exothermically welded attachments, and foreign line crossings where the operator may need only to remove soil from the top portion of the pipe) are not subject to the MPI requirement as described unless there is a priority of SCC in the segment. Coating condition should be assessed and documented. All SCC inspection activities shall be conducted using documented procedures. Any indications of SCC shall be addressed using guidance from Tables A-4.4-1 and A-4.4.1-1.

The response requirements applicable to the SCC crack severity categories are provided in Table A-4.4.1-1. The response requirements in Table A-4.4.1-1 incorporate conservative assumptions regarding remaining flaw sizes. Alternatively, an engineering critical assessment may be conducted to evaluate the threat.

A-4.4.2 Hydrostatic Testing for SCC. Hydrostatic testing conditions for SCC mitigation have been developed through industry research to optimize the removal of
A-4.4.4 Stress Corrosion Cracking Direct Assessment (SCCDA). SCCDA is a formal process to assess a pipe segment for the presence and severity of SCC, primarily by examining with MPI or equivalent technology selected joints of pipe within that segment after systematically gathering and analyzing data for pipe having similar operational characteristics and residing in a similar physical environment. The SCCDA process includes guidance for operators to select appropriate sites to conduct excavations for the purposes of conducting an SCC integrity assessment. Detailed guidance for this process is provided in NACE SP0204.

A-4.5 Other Data

During the integrity assessment and mitigation activities, the operator may discover other data that may be pertinent to other threats. These data should be used where appropriate for performing risk assessments for other threats.

A-4.6 Performance Measures

The following performance measures shall be documented for the SCC threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of in-service leaks/failures due to SCC
(b) number of repairs or replacements due to SCC
(c) number of hydrostatic test failures due to SCC

A-5 MANUFACTURING THREAT (PIPE SEAM AND PIPE)

A-5.1 Scope

Section A-5 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for manufacturing concerns. Manufacturing is defined in this context as pipe seam and pipe (see Figure A-5.1-1).

This section outlines the integrity management process for manufacturing concerns in general and also covers some specific issues. Pipeline incident analysis has identified manufacturing among the causes of past incidents.

A-5.2 Gathering, Reviewing, and Integrating Data

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. These data are collected for performing risk assessment and for special considerations such as identifying severe situations requiring additional activities.

(a) pipe material
(b) year of installation
(c) manufacturing process (age of manufacture as alternative; see note below)
(d) seam type
(e) longitudinal weld joint quality factor
(f) operating pressure history

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

NOTE: When pipe data is unknown, the operator may refer to History of Line Pipe Manufacturing in North America by J. F. Kiefner and E. B. Clark, 1996, ASME. In addition, this report provides information on historic pipe manufacturing processes, including legacy seams such as lap welded, electric-flash welded, and single submerged-arc welded.

A-5.3 Criteria and Risk Assessment

For cast iron pipe, steel pipe manufactured prior to 1952, mechanically coupled pipelines, or pipelines joined by means of acetylene girth welds, where low temperatures are experienced or where the pipe is exposed to movement such as land movement or removal of supporting backfill, examination of the terrain is required. If land movement is observed or can reasonably be anticipated, a pipeline movement monitoring program should be established and appropriate intervention activities undertaken.

If the pipe has a longitudinal weld joint quality factor of less than 1.0 (such as lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is composed of LFW ERW pipe or flash-welded pipe, a manufacturing threat is considered to exist.

Fatigue along longitudinal pipe seams due to operating pressure cycles has not been a significant issue for natural gas pipelines. However, if the pipeline segment operates with significant pressure fluctuations, seam fatigue shall be considered by the operator as an additional integrity threat. GRI Report GRI-04/0178 may be a useful reference regarding fatigue due to pressure cycling.

A-5.4 Integrity Assessment

For cast iron pipe, the assessment should include evaluation as to whether or not the pipe is subject to land movement or subject to removal of support.

For steel pipe seam concerns, when raising the MAOP of a pipeline or when raising the operating pressure above the historical operating pressure (highest pressure recorded in the past 5 yr), pressure testing must be performed to address the seam issue. Pressure testing shall be in accordance with ASME B31.8, to at least 1.25 times the MAOP. ASME B31.8 defines how to conduct tests for both post-construction and in-service pipelines.

A-5.5 Responses and Mitigation

For cast iron pipe, mitigation options include replacement of pipe or stabilization of pipe.

For steel pipe, any section that fails the pressure test shall be replaced.
considerations, such as identifying severe situations requiring additional activities.

- (a) pipe material
- (b) wrinkle bend identification
- (c) coupling identification
- (d) post-construction coupling reinforcement
- (e) welding procedures
- (f) post-construction girth weld reinforcement
- (g) NDT information on welds
- (h) hydrostatic test information
- (i) pipe inspection reports (bell hole)
- (j) potential for outside forces (see section A-10)
- (k) soil properties and depth of cover for wrinkle bends
- (l) maximum temperature ranges for wrinkle bends
- (m) bend radii and degrees of angle change for wrinkle bends
- (n) operating pressure history and expected operation, including significant pressure cycling and fatigue mechanism

Where the operator is missing data, conservative assumptions shall be used when performing the risk assessment or, alternatively, the segment shall be prioritized higher.

### A-6.3 Criteria and Risk Assessment

For girth welds, a review of the welding procedures and NDT information is required to ascertain that the welds are adequate.

For fabrication welds, a review of the welding procedures and NDT information, as well as a review of forces due to ground settlement or other outside loads, is required to ascertain that the welds are adequate.

For wrinkle bends and buckles as well as couplings, reports of visual inspection should be reviewed to ascertain their continued integrity. Potential movement of the pipeline may cause additional lateral and/or axial stresses. Information relative to pipe movement should be reviewed, such as temperature range, bend radius, degree of bend, depth of cover, and soil properties. These are important factors in determining whether or not bends are being subjected to injurious stresses or strains.

The existence of these construction-related threats alone does not pose an integrity issue. The presence of these threats in conjunction with the potential for outside forces significantly increases the likelihood of an event. The data must be integrated and evaluated to determine where these construction characteristics coexist with external or outside force potential.

### A-6.4 Integrity Assessment

For construction threats, the inspection should be by data integration, examination, and evaluation for threats that are coincident with the potential for ground movement or outside forces that will impact the pipe.

### A-6.5 Responses and Mitigation

The operator shall select the appropriate prevention practices. For this threat, the operator should develop excavation protocols to ensure the pipe is not moved and additional stresses introduced. In addition, the operator should conduct examinations and evaluations every time the pipe is exposed. Potential threats should be mitigated by proactive procedures that require inspection, repair, replacement, or reinforcement when the need to inspect the pipeline for other maintenance reasons occurs.

### A-6.6 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, reviewing the hydrostatic test information might reveal previous failures due to pipe seam defects. It is appropriate to use this information when conducting risk assessments for manufacturing threats.

### A-6.7 Assessment Interval

Periodic assessment is not required. Changes to the segment or changes in land use may drive reassessment. Change management is addressed in section 11.

### A-6.8 Performance Measures

The following performance measures shall be documented for the construction threat to establish the effectiveness of the program:

- (a) number of leaks or failures due to construction defects
- (b) number of girth welds/couplings reinforced/removed
- (c) number of wrinkle bends removed
- (d) number of wrinkle bend inspections
- (e) number of fabrication welds repaired/removed

### A-7 EQUIPMENT THREAT (GASKETS AND O-RINGS, CONTROL/RELIEF, SEAL/PUMP PACKING)

### A-7.1 Scope

Section A-7 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for pipeline equipment failure. Equipment is defined in this context as pipeline facilities other than pipe and pipe components. Meter/regulator and compressor stations are typical equipment locations (see Figure A-7.1-1).

This section outlines the integrity management process for equipment in general and also covers some specific issues. Pipeline incident analysis has identified pressure
A-8.7 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually. Changes to the segment may drive reassessment. Change management is addressed in section 11.

A-8.8 Performance Measures

The following performance measures shall be documented for the third-party threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by third-party damage
(b) number of leaks or failures caused by previously damaged pipe
(c) number of leaks or failures caused by vandalism
(d) number of repairs implemented as a result of third-party damage prior to a leak or failure

A-9 INCORRECT OPERATIONS THREAT

A-9.1 Scope

Section A-9 provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation, for incorrect operations. Incorrect operations are defined in this context as incorrect operating procedures or failure to follow a procedure (see Figure A-9.1-1).

This section outlines the integrity management process for incorrect operations in general and also covers some specific issues. Pipeline incident analysis has identified incorrect operations among the causes of past incidents.

A-9.2 Gathering, Reviewing, and Integrating Data

The following minimal data sets should be collected for each segment and reviewed before a risk assessment can be conducted. These data are collected in support of performing risk assessment and for special considerations, such as identifying severe situations requiring more or additional activities.

(a) procedure review information
(b) audit information
(c) failures caused by incorrect operation

A-9.3 Criteria and Risk Assessment

If the data shows the operation and maintenance are performed in accordance with operation and maintenance procedures, the procedures are correct, and operating personnel are adequately qualified to fulfill the requirements of the procedure, no additional assessment is required. Deficiencies in these areas require mitigation as outlined below.

A-9.4 Integrity Assessment

The audits and reviews are normally conducted on an ongoing basis. These inspections are conducted by company personnel and/or by third-party experts.

A-9.5 Responses and Mitigation

Mitigation in this instance is prevention. The operator shall ensure that procedures are current, the personnel are adequately qualified, and the following procedures are enforced.

The operator should have a program to quality operation and maintenance personnel for each activity that they perform. This program should include initial qualification and periodic reassessment of qualification. Certification by recognized organizations may be included in this program.

In addition, a strong internal review or audit program by in-house experts or third-party experts is necessary.

A-9.6 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.7 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.8 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.9 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.10 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.11 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.12 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.13 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.14 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.15 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.16 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.17 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.18 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.19 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.20 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.21 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.22 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.23 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.24 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.25 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.26 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.27 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.

A-9.28 Assessment Interval

Assessment shall be performed periodically. It is recommended that it be performed annually.

Changes to the segment may drive revision of procedures and additional training of personnel. Change management is addressed in section 11.

A-9.29 Performance Measures

The following performance measures shall be documented for the incorrect operations threat to establish the effectiveness of the program and for confirmation of the inspection interval:

(a) number of leaks or failures caused by incorrect operations
(b) number of audits/reviews conducted
(c) number of findings per audit/review, classified by severity
(d) number of changes to procedures due to audits/reviews

A-9.30 Other Data

During the inspection activities, the operator may discover other data that should be used when performing risk assessments for other threats. For example, when reviewing records required by procedures, it is discovered that there have been several unreported encroachments by third parties. It is appropriate to use this information when conducting risk assessments for third-party damage.