INDUSTRIAL GAS PIPELINE INTEGRITY MANAGEMENT

AIGA 118/21

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As part of a program of harmonization of industry standards, the Asia Industrial Gases Association (AIGA) has published AIGA 118, "*Industrial Gas Pipeline Integrity Management", jointly* produced by members of the International Harmonization Council and originally published by Compressed Gas Association (CGA) CGA P-8.10, "*Industrial Gas Pipeline Integrity Management"*.

This publication is intended as an international harmonized standard for the worldwide use and application of all members of the Asia Industrial Gases Association (AIGA), Compressed Gas Association (CGA), European Industrial Gases Association (EIGA), and Japan Industrial and Medical Gases Association (JIMGA). Each association's technical content is identical, except for regional regulatory requirements and minor changes in formatting and spelling.

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NOTE—Appendix A (Normative) is a requirement.

1 Introduction

Operation and maintenance guidelines for transmission pipelines are an important requirement due to the hazardous nature of certain gases and the presence of the pipelines through the public domain.

2 Scope and purpose

2.1 Scope

This publication covers the integrity of industrial gas transmission pipelines for gaseous nitrogen, oxygen, argon, helium, hydrogen, carbon monoxide, and Syngas. This publication addresses the integrity of industrial gas pipelines in the public domain including maintenance and operation as appropriate.

This publication covers active or in-service pipelines. Out of service or abandoned pipelines are not covered in this publication. However, the information contained in this publication may be applicable to those pipelines.

This publication addresses land-based pipelines and does not specifically address offshore pipelines.

This publication does not cover:

- Carbon dioxide, steam, natural gas, or water;
- Liquid pipelines;
- Pipelines fabricated from nonmetallic material such as plastic or composite material; and
- Design of pipelines. For information on design, see AIGA 033, *Hydrogen Pipeline Systems*; AIGA 034, *Carbon Monoxide and Syngas Pipeline Systems*; and AIGA 021, *Oxygen Pipeline and Piping Systems* [1, 2, 3].[1]

To the extent that they exist, national laws can supersede the practices included in this publication. It should be noted that all local regulations, tests, safety procedures, or methods are not included in this publication and that abnormal or unusual circumstances could warrant additional requirements.

2.2 Purpose

Managing the integrity of a gas pipeline system is one of the goals of every pipeline system operator. Pipeline system operators' primary goal is the safe and reliable continuous operation of the pipeline to provide safe and reliable delivery of industrial gas to their customers without interruptions, adverse effects on employees, the public, or the environment.

The goal of an integrity management program is to provide a set of safety management, operations, maintenance, evaluation, and assessment processes that are implemented in a manner to ensure pipeline system operators provide enhanced protection of pipeline assets.

The purpose of this publication is to guide individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. The pipeline integrity team typically consists of managers, engineers, and operating personnel with specific competence in detection, prevention, and mitigation activities.

[1] References are shown by bracketed numbers and are listed in order of appearance in the reference section.

3 Definitions

For the purpose of this publication, the following definitions apply.

3.1 Publication terminology

3.1.1 Shall

Indicates that the procedure is mandatory. It is used wherever the criterion for conformance to specific recommendations allows no deviation.

3.1.2 Should

Indicates that a procedure is recommended.

3.1.3 May

Indicates that the procedure is optional.

3.1.4 Will

Is used only to indicate the future, not a degree of requirement.

3.1.5 Can

Indicates a possibility or ability.

3.2 Technical definitions

3.2.1 Area(s) of concern

Specific locales and areas where a release could have significant adverse effects.

3.2.2 Cathodic protection

Technique to reduce the corrosion rate of a metal surface by making that surface the cathode of an electrochemical cell [4].

3.2.3 External corrosion direct assessment

Four step process that combines pre-assessment, indirect inspection, direct examination, and post assessment to evaluate the effect of external corrosion on the integrity of a pipeline [4].

3.2.4 In-line inspection

Inspection of a pipeline from the interior of the pipe using an in-line inspection tool.

NOTE—The tools used to conduct in-line inspection are known as pigs or smart pigs [5].

3.2.5 Maximum allowable operating pressure (MAOP)

Maximum internal pressure permitted during the operation of a pipeline [4].

3.2.6 Performance based integrity management program

Process that uses risk management principles and risk assessments to determine prevention, detection, and mitigation actions and their timing (risk based) [6].

NOTE—An example includes integrity assessment.

3.2.7 Pipeline(s)

Underground or aboveground piping system used to convey gaseous or liquid product from a producing facility, crossing third-party, or public property (for example, public road) to a customer's use point on their property.

NOTE—This normally necessitates the use of external governmental requirements depending on region.

NOTE—This definition does not include interplant process piping, which is underground or aboveground piping used to convey gaseous product from a producing facility to a customer's use point on their property without crossing a third-party or public property.

3.2.8 Prescriptive integrity management program

Integrity management process that follows preset conditions that result in fixed inspection and mitigation activities and timelines (time based) [6].

NOTE—Examples include patrolling and cathodic protection monitoring.

NOTE—Many pipeline system operators use a combination of both prescriptive and performance based integrity management programs.

3.2.9 Segment(s)

Length of a pipeline or part of the system that has unique characteristics in a specific geography location.

3.2.10 Status

3.2.10.1 Abandoned

Permanently removed from service.

NOTE—Pipeline may not be under pressure, may not be under a nitrogen blanket or water blanket, and is physically isolated from other pipelines via cutting and capping or installing a blind flange.

3.2.10.2 Active

Pipeline under pressure and is flowing product.

3.2.10.3 In service

Pipeline is under pressure, contains a product, and is not flowing.

3.2.10.4 Out of service

Pipeline is under pressure, under an inert gas blanket, and is not flowing product.

4 Hazards of gases

This publication does not cover the hazards of gases in detail. For more detailed information on hazards, see the following publications:

- Safety data sheets (SDS);
- CGA G-4, *Oxygen* [7];
- AIGA 021 [3];
- AIGA 033 [1];
- AIGA 034 [2];
- CGA P-9, *The Inert Gases: Argon, Nitrogen, and Helium* [8]; and
- CGA *Handbook of Compressed Gases* [9].

5 Integrity management program overview

A thorough, organized, and unified integrity management program provides the means to improve the safety of pipeline systems. Such a program provides the information for a pipeline system operator to allocate resources for prevention, detection, and mitigation actions that will result in improved safety and a reduction in the number of incidents. See Figure 1.

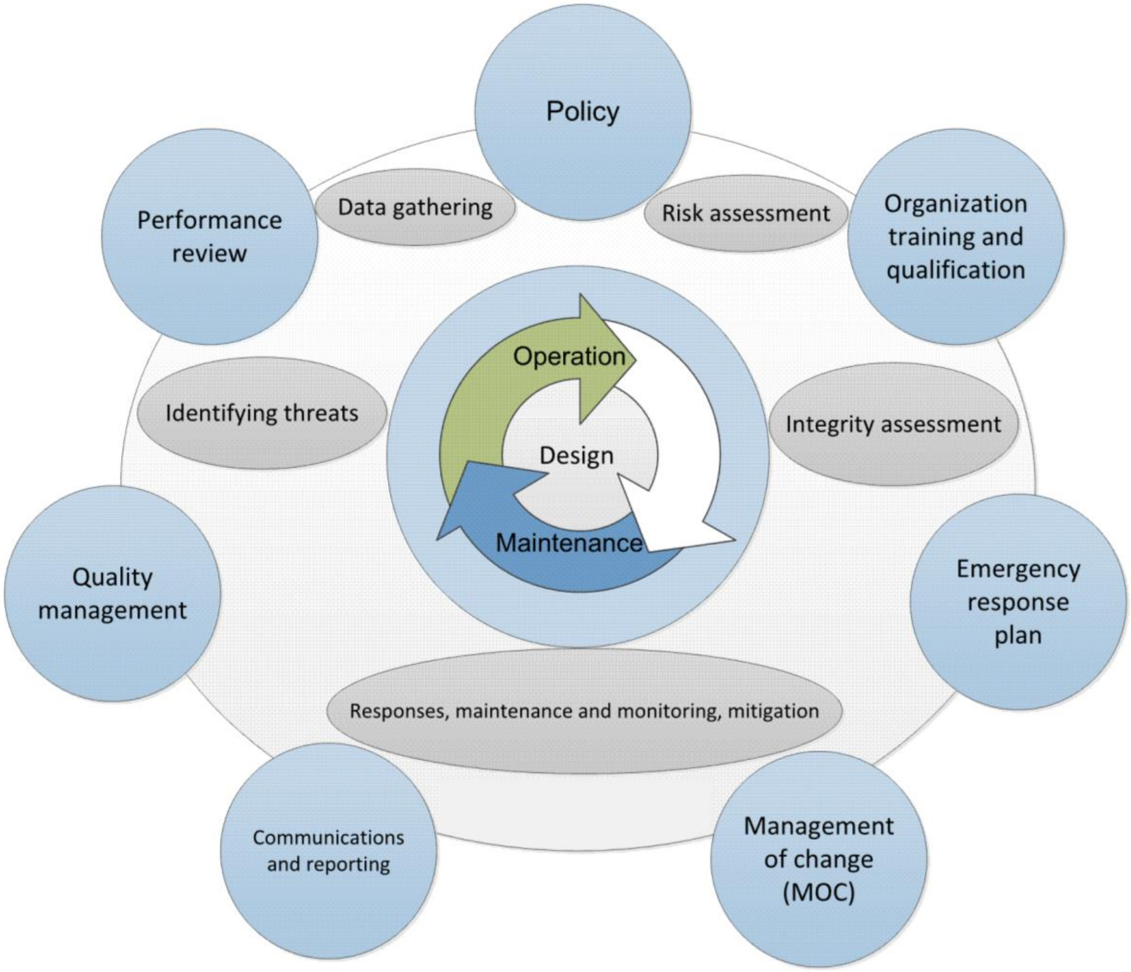

Figure 1—General overview of a pipeline integrity management system

This publication describes the means that a pipeline system operator may use to determine and mitigate risks to reduce both the probability and consequences of incidents. It covers performance and prescriptive based integrity management.

The performance based integrity management program employs more data and broad risk analysis, which permit pipeline system operators to comply with the requirements of this program in the areas of inspection intervals, tools used, and mitigation techniques used.

Inspection, prevention, detection, and mitigation are all part of the prescriptive process necessary to produce an integrity management program.

Prior to proceeding with the performance based integrity program, a pipeline system operator shall first ensure sufficient 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 shall meet or exceed that of a prescriptive program.

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

See Figure 2 for an integrity management plan process flow diagram.

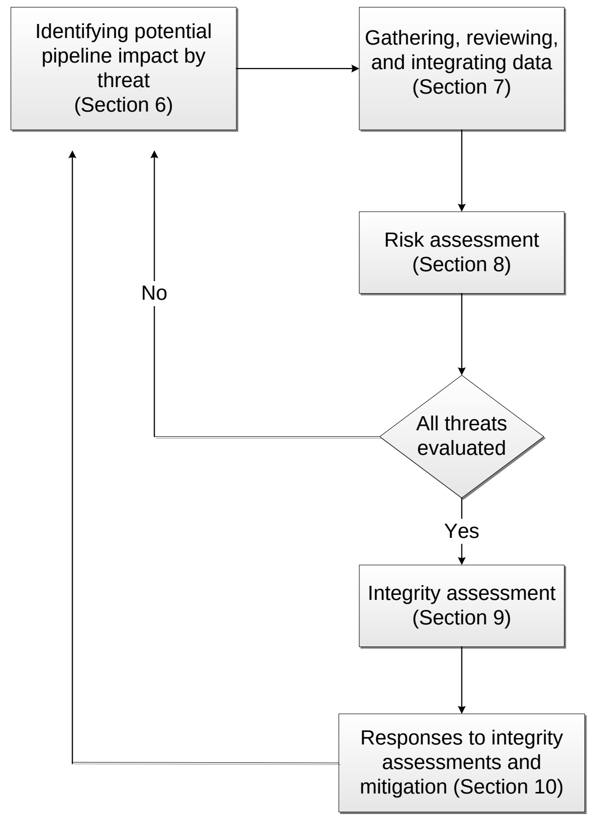

Figure 2—Integrity management plan process flow diagram[2]

6 Consequences

6.1 General

Risk is the mathematical product of the probability and the consequences of a failure. Risk can be decreased by reducing either the probability and/or the consequences of a failure. This section specifically addresses the consequences portion of the risk equation. The pipeline system operator shall determine the consequences of a potential failure when prioritizing inspections and mitigation activities.

6.2 Potential impact area

The potential impact area is typically calculated based on the diameter of the pipeline, the maximum operating pressure, and the type of gas. The potential impact area shall be determined for pipelines based upon applicable national and local regulations.

In a performance based program, the pipeline system operator may consider additional factors such as depth of burials that can reduce impact areas.

6.3 Factors to consider

When evaluating the consequences of a failure within the impact area, the pipeline system operator shall consider the following, at a minimum:

- population density;
- proximity of population to the pipeline;

[2] Reprinted from ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines* by permission of The American Society of Mechanical Engineers [6]. All rights reserved. No further copies can be made without written permission.

- proximity of populations with limited or impaired mobility (hospitals, schools, daycare centers, retirement communities, prisons, and recreation areas);
- property damage;
- environmental damage;
- effects of unignited gas release;
- security of gas supply (interruption of service); and
- potential for secondary failures.

The consequences of a failure can vary based on the properties and composition of the gas transported.

7 Gathering, reviewing, and integrating data

7.1 Procedure

7.1.1 Threat identification

Use the prescriptive approach to identify and evaluate all potential threats to pipelines per ASME B31.8S, *Managing System Integrity of Gas Pipelines* [6]. Threats are identified to determine the mechanisms that can result in the failure of pipelines, facilitate the selection of appropriate integrity assessment methods, set integrity assessment priorities, facilitate the selection of effective preventative and mitigative (P&M) measures, and evaluate the benefits of P&M measures.

As it relates to pipeline integrity, failure likelihood is the relative measure of the likelihood of failure of a pipeline because of an identified threat. The intent of failure likelihood is to provide resolution between each pipeline and to allow for grouping based on the magnitude of the identified threats. For such purposes, a failure likelihood algorithm based on the method of indexing is used.

The failure likelihood algorithm follows the approach employed in ASME B31.8S and addresses the likelihood of failure due to each of the following threats [6]. Within the failure likelihood algorithm, each identified threat is assigned a weighting based on the expected contribution of the identified threat to the overall failure susceptibility. The starting point for the assignment of identified threat weightings determined by failure likelihood is based on industry incident statistics but may be modified based on accrued pipeline operating experience. See Figure 3.

$$Risk_t = P_t \times C_t \text{ for a single threat}$$

$$\text{Risk} = \sum_{t=1}^{9} (P_t \text{ x } C_t) \text{ for threat categories 1 to 9}$$

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

Where:

C = failure consequence

P = failure likelihood

Pt = *P* total

C_t = *C* total

1 to 9 = failure threat category

1) External corrosion
2) Internal corrosion
3) Stress corrosion cracking (SCC)
4) Manufacturing related defects
5) Welding/fabrication related
6) Equipment
7) Third party/mechanical damage
8) Incorrect operational procedure
9) Weather-related and outside force

Figure 3—Failure likelihood algorithm[3]

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7.1.2 Threats

Per ASME B31.8S, identified threats to pipelines are classified in the following categories:

- Time-dependent threats—external corrosion, internal corrosion, stress corrosion cracking (SCC);
- Stable or resident threats—manufacturing defects, construction defects, equipment failure; and
- Time-independent threats—third party damage, incorrect operations, weather—outside forces [6].

Cyclic fatigue is not typically identified as a threat; however, if a pipeline system operator has a pipeline(s) that sees extreme demand patterns, cyclic fatigue shall be considered. External loading conditions are not typical identified threats. Pipelines shall be monitored for new potential identified threats.

For specific information on embrittlement and environmental damage mechanisms to pipelines used in hydrogen, carbon monoxide, and Syngas, see AIGA 033 and AIGA 034 [1, 2]. For more information on issues concerning oxygen pipelines, see AIGA 021 [3].

7.1.2.1 External corrosion

There are several factors that contribute to the susceptibility of pipelines to failure due to external corrosion including pipe age, factory coating type, field coating type, factory and field coating condition, cathodic protection system compliance, casings, soil-to-air interfaces, and soil type. These factors are offset to a lesser or greater extent by integrity assessments and P&M measures that are directed against external corrosion. Conversely, the factors can be enhanced by localized effects such as stray current and/or interference.

7.1.2.2 Internal corrosion

The threat of internal corrosion to pipelines is very low due to the dryness of the gas. A gas is considered to be dry with a dew point less than or equal to 20 °F (–7 °C).

7.1.2.3 Stress corrosion cracking

The threat of SCC to pipelines is low due to the control of the factors of specified minimum yield strength (SMYS), temperature, age of pipe, type of coating, and the distance from the compressor station.

7.1.2.4 Embrittlement and environmental damage mechanisms

Stress corrosion and embrittlement can occur internally to carbon monoxide and Syngas pipelines. For more information, see Appendix B of AIGA 034 [2].

For more information about hydrogen gas embrittlement, see Appendix B of AIGA 033 [1].

7.1.2.5 Manufacturing defects

Certain historical manufacturing practices have been shown to contribute to pipeline failure. The presence of seam defects, composition defects, hard spots, and factors leading to manufacturing inconsistencies are of concern.

7.1.2.6 Construction defects

Certain historical construction and joining practices have been shown to contribute to pipeline failure. The presence of wrinkle bends, buried couplings, buried threaded connections, poor selection and application of weld joint coatings, and factors leading to suspect welds are of concern.

7.1.2.7 Equipment failure

A review of historical equipment failure data shall be completed to determine which of the following types of equipment have a history of failure on pipelines:

- Regulator valves (set point drift outside of manufacturers' tolerances);

- Relief valves (set point drift outside of manufacturers' tolerances);
- Flange gaskets;
- O-rings; and
- Seals and packing.

7.1.2.8 Third-party damage

Third-party damage to pipelines can usually be classified into two different categories, sustaining a hit by a third party resulting in:

- damage that can affect its overall mechanical integrity (for example, damage to coatings, dents, etc.); and
- immediate loss of containment or breakage.

Third-party damage can occur as a result of regular operations, construction, vandalism, theft, sabotage, and/or terrorism, etc.

7.1.2.9 Incorrect operations

Incorrect operations of pipelines can lead to operating outside the integrity operating window (i.e., pressure fluctuations, humidity, etc.). Causes of incorrect operations include:

- deficient operating procedures; and/or
- failure to follow pipeline operating procedures.

7.1.2.10 Weather and outside forces

Weather and outside forces are the product of two independent factors:

- susceptibility of pipelines to lighting strikes; and
- susceptibility of pipelines to geotechnical threats (earthquakes, floods, extreme temperatures).

7.1.3 Interactive identified threats

The interactive nature of identified threats involves more than one identified threat occurring on pipelines at the same time. Interactive identified threats are considered within the failure likelihood algorithm.

7.1.4 Identified threat elimination

The elimination of an identified threat to pipelines from consideration in the integrity management plan shall be preceded by a subject matter expert (SME) review of pipeline manufacturing, design, construction, operation, maintenance, and failure history. The technical reason for the elimination of the identified threat shall be documented and maintained in accordance with the pipeline systems operator's standard operating procedures.

7.2 Data gathering and integration

A data management system such as a database should be used for the management of pipeline data. Transfer of pipeline centerline information and related data from hardcopy data sources should be transferred to the data management system.

Pertinent pipeline data shall be reviewed during the risk assessment process to ensure that the data is accurate and current for each pipeline in the system. Optimal risk assessment results depend on accurate and current pipeline data.

7.2.1 Data

7.2.1.1 Data gathering

Data shall be gathered by designated personnel during the risk assessment process and maintained for the life of the pipeline. Data can include, but are not limited to, records for:

- Pipe characteristics;
- Design and construction;
- Operations and maintenance;
- Weather and outside forces;
- Inspection and assessment;
- Damage and repair;
- Equipment failures and malfunctions; and
- P&M measures.

See the table titled *Data Elements for Prescriptive Pipeline Integrity Program* in ASME B31.8S for more examples of data [6].

7.2.1.2 Data missing or of poor quality

In cases when data is missing or of poor quality, at least one of the following supplementary actions shall be taken:

- Search and/or review additional resources to locate data;
- Consult with a SME or other technical resource to define a conservative estimate for the data;
- Conduct field investigations to determine or confirm the data; or
- Assume threats exist due to the lack of data or poor quality data.

Records shall be maintained that identify how data of poor quality are used to facilitate consideration of the impact of the data of poor quality on risk assessments.

7.2.1.3 Data sources metadata

The following metadata should be maintained for all data sources gathered to facilitate tracking and establish a history for the purposes of activities:

- record document number and/or name;
- record revision number;
- date record created;
- date record gathered; and
- record resource (for example, project files, construction files, operations files).

7.2.2 Assessment data

Data shall be gathered during the periodic risk assessment process and maintained for the life of the pipeline accompanied by the storage requirements. Inspection and assessment (for example, risk assessment and integrity assessment) records shall be integrated into the data management system upon completion.

7.2.2.1 Assessment data review

Assessment data shall be reviewed as it is populated into the data management system during the execution of the periodic risk assessment process to verify the quality and completeness. In cases when assessment data is found to be inaccurate or incomplete, at least one of the supplementary actions listed in 7.2.1.2 shall be taken.

Consider the following factors when checking the quality of assessment data:

- accuracy;
- age;
- assembly;
- completeness;
- consistency;
- metadata;
- quality;
- resolution; and
- units of measure.

In cases when assessment data is of poor quality, at least one of the supplementary actions as described in 7.2.1.2 shall be taken.

7.2.3 New data incorporation

When new or changed data is identified during the periodic risk assessment process, the new or changed data shall be incorporated in a timely and effective manner according to the execution intervals specified by the risk assessment process. In cases when the new or changed data results in a subsequent change to the risk scores of pipelines, the change shall be communicated per the communications plan (see Section 14).

8 Risk assessment

8.1 Introduction

Risk assessments should be performed on pipelines and related facilities such as meter and valve stations. Risk assessments are part of the integrity management program and can be either prescriptive based or performance based. If a risk assessment is not performed, the pipeline system operator(s) shall document the reasons for not performing the risk assessment and the operator is responsible for prioritizing all future pipeline integrity assessments, P&M measures, and for defining the integrity assessment intervals.

For prescriptive based programs, risk assessments are used to prioritize plan activities and help to organize data and information to make decisions.

For performance based programs, risk assessments serve to organize data and information and to help prioritize and plan activities as well as to determine which inspection, prevention, and/or mitigation activities are performed and when.

8.2 Definition of risk

Risk is typically described as the product of two primary factors. The probability of failure (PoF) and the resulting consequences of the failure (CoF). For more information, see ISO 31000, *Risk Management - Guidelines* [10].

All threats to pipeline integrity shall be considered. See Section 7.

Risk consequences typically consider items such as the potential impact of the event on individuals, property, businesses, and the environment.

8.3 Risk assessment objectives

The risk assessment enables the pipeline system operator to determine the following:

- rank of priority sections for inspection;
- active threats for which integrity assessments are needed; and
- mitigation measures to put in place based on the impact on risk reduction.

Risk assessments provide for both the potential impact of incidents and the likelihood that such events can occur. This supports the integrity management process by promoting rational and consistent decisions. Risk results are used to identify areas for integrity assessments and mitigative actions. Examining both primary risk factors (PoF and CoF) avoids focusing solely on the most visible or frequently occurring problems while ignoring potential events that could cause significantly greater damage. Conversely, the process avoids focusing on less likely catastrophic events while overlooking more likely scenarios.

8.4 Developing a risk assessment

An effective risk assessment process shall provide risk estimates to facilitate decision making. When properly implemented, risk assessment methods are robust analytic methods, using a variety of inputs, that provide an improved understanding of the nature and locations of risks along a pipeline or facility.

Risk assessment methods alone should not be completely relied upon to establish risk estimates or to address or mitigate known risk. SMEs or other experienced personnel should validate risk assessment outputs with other relevant factors not included in the risk assessment methods. SMEs should apply their knowledge to validate the outputs of the assessment process.

A vital part of the risk assessment process is to incorporate any changes to a pipeline or facility data. The pipeline system operator shall perform a review at regular intervals to determine that a risk assessment is up to date.

8.5 Risk assessment approaches

In order to organize integrity assessments for pipeline segments, a risk priority shall be established. This risk value combines a number reflecting the PoF and a number reflecting the CoF. The risk analysis output can be fairly simple with rankings of low, medium, and high likelihood and consequences or more complex involving a larger range to provide greater contrast between pipeline segments. Multiplying the relative PoF × CoF provides the pipeline system operator with a relative risk for the segment and a relative priority for its assessment.

There are several risk assessment approaches a pipeline system operator can use that are consistent with the objectives of the integrity management program. A pipeline system operator shall use one or more of the following approaches:

- SMEs from the company or consultants, using technical literature, can be used to provide a relative numeric value describing the PoF and CoF. Each pipe segment is assigned a PoF and a CoF and the relative risk is calculated;
- Relative assessment models use pipeline specific characteristics and more extensive data and include the development of risk models addressing the known threats that have historically impacted pipeline operations. These models use algorithms weighing the threats and consequences and provide sufficient data to assess them;
- Scenario-based models use models that generate a description of an event or series of events leading to a level of risk and includes both the PoF and the CoF from such events; and
- Probabilistic models are 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 pipeline system operator, rather than using a comparative basis [6].

All risk assessment approaches described previously have the following common components:

- identification of potential events or conditions that could threaten system integrity;
- evaluation of PoF and CoF;
- rank of risk and identification of threats that influence or drive each risk;
- identification of integrity assessment and/or mitigation options; and
- record for continuous updating for risk reassessments.

8.6 Risk ranking

When a risk assessment is conducted, the risk scores generated shall be used to establish the basis for prioritizing all future pipeline integrity assessments and P&M measures, and for defining the integrity assessment intervals.

9 Integrity assessment

Integrity assessment is a process that includes inspection of the pipeline, evaluating the indications resulting from the inspections, direct examinations, evaluating the results of the examinations, and determining the resulting integrity of the pipeline through analysis.

Integrity assessment methods are adapted to each threat category. See Table 1.

9.1 Integrity assessment plan

An integrity assessment plan shall be established and shall cover the following items:

- Schedule for baseline inspection as well as continual assessment of all pipeline segments based on a prioritizing process implemented within the risk assessment according to Section 8;
- Inspections in order to localize indications of possible pipe defects. These inspections include possible direct examinations to confirm the relevance of indications;
- Analysis and assessment of the inspection results in order to verify and demonstrate the fitness for purpose of the pipeline;
- Completion of appropriate repairs; and
- Determination of the appropriate re-inspection interval.

9.2 Inspection plan

An inspection plan shall be developed and include:

- choice of inspection method for each pipeline segment;
- baseline and continual assessment;
- defect assessment;
- repairs and mitigation; and
- re-assessment interval(s).

9.3 Selection of assessment method

Integrity assessment methods are to be adapted to each threat category.

The following inspections are recognized as integrity assessment methods:

- pressure testing;
- in-line inspection;

- direct assessment (includes external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment); and
- visual inspection of aboveground pipeline sections.

See Section 11 for more details about these methods.

For the corrosion threats, dents, cracks, or other mechanical damage of buried pipelines, the integrity assessment methods are:

- in-line inspection with a tool capable of detecting these defects;
- pressure test; or
- conducting direct assessment.

Table 1 indicates the effective integrity assessment methods for each threat. The threats are listed in three groups: time-dependent, stable, and time-independent.

Time-dependent threats can typically be addressed by using any one of the four integrity assessment methods mentioned.

Stable 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.

Time independent or random threats typically cannot be addressed through use of any of the integrity assessment methods addressed in this publication but are subject to the prevention measures.

Other criteria that shall be taken into account when determining the appropriate assessment method, include:

- Possibility of taking the pipeline segment out of service for the expected duration of the inspection. This greatly depends on the number of customers affected and whether supply disruption is an option;
- Pigability of the pipeline section. The selection criteria include:
  - Geometry
  - Constraints related to the propulsion fluid (velocity control, availability and possibility of disposal of water, and quality of water)
  - Capability of aboveground pipe support to carry the weight of the water or other propulsion fluid
- Re-inspection interval;
- Presence of parallel pipeline (electrical interference); and
- Transported gas (type of expected defects).

In addition to the previous technical criteria, other criteria related to safety shall be taken into account such as the evaluation of the consequences of a possible failure during pressure testing.

Table 1—Effective integrity assessments based on threats

Integrity threats	Method: Direct assessment	Method: In-line inspection	Method: Pressure test	Method: Visual	Method: Operating & maintenance procedures
Time-dependent threats					
Corrosion:					
Internal		X	X		X
External underground	X	X	X	X	
External aboveground		X	X	X	X
Stress corrosion cracking (SCC)	X	X			X
Hydrogen embrittlement		X	X		X
Stable threats					
Manufacturing defects:					
Pipe		X	X [1)]		X
Pipe seam		X	X [1)]		X
Construction defects:					
Girth weld		X	X [1)]		X
Buckle/Dent		X	X [1)]		X
Wrinkle bend		X	X [1)]		X
Equipment:					
Control/relief valve					X
Time-independent threats					
Third-party/mechanical damage	X	X	X		X
Incorrect operation:					X
Including cold embrittlement					X
Weather and outside forces:					
Cold weather					X
Lightning	X				X
Flooding/Erosion				X	X
Subsidence				X	X
Landslide				X	X

[1)] Refers to postconstruction.

9.4 Baseline and continual assessment

9.4.1 Baseline assessment plan

The baseline is defined as the first inspection for integrity assessment.

A baseline assessment plan shall be developed in order to assess the integrity of all of the pipelines or pipeline segments included in the integrity management program. The baseline assessment plan shall show when each line is to be assessed and the assessment method that will be used.

The baseline assessment plan is an integral part of the pipeline integrity management system. The baseline assessment plan shall, as a minimum:

- Identify the specific integrity assessment method(s) to be conducted,

- Specify the schedule by which those integrity assessments will be performed. This schedule is based on the priority according to:
    - Legal requirements
    - Results from risk assessment
    - Past incidents
    - Specific environment localized features; and
- Provide the technical justification for the selection of the integrity assessment method(s) and the risk basis for establishing the assessment schedule.

9.4.2 Continual evaluation of pipeline integrity

Once the baseline assessment has been performed on a pipeline, further risk assessments take into account the information gathered during the last inspection. Based on the results from the risk assessment (including the inspection priorities consistent with the determined re-inspection interval) a periodic pipeline integrity assessment plan (including the same elements as the baseline assessment plan) shall be developed. Comparing the results of subsequent inspections allows more accurate evaluation and understanding of current pipeline conditions and their development over the time as well as identifies integrity issues. This periodic assessment and evaluation cycle are recognized as a continual evaluation of pipeline integrity.

9.5 Defect assessment

Defects shall be assessed and action taken as required according to applicable local codes/regulations and company requirements (for example, ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines;* API 579-1/ASME FFS-1, *Fitness-for-Service*; BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*) [11, 12, 13]. Defects can include:

- Corrosion—Some amount of metal loss due to external corrosion can be tolerated without impairing the ability of the pipeline to operate safely;
- Dents—Dents are indentations of the pipe or distortions of the pipe's circular cross section caused by external forces; and/or
- Other mechanical damage and cracks.

10 Responses to integrity assessments and mitigation (repair and prevention)

10.1 Introduction

This section establishes the responses to the indications obtained by inspection (Section 9) and the inspection interval. The responses can be divided into:

- Repair—actions used to remedy or eliminate an unsafe condition; and
- Preventative actions—actions taken to reduce or eliminate a threat by establishing P&M measures to maintain inspection intervals.

The inspection intervals are going to be defined based on the characterization of defect indications, the level of mitigation achieved, and the prevention methods employed.

For indications, response schedules are divided into the following groups:

- Immediate Response—Indication shows that the defect is at a failure point. A quick response is required;
- Scheduled Response—Indication shows that the defect is significant but not at a failure point. Given that there is no immediate risk of failure, it is possible to schedule the pipeline defect repair. A response is required prior to the next inspection; and

- Monitored Response—Indication shows that the defect will not fail before the next inspection. Continue monitoring during each subsequent inspection.

To achieve risk reduction in each segment of the pipeline, it is necessary to select and schedule examination, evaluation, and mitigation actions as part of the integrity management program.

The integrity management program shall provide analysis of existing and newly implemented mitigation actions to evaluate their effectiveness and justify their use in the future.

10.2 Responses to pipeline in-line inspections

Based on the results of a risk assessment and the severity of in-line inspection indications, the pipeline system operator shall complete the response according to an established prioritized schedule. As soon as the damage or condition is detected, the required response schedule begins.

The pipeline system operator shall promptly review the results for Immediate Response indications. Other indications shall be reviewed in a timely fashion and a response plan shall be developed. The plan shall include the methods and timing of the response. For Scheduled or Monitored Responses, the pipeline system operator may reinspect rather than examine and evaluate considering the specified time frame.

10.2.1 Internal and external corrosion metal loss

In this case, the indications requiring Immediate Response due to immediate or near-term leaks or ruptures would be any corroded areas that have a predicted failure pressure level less than 1.1 times the maximum allowable operating pressure (MAOP) as determined by ASME B31G or equivalent [11]. Also, in this group would be any metal-loss indication affecting a detected longitudinal seam.

The pipeline system operator shall promptly confirm these indications following determination of the condition. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair or removal unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

Scheduled Responses to certain indications are suitable for continued operation. Indications characterized with a predicted failure pressure greater than 1.1 times the MAOP shall be confirmed and evaluated.

Monitored Responses are the least severe indications and do not require confirmation and evaluation until the next scheduled integrity assessment interval stipulated by the integrity management plan, provided that they are not expected to grow to critical dimensions prior to the next scheduled assessment.

10.2.2 Stress corrosion cracking

All indications of SCC require an Immediate Response. The pipeline system operator shall confirm and evaluate these indications immediately following determination of the condition. After confirmation and evaluation, any defect found to require repair or removal shall be promptly remediated by repair (permanent or temporary) or removal. It is not recommended to continue with pipeline operation.

10.2.3 Third-party damage and mechanical damage

Indications requiring Immediate Response are those that could be expected to cause leaks or ruptures in near terms. An Immediate Response may also be necessary for dents with gouges and/or corrosion. The pipeline system operator shall examine these indications immediately following determination of the condition.

Other indications that require a Scheduled Response include mechanical damage with or without concurrent visible indentation of the pipe, dents with cracks, dents that affect ductile girth or seam welds if the depth is in excess of 2% of the nominal pipe diameter, and dents of any depth that affect nonductile welds. The pipeline system operator shall examine theses indications within a period not to exceed 1 year following determination of the condition. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair or removal, unless the operating pressure is lowered to mitigate the need to repair or remove the defect.

10.2.4 Limitations to response time for prescriptive based program

When time-dependent anomalies such as external corrosion or SCC are being evaluated, an analysis shall be completed to ensure that the defect will not reach critical dimensions prior to the scheduled repair or next inspection.

When determining repair intervals, the pipeline system operator should consider that certain threats to specific pipeline operating conditions could require a reduced examination and evaluation interval. This can include third-party damage or construction threats in pipelines subject to external loading that could promote increased defect growth rates. For prescriptive based programs, the inspection intervals are conservative for potential defects that could lead to a rupture.

When the analysis results show a time to failure is short, the pipeline system operator should plan for potential delays such as access, environmental permit issues, and gas supply requirements and should apply mitigation such as pressure reduction, limiting access, etc.

10.2.5 Responses to failed pressure testing

If a pressure test fails, the pipeline shall be immediately remediated by repair. See 10.4.

10.2.6 External corrosion threats

The intervals between tests for external corrosion threats shall be consistent with the pipeline system operator's integrity management plan.

10.2.7 Stress corrosion cracking threats

The intervals between tests for SCC threats shall be consistent with the pipeline system operator's integrity management plan.

10.2.8 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.

10.3 Responses to direct assessment inspections

10.3.1 External corrosion direct assessment

For the external corrosion direct assessment prescriptive program for pipelines, the pipeline system operator should examine and evaluate all the indications found by inspection. The pipeline system operator should then prioritize each indication where corrosion is most likely to occur.

For indications, response schedules are divided into the following groups:

- Immediate Response—Should include indications that the pipeline system operator considers likely to have ongoing corrosion activity and that, when coupled with prior corrosion, pose an immediate threat to the pipeline under normal operating conditions;
- Scheduled Response—Should include indications that the pipeline system operator considers can have ongoing corrosion activity but that, when coupled with prior corrosion, do not pose an immediate threat to the pipeline under normal operating conditions; and
- Suitable for Monitoring—Should include indications that the pipeline system operator considers inactive or as having the lowest likelihood of ongoing or prior corrosion activity [4].

Pipeline system operators shall excavate all immediate indications in a timely manner. Pipeline system operators shall excavate all scheduled indications before the next assessment. Pipeline system operators may monitor all other indications.

10.4 Repair methods

For acceptable repair methods, see the table titled *Acceptable Threat Prevention and Repair Methods* in ASME B31.8S [6].

Each pipeline system operator's integrity management program shall include documented repair procedures. All repairs shall be made with materials and processes that are suitable for the pipeline operating conditions and meet ASME B31.8S requirements or equivalent [6].

10.5 Prevention strategy/methods

Prevention is an important proactive element of an integrity management program. Prevention strategies should be based on data gathering, threat identifications, and risk assessments. Preventive measures shown to be effective in the past should be continued in the integrity management program. Prevention strategies (including intervals) should also consider the classification of identified threats as time-dependent, stable, or time-independent in order to ensure that effective prevention methods are used.

10.6 Prevention options

A pipeline system operator's integrity management program shall include applicable activities to prevent and minimize the consequences of unintended releases. Prevention activities do not necessarily require justification through additional inspection data. Prevention actions can be identified during normal pipeline operation, risk assessment, implementation of the inspection plan, or during repair.

The predominant prevention activities are:

- preventing third-party damage;
- controlling corrosion;
- detecting unintended releases; and
- operating at lower pressure.

There are other prevention activities that the pipeline system operator may consider. See ASME B31.8S [6].

11 Integrity management plan

11.1 Method selection

The pipeline integrity manager or designee shall select at least one of the following integrity assessment methods for the pipelines:

- internal inspection;
- pressure testing;
- direct assessment; and/or
- other technology that can provide an equivalent understanding of the condition of the pipeline.

Selection of more than one integrity assessment method may be required to sufficiently address all identified threats to the pipeline(s). See ASME B31.8S or NACE SP0113, *Pipeline Integrity Method Selection* for more information [6, 14]. The pipeline integrity manager shall review the most current risk assessments to determine the most significant identified threats before selecting integrity assessment methods for the pipelines.

Consideration shall be given to all time-dependent threats including external corrosion, internal corrosion, and SCC and critical time-independent threats including third-party damage to select integrity assessment methods that are best able to detect anomalies associated with said identified threats for the pipelines. Consideration shall be given to the development of a P&M measures plan to reduce these threats. See the table titled *Acceptable Threat Prevention and Repair Methods* in ASME B31.8S [6].

P&M measures shall be identified with the intent of preventing pipeline failures and mitigating the consequences of pipeline failures. The P&M measures to be used shall be reviewed for each pipeline at regular intervals as determined by the pipeline system operator. The most current risk assessment for the pipeline shall be the basis for identification of P&M measures. The schedule for implementation of selected P&M measures shall be documented.

11.2 Identified threats

The integrity assessment methods and additional measures used to minimize the risk of the pipeline failures for all identified threats are listed in Appendix A. The integrity assessment methods are appropriate for the identified threats per ASME B31.8S and NACE SP0113 [6, 14].

11.3 Integrity assessment methods

The following considerations shall be made when selecting integrity assessment methods for the pipeline(s). The integrity assessment methods are principally selected for the assessment of the primary threats associated with each pipeline. Those threats are listed and explained in Section 7. The following are the allowable assessment methods and a brief description of each. To get a more detailed description and their appropriate implementation, refer to listed reference material provided in this publication.

11.3.1 External corrosion direct assessment

External corrosion direct assessment is an assessment method that can be performed without interruption of product delivery and requires the least amount of modification to pipeline components. External corrosion direct assessment should be used for the assessment of external corrosion and third-party damage but can be successful for other threats as a supplemental method. External corrosion direct assessment should be used as an integrity assessment method only if it is determined to be feasible for each pipeline that is being considered. See ASME B31.8S, NACE SP0113, and NACE SP0502 [6, 14, 4].

Issues that could prevent the pipeline system operator from using external corrosion direct assessment as an assessment method include:

- excessive pipeline depth;
- pipeline not accessible for excavating;
- coating that is not conducive to aboveground surveys, i.e. plastic backed tape coating;
- entire length of the pipeline runs under pavement or asphalt;
- excessive interference from stray current(s); and
- bare or poorly coated pipe.

11.3.2 Internal corrosion direct assessment

Internal corrosion is not considered to be a significant threat to industrial gas pipelines. Internal corrosion direct assessment would not be feasible to run on industrial gas pipelines. Should the pipeline system operator suspect that internal corrosion could be an issue, an in-line inspection tool or pressure test should be conducted.

11.3.3 Stress corrosion cracking direct assessment

External SCC is not considered to be a significant threat to most industrial gas pipelines. For SCC to be considered a threat the following has to be present:

- pipeline is over 10 years old;
- pipeline is coated with nonfusion bond epoxy (nonFBE) coating;
- product temperature exceeds 100 °F (37 °C);
- pipeline operates at or greater than 60% SMYS; and
- pipeline is less than 20 miles (32 km) downstream of a compressor station [6, 14, 4].

If the pipeline does not meet all of these conditions, it is not susceptible to SCC.

11.3.4 Pressure testing

Pressure testing can be used for the assessment of external corrosion, internal corrosion, SCC, mechanical damage, and construction defects. Pressure testing can be used as an integrity assessment method if determined to be feasible per ASME B31.8S and NACE SP0113 [6, 14].

The pipeline integrity manager shall select pressure testing as the integrity assessment method for pipelines with low-frequency electric resistance welded pipe or lap welded pipe that have experienced a seam failure or that have experienced an increase in operating pressure greater than the established MAOP in the five years before inclusion in the integrity assessment schedule. Pressure testing is capable of assessing seam integrity and seam corrosion anomalies.

11.3.5 In-line Inspection

In-line inspection can be used for the assessment of external corrosion, internal corrosion, SCC, mechanical damage, and construction defects. For more information on the selection of the appropriate inspection tool, see ASME B31.8S; NACE Publication 35100, *In-Line Inspection of Pipelines;* NACE SP0102; and NACE SP0113 [6, 15, 5, 14]. At a minimum, the following pipeline features shall be evaluated to determine if in-line inspection is feasible:

- Reduced port valves can result in tool damage and could cause the tool to become lodged;
- Bends installed back-to-back, without intervening section of straight pipe, can present a sticking hazard;
- Short radius bends—most in-line inspection tools can pass through a 3D (3 times the diameter) bends. Any bend that is tighter than that can present a sticking hazard;
- Unbarred and back-to-back tees—branch connection of 30% of the pipe diameter should have scrapper bars installed to allow the passing of the tool;
- Launching and receiving facilities shall be available and adequate for the tool type. The launchers and receivers do not need to be permanent, but there should be enough room at the valve stations to accommodate temporary facilities; and
- Multiple diameter and multiwall thickness pipelines can pose a sticking issue.

At a minimum, the following factors shall be evaluated before choosing a tool:

- inspection tool history;
- detection sensitivity;
- sizing accuracy;
- location accuracy;
- ability to inspect the full length of the pipeline;
- ability to inspect the full circumference of the pipeline;
- anomaly classification;
- ability to indicate the presence of multiple cause anomalies; and
- requirements for direct examination to determine the general reliability of in-line inspection.

11.3.6 Other technology

The following should be considered if other technology is to be used for integrity assessment:

- background of technology;
- capabilities of technology to existing and/or new identified threats;

- limitations of technology to existing and/or new identified threats;
- availability of technology; and
- impact of technology to the safety of personnel, contractors, the public, and the environment.

11.4 Environmental and safety risks

Integrity assessments shall be conducted in a manner that minimizes environmental and safety risks. As a precaution, only authorized personnel and contractors shall perform activities related to integrity assessments. Authorized personnel and contractors shall be responsible for the safety of the activities related to integrity assessments and the protection of other personnel, contractors, members of the public, and the environment from potential hazards.

11.5 Scheduling

An integrity assessment schedule shall be developed and maintained. The integrity assessment schedule is determined by prior assessments and identified threats. This schedule shall document the completion of prior assessments and the pipelines that require integrity assessments, including pipelines currently lacking a prior assessment.

Integrity assessment methods and the completion dates for field activities associated with integrity assessments shall be maintained.

11.5.1 Operational status

The operational status of the pipelines shall be recorded. For examples of commonly used statuses, see 3.2.10.

11.5.2 Prioritization

Based on identified threats and the most current risk assessment, the pipelines shall be prioritized in the integrity assessment schedule. The prioritization is per the threat identification, data gathering and integration, and risk assessment.

11.5.3 High-risk conditions

The pipelines that meet the following high-risk conditions shall be prioritized.

11.5.3.1 Low-frequency electric resistance welded and lap welded pipe

Pipelines using low-frequency electric resistance welded pipe or lap welded pipe that have experienced an increase in operating pressure greater than the established MAOP in 5 years before inclusion in the integrity assessment schedule or have experienced a seam failure shall be prioritized.

11.5.3.2 Manufacturing and construction defects

Pipelines that experience manufacturing/construction defects and any of the following changes shall be prioritized:

- Increase in operating pressure greater than the established MAOP in the five years before inclusion in the integrity assessment schedule;
- Increase in MAOP; and
- Increase in identified stresses that lead to cyclic failure.

11.5.4 Updating

The integrity assessment schedule shall be reviewed periodically to determine if updates are necessary. New information, identified threats, and risks resulting in updates to the prioritization of integrity assessments or integrity assessment methods shall be included in the review of the integrity assessment schedule. Additionally, the following events could potentially prompt updates to the integrity assessment schedule:

- recommendations from integrity assessments;
- completion of integrity assessments and resetting of the reassessment due date;
- identification of a new area of concern;
- modification of an existing area of concern;
- elimination of an existing area of concern;
- construction of a new pipeline;
- acquisition of a new pipeline;
- modification of an existing pipeline;
- abandonment of an existing pipeline;
- divestiture of an existing pipeline;
- discovery of damage to a pipeline;
- discovery of new information resulting in the determination of high-risk conditions;
- discovery of a new identified threat;
- change in pipeline conditions; and
- use of a new or enhanced integrity assessment method.

11.6 New areas of concern

When a new area of concern is identified, the integrity management plan shall be updated and the integrity assessment schedule shall be adjusted to include this area.

11.7 New pipelines

When a new pipeline is added to the integrity management plan, the plan shall be updated and the integrity assessment schedule shall be adjusted to include this pipeline.

11.8 Documentation

The following updates to the integrity management plan shall be documented:

- adding or removing pipelines;
- modifying the integrity assessment date or method; and
- identifying, modifying, or eliminating areas of concern.

The following information shall accompany all updates to the integrity management plan:

- reason;
- implications analysis; and
- approving authority within the pipeline system operator's company.

12 Maintenance and monitoring

A monitoring and maintenance plan shall be developed based on risk assessment results or integrity assessment results and applicable regulations.

The monitoring and maintenance plan shall cover the following items:

- Monitoring of the pipeline route. This comprises all activities for identification and prevention of external threats to the pipeline, the assessment of the effectiveness of the cathodic protection to prevent external corrosion as well as the detection of any changes in the environment that could increase the risks;
- Pipeline maintenance with the objective to restore to proper condition anything that is defective or otherwise deficient; and
- Maintenance of pipeline stations.

The plan shall particularly state the monitoring and maintenance activities in the areas of concern defined through the risk assessment or integrity assessment.

Maintenance and testing of protection equipment shall be subject to documented procedures.

The plan shall be reviewed according to the update of the risk assessment or integrity assessment and performance review.

Monitoring encompasses prevention activities with the purpose of controlling any external activities on the pipeline and preventing external corrosion, the main threats to which a transmission pipeline is subjected. These activities include:

- pipeline patrol;
- management of third-party activities;
- monitoring of the effectiveness of the protection systems against external corrosion;
- maintenance of the right-of-way of underground pipelines;
- maintenance of aboveground sections;
- maintenance of the cathodic protection equipment; and
- maintenance inspections at specific points such as:
    - pipelines crossing rivers other than aboveground such as buried in the riverbed or bored crossings
    - tunnels with or without access for visual inspection
    - cased crossings under roads or railways
    - double shells used for crossings without any access for visual inspection such as in box culverts
    - areas prone to soil displacement
    - crossings with ditches
    - any other special point identified as such through the risk or integrity assessment.

The purpose of the maintenance inspection of aboveground sections is to carry out the following verifications:

- Visual inspection of all aboveground piping sections for damage;
- Visual inspection of the condition of the painting (absence of evidence of corrosion);
- Proper condition of mechanical protection equipment (including fences of stations) and accesses;
- Proper condition of pipe supports, including condition of the antifriction pads between the pipe and the steel part of the support;
- Good state of marking, identification, and other means of information to the public;
- If the aboveground section is isolated from the buried pipeline by insulating joints, check adequate grounding and electrical continuity of piping and supporting structures;

- If the aboveground section is electrically connected to the buried pipeline, check proper isolation at all supports and proper condition of protections that prevent unauthorized access; and
- Check the risers of the aboveground section for corrosion, the coating shall be removed and replaced if found to be defective (for example, cracks or/and blistering).

13 Performance plan

A performance review of the pipeline integrity management plan shall be performed. The plan should be reviewed once a year. This pipeline review will be part of the industrial management system review and will help answer the questions:

- Were all integrity management program objectives accomplished?
- Were pipeline integrity and safety effectively improved through the integrity management program?

13.1 Management review inputs

Management review inputs should include:

- integrity management plan progress status;
- communication plan progress status;
- key performance indicators results;
- audits results and progress of corrective actions;
- deployment of group procedures and standards status;
- regulation evolutions and their potential impact;
- technology improvements;
- pipeline incidents, root cause analysis, and status of remedial actions;
- anomalies and nonconformities;
- inspections results;
- pipeline patrols results;
- risk assessment updated results, if applicable;
- integrity management plan for the year to come; and
- budgeted resources.

13.2 Management review outputs

Management review outputs should include:

- approved objectives;
- approved plans for the year to come (maintenance, inspection);
- recommendations for pipeline integrity management improvements;
- internal audits plan; and
- approved resources.

13.3 Key performance indicators

Key performance indicators should include, but are not limited to:

- percentage of completion of integrity management plan;

- number of incidents due to third-party work carried out. Four levels of incidents can be distinguished:
  - leak of the pipeline
  - damage to the metal of the pipeline
  - damage to the coating
  - near misses;
- number of other incidents (corrosion, construction/material, natural causes, and other);
- number of repair actions following integrity assessment;
- number of third-party activities without notification; and
- number of third-party activities with notification requests.

14 Communications plan

A communication plan should be developed and implemented.

A communication plan is necessary to keep company personnel, authorities having jurisdiction (AHJ), and the public informed about the integrity management efforts and the results of the integrity management activities. Some information should be communicated routinely while other information may be communicated upon request. Communications should be conducted as often as necessary to ensure that appropriate individuals and authorities have up-to-date information.

Examples of external communications include:

- landowners and tenants along the right-of-way;
- public officials (nonemergency);
- local and regional emergency responders; and
- public.

15 Management of change process

A management of change (MOC) process is an important element of an industrial management system. The introduction of any change to the pipeline, if not appropriately managed, can significantly increase the levels of personal, environmental, security, reliability, and process safety risk, impacting pipeline integrity and potentially causing a product supply failure.

The MOC process shall ensure that risks arising from any form of change are systematically identified, assessed, and managed. It shall address technical, physical, procedural, and organizational changes to the system, whether permanent, temporary, or emergency. To identify and assess the impact of changes to the pipeline systems and their integrity, management of change procedures shall be developed.

The following points are important for the correct performance of the MOC process and also, the integrity management program:

- All the MOC procedures shall be well understood by the personnel that use them;
- The pipeline system operator shall recognize that system changes can require changes in the integrity management program and, conversely, results from the program can cause system changes;

- All affected personnel shall be involved in the review of procedures along with management, since they can assess safety impact and suggest modifications; and
- To ensure the integrity of the pipeline, it is necessary to develop and maintain a documented record of changes. In case of any change, it is necessary to include documentation both before and after the changes were performed. All documents concerning the changes should be preferably saved in a central electronic system accessible for all relevant personnel. This information will provide a better understanding of the system and possible threats to its integrity.

Communication of the changes carried out in the pipeline system to any affected parties is imperative to the safety of the system. Any changes to the system should be included in the information provided in communication from the pipeline system operator to affected parties.

In the event of changes, refresher training should be provided to ensure that personnel understand and adhere to the current operating procedures.

The application of new technologies in the integrity management program and the results of such applications should be documented and communicated to appropriate personnel and stakeholders.

15.1 Temporary changes

Temporary changes shall follow the same procedure as permanent changes. They have a limited validity and at the end of the period, the pipeline shall revert to its original state or a permanent change shall be implemented.

15.2 Emergency changes

An emergency change shall be initiated on an emergency basis if a temporary or permanent change cannot be implemented promptly. The situations that justify an emergency change are:

- to correct a deficiency that could cause a hazardous condition that is an immediate threat to the safety and health of the site personnel or the public;
- to prevent an immediate environmental release; and
- in case of product supply failure.

An emergency change may initially bypass the use of the full MOC process but still requires an assessment of the change.

16 Quality control plan

A quality control plan shall be established to identify the required measures and documentation that will ensure the pipeline system operator meets all the requirements comprising their integrity management program. To develop a quality control program as part of an integrity management plan, see ASME B31.8S for more information [6].

17 Additional applicable relevant publications

The following are additional resources on pipeline integrity management:

- Title 49 of the U.S. *Code of Federal Regulations* (49 CFR) Part 192 Subpart O (Gas Transmission Pipeline Integrity Management) [16];
- EN 16348, *Gas infrastructure - Safety Management System (SMS) for gas transmission infrastructure and Pipeline Integrity Management System (PIMS) for gas transmission pipelines - Functional requirements* [17]; and
- PHMSA *Gas Integrity Inspection Manual* (inspection protocols, guideline) [18].

18 References

Unless otherwise stated, the latest edition shall apply.

[1] AIGA 033, *Hydrogen Pipeline Systems*, Asia Industrial Gases Association. www.asiaiga.org

NOTE—This publication is part of an international program for industry standards. The technical content of each regional document is identical, except for regional regulatory requirements. See the referenced document preface for a list of harmonized regional references.

[2] AIGA 034, *Carbon Monoxide and Syngas Pipeline Systems*, Asia Industrial Gases Association. www.asiaiga.org

NOTE—This publication is part of an international program for industry standards. The technical content of each regional document is identical, except for regional regulatory requirements. See the referenced document preface for a list of harmonized regional references.

[3] AIGA 021, *Oxygen Pipeline and Piping Systems*, Asia Industrial Gases Association. www.asiaiga.org

NOTE—This publication is part of an international program for industry standards. The technical content of each regional document is identical, except for regional regulatory requirements. See the referenced document preface for a list of harmonized regional references.

[4] NACE SP0502, *Pipeline External Corrosion Direct Assessment Methodology*, NACE International. www.nace.org

[5] NACE SP0102, *In-Line Inspection of Pipelines*, NACE International. www.nace.org

[6] ASME B31.8S, *Managing System Integrity of Gas Pipelines*, The American Society of Mechanical Engineers. www.asme.org

[7] CGA G-4, *Oxygen*, Compressed Gas Association, Inc. www.cganet.com

[8] CGA P-9, *The Inert Gases: Argon, Nitrogen, and Helium*, Compressed Gas Association, Inc. www.cganet.com

[9] *Handbook of Compressed Gases*, Compressed Gas Association, Inc. www.cganet.com

[10] ISO 31000, *Risk Management - Guidelines*, American National Standards Institute. www.ansi.org

[11] ASME B31G, *Manual for Determining the Remaining Strength of Corroded Pipelines*, The American Society of Mechanical Engineers. www.asme.org

[12] API 579-1/ASME FFS-1, *Fitness-for-Service*, The American Society of Mechanical Engineers. www.asme.org

[13] BS 7910, *Guide to methods for assessing the acceptability of flaws in metallic structures*, British Standards Institute. www.shop.bsigroup.com

[14] NACE SP0113, *Pipeline Integrity Method Selection*, NACE International. www.nace.org

[15] NACE 35100, *In-Line Inspection of Pipelines*, NACE International. www.nace.org

[16] *Code of Federal Regulations*, Title 49 Subpart O (Gas Transmission Pipeline Integrity Management), U.S. Government Printing Office. www.gpo.gov

[17] EN 16348, *Gas infrastructure. Safety Management System (SMS) for gas transmission infrastructure and Pipeline Integrity Management System (PIMS) for gas transmission pipelines. Functional requirements*, British Standards Institute. www.shop.bsigroup.com

[18] PHMSA *Gas Integrity Inspection Manual*. https://www.phmsa.dot.gov/pipeline/gas-transmission-integrity-management/gas-transmission-integrity-management-gt-im-overview

[19] INGAA Final Report No. 05-12R, *Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*, Interstate Natural Gas Association of America. www.ingaa.org

Appendix A—Integrity assessment methods and additional measures (Normative)

<table>
<tr><th>Identified threat</th><th>Baseline assessment</th><th>Reassessment</th><th>Additional measures</th></tr>
<tr><td>External corrosion</td><td colspan="2">External corrosion direct assessment, pressure test, or in-line inspection.</td><td>Threat reduced by P&M measures.</td></tr>
<tr><td>Internal corrosion</td><td colspan="3" rowspan="2">Not considered to be a threat to pipelines. See 7.1.2.</td></tr>
<tr><td>Stress corrosion cracking</td></tr>
<tr><td>Manufacturing defects</td><td colspan="2" rowspan="2">Considered stable because of pressure testing executed during the commissioning of pipelines per INGAA Final Report No. 05-12R, Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines [19].</td><td rowspan="2">Threat reduced by P&M measures.</td></tr>
<tr><td>Construction defects</td></tr>
<tr><td>Equipment failure</td><td colspan="2" rowspan="4">Considered through execution of pipeline operations and maintenance.</td><td rowspan="4">Threat reduced by P&M measures.</td></tr>
<tr><td>Third-party damage</td></tr>
<tr><td>Incorrect operations</td></tr>
<tr><td>Weather—Outside forces</td></tr>
</table>