ASME B31.8S-2018

(Revision of ASME B31.8S-2016)

Managing System Integrity of Gas Pipelines

ASME Code for Pressure Piping, B31
Supplement to ASME B31.8

AN INTERNATIONAL PIPING CODE®

The American Society of Mechanical Engineers

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The American Society of Mechanical Engineers
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FOREWORD

Pipeline system operators continuously work to improve the safety of their systems and operations. In the United States, both liquid and gas pipeline operators have been working with their regulators for several years to develop a more systematic approach to pipeline safety integrity management.

The gas pipeline industry needed to address many technical concerns before an integrity management standard could be written. A number of initiatives were undertaken by the industry to answer these questions; as a result of two years of intensive work by a number of technical experts in their fields, 20 reports were issued that provided the responses required to complete the 2001 edition of this Code. (The list of these reports is included in the reference section of this Code.)

This Code is nonmandatory, and is designed to supplement B31.8, ASME Code for Pressure Piping, Gas Transmission and Distribution Piping Systems. Not all operators or countries will decide to implement this Code. This Code becomes mandatory if and when pipeline regulators include it as a requirement in their regulations.

This Code is a process code that describes the process an operator may use to develop an integrity management program. It also provides two approaches for developing an integrity management program: a prescriptive approach and a performance- or risk-based approach. Pipeline operators in a number of countries are currently utilizing risk-based or risk-management principles to improve the safety of their systems. Some of the international standards issued on this subject were utilized as resources for writing this Code. Particular recognition is given to API and their liquids integrity management standard, API Std 1160, which was used as a model for the format of this Code.

The intent of this Code is to provide a systematic, comprehensive, and integrated approach to managing the safety and integrity of pipeline systems. The task force that developed this Code hopes that it has achieved that intent.

The 2018 Edition of the Supplement is a compilation of the 2016 Edition and the revisions that have occurred since the issuance of the 2016 Edition. This Edition was approved by ANSI on July 2, 2018.

ASME B31.8S-2018
SUMMARY OF CHANGES

Following approval by the ASME B31 Committee and ASME, and after public review, ASME B31.8S-2018 was approved by the American National Standards Institute on July 2, 2018.

ASME B31.8S-2018 includes the following changes identified by a margin note, (18).

Page	*Location*	*Change*
3	2.2	(1) Subparagraphs (c) and (c)(3)(-a) through (c)(3)(-d) revised
		(2) Subparagraph (c)(3)(-e) added
4	Figure 2.1-2	Revised
8	3.3	(1) Subparagraphs (a), (c), and (g) revised
		(2) Subparagraph (j) added
16	5.8	Second paragraph revised
23	Table 7.1-1	Nineteenth column and General Note revised
26	7.2.5	Revised
34	10	Revised in its entirety
36	Figure 13-1	Final line in bottom box of "Category" column revised
42	14	Updated

MANAGING SYSTEM INTEGRITY OF GAS PIPELINES

1 INTRODUCTION

1.1 Scope

This Code applies to onshore pipeline systems constructed with ferrous materials and that 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 utilizing 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 the ASME B31.8 Code 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 in order to reduce both the likelihood and 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 utilizes more data and more extensive risk analyses, which enables the operator to achieve a greater degree of flexibility in order to meet or exceed the requirements of this Code specifically in the areas of inspection intervals, tools used, and mitigation techniques employed. 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 in order 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 in order 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. In order to have an effective integrity management program, the program shall address the operator's organization, processes, and the physical system.

An integrity management program is 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 that the program utilizes 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 impact 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 impact 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, operating, 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 assessing risks 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 in order 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.

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.

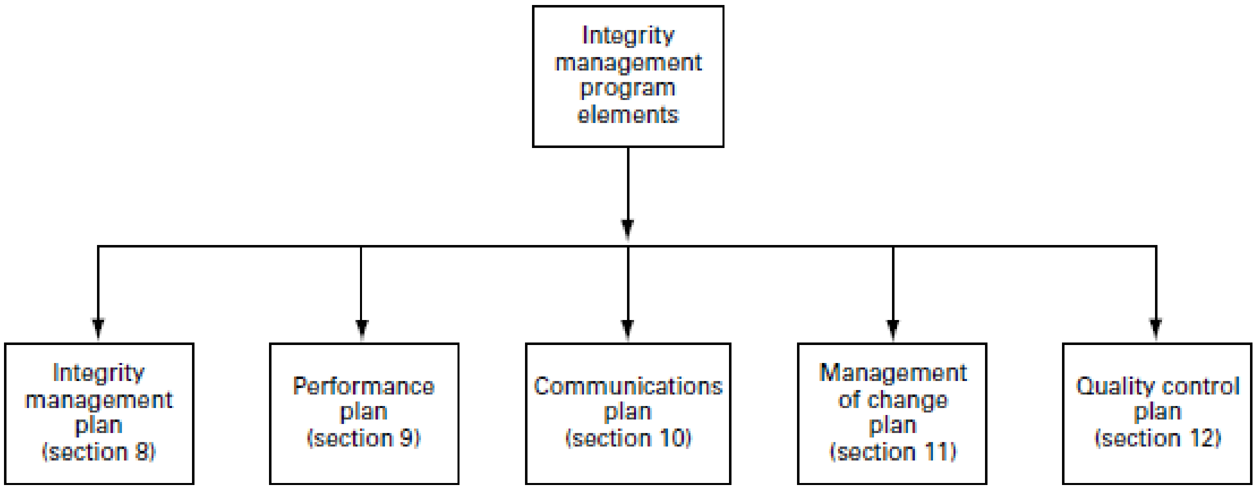
This Code requires that the operator document how its integrity management program will address the key program elements. This Code utilizes recognized industry practices for developing an integrity management program.

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 intervals, 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

Figure 2.1-1 Integrity Management Program Elements



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 for all situations. This Code recognizes the importance of flexibility in designing integrity management programs and provides alternatives commensurate with this need. 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 (18)

The first step in managing integrity is identifying potential threats to integrity. All 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

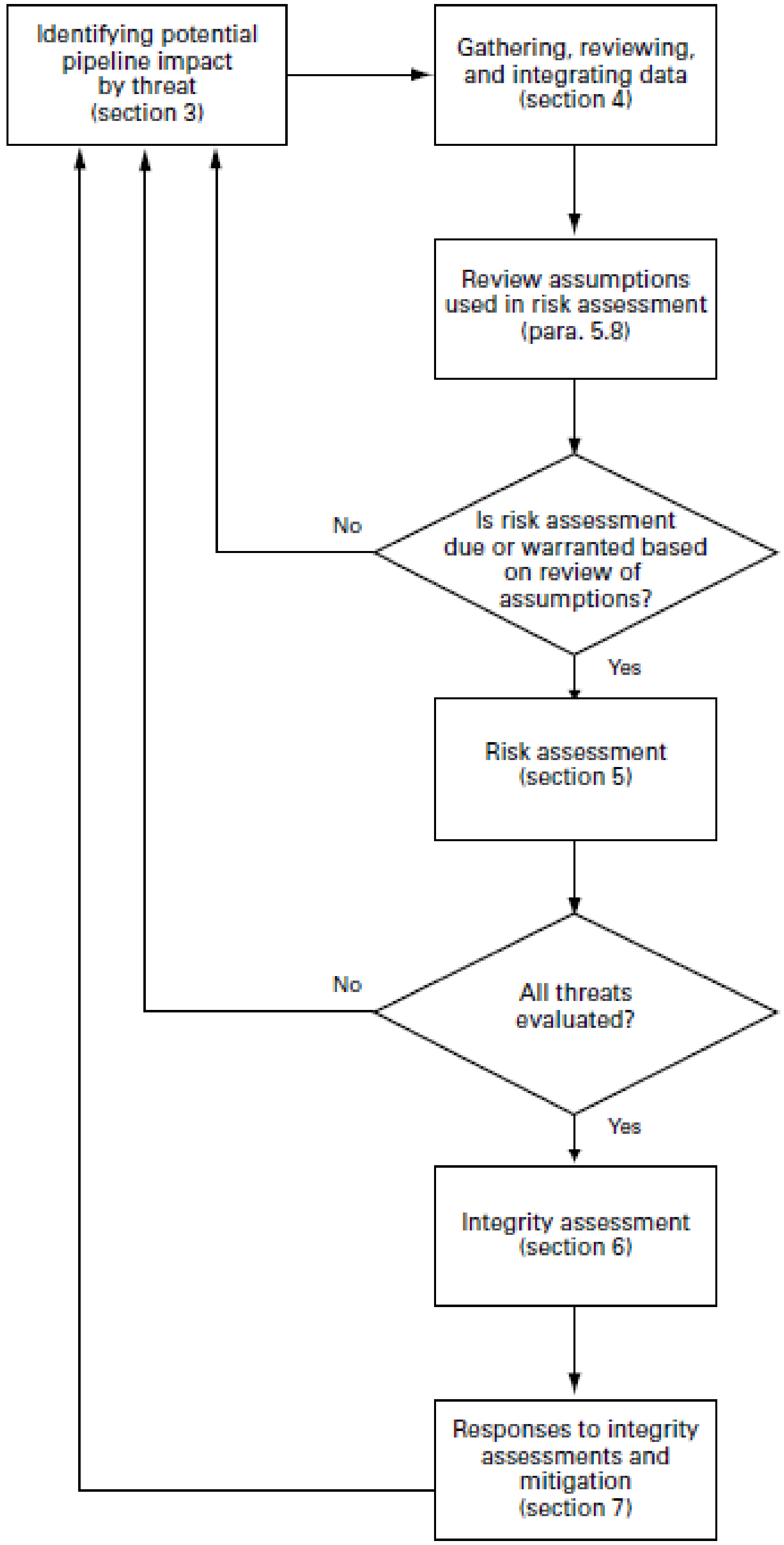
(2) welding/fabrication related

(-a) defective pipe girth weld (circumferential) including branch and T-joints

(-b) defective fabrication weld

(-c) wrinkle bend or buckle

(18) **Figure 2.1-2 Integrity Management Plan Process Flow Diagram**



(-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 the operational mode changes and pipeline segments are subjected to significant pressure cycles, pressure differential, and rates of change of pressure fluctuations, fatigue shall be considered by the operator, including any combined effect from other failure mechanisms that are considered to be present, such as corrosion. A useful reference to help the operator with this consideration is GRI 04-0178, Effect of Pressure Cycles on Gas Pipelines.

2.3 The Integrity Management Process

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

2.3.1 Identify 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 that are needed to understand the condition of the pipe; identify the location-specific threats to its integrity; and understand 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., deficiencies in cathodic protection), reduce pipe properties (e.g., field welding), or relate to the introduction of new defects (e.g., excavation work near a pipeline). Section 3 provides information on consequences. Section 4 provides details for data gathering, review, and integration of pipeline data.

2.3.3 Risk Assessment. In this step, the data assembled from the previous step are used to conduct a risk assessment of the pipeline system or segments. Through the integrated evaluation of the information and data collected in the previous step, the risk assessment process identifies the location-specific events and/or conditions that could lead to a pipeline failure, and provides an understanding of the likelihood and consequences (see section 3) of an event. The output of a risk assessment should include the nature and location of the most significant risks to the pipeline.

Under the prescriptive approach, available data are compared to prescribed criteria (see Nonmandatory Appendix A). Risk assessments are required in order to rank the segments for integrity assessments. The performance-based approach relies on detailed risk assessments. There are a variety of risk assessment methods that can be applied based on the available data and the nature of the threats. The operator should tailor the method to meet the needs of the system. An initial screening risk assessment can be beneficial in terms of focusing resources on the most important areas to be addressed and where additional data may be of value. Section 5 provides details on the criteria selection for the prescriptive approach and risk assessment for the performance-based approach. The results of this step enable the operator to prioritize the pipeline segments for appropriate actions that will be defined in the integrity management plan. Nonmandatory Appendix A provides the steps to be followed for a prescriptive program.

2.3.4 Integrity Assessment. Based on the risk assessment made in the previous step, the appropriate integrity assessments are selected and conducted. The integrity assessment methods are in-line inspection, pressure testing, direct assessment, or other integrity assessment methods, as defined in para. 6.5. Integrity assessment method selection is based on the threats that have been identified. More than one integrity assessment method may be required to address all the threats to a pipeline segment.

A performance-based program may be able, through appropriate evaluation and analysis, to determine alternative courses of action and time frames for performing integrity assessments. It is the operator's responsibility to document the analyses justifying the alternative courses of action or time frames. Section 6 provides details on tool selection and inspection.

Data and information from integrity assessments for a specific threat may be of value when considering the presence of other threats and performing risk assessment for those threats. For example, a dent may be identified when running a magnetic flux leakage (MFL) tool while checking for corrosion. This data element should be integrated with other data elements for other threats, such as third-party or construction damage.

Indications that are discovered during inspections shall be examined and evaluated to determine if they are actual defects or not. Indications may be evaluated using an appropriate examination and evaluation tool. For local internal or external metal loss, ASME B31G or similar analytical methods may be used.

2.3.5 Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Setting Inspection Intervals. In this step, schedules to respond to indications from inspections are developed. Repair activities for the anomalies discovered during inspection are identified and initiated. Repairs are performed in accordance with accepted industry standards and practices.

Prevention practices are also implemented in this step. For third-party damage prevention and low-stress pipelines, mitigation may be an appropriate alternative to inspection. For example, if damage from excavation was identified as a significant risk to a particular system or segment, the operator may elect to conduct damage-prevention activities such as increased public communication, more effective excavation notification systems, or increased excavator awareness in conjunction with inspection.

The mitigation alternatives and implementation time frames for performance-based integrity management programs may vary from the prescriptive requirements. In such instances, the performance-based analyses that lead to these conclusions shall be documented as part of the integrity management program. Section 7 provides details on repair and prevention techniques.

2.3.6 Update, Integrate, and Review Data. After the initial integrity assessments have been performed, the operator has improved and updated information about the condition of the pipeline system or segment. This information shall be retained and added to the database of information used to support future risk assessments and integrity assessments. Furthermore, as the system continues to operate, additional operating, maintenance, and other information is collected, thus expanding and improving the historical database of operating experience.

2.3.7 Reassess Risk. Risk assessment shall be performed periodically within regular intervals and when substantial changes occur to the pipeline. The operator shall consider recent operating data, consider changes to the pipeline system design and operation, analyze the impact of any external changes that may have occurred since the last risk assessment, and incorporate data from risk assessment activities for other threats. The results of integrity assessment, such as internal inspection, shall also be factored into future risk assessments, to ensure that the analytical process reflects the latest understanding of pipe condition.

2.4 Integrity Management Program

The essential elements of an integrity management program are depicted in Figure 2.1-1 and are described below.

2.4.1 Integrity Management Plan. The integrity management plan is the outcome of applying the process depicted in Figure 2.1-2 and discussed in section 8. The plan is the documentation of the execution of each of the steps and the supporting analyses that are conducted. The plan shall include prevention, detection, and mitigation practices. The plan shall also have a schedule established that considers the timing of the practices deployed. Those systems or segments with the highest risk should be addressed first. Also, the plan shall consider those practices that may address more than one threat. For instance, a hydrostatic test may demonstrate a pipeline's integrity for both time-dependent threats like internal and external corrosion as well as static threats such as seam weld defects and defective fabrication welds.

A performance-based integrity management plan contains the same basic elements as a prescriptive plan. A performance-based plan requires more detailed information and analyses based on more extensive knowledge about the pipeline. This Code does not require a specific risk analysis model, only that the risk model used can be shown to be effective. The detailed risk analyses will provide a better understanding of integrity, which will enable an operator to have a greater degree of flexibility in the timing and methods for the implementation of a performance-based integrity management plan. Section 8 provides details on plan development.

The plan shall be periodically updated to reflect new information and the current understanding of integrity threats. As new risks or new manifestations of previously known risks are identified, additional mitigative actions to address these risks shall be performed, as appropriate. Furthermore, the updated risk assessment results shall also be used to support scheduling of future integrity assessments.

2.4.2 Performance Plan. The operator shall collect performance information and periodically evaluate the success of its integrity assessment techniques, pipeline repair activities, and the mitigative risk control activities. The operator shall also evaluate the effectiveness of its management systems and processes in supporting sound integrity management decisions. Section 9 provides the information required for developing performance measures to evaluate program effectiveness.

The application of new technologies into the integrity management program shall be evaluated for further use in the program.

2.4.3 Communications Plan. The operator shall develop and implement a plan for effective communications with employees, the public, emergency responders, local officials, and jurisdictional authorities in order to keep the public informed about their integrity management efforts. This plan shall provide information to be communicated to each stakeholder about the integrity plan and the results achieved. Section 10 provides further information about communications plans.

2.4.4 Management of Change Plan. Pipeline systems and the environment in which they operate are seldom static. A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated. After these changes are made, they shall be incorporated, as appropriate, into future risk assessments to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the plan's mitigative activities should be used as a feedback for systems and facilities design and operation. Section 11 discusses the important aspects of managing changes as they relate to integrity management.

2.4.5 Quality Control Plan. Section 12 discusses the evaluation of the integrity management program for quality control purposes. That section outlines the necessary documentation for the integrity management program. The section also discusses auditing of the program, including the processes, inspections, mitigation activities, and prevention activities.

3 CONSEQUENCES

3.1 General

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result from a failure. Risk may be decreased by reducing either the likelihood or the consequences of a failure, or both. This section specifically addresses the consequence portion of the risk equation. The operator shall consider consequences of a potential failure when prioritizing inspections and mitigation activities.

The ASME B31.8 Code manages risk to pipeline integrity by adjusting design and safety factors, and inspection and maintenance frequencies as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequences of a failure.

Paragraph 3.2 describes how to determine the area that is affected by a pipeline failure (potential impact area) in order 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 formula:

(U.S. Customary Units)

$$r = 0.69 \cdot d\sqrt{p} \tag{1}$$

(SI Units)

$$r = 0.00315 \cdot d\sqrt{p}$$

where

d = outside diameter of the pipeline, in. (mm)
p = pipeline segment's maximum allowable operating pressure (MAOP), psig (kPa)
r = radius of impact, ft (m)

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EXAMPLES:

(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.

$$r = 0.69 \cdot d\sqrt{p} = 0.69(30\text{ in.})(1{,}000\text{ lb/in.}^2)^{1/2}$$
$$= 654.6\text{ ft} \approx 660\text{ ft}$$

(2) A 762-mm diameter pipe with a maximum allowable operating pressure of 6 900 kPa has a radius of impact of approximately 200 m.

$$r = 0.00315 \cdot d\sqrt{p} = 0.00315\ (762\text{ mm})(6\ 900\text{ kPa})^{1/2}$$
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Use of this equation shows that failure of a smaller diameter, lower pressure pipeline will affect a smaller area than a larger diameter, higher pressure pipeline. (See GRI-00/0189.)

Equation (1) is derived from

$$r = \sqrt{\frac{115{,}920}{8} \cdot \mu \cdot \chi_g \cdot \lambda \cdot C_d \cdot H_C \cdot \frac{Q}{a_o} \cdot \frac{pd^2}{I_{th}}}$$

where

a_o = sonic velocity of gas, ft/sec (m/s)

$= \sqrt{\frac{\gamma RT}{m}}$

C_d = discharge coefficient

d = line diameter, in. (m)

H_C = heat of combustion (lower or net heat value), Btu/lbm (kJ/kg)

I_{th} = threshold heat flux, Btu/hr-ft^2 (kW/m^2)

m = gas molecular weight, lbm/lb-mole (g/mole)

p = live pressure, lbf/in.^{2} (Pa)

Q = flow factor

$= \gamma\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{2(\gamma-1)}}$

R = gas constant, ft-lbf/lb-mole °R (J/kmole K)

r = radius of impact, ft (m)

T = gas temperature, °R (K)

γ = specific heat ratio of gas

λ = release rate decay factor

μ = combustion efficiency factor

χ_g = 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 the following:

(a) 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

(b) 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 or sufficient 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 demonstrate 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 (18)

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

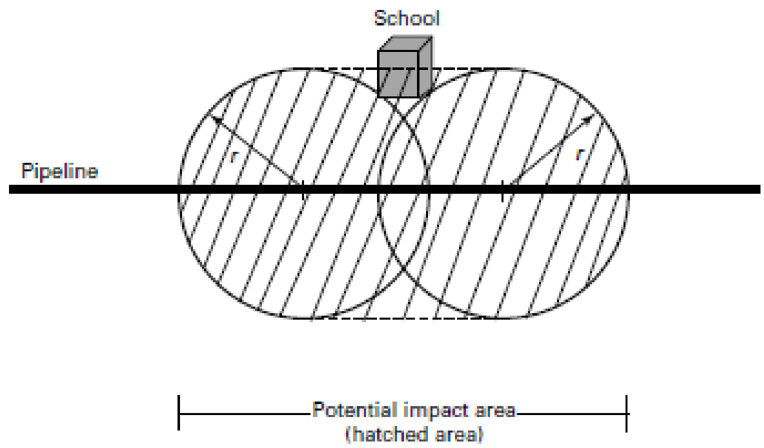
(d) property damage

(e) environmental damage

(f) effects of unignited gas releases

(g) security or reliability of gas supply (e.g., impacts resulting from interruption of service)

Figure 3.2.4-1 Potential Impact Area



GENERAL NOTE: This diagram represents the results for a 30-in. (762-mm) pipe with an MAOP of 1,000 psig (6 900 kPa).

(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 decompresses. The richer the gas, the more important defects and material properties are in modeling the characteristics of the failure.

4 GATHERING, REVIEWING, AND INTEGRATING DATA

4.1 General

This section provides a systematic process for pipeline operators to collect and effectively utilize 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 in order 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 in order 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

Table 4.2.1-1 Data Elements for Prescriptive Pipeline Integrity Program

Category	Data
Attribute data	Pipe wall thickness
	Diameter
	Seam type and joint factor
	Manufacturer
	Manufacturing date
	Material properties
	Equipment properties
Construction	Year of installation
	Bending method
	Joining method, process and inspection results
	Depth of cover
	Crossings/casings
	Pressure test
	Field coating methods
	Soil, backfill
	Inspection reports
	Cathodic protection (CP) installed
	Coating type
Operational	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP system performance
	Pipe wall temperature
	Pipe inspection reports
	OD/ID corrosion monitoring
	Pressure fluctuations
	Regulator/relief performance
	Encroachments
	Repairs
	Vandalism
	External forces
Inspection	Pressure tests
	In-line inspections
	Geometry tool inspections
	Bell hole inspections
	CP inspections (CIS)
	Coating condition inspections (DCVG)
	Audits and reviews

and facility risk assessments. This 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 initiated 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 valuable data source. These may reflect additional needs in personnel training or qualifications.

Valuable data for integrity management program implementation can also be obtained from external sources. These may include jurisdictional agency reports and databases that include information such as soil data, demographics, and hydrology, as examples. Research organizations can provide background on many pipeline-related issues useful for application in an integrity management program. Industry consortia and other operators can also be useful information sources.

The data sources listed in Table 4.3-1 are necessary for integrity management program initiation. As the integrity management program is developed and implemented, additional data will become available. This will include inspection, examination, and evaluation data obtained from the integrity management program and data developed for the performance metrics covered in section 9.

4.4 Data Collection, Review, and Analysis

A plan for collecting, reviewing, and analyzing the data shall be created and in place from the conception of the data collection effort. These processes are needed to verify the quality and consistency of the data. Records shall be maintained throughout the process that identify where and how unsubstantiated data are used in the risk assessment process, so the potential impact on the variability and accuracy of assessment results can be considered. This is often referred to as metadata or information about the data.

Table 4.3-1 Typical Data Sources for Pipeline Integrity Program

Process and instrumentation drawings (P&ID)
Pipeline alignment drawings
Original construction inspector notes/records
Pipeline aerial photography
Facility drawings/maps
As-built drawings
Material certifications
Survey reports/drawings
Safety-related condition reports
Operator standards/specifications
Industry standards/specifications
O&M procedures
Emergency response plans
Inspection records
Test reports/records
Incident reports
Compliance records
Design/engineering reports
Technical evaluations
Manufacturer equipment data

Data resolution and units shall also be determined. Consistency in units is essential for integration. Every effort should be made to utilize all of the actual data for the pipeline or facility. Generalized integrity assumptions used in place of specific data elements should be avoided.

Another data collection consideration is whether the age of the data invalidates its applicability to the threat. Data pertaining to time-dependent threats such as corrosion or stress corrosion cracking (SCC) may not be relevant if it was collected many years before the integrity management program was developed. Resident and time-independent threats do not have implied time dependence, so earlier data are applicable.

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 inspection actions or field data collection efforts may be required.

4.5 Data Integration

Individual data elements shall be brought together and analyzed in their context to realize the full value of integrity management and risk assessment. A major strength of an effective integrity management program lies in its ability to merge and utilize multiple data elements obtained from several sources to provide an improved confidence that a specific threat may or may not apply to a pipeline segment. It can also lead to an improved analysis of overall risk.

For integrity management program applications, one of the first data integration steps includes development of a common reference system (and consistent measurement units) that will allow data elements from various sources to be combined and accurately associated with common pipeline locations. For instance, in-line inspection (ILI) data may reference the distance traveled along the inside of the pipeline (wheel count), which can be difficult to directly combine with over-the-line surveys such as close interval survey (CIS) that are referenced to engineering station locations.

Table 4.2.1-1 describes data elements that can be evaluated in a structured manner to determine if a particular threat is applicable to the area of concern or the segment being considered. Initially, this can be accomplished without the benefit of inspection data and may only include the pipe attribute and construction data elements shown in Table 4.2.1-1. As other information such as inspection data becomes available, an additional integration step can be performed to confirm the previous inference concerning the validity of the presumed threat. Such data integration is also very effective for assessing the need for and type of mitigation measures to be used.

Data integration can also be accomplished manually or graphically. An example of manual integration is the superimposing of scaled potential impact area circles (see section 3) on pipeline aerial photography to determine the extent of the potential impact area. Graphical integration can be accomplished by loading risk-related data elements into an MIS/GIS system and graphically overlaying them to establish the location of a specific threat. Depending on the data resolution used, this could be applied to local areas or larger segments. More specific data integration software is also available that facilitates use in combined analyses. The benefits of data integration can be illustrated by the following hypothetical examples:

EXAMPLES:

(1) In reviewing ILI data, an operator suspects mechanical damage in the top quadrant of a pipeline in a cultivated field. It is also known that the farmer has been plowing in this area and that the depth of cover may be reduced. Each of these facts taken individually provides some indication of possible mechanical damage, but as a group the result is more definitive.

(2) An operator suspects that a possible corrosion problem exists on a large-diameter pipeline located in a populated area. However, a CIS indicates good cathodic protection coverage in the area. A direct current voltage gradient (DCVG) coating condition inspection is performed and reveals that the welds were tape-coated and are in poor condition. The CIS results did not indicate a potential integrity issue, but data integration prevented possibly incorrect conclusions.

5 RISK ASSESSMENT

5.1 Introduction

Risk assessments shall be conducted for pipelines and related facilities. Risk assessments are required for both prescriptive-based and performance-based integrity management programs.

For prescriptive-based programs, risk assessments are primarily utilized to prioritize integrity management plan activities. They help to organize data and information to make decisions.

For performance-based programs, risk assessments serve the following purposes:

(a) to organize data and information to help operators prioritize and plan activities

(b) to determine which inspection, prevention, and/or mitigation activities will be performed and when

5.2 Definition

The operator shall follow section 5 in its entirety to conduct a performance-based integrity management program. A prescriptive-based integrity management program shall be conducted using the requirements identified in this section and in Nonmandatory Appendix A.

Risk is typically described as the product of two primary factors: the failure likelihood (or probability) that some adverse event will occur and the resulting consequences of that event. One method of describing risk is

$$\text{Risk}_i = P_i \times C_i \text{ for a single threat}$$

$$\text{Risk} = \sum_{i=1}^{9} (P_i \times C_i) \text{ for threat categories 1 to 9}$$

$$\text{Total segment risk} = (P_1 \times C_1) + (P_2 \times C_2) + \ldots + (P_9 \times C_9)$$

where

1 to 9 = failure threat category (see para. 2.2)
C = failure consequence
P = failure likelihood

The risk analysis method used shall address all nine threat categories or each of the individual 21 threats to the pipeline system. Risk consequences typically consider components such as the potential impact of the event on individuals, property, business, and the environment, as shown in section 3.

5.3 Risk Assessment Objectives

For application to pipelines and facilities, risk assessment has the following objectives:

(a) prioritization of pipelines/segments for scheduling integrity assessments and mitigating action

(b) assessment of the benefits derived from mitigating action

(c) determination of the most effective mitigation measures for the identified threats

(d) assessment of the integrity impact from modified inspection intervals

(e) assessment of the use of or need for alternative inspection methodologies

(f) more effective resource allocation

Risk assessment provides a measure that evaluates both the potential impact of different incident types and the likelihood that such events may occur. Having such a measure supports the integrity management process by facilitating rational and consistent decisions. Risk results are used to identify locations for integrity assessments and resulting mitigative action. Examining both primary risk factors (likelihood and consequences) avoids focusing solely on the most visible or frequently occurring problems while ignoring potential events that could cause significantly greater damage. Conversely, the process also avoids focusing on less likely catastrophic events while overlooking more likely scenarios.

5.4 Developing a Risk Assessment Approach

As an integral part of any pipeline integrity management program, an effective risk assessment process shall provide risk estimates to facilitate decision-making. When properly implemented, risk assessment methods can be very powerful analytic methods, using a variety of inputs, that provide an improved understanding of the nature and locations of risks along a pipeline or within a facility.

Risk assessment methods alone 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 input, assumptions, and results of the risk assessments. Such experience-based reviews should validate risk assessment output with other relevant factors not included in the process, the impact of assumptions, or the potential risk variability caused by missing or estimated data. These processes and their results shall be documented in the integrity management plan.

An integral part of the risk assessment process is the incorporation of additional data elements or changes to facility data. To ensure regular updates, the operator shall incorporate the risk assessment process into existing field reporting, engineering, and facility mapping processes and incorporate additional processes as required (see section 11).