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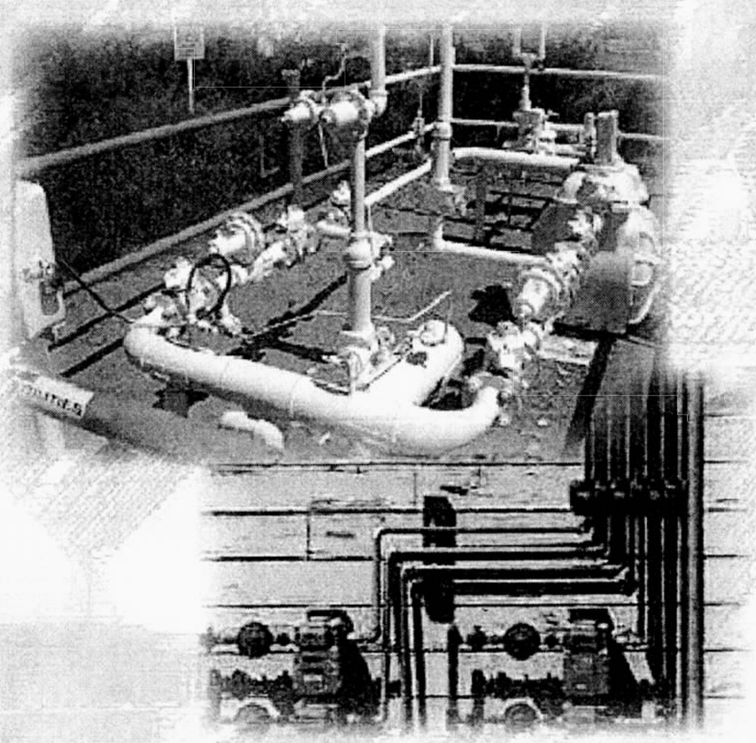
NOPE Ex. 14

Integrity Management for Gas Distribution



Report of Phase 1 Investigations

December 2005

Prepared by joint work/study groups including representatives of:

Stakeholder Public
Gas Distribution Pipeline Industry
State Pipeline Safety Representatives
Pipeline and Hazardous Materials Safety Administration

Integrity Management for Gas Distribution Pipelines

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Acronym List

AGF – American Gas Foundation
ASME – American Society of Mechanical Engineers
ASTM – American Society of Testing and Materials
BAA – Broad Agency Announcement
DIMP – Distribution Integrity Management Program
DOT – Department of Transportation
EFV – Excess Flow Valve
GPTC – Gas Piping Technology Committee
IAFC – International Association of Fire Chiefs
IG – Inspector General
IM – Integrity Management
IMP – Integrity Management Program
LDC – Local Distribution Company
LEAKS – Leak Management Program Consisting of: Locate, Evaluate, Act, Keep Records, and Self-Assess
NAPSR – National Association of Pipeline Safety Representatives
NARUC – National Association of Regulatory Utility Commissioners
PHMSA – Pipeline and Hazardous Materials Safety Administration
PIM – Pipeline Integrity Management (transmission)
PSIA – Pipeline Safety Improvement Act of 2002
R&D – Research and Development
SMYS – Specified Minimum Yield Strength

Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has implemented integrity management requirements for hazardous liquid and gas transmission pipelines. No similar requirements presently exist for gas distribution pipelines, but observers have suggested that they are needed. Four multi-stakeholder work/study groups were established to collect and analyze available information and to reach findings and conclusions to inform future work by the PHMSA relative to implementing integrity management principles for gas distribution pipelines. The groups have concluded that current pipeline safety regulations (49 CFR Part 192) do not now convey the concept of a risk-based distribution integrity management process and that it would be appropriate to modify the regulations to do so.

The groups found that the most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for One-Call programs, and continuing research and development.

Differences between gas distribution pipeline operators, and the pipeline systems they operate, make it impractical simply to apply the integrity management requirements for transmission pipelines to distribution. The significant diversity among gas distribution pipeline operators also makes it impractical to establish prescriptive requirements that would be appropriate for all circumstances. Instead, the groups concluded that it would be appropriate to require that all distribution pipeline operators, regardless of size, implement an integrity management program including seven key elements, namely that each operator:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report a limited set of performance measures to its regulator.

Since entire distribution systems would be covered by the distribution integrity management plan, there is no need to identify high consequence areas or identified sites as part of the plan as was required for transmission pipelines.

The Executive Steering Group considers that it should be possible to develop and promulgate a regulation within about two years so that distribution operators can develop integrity management plans during 2008 and begin implementing those plans in about 2009. Guidance will be needed to assist operators in implementing the high-level regulatory provisions in their particular circumstances. Detailed guidance will be needed

for the smallest operators, who have limited resources for developing customized programs.

The groups concluded that excavation damage poses the most significant single threat to distribution system integrity. Reducing this threat requires affecting the behavior of persons not subject to the jurisdiction of pipeline safety authorities (e.g., excavators working for other than pipeline facility owners/operators). Some states have implemented effective comprehensive damage prevention programs that have resulted in significant reductions in the frequency of damage from excavation. Effective programs include nine elements:

1. Enhanced communication between operators and excavators
2. Fostering support and partnership of all stakeholders in all phases (enforcement, system improvement, etc.) of the program
3. Operator's use of performance measures for persons performing locating of pipelines and pipeline construction
4. Partnership in employee training
5. Partnership in public education
6. Enforcement agencies' role as partner and facilitator to help resolve issues
7. Fair and consistent enforcement of the law
8. Use of technology to improve all parts of the process
9. Analysis of data to continually evaluate/improve program effectiveness

Not all states have implemented such programs. Federal legislation is likely needed to support the development and implementation of such programs by all states. Work on this legislation can begin immediately. This represents the greatest single opportunity for distribution pipeline safety improvements.

The groups concluded that excess flow valves (EFVs) can be a valuable incident mitigation option, but that a federal mandate for their installation would be inappropriate. (All groups agreed with this conclusion, although some individual members favored a mandate). Analysis of operational experience demonstrated that when properly specified and installed, the valves function as designed; they successfully terminate gas flow under accident conditions and only rarely malfunction to prevent flow when an accident has not occurred. A regulatory provision that would require that operators consider certain risk factors in deciding when to install EFVs would be appropriate. Guidance would be useful concerning the conditions under which EFVs are not feasible (e.g., low pressures, gas constituents inconsistent with valve operation) and concerning risk factors indicating when their installation might be appropriate.

The groups also concluded that management of gas leaks is fundamental to successful management of distribution risk, and an effective leak management program is thus a vital risk control practice. Effective programs include the following elements:

1. ***L*ocate** the leak,
2. ***E*valuate** its severity,

3. ***A*ct** appropriately to mitigate the leak,
4. ***K*eep** records, and
5. ***S*elf-assess** to determine if additional actions are necessary to keep the system safe.

This effort concluded, as did the American Gas Foundation before it[1], that distribution pipelines are safe. Incidents continue to occur, but their frequency has been reduced. There is room for improvement. Implementing integrity management, consistent with the findings and conclusions of the work/study groups, should help achieve additional improvement.

1. Structure of This Report

This report covers the work of four work/study groups, as described in the next section. The main body of the report (Sections 2 through 5) describes the context in which this work was performed and the key overall findings and conclusions. The appendices present:

- A: a list of participants,
- B: the complete list of findings and conclusions from all four work/study groups,
- C: the complete list of path forward actions suggested by the four groups, and
- D: independent comments on excess flow valves from the International Association of Fire Chiefs and related organizations.

The separate reports of each of the four work/study groups are included as attachments to this report.

2. Introduction

Background

The Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) published new rules requiring "integrity management" programs for hazardous liquid pipelines in 2000[2] and 2002[3] and for natural gas transmission pipelines in 2003.[4] Under these rules, operators of hazardous liquid and gas transmission pipelines were required to identify the threats to their pipelines, analyze the risk posed by these threats, collect information about the physical condition of their pipelines, and take actions to address applicable threats and integrity concerns before pipeline accidents could occur.

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[1] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January, 2005.
[2] 65 FR 75378, December 1, 2000.
[3] 67 FR 2136, January 16, 2002.
[4] 68 FR 69778, December 15, 2003.

The initial implementation of these integrity management regulations has resulted in the identification and repair of many conditions that could potentially have resulted in pipeline accidents had they not been addressed. The early results of these programs led PHMSA to consider whether a similar regulatory approach would be appropriate for gas distribution pipelines.

Distribution pipelines are different from other pipelines. Hazardous liquid and gas transmission pipelines traverse long distances (including many rural areas), are generally of large diameter (up to 48 inches), are comprised primarily of steel pipe, typically operate at relatively high stress levels, and have few branch connections. Failures of hazardous liquid pipelines can result in significant environmental contamination. Failures of gas transmission pipelines usually occur as a catastrophic rupture of the pipeline, caused by the high pressure of the contained gas.

Distribution pipeline systems exist in restricted geographical areas that are predominantly urban/suburban, because the purpose of these pipelines is to deliver natural gas to end users – residential, commercial, industrial, institutional, and electric generation customers. Distribution pipelines are generally small in diameter (as small as 5/8 inch), and are constructed of several kinds of materials including a significant percentage of plastic pipe. Distribution pipelines also have frequent branch connections, since service lines, providing gas to individual customers, branch off of a common "main" pipeline, typically installed under the street. The dominant cause of distribution incidents is excavation damage with third party damage being the major contributor to these incidents. Other than as caused by excavation damage, distribution pipeline failures almost always involve leaks, rather than ruptures, because the internal gas pressure is much lower than for transmission pipelines. These differences mean that many of the tools and techniques used in integrity management programs for other types of pipelines are not appropriate or cannot be used for distribution pipelines.

American Gas Foundation Study

In considering whether and how integrity management principles could be applied to distribution pipelines, the first question that was addressed was whether performance supported the need for additional regulations. The American Gas Foundation (AGF) undertook a study[5] in 2003-2004 to characterize the state of distribution pipeline safety. This study analyzed the safety performance of gas distribution pipeline systems from 1990 to 2002 as represented by the number of incidents reported to PHMSA by operators during that period.[6]

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[5] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January, 2005.

[6] 49 CFR 191.3 defines an incident as an event that involves a release of gas from a pipeline and (1) a death or (2) a personal injury necessitating in-patient hospitalization or (3) that results in estimated property damage of $50,000 or more. 49 CFR 191.9 requires operators of distribution pipelines to submit written reports of all incidents meeting these criteria.

The AGF study compared the number of incidents reported for gas transmission pipelines to those reported for distribution pipelines. Direct comparison of reported incident totals can be misleading, however, since there are many more miles of distribution pipelines than there are transmission pipelines (approximately 1.9 million miles of distribution pipeline compared to approximately 300,000 miles of transmission pipeline[7]). The AGF study allowed for comparison by "normalizing" the incident statistics for both types of pipelines by considering the number of incidents reported per 100,000 miles of in-service pipeline.

The AGF study found that the total number of incidents reported per 100,000 miles was generally less for distribution pipelines than that reported for gas transmission pipelines over the same period. There was no statistically-significant trend (i.e., neither increase nor decrease) in the number of incidents per year for either type of pipeline.

The AGF study also found that the number of incidents that resulted in death or injury (called "serious incidents" within the study) was approximately the same for both transmission and distribution pipelines over the study period. The study found a statistically significant downward trend in the number of serious incidents for both types of pipelines.

The AGF study thus demonstrated that the safety performance of distribution pipelines is good, comparable to that of gas transmission pipelines. The study did not show, however, that the level of safety of distribution pipelines was so great as to preclude the need for a new regulatory approach.

Origins of the Current Study

In 2004, the Department of Transportation (DOT) Inspector General (IG) suggested that application of integrity management (IM) principles could help improve the safety of distribution pipelines. In testimony before Congress in July 2004[8], the IG noted that recently-issued rules had required that operators of hazardous liquid and gas transmission pipelines implement integrity management plans (IMP), but that no such requirement had been imposed on operators of distribution pipelines. The IG acknowledged that a reason why distribution pipeline operators had been excluded from the requirements applicable to operators of gas transmission pipelines was that smart pigs could not be used to inspect distribution pipeline systems. (Such inspections were a principal element of the IM requirements for transmission pipelines). The IG concluded, however, that there was no reason that other elements of IM could not be implemented for distribution pipelines.

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[7] 2003 values reported on the Office of Pipeline Safety web site, http://ops.dot.gov/stats/GTANNUAL2.HTM.
[8] "Progress and Challenges in Improving Pipeline Safety," Statement of the Honorable Kenneth M. Mead, Inspector General, Department of Transportation, before the Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, U. S. House of Representatives, July 20, 2004.

The IG's testimony recommended that DOT should define an approach for requiring operators of distribution pipeline systems to implement some form of integrity management or enhanced safety program with elements similar to those required in hazardous liquid and gas transmission pipeline integrity management programs. The Appropriations Committee asked PHMSA "to report to the House and Senate Committees on Appropriations by May 1, 2005, detailing the extent to which integrity management plan [IMP] elements may be applied to the natural gas distribution pipeline industry in order to enhance distribution system safety."[9]

PHMSA conducted a public meeting on December 16, 2004, in Washington, DC, to solicit comments from all stakeholders on ways in which distribution pipeline integrity might be improved through application of IM principles. Comments made during this meeting emphasized the differences between distribution pipeline systems and those for gas transmission. These differences make it impractical to apply the gas transmission IM requirements to distribution pipelines directly. Comments at the meeting also noted that there is significant diversity among operators of distribution pipeline systems and among the systems they operate, meaning that any new requirements addressing distribution pipeline operators needed to incorporate a high degree of flexibility.

Following the public meeting, PHMSA embarked on a multi-phased effort intended to develop an approach that will address the three elements of the strategy described by the DOT Inspector General:

- understand the infrastructure,
- identify and characterize the threats, and
- determine how best to manage the known risks (prevention, detection and mitigation).

This effort was described in PHMSA's report to Congress, submitted in response to the direction in the Appropriations Committee's report.[10] Phase 1 was described as working with a number of groups comprised of state pipeline safety regulators, pipeline operators, and representatives of the public to seek out additional information about the issues affecting distribution system integrity. This report documents the results of the Phase 1 investigations.

Phase 1 Program Structure

Most distribution pipelines in the United States are regulated by state pipeline safety agencies. It was important to involve state pipeline safety regulators and operators of distribution pipelines in the Phase 1 program, in order to tap their expertise and help assure that conclusions were practical. The Phase 1 effort was designed to involve representatives of state pipeline safety agencies, representatives of distribution pipeline

[9] House of Representatives Report 108-792, November 20, 2004.
[10] Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, "Assuring the Integrity of Gas Distribution Pipeline Systems: A Report to the Congress," May 2005.

owners (both investor-owned and municipal agencies), and members of the interested public. Representatives of PHMSA also participated.

Management oversight was provided by an Executive Steering Group, consisting of state regulatory commissioners, industry executive managers, and members of the public. Day-to-day coordination was by a Coordinating Group that included managers from state agencies and the industry trade associations (American Gas Association and American Public Gas Association). The principal investigations were conducted by four work/study groups:

- Strategic Options Group – evaluating strategic approaches to implementing integrity management elements for distribution pipelines
- Risk Control Practices Group – evaluating existing risk control practices, required and/or implemented voluntarily by operators, and the adequacy of existing regulations and guidance
- Excavation Damage Prevention Group – evaluating means to reduce the frequency of damage from excavation near pipelines, which is the predominant cause of distribution pipeline incidents
- Data Group – evaluating existing data on incidents and leaks to identify factors important in preventing distribution incidents and correlating information from surveys of the efficacy of excess flow valves as a risk mitigation tool

The groups conducted their investigations in parallel, to allow this program to be completed promptly (work began in March 2005). Information was exchanged among the groups as needed. Each group prepared a report documenting its work, and these reports are included as attachments to this report. The responsibilities of each work/study group are described in more detail in the May, 2005, PHMSA Report to Congress and in the Action Plan that was included in that report.

The findings and conclusions of each work/study group are presented in their individual reports (which are attached to this report). Inconsistencies or conflicts between the findings of individual groups were addressed by the Coordinating Group. The resulting key findings of the overall program are described in the sections of this report that follow. In the event conflicting statements exist between the work/study group reports and the main body, the information in the main body prevails. The work/study groups also identified, and documented in their reports, a number of actions that would be appropriate for future work as PHMSA and industry prepare to implement an integrity management approach for distribution pipelines. The key elements of this path forward are also described in this summary report.

The members of the groups involved in Phase 1 provide this report to support actions by PHMSA and industry as they proceed with subsequent phases. This summary report has been prepared to make the findings and conclusions readily available for all stakeholders who will be involved in implementing integrity management principles for distribution pipelines.

Review by PHMSA Advisory Committees

The status of this work was reviewed with the Technical Pipeline Safety Standards Committee and the Technical Hazardous Liquid Pipeline Safety Standards Committee, meeting in joint session, on December 13, 2005. The hazardous liquid pipeline committee was included in this review, because the findings regarding federal legislation to advance damage prevention programs will affect all types of pipelines.

The committees supported the general concepts reflected by the product of this effort, recognizing that PHMSA would proceed with rulemaking based on these concepts. Members expressed concern about the imposition of a complex federal requirement on small pipeline operators, including master meter operators, and agreed that additional clear guidance will be needed to facilitate their compliance.

3. Key Findings

Each work/study group reached a number of findings and conclusions about the areas covered by their investigations. A complete list of the group findings is presented in Appendix B to this report. Additional discussion, including further explanation by the groups regarding their findings and conclusions, can be found in the individual group reports, which stand alone but are attached to this report for the reader's convenience.

Each work/study group was asked to identify its "key" findings for purposes of this summary report. These key findings address a number of issues that will be important as further work is undertaken to enhance the integrity management approach for distribution pipelines. These issues are discussed here, along with the key findings that relate to each. This presentation is intended to allow the reader to gain an overview of the important issues. It must be emphasized that, although the work/study groups have identified these as their most important findings, all group findings have importance. Future work should consider all group findings and conclusions.

National Focus of Integrity Management Efforts (Threats)

The integrity management process begins with consideration of what is important to assure pipeline safety, that is, what are the threats to integrity? Understanding the threats is the first step in identifying the appropriate actions to assure integrity. The PHMSA collects data on threats affecting pipelines through incident reports. Operators must characterize each incident they report as being in one of eight categories. The categories are:

Corrosion	Material or Welds
Natural Forces	Equipment
Excavation	Operations
Other Outside Force Damage	Other

These threat categories are appropriate as a foundation for integrity management programs. They represent broad categories. Each can be further subdivided into specific threats. For example, corrosion can be internal or external corrosion. It can be general corrosion or localized pitting. Where appropriate, operators will need to evaluate their threats at this finer level of detail to identify and implement appropriate responsive actions. However, the general categories, matching the current data collection requirements, are appropriate categories for integrity threats on a national basis.

The Data Group evaluated available historical data to identify trends. For distribution pipelines, excavation damage is the predominant cause of reported incidents. Corrosion is the major cause of leaks, but a small fraction of incidents result from corrosion. The Data Group reached a key finding concerning this review of available data:

> *While a decreasing trend in the rate of reportable distribution incidents resulting in fatalities and injuries, including incidents caused by outside force damage, exists for the preceding 13-years, no statistically significant trend was identified for total reportable distribution incidents for that same period.*

While this conclusion is encouraging, it supports the need to explore new requirements for integrity management that will help reduce the occurrence rate of all incidents.

Regulatory Needs

The major question, then, is what kind of requirements would be most appropriate to implement an integrity management approach for distribution pipelines? This question was considered by the Risk Control Practices Group and the Strategic Options Group.

It is important to recognize the wide diversity that exists among distribution pipeline operators. Some operators are very large, serving more than one million customers. Some operators are very small, such as master meter operators serving only a few customers. Many operators serve from 100 and 10,000 customers, and a sizable majority of these operators are municipal agencies.

The pipeline systems that these operators manage are very diverse. Larger systems, in areas where gas service has been available for many years, can include thousands of miles of pipeline of various materials and ages. Systems in areas where gas service has only been available in recent years can be more uniform, consisting of one or a few types of pipe with similar fittings and connections installed using uniform procedures. The smallest systems, such as many master meter systems, may include a limited amount of pipeline, of one material, and all installed at the same time. The issues important to assuring the integrity of these diverse systems will vary.

This diversity makes it difficult for any one prescriptive requirement to address all possible circumstances. It is important that any new requirements that are developed allow sufficient flexibility for the operators of distribution pipeline systems, and the state regulators who oversee their operations, to customize their integrity management efforts to address their specific systems, threats, and issues.

The Risk Control Practices Group examined existing federal regulations and the effect they are having, to determine if there were any gaps that would need to be filled by any new integrity management regulations. The group reached a key finding in this area:

> *Current design, construction, installation, initial testing, corrosion control, and operation and maintenance regulations should be effective in providing for integrity of the distribution facilities that are being installed today.*

This conclusion assures us that current requirements are adequate to "build in" necessary safety for new distribution pipeline systems. New integrity management requirements, then, can focus on improving safety for existing systems and assuring that the built-in level of safety is maintained for new pipelines.

The Strategic Options Group considered the form in which new requirements implementing integrity management would be most useful. The group reached two key findings in this area:

> *The most useful option for implementing distribution integrity management requirements is a high-level, flexible federal regulation that excludes no operators, in conjunction with implementation guidance, a nation-wide education program expected to be conducted as part of implementing 3-digit dialing for one-call programs, and continuing research and development.*
>
> *A small number of elements are all that is needed to describe the basic structure of a high-level, flexible federal regulation addressing distribution integrity management. These elements are:*
>
> - *Development of an integrity management plan*
> - *Know your infrastructure*
> - *Identify threats (existing and potential)*
> - *Assess and prioritize risk*
> - *Identify and implement measures to mitigate risks*
> - *Measure performance, monitor results, and evaluate effectiveness*
> - *Report results*

Finally, the Risk Control Practices Group reached a key finding regarding the necessary scope of any new integrity management requirements.

> *Since the entire distribution system will be covered by the proposed distribution integrity management program (DIMP) plan, there is no need to identify high consequence areas or identified sites as part of the DIMP plan.*

This means that integrity management requirements for distribution pipelines can be both simpler and more broadly applied than the requirements applicable to other pipelines.

For hazardous liquid and gas transmission pipelines, it was necessary to identify high consequence areas – those locations in which a pipeline accident could have the greatest effect. The focus of integrity management requirements for those pipelines was then on the identified areas. For distribution pipelines, high consequence areas need not be defined, and integrity management requirements will affect the entire pipeline system.

Guidance

Historically, guidance developed by a consensus process has been used by operators to assist them in implementing most regulatory requirements. The Gas Piping Technology Committee (GPTC) has developed and maintains a guideline addressing federal requirements applicable to distribution pipeline systems. The American Society of Mechanical Engineers (ASME) and the American Society of Testing and Materials (ASTM) have also developed consensus standards addressing specific technical issues within their areas of expertise that are important in implementing safety requirements. In addition, DOT, through the Transportation Safety Institute (TSI), maintains a small operator's handbook that provides guidance for operators to help assure compliance with the regulations even for operators who lack the resources to develop compliance plans of their own.

High-level, flexible requirements for integrity management will mean that operators will face many choices in deciding what actions to take. Such choices can be facilitated by providing additional guidance that will assist the operators and help to assure that integrity management activities are appropriate for particular circumstances.

The Risk Control Practices Group reached two key findings in this area:

> *The PHMSA plan for a "high level, risk-based, performance-oriented Federal regulation"[11] that requires a specific distribution IMP is supported by the fact that (a) the elements necessary to implement a distribution IMP have been identified; (b) the threats have been identified; and (c) methods exist for operators to develop the elements. Operators may need additional guidance materials.*
>
> *The Gas Piping Technology Committee should develop guidance to assist operators in determining (a) which threat prioritization methods, (b) which risk control practices, and (c) which performance measures are most appropriate for their risk control program.*

These findings provide assurance that the foundation for distribution integrity management requirements is firm, and suggest areas in which additional guidance would be useful. Special attention will likely need to be given to the needs of the smallest operators, who lack the resources to develop integrity management plans on their own.

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[11] "Assuring the Integrity of Gas Distribution Pipeline Systems," Report to the Congress, May 2005, Submitted by Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, p. 3.

Preventing Excavation Damage

Excavation damage is the single most significant cause of incidents on distribution pipeline systems. Many, perhaps most, incidents that result from excavation damage occur immediately, at the time the damage is inflicted. Thus, reducing incidents caused by this threat requires that the threat itself be reduced, i.e., that damage be prevented in the first place.

The significance of this threat led to the establishment of a work/study group dedicated specifically to considering ways in which excavation damage could be reduced. Reducing the frequency of excavation damage requires changes in behavior by persons who are not regulated by pipeline safety authorities, that is, contractors and others who perform excavation. Practical actions that operators can implement can have only limited effectiveness in reducing the frequency of damage events. It would be impractical to require that distribution pipeline operators monitor and restrict the activities of those conducting excavations near their pipelines. Instead, action is needed on a broader basis than simply additional regulation imposed on pipeline operators.

The Excavation Damage Prevention Group reached four key findings in this area:

> *Excavation damage poses by far the single greatest threat to distribution system safety, reliability and integrity; therefore excavation damage prevention presents the most significant opportunity for distribution pipeline safety improvements.*
>
> *States with comprehensive damage prevention programs that include effective enforcement have a substantially lower probability of excavation damage to pipeline facilities than states that do not. The lower probability of excavation damage translates to a substantially lower risk of serious incidents and consequences resulting from excavation damage to pipelines.*
>
> *A comprehensive damage prevention program requires nine important elements be present and functional for the program to be effective. All stakeholders must participate in the excavation damage prevention process. The elements are:*
>
> 1. *Enhanced communication between operators and excavators*
> 2. *Fostering support and partnership of all stakeholders in all phases (enforcement, system improvement, etc.) of the program*
> 3. *Operator's use of performance measures for persons performing locating of pipelines and pipeline construction*
> 4. *Partnership in employee training*
> 5. *Partnership in public education*
> 6. *Enforcement agencies' role as partner and facilitator to help resolve issues*
> 7. *Fair and consistent enforcement of the law*
> 8. *Use of technology to improve all parts of the process*
> 9. *Analysis of data to continually evaluate/improve program effectiveness*

> *Federal Legislation is needed to support the development and implementation of damage prevention programs that include effective enforcement as a part of the state's pipeline safety program. This is consistent with the objectives of the state pipeline safety programs, which are to ensure the safety of the public by addressing threats to the distribution infrastructure. The legislation will not be effective unless it includes provisions for ongoing funding such as federal grants to support these efforts. This funding is intended to be in addition to, and independent of, existing federal funding of state pipeline safety programs*[12].

Addressing these findings will help establish a situation in which those responsible for excavation damage to pipelines will be required and motivated to modify behavior in a way that will reduce the frequency of such damage. As noted in the first key finding above, this represents the greatest single opportunity for distribution pipeline safety improvements.

Excess Flow Valves

Excess Flow Valves (EFV) are devices that can be installed in each service line and that may shut off gas flow if the line is severed downstream of the valve. These valves represent a measure that may mitigate the consequences of some incidents if they occur despite the preventive actions that may be taken to reduce the likelihood. PHMSA reported, in its May 2005 report to Congress, that EFVs would be considered as part of this program.[13] The basis for this was reported to be that their use would be similar to additional preventive and mitigative measures that operators of hazardous liquid and gas transmission pipelines are required to consider as part of the integrity management regulations applicable to those pipelines, such as emergency flow restricting devices for hazardous liquid pipelines or automatic/remote control valves for gas transmission.

All work/study groups considered the question of how EFVs could best be treated within distribution integrity management requirements. The Data Group considered surveys conducted by the National Regulatory Research Institute (NRRI) for the National Association of Regulatory Utility Commissioners (NARUC) and by PHMSA, studies performed by PHMSA concurrently with this program, and data that it collected from operators who have installed EFVs for many years to evaluate the extent of use and efficacy of the valves. The Excavation Damage Prevention Group considered the usefulness of EFVs in mitigating incidents caused by excavation damage. The Strategic Options Group and the Risk Control Practices Group considered means by which requirements addressing use of EFVs could be incorporated into any new distribution integrity management requirements.

In addition, PHMSA conducted a public meeting on EFVs on June 17, 2005. Members of work/study groups participated in that meeting, and the comments made at that meeting were considered in the work/study group deliberations.

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[12] Conforming changes to 49 CFR Part 198 also will be needed if this legislation is enacted.
[13] Ibid, p. 25

From its review of relevant data, the Data Group reached a key finding:

> *The preponderance of information supports the conclusion that, when properly specified and installed, EFVs function as designed*

This finding addresses concerns that have been raised that EFVs either would not function as intended to shut off the flow of gas in the event of the rupture of a service line or that they would actuate when not required, thus necessitating action by pipeline operators to restore gas service to customers with intact service lines. The available data now supports the reliability of EFVs.

The Strategic Options Group reached a key finding on how a requirement addressing the use of EFVs could be included in distribution integrity management requirements.

> *As part of its distribution integrity management plan, an operator should consider the mitigative value of excess flow valves (EFV)s. EFVs meeting performance criteria in 49 CFR 192.381 and installed per 192.383 may reduce the need for other mitigation options. It is not appropriate to mandate excess flow valves (EFV) as part of a high-level, flexible regulatory requirement. An EFV is one of many potential mitigation options. (One member, representing the public, did not subscribe to the group conclusion on this issue).*

The Strategic Options Group report (attached) provides additional discussion of how such a requirement might be formulated.

The International Association of Fire Chiefs (IAFC), on behalf of itself and other organizations representing fire fighters, submitted comments to PHMSA espousing a different conclusion. IAFC participated in the June 2005 public meeting on EFVs and was thereafter invited to participate in activities of the Risk Control Practices and Excavation Damage Prevention Groups to assure that its strong views on EFVs would be represented in this program. IAFC did not participate. Nevertheless, they were provided a draft copy of the Risk Control Practices Group report for review. Their written comments to PHMSA, provided following their review of that draft report, are included as Appendix D to this report.

Data Reporting

Our understanding of the state of distribution pipeline safety and the actions that could be taken to improve it are founded in the data concerning current and historical performance. This effort included significant review of available data. That review highlighted areas in which improvements in the data could improve understanding.

PHMSA changed the form used by operators to report incidents in early 2004. This action, among other changes, increased the number of threat categories to which incidents must be characterized to the eight noted above. This change particularly expanded the former category of "damage by outside forces" to separate out excavation damage, natural forces, and other outside force damage. This refinement makes the recent incident report data more useful in understanding the significance of the threats facing distribution pipeline systems.

Data regarding leaks is another performance metric that can be used to evaluate the efficacy of distribution pipeline safety efforts. Operators report leaks on annual reports that they are required to submit.[14] The annual report form requires that operators report "Total Leaks Eliminated/Repaired During Year," separated into whether they occurred on mains or services and broken down by the same eight threat categories used for incident reports. Operators must also report "Number of Known System Leaks at End of Year Scheduled for Repair" with no breakdown as to location or cause.

Reporting is inconsistent among operators, in part because of the focus on leaks eliminated/repaired. Not all leaks require repair. Many leaks are small, such as leaks from threaded fittings, and pose no hazard. Some operators may elect to repair small leaks, for example because of upgrades to a portion of their system. Others monitor such leaks. As a result, data reported by some operators includes only leaks that were repaired because they posed a potential hazard, while data from other operators includes many leaks eliminated for other reasons. Comparisons and analysis using this data must therefore be done with great caution, and it is difficult to reach firm conclusions. The difficulty of using available leak data has previously been identified by AGF.[15]

The Data Group concluded that changes in leak reporting would be appropriate.

> *Several data reporting changes were suggested, including reporting of hazardous leaks removed by material; this could provide data to support a leak-related national performance measure*

Performance Measures

It is important to measure performance in order to determine whether a regulatory change has the desired effect of improving pipeline safety. The suggested elements of a distribution integrity management regulation (see "Regulatory Needs" above) would require that operators measure their performance and use those measures to help determine whether changes to their integrity management programs are needed. At the national level, performance measures would also be useful to allow PHMSA to determine if changes are needed to regulation or oversight.

Operators of gas transmission lines are similarly required to measure their performance and use those measurements to assess the efficacy of their programs. Transmission pipeline operators are also required to submit to PHMSA four overall performance

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[14] 49 CFR 191.17

[15] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005, page 6-1.

measures, to be used on a national level for monitoring the effectiveness of the integrity management regulation.[16]

The Data Group concluded that national reporting of a small set of performance measures would also be appropriate for distribution pipelines.

> *Approach to characterizing the National performance baseline is described in the report (Attached); reference was made to areas in which current information will not support definition of a baseline (e.g., maturity of IM practices)*

The Risk Control Practices Group and Excavation Damage Prevention Group considered what measures operators could use to monitor the effectiveness of their integrity management programs, and the group reports contain findings in this regard. The Strategic Options Group considered the findings and conclusions of the other groups in evaluating which performance measures would be most useful at a national level, and which operators should thus be required to report. The Strategic Options Group found that three categories of performance measures would be most useful:

> *Three categories of reported performance measures for use at the national level were identified*
> - *DOT Reportable incident statistics and normalized incident statistics (per mile or per service)*
> - *Excavation damages normalized by number of tickets*
> - *Refined measure related to leaks - no consensus on specifics*

Incidents are currently reported. The number of incidents, and their consequences, is the key national measure of distribution pipeline safety. For an individual operator, however, the measure is not as useful. There are approximately 125 incidents reported throughout the U.S. by distribution pipeline operators each year. Most pipeline operators report none. It would be extremely rare for an individual operator to experience two reportable incidents in a year. Still, the direct importance of the number of incidents as a measure of the national state of distribution pipeline safety makes it appropriate for reported incidents to be treated as an integrity management performance measure. No new reporting requirements would be needed to capture the number of incidents that occur. Reports currently submitted to PHMSA provide this information and can be used for integrity management purposes. As discussed below, however, this effort has found that some changes to the specific information included with each incident report would be useful.

As noted in its finding, the Strategic Options Group concluded that a measure related to leaks was needed, but that it should reflect different information from what is now reported on OPS annual reports. The group could not reach consensus on the specific changes to leak reporting which would be appropriate. The Data Group also considered

[16] 49 CFR 192.945(a).

the need for changes to leak reporting requirements. The Data Group concluded that annual reporting should be revised to limit reporting of leaks to those leaks eliminated that required immediate action (also called "hazardous" leaks) and that operators should also report the material of the pipe from which these leaks were eliminated.

A majority of the members of the Coordinating Group concluded that these changes would make leak information from the annual reports a useful integrity management performance measure. The representative of the American Gas Association did not agree with this conclusion as it relates to reporting pipe material. AGA supports the suggestion to nationally report leaks eliminated that require immediate action by cause in that this data provides the clearest and most meaningful national statistic. AGA concludes that it would be essential for operators to maintain pipe material data along with other diagnostic information on leaks in order to perform effective risk assessment and for the review and oversight of local regulators. However, AGA considers that it is not informative and, in fact, is potentially misleading to report leaks by pipe material at a national level, since a false correlation independent of the other causation factors could be derived.

In its discussion of this issue, the Executive Steering Group agreed that the underlying issue is the need for a proactive process to identify construction materials concerns that may affect distribution pipeline integrity. The Executive Steering Group concluded that this issue should be addressed outside the context of this Phase 1 effort.

Excavation damages, as defined in the Excavation Damage Prevention Group report, and the number of locate tickets received would be new reporting requirements. Such measures are important in light of the fact that excavation damage is the most significant cause of distribution pipeline incidents and that preventing damage is the most effective means of reducing such incidents. To minimize the added burden to operators to report this data, it would be most appropriate for it, too, to be incorporated into the PHMSA annual report.

4. Path Forward

This first phase of evaluating the application of integrity management principles to distribution pipelines involved fact gathering and analysis. Much work remains to be completed before regulations and supporting guidance, leading to effective implementation of integrity management, are in place. During the course of their investigations, the work/study groups reached conclusions regarding activities that will be needed in future phases. These conclusions are reported in the work/study group reports for the benefit of those who will be involved in future work, but are not separated out as distinct sections.

Based on findings from this report, PHMSA will decide on future activities. The Coordinating Group would expect that PHMSA will collaborate with the National Association of Pipeline Safety Representatives (NAPSR), the group representing the managers of state pipeline safety agencies, since most distribution pipelines are under state regulatory jurisdiction. No action plan now exists for future work. PHMSA, with NAPSR, will need to develop one. The participants involved in Phase 1 hope that the work/study group conclusions regarding needed future actions will assist PHMSA and NAPSR in developing that action plan.

As with findings in the previous section, the Coordinating Group concluded that it would be worthwhile to highlight in this summary report the key conclusions of the work/study groups regarding future actions to be accomplished. The work/study groups were again asked to identify the most important of the actions discussed in their reports. These are presented in the following sections, again organized around the major issues of concern. This summary of actions is intended to allow readers of this summary report to gain an overall view of the most important future actions. The complete lists of actions identified by the work/study groups for the path forward are presented in Appendix C.

Regulatory Needs

There is presently no requirement that operators of distribution pipelines implement integrity management principles. Participants in this phase 1 effort have assumed that new requirements would be developed in future phases, and have explicitly identified that need.

> *Develop a high-level, flexible rule requiring integrity management for distribution operators*

This action is consistent with the key finding of the Strategic Options Group that a high-level, flexible federal regulation, excluding no operators and supported by implementation guidance, is an essential element of implementing integrity management principles. Developing federal regulations for pipeline safety is uniquely a PHMSA responsibility. Existing law requires that states adopt requirements at least as stringent as those established by PHMSA to maintain their certification to exercise regulatory jurisdiction over pipeline safety. This requirement will assure that a federal rule, which provides for a consistent approach to distribution integrity management, is implemented by the states that have such jurisdiction.

Guidance

Adequate guidance will be critical to facilitating operator implementation of the flexible requirement for integrity management described in the Key Findings section above. Developing that guidance will thus need to be a key element of the future action plan. The Risk Control Practices Group considered the scope of guidance that will be needed.

> *Request GPTC to develop guidance to support implementation of integrity management requirements (see finding 4/5-8 in the Risk Control Practices report attached) and to address other areas in which existing guidance may require improvement to better assure the integrity of distribution pipelines (finding 4/5-9).*

The Strategic Options Group also identified the need for guidance as a key element of the path forward:

> *Develop guidance to support operator implementation of any resulting rule and decision support guidance for any EFV-related requirement*

Both groups recognized the development of guidance as a key element of the work that needs to be performed. The Strategic Options Group conclusion adds to the needs identified by the Risk Control Practices Group the specific element of guidance supporting a decision for implementing an EFV requirement.

Implementing integrity management will be particularly difficult for the smallest distribution operators, since they lack resources to devote to developing customized integrity management approaches. The issues faced by the smallest operators are likely to be similar, since their systems are likely to be smaller and simpler. The work/study groups concluded that it will be necessary to provide specific guidance that small operators can use. In particular, the Risk Control Practices Group concluded there is a need to:

> *Develop and implement an approach for preparing guidance for small operators*

Although the principal focus of this action is to develop guidance for the smallest operators, the Coordinating Group concludes that the guidance should be available to all. Any future regulatory requirements should apply equally to all operators, consistent with the Strategic Options Group finding that new requirements should exclude no operator. The Coordinating Group expects that guidance for the small operators will be structured around the relative simplicity of their systems. For example, the guidance may suggest specific actions if the system contains only one kind of pipeline material. Use of such guidance by any operator whose system, or sub-systems, meets the conditions inherent in the guidance (in this example, a single material) should be acceptable regardless of the operator's size. The Coordinating Group expects that larger operators, with more available resources, may desire flexibility in developing their own plans rather than following any small operator guidance, but the option should still be available to them.

Preventing Excavation Damage

As noted in the key findings above, preventing excavation damage will necessarily involve affecting the behavior of persons not subject to pipeline safety regulation (i.e., excavators). Preventing excavation damage is thus an area in which significant actions are needed that go beyond the authority of pipeline safety regulators to implement. The Excavation Damage Prevention Group considers that the most effective means to induce states to implement the comprehensive damage prevention programs that are needed to reduce the incidence of pipeline damage would be federal legislation.

> *Propose Federal legislation, including appropriate funding mechanisms, to support state implementation of effective damage prevention programs that*

> *incorporates the nine essential elements (described in the Excavation Damage Prevention Group report). Encourage incorporation in next PHMSA reauthorization*

The Excavation Damage Prevention Group, working with PHMSA Counsel, has developed draft legislative language to accomplish this objective. That language is included in the Excavation Damage Prevention Group report.

Federal legislation, and implementation of comprehensive damage prevention programs by states in response to that legislation, will help reduce instances of damage to underground facilities, including pipelines. Assuring compliance with damage prevention requirements, though, will still require that the behavior of excavators be targeted. The Excavation Damage Prevention Group concludes that necessary change cannot be brought about without education.

> *Design and implement effective public education programs regarding excavation damage prevention - efforts to promote awareness and use of "811" should be included at core*

The reference to "811" within this action reflects the recent decision by the Federal Communications Commission to designate 811 as the national abbreviated dialing code to be used by state One Call notification systems for providing advanced notice of excavation activities to underground facility operators, in compliance with the Pipeline Safety Act of 2002.[17] Under the FCC rule, 811 must be used as an abbreviated dialing code for one-call centers by April 13, 2007. This change will undoubtedly be accompanied by education programs to inform the public of the new, abbreviated dialing arrangements. These education programs will provide an opportunity to further emphasize the importance of preventing damage to underground pipelines.

In addition, PHMSA published a rule on May 17, 2005[18], requiring that pipeline operators develop and implement improved public education programs. These programs also provide an opportunity to emphasize the importance of preventing damage to pipeline facilities.

Data Reporting

As discussed in the key findings section of this report, limitations in the available data made it difficult to draw conclusions regarding distribution pipeline integrity. Two of the work/study groups reached specific conclusions regarding additional information that, if included in PHMSA data reporting, would facilitate future analyses.

> *Consider revisions to incident data form (PHMSA 7100.1) and its instructions addressing the causes of incidents resulting from vehicles hitting gas facilities*

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[17] 70 FR 19321.
[18] 70 FR 28833.

An analysis of recent incident data conducted by Allegro Energy Consulting for PHMSA found that vehicles striking portions of pipeline systems (often meter sets) caused 11 percent of all distribution incidents over the five-year period analyzed.[19] Data are not available to understand these incidents or to help focus actions to prevent their occurrence. The Risk Control Practices Group finding is intended to assure that data is available for future analyses of this threat. The Coordinating Group concluded[20], based on input from the Data and Strategic Options Groups, that there is a need to:

Consider changes to data reporting

- *Require additional information for incidents when cause is excavation damage – identify useful information from review of the Damage Information Reporting Tool (DIRT) and state reporting requirements*
- *Expand incident report form to add information on the causes of incidents resulting from vehicles hitting gas facilities*
- *Report hazardous leaks eliminated by material in addition to cause; indicate presence of protection (e.g., coating, cathodic protection)*
- *Report hazardous leaks eliminated rather than all leaks eliminated/repaired during the year and the known system leaks at the end of the year scheduled for repair*
- *Add a check box (and appropriate criteria) on whether the regulations clearly require reporting or whether the report is submitted at the discretion of the operator*

These changes are all intended to address limitations in the currently-available data that hampered the ability to understand fully the issues related to distribution integrity management. Making these changes would facilitate future analysis of the effectiveness of regulatory changes in this area.

Performance Measures

The purpose of performance measures, as discussed in the key findings section above, would be to provide information that could be used to evaluate the effectiveness of new distribution integrity management requirements. The regulations would be demonstrated to be effective if the performance measures show improvement in the state of distribution integrity. All Work/study groups and the Coordinating group agree that tracking performance is needed.

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[19] Trench, Cheryl J., "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards", April 2005, page 23.

[20] As described above, the representative of AGA on the Coordinating Group did not agree that the change related to reporting leaks eliminated by material was needed, and the Executive Steering Group agreed that the underlying issue is the need for a proactive process to identify construction materials concerns that may affect distribution pipeline integrity, to be addressed outside the context of this work.

> *Track damage prevention metrics both for internal use in evaluating the effectiveness of an operator's program (by operators) and for evaluating progress at the national level.*

The Data Group found that to show improvement, it will be necessary to know the level of performance that was being obtained before any new requirements are implemented.

> *Once reportable Performance Measures are finalized, develop a national baseline from which trends in performance can be monitored, and a means of tracking trends from the baseline*

In addition, the Coordinating Group addressed the issue of how best to assure that valid conclusions are drawn from future analysis of reportable performance data. These data are complex and drawing valid conclusions from analysis may require insights only available through discussion involving a cross-section of knowledgeable regulators and operators. Therefore, the Coordinating Group concluded that it would be appropriate to:

> *Form a joint stakeholder group to conduct an annual data review, to resolve issues, and to produce a national performance measures report.*

Research and Development

A key finding of the Strategic Options Group (described above) was that continued research and development (R&D) is an element of the "best options" for implementing distribution integrity management. R&D can provide for improved methods of assessing the condition of distribution pipelines and for mitigating threats to distribution pipeline integrity.

The Excavation Damage Group identified one R&D project as a key path forward action. This action involves an issue for which PHMSA is already planning a pilot project. The group concludes that the pilot project will have value in enhancing protection of distribution pipelines from the principal threat to their integrity.

> *Conduct pilot project to research, develop and implement technologies to enhance the communication of accurate information between excavators and operators*

Scope

The Strategic Options Group also considered the appropriate scope of new regulations. In particular, the group considered the treatment of pipelines that are classified as transmission pipelines because they operate at stress levels greater than 20 percent of specified minimum yield strength (SMYS). These pipelines are currently subject to the integrity management requirements for transmission pipelines in 49 CFR Part 192, Subpart O. In promulgating Subpart O, however, PHMSA recognized that these pipelines are different than transmission pipelines operating at higher stresses, since these low-stress pipelines pose relatively lower risk.[21] Subpart O provided for alternative reassessment methods for these low-stress pipelines (operating below 30 percent SMYS) in recognition of their relatively low risk.[22]

Many low-stress transmission pipelines are operated by local distribution companies. Often these lines represent the only transmission pipelines for which the operators are responsible. Since these operators likely will be required to implement integrity management plans for their distribution pipelines, it might be more appropriate to allow them to treat their low-stress transmission pipeline under their distribution integrity management plans. In considering the appropriateness of such a change, the Strategic Options Group evaluated the existing research concerning the likely failure mode of pipeline operating below 30 percent SMYS to ascertain the accuracy of the commonly-stated belief that such pipeline tends to fail by leakage.

The group discovered that the record indicates that failure is expected to be by leakage when the failure results from corrosion. It is less clear that the likely failure mode would be leakage when the failure results from prior mechanical damage (e.g., from outside force). Additional technical work is needed to better define the threshold stress level at which the likely failure mode transitions from leakage to rupture to evaluate the appropriateness of treating low-stress transmission pipeline under distribution integrity management programs.

The Strategic Options Group thus reached a finding regarding appropriate consideration of low-stress transmission pipeline in any future rulemaking:

> *Consider whether low stress pipes currently defined as transmission should be treated as distribution for purposes of Integrity Management. Conduct additional research to define the threshold stress level at which pipe with latent mechanical damage is expected to fail by rupture.*

5. Conclusion

The Phase 1 investigations have demonstrated that the operation of distribution pipeline systems is currently safe. Incidents, including incidents involving fatality and injury, do occur. Their number is small. The number of incidents per 100,000 miles on distribution pipeline systems has been lower than the corresponding number for transmission pipelines for the last several years. The number of incidents involving fatality or injury per 100,000 miles has been similar to the number for gas transmission pipelines. Still, implementing integrity management principles, as has already been done for transmission pipelines, can result in an improvement in this already-good safety record.

The foundation for implementing integrity management principles for distribution pipelines is secure. Considerable information and many good practices are now available

[21] 68 FR 69797.
[22] 49 CFR 192.941.

that would be useful in this endeavor. Additional work is needed, however. New requirements and new guidance are both needed. Other changes, described in this report, would also help facilitate the effective implementation of integrity management for distribution pipelines.

The Phase 1 work described herein has resulted in findings and conclusions and suggestions for future action that will serve to support the effective implementation of integrity management for distribution pipelines.

As a separate, related effort, the Executive Steering Group prepared a statement on cost recovery for distribution integrity management to inform later actions of operators and rate regulators. That statement is included as Appendix E to this report.

Appendices

A. Participants

B. Complete list of Findings

C. Complete list of Path Forward Actions

D. Comments of International Association of Fire Chiefs

E. Statement on Distribution Integrity Management Cost Recovery

NOPE Ex. 15

Pipeline Serious Incident 20 Year Trend
Date run 3/30/2019

Portal - Data as of **3/28/2019**
Data Source: US DOT Pipeline and Hazardous Materials Safety Administration

PHMSA Pipeline Incidents: (1999-2018)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** (All Column Values)

Calendar Year	Number	Fatalities	Injuries
1999	52	16	80
2000	51	22	59
2001	30	5	46
2002	30	10	44
2003	51	11	58
2004	38	18	37
2005	28	14	37
2006	24	16	28
2007	29	9	29
2008	28	6	47
2009	37	9	47
2010	25	8	39
2011	29	11	48
2012	23	7	43
2013	19	7	34
2014	24	18	92
2015	22	2	32
2016	31	10	74
2017	20	16	32
2018	35	7	81
Grand Total	**626**	**222**	**987**

PHMSA Pipeline Incidents: Multi-Year Averages (1999-2018)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** (All Column Values)

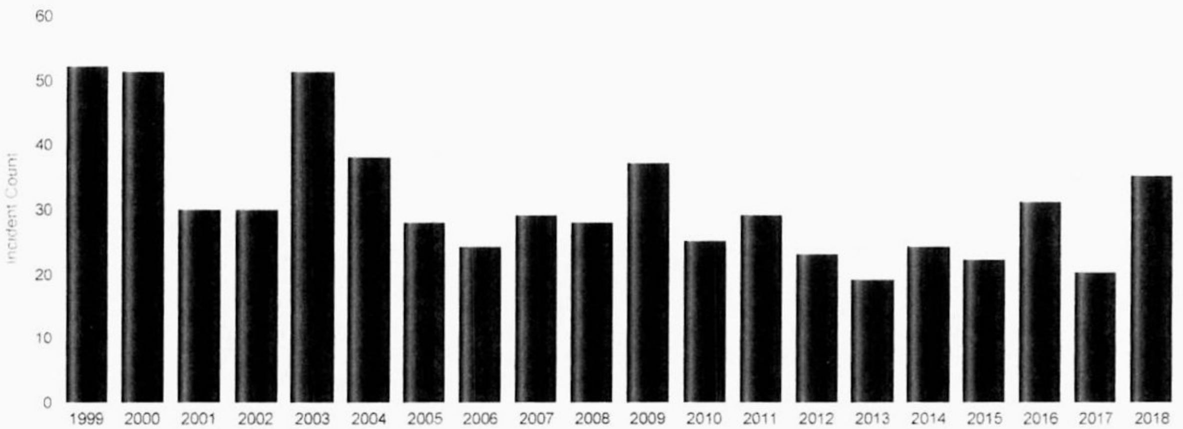
	Incident Count
3 Year Average - (2016-2018)	29
5 Year Average - (2014-2018)	26
10 Year Average - (2009-2018)	27
20 Year Average - (1999-2018)	31

	Fatalities
3 Year Average	11
5 Year Average	11
10 Year Average	10
20 Year Average	11

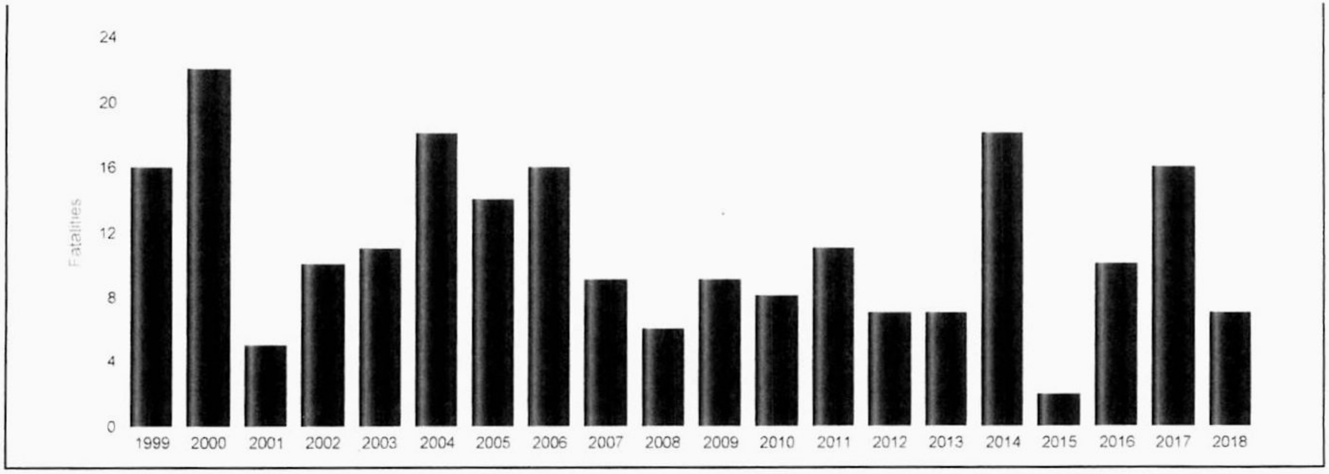
	Injuries
3 Year Average	62
5 Year Average	62
10 Year Average	52
20 Year Average	49

	2019 Year-To-Date
Incidents	2
Fatalities	0
Injuries	2

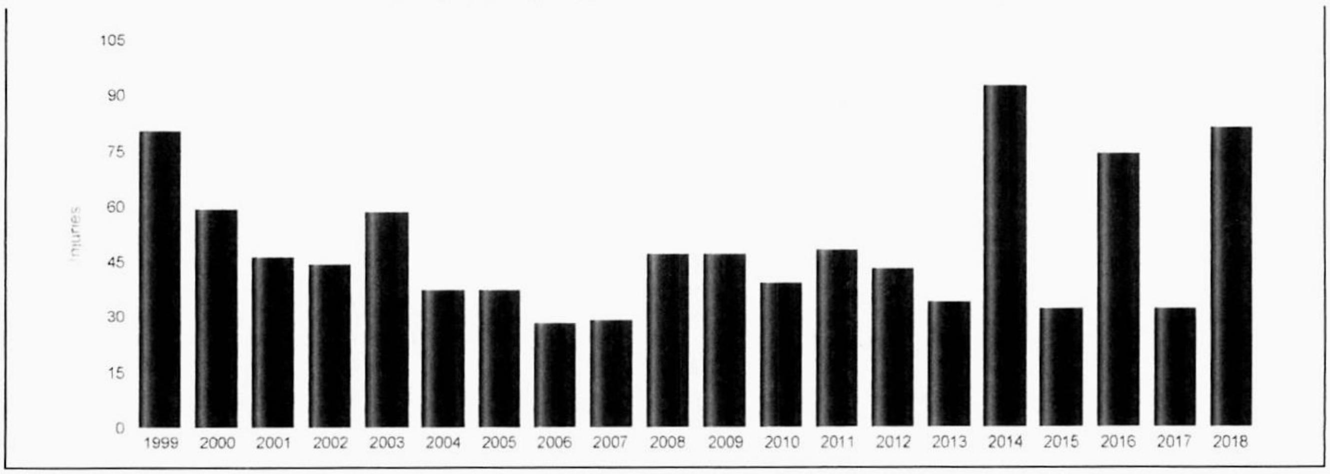
PHMSA Pipeline Incidents: Count (1999-2018)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** (All Column Values)



PHMSA Pipeline Incidents: Fatalities (1999-2018)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** (All Column Values)



PHMSA Pipeline Incidents: Injuries (1999-2018)
Incident Type: Serious **System Type:** GAS DISTRIBUTION **State:** (All Column Values)



NOPE Ex. 16

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

MAR 2 2 2010

Mr. Joe M. Johnson
Acting Bureau Chief
New Mexico Public Regulation Commission
Pipeline Safety Bureau
1120 Paseo de Peralta
Santa Fe, New Mexico 87504

Dear Mr. Johnson:

In a letter to the Pipeline and Hazardous Materials Safety Administration (PHMSA) dated September 15, 2009, you requested an opinion/interpretation on whether the following pipelines operated by New Mexico Gas Company (NMGC) should be regulated as transmission pipelines or distribution pipelines (as described by New Mexico Public Regulation Commission):

1. Animas Power Plant 6" diameter - an intrastate natural gas pipeline that transports natural gas from a transmission line to a large volume customer (Animas Power Plant).

2. Farmington (Bluffview) Power Plant 8" diameter - an intrastate natural gas pipeline that transports natural gas directly from a transmission line to large volume customers (Animas and Bluffview power plants).

3. Tucumcari Mainline - an intrastate natural gas pipeline that transports natural gas directly from a transmission to distribution centers (Tucumcari Townplant, Northeast Regulator Station, and Baker Kelso Regulator Station). This pipeline is a continuation of the Clovis Transmission Line that transports natural gas from El Paso Natural Gas Company's intrastate pipeline system to New Mexico Gas Company's Northeast Area distribution centers, and is not downstream of a distribution center.

   NMGC has designated a valve at the Clovis Border Regulator Station as the end point of the Clovis Transmission Line and the beginning of the Tucumcari and Cannon mainlines. The Clovis Transmission line and the Tucumcari and Cannon mainlines all operate at 300 psig. The Tucumcari Mainline runs approximately 62 miles from Mile Post 0 at the Clovis Border Regulator Station to the Tucumcari Townplant distribution center.

4. Cannon Mainline - an intrastate natural gas pipeline that transports natural gas directly from a transmission to distribution centers (Northwest Regulator Station, Mixon lane Regulator Station, Hayfield Farmers Regulator Station, 6084 Regulator Station, Port Air Dairyman Regulator Station, Port Air Farmers Regulator Station, and Clovis Expansion Regulator Station). This pipeline is a continuation of the Clovis Transmission line that

transports natural gas from El Paso Natural Gas Company's Intrastate pipeline system to New Mexico Gas Company's Northeast Area distribution centers, and is not downstream of a distribution center.

5. Northeast Distribution Mainline - an intrastate natural gas pipeline. The pipeline is a loop line that can be used to: (a) transports natural gas from El Paso Natural Gas Company's interstate pipeline via NMGC's Clovis Transmission line to the Tucumcari Townplant distribution center without going to the Clovis Border Regulator Station, or (b) transport natural gas to the Clovis Townplant distribution center via the Tucumcari Mainline.

6. Portales Mainline - an intrastate natural gas pipeline that transports natural gas from the Clovis Transmission line, and Transwestern's interstate transmission line to distribution centers (Portales Townplant, Grinder Regulator Station, Baxter Regulator Station, Midway Regulator Station, and Cameo Regulator Station). Pressure on the pipeline is regulated at 200 psig just downstream of the Transwestern interconnect at the Clovis Transmission line. There are no service lines on the Portales Mainline and the pipeline runs approximately 20 miles to the Portales Townplant distribution center.

Based on the provided information, we agree with the Commission's determination that all of the specified lines meet the definition of a transmission line. PHMSA's responses concerning each of the specified lines are as follows:

1. Regarding the Animas Power Plant 6" line, we believe this line is a transmission line because under the first definition of a transmission line this line transports gas from a transmission line to a large volume customer that is not downstream from a distribution center.

2. Regarding the Farmington (Bluffview) Power plant 8" line, we believe this line is a transmission line because under the first definition of a transmission line this line transports gas from a transmission line to a large volume customer that is not downstream from a distribution center.

3. Regarding the Tucumcari Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line.

4. Regarding the Cannon Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to

customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line.

5. Regarding the Northeast Distribution Mainline, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis transmission line or the Tucumcari Mainline as described by PSB.

6. Regarding the Portales Main line, we do not consider a decrease in pressure to below 20 percent SMYS at a transmission line to be a "distribution center" and lines downstream of that point to be distribution lines – this would violate the intent of the pipeline safety regulations. We consider a "distribution center" to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale. Therefore, in our opinion, this line is an extension of the Clovis Transmission line and Transwestern transmission line.

For your information, on September 25, 2009, PHMSA received a letter from NMGC concerning your interpretation request. PHMSA is providing NMGC with a copy of this letter and a copy of PHMSA's response to NMGC is enclosed. I hope that this information is helpful to you. If I can be of further assistance, please contact me at (202) 366-4046.

Sincerely,

John A. Gale
Director, Office of Regulations

Enclosures

NOPE Ex. 17

Duke Energy Ohio
Case No. 16-253-GA-BTX
KENWOOD First Set Requests for Production of Documents
Date Received: June 20, 2017

KENWOOD-POD-01-003 SUPPLEMENT

REQUEST:

Produce any and all reports, studies, analyses, diagrams, charts, maps, and other documents relating to one or more of the following:

(a) potential failure modes of the Pipeline;
(b) locations of potential structural weak points in the Pipeline;
(c) projected or estimated injuries and/or property damage resulting from a Pipeline failure;
(d) High Consequence Areas (as defined in 49 CFR § 192.903) along the Preferred Route; and/or
(e) Potential Impact Radius (PIR) (as defined in 49 CFR § 192.903) data along the Preferred Route.

RESPONSE:

a. Duke Energy Ohio has prepared no reports, studies, analyses, diagrams, charts, maps, or other documents relating to potential failure modes of the Pipeline.
b. Duke Energy Ohio has prepared no reports, studies, analyses, diagrams, charts, maps, or other documents relating to potential structural weak points in the Pipeline.
c. There are too many variables to calculate a response to this question.
d. Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding. HCAs, as defined in 49 CFR 192.903, relate solely to transmission lines. Because the proposed Pipeline is not a transmission line, HCAs are not relevant. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, because Duke Energy Ohio designs all its pipelines to Class 4 (the most stringent design classification), individual locations of HCAs are not determined due to classifying the entire pipeline as an HCA.
e. Objection. This Interrogatory is overly broad and unduly burdensome, given that it seeks information that is neither relevant to this proceeding nor likely to lead to the discovery of admissible evidence in this proceeding. PIRs, as defined in 49 CFR 192.903, relate solely to transmission lines. Because the proposed Pipeline is not a transmission line, PIRs are not relevant. Without waiving said objection, to the extent discoverable, and in the spirit of discovery, if this was a transmission line: PIR - r =0.69*(square root of p*d2) [500*400=200000] square root = 447.21 * .69 = 308.58'

PERSON RESPONSIBLE:

As to objection: Legal
As to response to parts a and b: Bradley Seiter
As to response to parts c, d, and e: James Collins

NOPE 18

CERTIFICATE

By Authority Of
THE UNITED STATES OF AMERICA
Legally Binding Document

By the Authority Vested By Part 5 of the United States Code § 552(a) and Part 1 of the Code of Regulations § 51 the attached document has been duly INCORPORATED BY REFERENCE and shall be considered legally binding upon all citizens and residents of the United States of America. *HEED THIS NOTICE*: Criminal penalties may apply for noncompliance.

Document Name: ASME B318S: Managing System Integrity of Gas Pipelines

CFR Section(s): 49 CFR 192.903(c)

Standards Body: American Society of Mechanical Engineers

APPROVED

Official Incorporator:
THE EXECUTIVE DIRECTOR
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Managing System Integrity of Gas Pipelines

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

AN AMERICAN NATIONAL STANDARD

The American Society of Mechanical Engineers

Three Park Avenue • New York, NY 10016

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The next edition of this Standard is scheduled for publication in 2006. There will be no addenda issued to this edition.

ASME issues written replies to inquiries concerning interpretations of technical aspects of this Standard. Interpretations are published on the ASME Web site under the Committee Pages at http://www.asme.org/codes/ as they are issued.

The American Society of Mechanical Engineers
Three Park Avenue, New York, NY 10016-5990

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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' intensive work by a number of technical experts in their fields, 20 reports were issued that provided the responses required to complete the 2002 edition of this Standard. (The list of these reports is included in the reference section of this Standard.)

This Standard 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 Standard. This Standard becomes mandatory if and when pipeline regulators include it as a requirement in their regulations.

This Standard is a process standard, which 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 Standard. Particular recognition is given to API and their liquids integrity management standard, API 1160, which was used as a model for the format of this Standard.

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

This Supplement was approved by the B31 Standards Committee and by the ASME Board on Pressure Technology Codes and Standards. It was approved as an American National Standard on March 17, 2004.

ASME CODE FOR PRESSURE PIPING, B31

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K. B. Kaplan, Kellogg Brown and Root
R. D. Lewis, H. Rosen USA Inc.
W. B. McGehee, Pipeline Engineering Consultant
A. T. Richardson, Richardson Engineering Co.

SUMMARY OF CHANGES

Changes given below are identified on the pages by a margin note, **(04)**, placed next to the affected area.

Page	*Location*	*Change*
1–3	1.3	Seventh paragraph revised
	2.1	Last paragraph revised
5, 6	2.3.4	Last paragraph revised
	2.4.2	Title revised
10, 11	4.5	Examples revised
	5.3	Last paragraph revised
14	5.7(j)	Revised
15, 16	5.10	Third and penultimate paragraphs revised
	5.11	Second paragraph revised
	5.12	Revised
	6.1	Third paragraph revised
17	6.2	Revised
18	6.2.6	Second paragraph revised
19	6.3.2	Second and third paragraphs revised
20, 23	7.2.1	Last paragraph revised
24	7.4.1	First paragraph revised
26	9.1	First paragraph revised
27	9.2	Second paragraph revised
	9.2.2	Revised
31, 32	10.2	Last paragraph revised
	11(b)(1)	Revised
33, 36	12.2(b)(4)	Revised
	13	(1) *B31G* deleted (2) *right-of-way* revised
45	A3.4.2(d)(2)(a)	Revised
60	Appendix C	Added

MANAGING SYSTEM INTEGRITY OF GAS PIPELINES

1 INTRODUCTION

1.1 Scope

This Standard applies to onshore pipeline systems constructed with ferrous materials and that transport gas. *Pipeline system* means all parts of physical facilities through which gas is transported, including pipe, valves, appurtenances attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies. The principles and processes embodied in integrity management are applicable to all pipeline systems.

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

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 Standard 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 Standard 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- 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 Standard 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- and performance-based integrity management programs are provided in each of the paragraphs in this Standard. 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 Standard 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 (04)

A set of principles is the basis for the intent and specific details of this Standard. They are enumerated here so that the user of this Standard 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 Standard. 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 might 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 might 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 (04)

This paragraph 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 Fig. 1 are required for all integrity management programs.

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

The process shown in Fig. 2 provides a common basis to develop (and periodically reevaluate) an operator-specific program. In developing the program, pipeline operators shall consider their companies' specific integrity management goals and objectives, and then apply the processes to assure that these goals are achieved. This Standard 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 Standard and Nonmandatory Appendix A. The prescriptive method incorporates expected

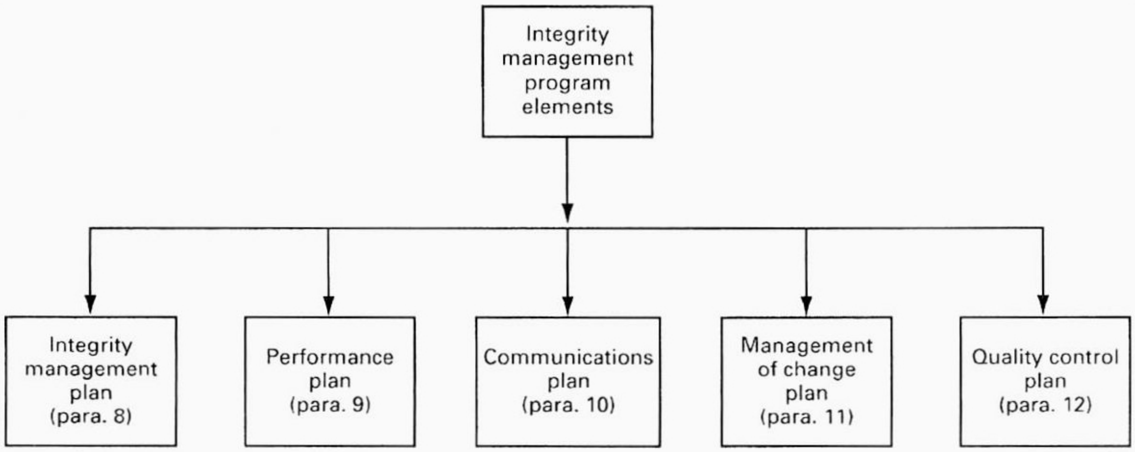


Fig. 1 Integrity Management Program Elements

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 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 Standard.

There is no single "best" approach that is applicable to all pipeline systems for all situations. This Standard recognizes the importance of flexibility in designing integrity management programs and provides alternatives commensurate with this need. Operators may choose either a prescriptive- or a performance-based approach for their entire system, individual lines, segments, or individual threats. The program elements shown in Fig. 1 are required for all integrity management programs.

The process of managing integrity is an integrated and iterative process. Although the steps depicted in Fig. 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 is 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 para. 2, as well as instructions to the more specific and detailed description of the individual elements comprising the remainder of this Standard. References to the specific detailed paragraphs in this Standard are shown in Figs. 1 and 2.

2.2 Integrity Threat Classification

The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has 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 have been grouped into nine categories of related failure types according to their nature and growth characteristics, and further delineated by three time-related defect types.

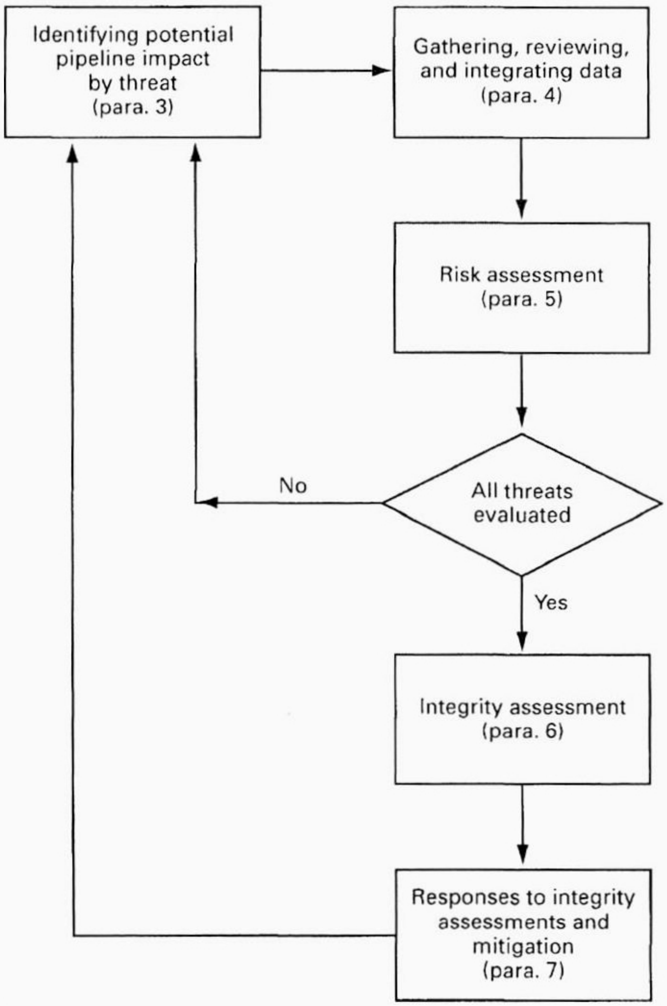


Fig. 2 Integrity Management Plan Process Flow Diagram

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) *Stable*

(1) manufacturing related defects

(a) defective pipe seam

(b) defective pipe

(2) welding/fabrication related

(a) defective pipe girth weld

(b) defective fabrication weld

(c) wrinkle bend or buckle

(d) stripped threads/broken pipe/coupling failure

(3) equipment

(a) gasket O-ring failure

(b) control/relief equipment malfunction

(c) seal/pump packing failure

(d) miscellaneous

(c) *Time-Independent*

(1) third party/mechanical damage

(a) damage inflicted by first, second, or third parties (instantaneous/immediate failure)

(b) previously damaged pipe (delayed failure mode)

(c) vandalism

(2) incorrect operational procedure

(3) weather-related and outside force

(a) cold weather
(b) lightning
(c) heavy rains or floods
(d) earth movements

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.

Historically, metallurgical fatigue has not been a significant issue for gas pipelines. However, if operational modes change and pipeline segments operate with significant pressure fluctuations, fatigue shall be considered by the operator as an additional factor.

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.

2.3 The Integrity Management Process

The integrity management process depicted in Fig. 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 is 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). Paragraph 3 provides information on consequences. Paragraph 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 para. 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. Paragraph 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. (04)

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 operators' responsibility to document the analyses justifying the alternative courses of action or time frames. Paragraph 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 timeframes 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. Paragraph 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 assure 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 Fig. 1 and are described below.

2.4.1 Integrity Management Plan. The integrity management plan is the outcome of applying the process depicted in Fig. 2 and discussed in para. 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 Standard 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. Paragraph 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. Paragraph 9 provides the information required for developing performance measures to evaluate program effectiveness. (04)

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. Paragraph 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. Paragraph 11 discusses the important aspects of managing changes as they relate to integrity management.

2.4.5 Quality Control Plan. Paragraph 12 discusses the evaluation of the integrity management program for quality control purposes. That paragraph outlines the necessary documentation for the integrity management program. The paragraph 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 paragraph 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 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

The refined radius of impact for natural gas is calculated using the formula

$$r = 0.69 \cdot d\sqrt{p} \qquad (1)$$

where

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

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

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

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.)

NOTE: 0.69 is the factor for natural gas. Other gases or rich natural gas shall use different factors.

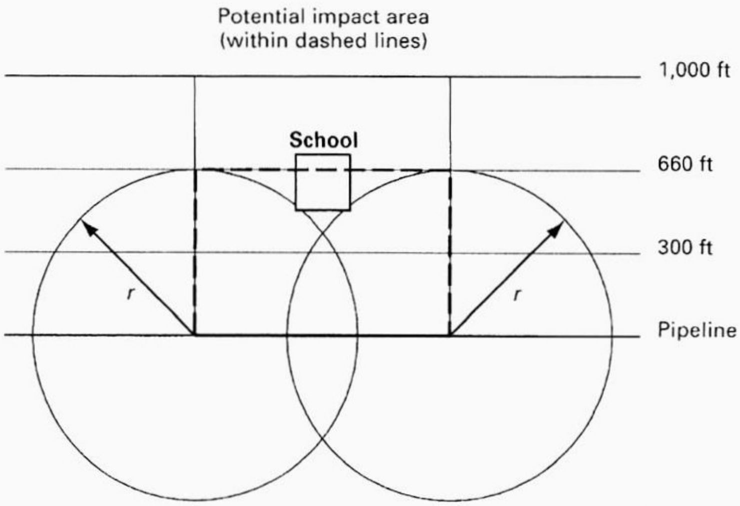
Equation (1) is derived from

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

where

C_d = discharge coefficient
H_C = heat of combustion
I_{th} = threshold heat flux
Q = flow factor $= \gamma\left(\frac{2}{\gamma + 1}\right)^{\frac{\gamma+1}{2(\gamma-1)}}$
R = gas constant
T = gas temperature
a_o = sonic velocity of gas $= \sqrt{\frac{\gamma RT}{m}}$
d = line diameter
m = gas molecular weight
p = live pressure
r = refined radius of impact
γ = specific heat ratio of gas
λ = release rate decay factor
μ = combustion efficiency factor
χ_g = emissivity factor

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. 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 center of the first affected circle to the center of the last affected circle (see Fig. 3). This housing unit count can then be used to help determine the relative consequences of a rupture of the pipeline segment.



GENERAL NOTE: This diagram represents the results for a 30 in. pipe with an MAOP of 1,000 psig.

Fig. 3 Potential Impact Area

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 paras. 4 and 5).

3.3 Consequence Factors to Consider

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

(a) population density

(b) proximity of the population to the pipeline (including consideration of manmade 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 communities, prisons, recreation areas), particularly in unprotected outside areas

(d) property damage

(e) environmental damage

(f) effects of unignited gas releases

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

(h) public convenience and necessity

(i) potential for secondary failures

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 paragraph 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 para.

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 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 and facility risk assessments. This data is 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, 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

Table 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 installed
	Coating type
Operational	Gas quality
	Flow rate
	Normal maximum and minimum operating pressures
	Leak/failure history
	Coating condition
	CP (cathodic protection) 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

Table 2 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

management program. Industry consortia and other operators can also be useful information sources.

The data sources listed in Table 2 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 para. 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 is used in the risk assessment process, so its 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.

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. Stable and time-independent threats do not have implied time dependence, so earlier data is 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 (04)

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 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 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 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 para. 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- 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 para. 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 paragraph 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

C = failure consequence

P = failure likelihood

1 to 9 = failure threat category (see para. 2.2)

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 para. 3.

5.3 Risk Assessment Objectives (04)

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) that 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 para. 11).

5.5 Risk Assessment Approaches

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

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

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

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

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

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

It is the operator's responsibility to apply the level of integrity/risk analysis methods that meets the needs of the operator's integrity management program. More than one type of model may be used throughout an operator's system. A thorough understanding of the strengths and limitations of each risk assessment method is necessary before a long-term strategy is adopted.

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

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

(2) they evaluate likelihood of failure and consequences

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

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

(5) they provide for a data feedback loop mechanism

(6) they provide structure and continuous updating for risk reassessments

Some risk assessment approaches consider the likelihood and consequences of damage, but they do not consider whether failure occurs as a leak or rupture. Ruptures have more potential for damage than leaks. Consequently, when a risk assessment approach does not consider whether a failure may occur as a leak or rupture, a worst-case assumption of rupture shall be made.

5.6 Risk Analysis

5.6.1 Risk Analysis for Prescriptive Integrity Management Programs. The risk analyses developed for a prescriptive integrity management program are used to prioritize the pipeline segment integrity assessments. Once the integrity of a segment is established, the reinspection interval is specified in Table 3. The risk analyses for prescriptive integrity management programs use

Table 3 Integrity Assessment Intervals: Time-Dependent Threats, Prescriptive Integrity Management Plan

		Criteria		
Inspection Technique	Interval (Years) [Note (1)]	At or Above 50% SMYS	At or Above 30% up to 50% SMYS	Less Than 30% SMYS
Hydrostatic testing	5	TP to 1.25 times MAOP [Note (2)]	TP to 1.4 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]
	10	TP to 1.39 times MAOP [Note (2)]	TP to 1.7 times MAOP [Note (2)]	TP to 2.2 times MAOP [Note (2)]
	15	Not allowed	TP to 2.0 times MAOP [Note (2)]	TP to 2.8 times MAOP [Note (2)]
	20	Not allowed	Not allowed	TP to 3.3 times MAOP [Note (2)]
In-line inspection	5	P_f above 1.25 times MAOP [Note (3)]	P_f above 1.4 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]
	10	P_f above 1.39 times MAOP [Note (3)]	P_f above 1.7 times MAOP [Note (3)]	P_f above 2.2 times MAOP [Note (3)]
	15	Not allowed	P_f above 2.0 times MAOP [Note (3)]	P_f above 2.8 times MAOP [Note (3)]
	20	Not allowed	Not allowed	P_f above 3.3 times MAOP [Note (3)]
Direct assessment	5	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	10	All indications examined	Sample of indications examined [Note (4)]	Sample of indications examined [Note (4)]
	15	Not allowed	All indications examined	All indications examined
	20	Not allowed	Not allowed	All indications examined

NOTES:

(1) Intervals are maximum and may be less, depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate reassessment of the interval.

(2) TP is test pressure.

(3) P_f is predicted failure pressure as determined from ASME B31G or equivalent.

(4) For the Direct Assessment Process, the intervals for direct examination of indications are contained within the process. These intervals provide for sampling of indications based on their severity and the results of previous examinations. Unless all indications are examined and repaired, the maximum interval for reinspection is 5 years for pipe operating at or above 50% SMYS and 10 years for pipe operating below 50% of SMYS.

minimal data sets. They cannot be used to increase the reinspection intervals.

When the operator follows the prescriptive reinspection intervals, the more simplistic risk assessment approaches provided in para. 5.5 are considered appropriate.

5.6.2 Risk Analysis for Performance-Based Integrity Management Programs. Performance-based integrity management programs shall prioritize initial integrity assessments utilizing any of the methods described in para. 5.5.

Risk analyses for performance-based integrity management programs may also be used as a basis for establishing inspection intervals. Such risk analyses will require more data elements than required in Nonmandatory Appendix A and more detailed analyses. The results of these analyses may also be used to evaluate alternative mitigation and prevention methods and their timing.

An initial strategy for an operator with minimal experience using structured risk analysis methods may include adopting a more simple approach for the short term, such as knowledge-based or a screening relative risk model. As additional data and experience are gained, the operator can transition to a more comprehensive method.

5.7 Characteristics of an Effective Risk Assessment Approach

Considering the objectives summarized in para. 5.3, a number of general characteristics exist that will contribute to the overall effectiveness of a risk assessment for either prescriptive or performance-based integrity management programs. These characteristics shall include the following:

(a) Attributes. Any risk assessment approach shall contain a defined logic and be structured to provide a complete, accurate, and objective analysis of risk. Some risk methods require a more rigid structure (and considerably more input data). Knowledge-based methods are less rigorous to apply and require more input from subject-matter experts. They shall all follow an established structure and consider the nine categories of pipeline threats and consequences.

(b) Resources. Adequate personnel and time shall be allotted to permit implementation of the selected approach and future considerations.

(c) Operating/Mitigation History. Any risk assessment shall consider the frequency and consequences of past events. Preferably, this should include the subject pipeline system or a similar system, but other industry data can be used where sufficient data is initially not available. In addition, the risk assessment method shall account for any corrective or risk mitigation action that has occurred previously.

(d) Predictive Capability. To be effective, a risk assessment method should be able to identify pipeline integrity threats previously not considered. It shall be able to make use of (or integrate) the data from various pipeline inspections to provide risk estimates that may result from threats that have not been previously recognized as potential problem areas. Another valuable approach is the use of trending, where the results of inspections, examinations, and evaluations are collected over time in order to predict future conditions.

(e) Risk Confidence. Any data applied in a risk assessment process shall be verified and checked for accuracy (see para. 12). Inaccurate data will produce a less accurate risk result. For missing or questionable data, the operator should determine and document the default values that will be used and why they were chosen. The operator should choose default values that conservatively reflect the values of other similar segments on the pipeline or in the operator's system. These conservative values may elevate the risk of the pipeline and encourage action to obtain accurate data. As the data are obtained, the uncertainties will be eliminated and the resultant risk values may be reduced.

(f) Feedback. One of the most important steps in an effective risk analysis is feedback. Any risk assessment method shall not be considered as a static tool, but as a process of continuous improvement. Effective feedback is an essential process component in continuous risk model validation. In addition, the model shall be adaptable and changeable to accommodate new threats.

(g) Documentation. The risk assessment process shall be thoroughly and completely documented, to provide the background and technical justification for the methods and procedures used and their impact on decisions based on the risk estimates. Like the risk process itself, such a document should be periodically updated as modifications or risk process changes are incorporated.

(h) "What if" Determinations. An effective risk model should contain the structure necessary to perform "what if" calculations. This structure can provide estimates of the effects of changes over time and the risk reduction benefit from maintenance or remedial actions.

(i) Weighting Factors. All threats and consequences contained in a relative risk assessment process should not have the same level of influence on the risk estimate. Therefore, a structured set of weighting factors shall be included that indicate the value of each risk assessment component, including both failure probability and consequences. Such factors can be based on operational experience, the opinions of subject matter experts, or industry experience.

(j) Structure. Any risk assessment process shall provide, as a minimum, the ability to compare and rank the risk results to support the integrity management program's decision process. It should also provide for several types of data evaluation and comparisons, establishing which particular threats or factors have the most influence on the result. The risk assessment process shall be structured, documented, and verifiable. **(04)**

(k) Segmentation. An effective risk assessment process shall incorporate sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline. Such analysis will facilitate location of local high-risk areas that may need immediate attention. For risk assessment purposes, segment lengths can range from units of feet to miles, depending on the pipeline attributes, its environment, and other data.

Another requirement of the model involves the ability to update the risk model to account for mitigation or other action that changes the risk in a particular length. This can be illustrated by assuming that two adjacent mile-long segments have been identified. Suppose a pipe replacement is completed from the midpoint of one segment to some point within the other. In order to account for the risk reduction, the pipeline length comprising these two segments now becomes four risk analysis segments. This is called *dynamic segmentation.*

5.8 Risk Estimates Using Assessment Methods

A description of various details and complexities associated with different risk assessment processes has been provided in para. 5.5. Operators that have not previously initiated a formal risk assessment process may find an initial screening to be beneficial. The results of this screening can be implemented within a short time frame and focus given to the most important areas. A screening risk assessment may not include the entire pipeline system, but be limited to areas with a history of problems or where failure could result in the most severe consequences, such as areas of concern. Risk assessment and data collection may then be focused on the most likely threats without requiring excessive detail. A screening risk assessment suitable for this approach can include subject matter experts or simple relative risk models as described in para. 5.5. A group of subject-matter experts representing pipeline operations, engineering, and others knowledgeable of threats that may exist is assembled to focus on the potential threats and risk reduction measures that would be effective in the integrity management program.

Application of any type of risk analysis methodology shall be considered as an element of continuous process and not a one-time event. A specified period defined by the operator shall be established for a system-wide risk reevaluation, but shall not exceed the required maximum interval in Table 3. Segments containing indications that are scheduled for examination or that are to be monitored must be assessed within time intervals that will maintain system integrity. The frequency of the system-wide reevaluation must be at least annually, but may be more frequent, based on the frequency and importance of data modifications. Such a reevaluation should include all pipelines or segments included in the risk analysis process, to assure that the most recent inspection results and information is reflected in the reevaluation and any risk comparisons are on an equal basis.

The processes and risk assessment methods used shall be periodically reviewed to ensure they continue to yield relevant, accurate results consistent with the objectives of the operator's overall integrity management program. Adjustments and improvements to the risk assessment methods will be necessary as more complete and accurate information concerning pipeline system attributes and history becomes available. These adjustments shall require a reanalysis of the pipeline segments included in the integrity management program, to ensure that equivalent assessments or comparisons are made.

5.9 Data Collection for Risk Assessment

Data collection issues have been discussed in para. 4. When analyzing the results of the risk assessments, the operator may find that additional data is required. Iteration of the risk assessment process may be required to improve the clarity of the results, as well as confirm the reasonableness of the results.

Determining the risk of potential threats will result in specification of the minimum data set required for implementation of the selected risk process. If significant data elements are not available, modifications of the proposed model may be required after carefully reviewing the impact of missing data and taking into account the potential effect of uncertainties created by using required estimated values. An alternative could be to use related data elements in order to make an inferential threat estimate.

5.10 Prioritization for Prescriptive-Based and Performance-Based Integrity Management Programs (04)

A first step in prioritization usually involves sorting each particular segment's risk results in decreasing order of overall risk. Similar sorting can also be achieved by separately considering decreasing consequences or failure probability levels. The highest risk level segment shall be assigned a higher priority when deciding where to implement integrity assessment and/or mitigation actions. Also, the operator should assess risk factors that cause higher risk levels for particular segments. These factors can be applied to help select, prioritize, and schedule locations for inspection actions such as hydrostatic testing, in-line inspection, or direct assessment. For example, a pipeline segment may rank extremely high for a single threat, but rank much lower for the aggregate of threats compared to all other pipeline segments. Timely resolution of the single highest threat segment may be more appropriate than resolution of the highest aggregate threat segment.

For initial efforts and screening purposes, risk results could be evaluated simply on a "high–medium–low" basis or as a numerical value. When segments being compared have similar risk values, the failure probability and consequences should be considered separately. This may lead to the highest consequence segment being given a higher priority. Factors including line availability and system throughput requirements can also influence prioritization.

The integrity plan shall also provide for the elimination of any specific threat from the risk assessment. For a prescriptive integrity management program, the minimum data required and the criteria for risk assessment in order to eliminate a threat from further consideration are specified in Nonmandatory Appendix A. Performance-based integrity management programs that use more comprehensive analysis methods should consider the following in order to exclude a threat in a segment:

(a) there is no history of a threat impacting the particular segment or pipeline system

(b) the threat is not supported by applicable industry data or experience

(c) the threat is not implied by related data elements

(d) the threat is not supported by like/similar analyses

(e) the threat is not applicable to system or segment operating conditions

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

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

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

(04) 5.11 Integrity Assessment and Mitigation

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

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

(04) 5.12 Validation

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

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

6 INTEGRITY ASSESSMENT

6.1 General (04)

Based on the priorities determined by risk assessment, the operator shall conduct integrity assessments using the appropriate integrity assessment methods. The integrity assessment methods that can be used are in-line inspection, pressure testing, direct assessment, or other methodologies provided in para. 6.5. The integrity assessment method is based on the threats to which the segment is susceptible. More than one method and/or tool may be required to address all the threats in a pipeline segment. Conversely, inspection using any of the integrity assessment methods may not be the appropriate action for the operator to take for certain threats. Other actions, such as prevention, may provide better integrity management results.

Paragraph 2 provides a listing of threats by three groups: time-dependent, stable, and time-independent. Time-dependent threats can typically be addressed by utilizing any one of the integrity assessment methods discussed in this paragraph. 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. Random threats typically cannot be addressed through use of any of the integrity assessment methods discussed in this paragraph, but are subject to the prevention measures discussed in para. 7.

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

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

(04) 6.2 Pipeline In-Line Inspection

In-line inspection (ILI) is an integrity assessment method used to locate and preliminarily characterize metal loss indications in a pipeline. The effectiveness of the ILI tool used depends on the condition of the specific pipeline section to be inspected and how well the tool matches the requirements set by the inspection objectives. The following paragraphs discuss the use of ILI tools for certain threats.

6.2.1 Metal Loss Tools for the Internal and External Corrosion Threat. For these threats, the following tools can be used. Their effectiveness is limited by the technology the tool employs.

(a) Magnetic Flux Leakage, Standard Resolution Tool. This is better suited for detection of metal loss than for sizing. Sizing accuracy is limited by sensor size. It is sensitive to certain metallurgical defects, such as scabs and slivers. It is not reliable for detection or sizing of most defects other than metal loss, and not reliable for detection or sizing of axially aligned metal-loss defects. High inspection speeds degrade sizing accuracy.

(b) Magnetic Flux Leakage, High Resolution Tool. This provides better sizing accuracy than standard resolution tools. Sizing accuracy is best for geometrically simple defect shapes. Sizing accuracy degrades where pits are present or defect geometry becomes complex. There is some ability to detect defects other than metal loss, but ability varies with defect geometries and characteristics. It is not generally reliable for axially aligned defects. High inspection speeds degrade sizing accuracy.

(c) Ultrasonic Compression Wave Tool. This usually requires a liquid couplant. It provides no detection or sizing capability where return signals are lost, which can occur in defects with rapidly changing profiles, some bends, and when a defect is shielded by a lamination. It is sensitive to debris and deposits on the inside pipe wall. High speeds degrade axial sizing resolution.

(d) Ultrasonic Shear Wave Tool. This requires a liquid couplant or a wheel-coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the defect. Sizing accuracy is degraded by the presence of inclusions and impurities in the pipe wall. High speeds degrade sizing resolution.

(e) Transverse Flux Tool. This is more sensitive to axially aligned metal-loss defects than standard and high resolution MFL tools. It may also be sensitive to other axially aligned defects. It is less sensitive than standard and high resolution MFL tools to circumferentially aligned defects. It generally provides less sizing accuracy than high resolution MFL tools for most defect geometries. High speeds can degrade sizing accuracy.

6.2.2 Crack Detection Tools for the Stress Corrosion Cracking Threat. For this threat, the following tools can be used. Their effectiveness is limited by the technology the tool employs.

(a) Ultrasonic Shear Wave Tool. This requires a liquid couplant or a wheel-coupled system. Sizing accuracy is limited by the number of sensors and the complexity of the crack colony. Sizing accuracy is degraded by the presence of inclusions and impurities in the pipe wall. High inspection speeds degrade sizing accuracy and resolution.

(b) Transverse Flux Tool. This is able to detect some axially aligned cracks, not including SCC, but is not considered accurate for sizing. High inspection speeds can degrade sizing accuracy.

6.2.3 Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage Threat. Dents and areas of metal loss are the only aspect of these threats for which ILI tools can be effectively used for detection and sizing.

Deformation or geometry tools are most often used for detecting damage to the line involving deformation of the pipe cross section, which can be caused by construction damage, dents caused by the pipe settling onto rocks, third-party damage, and wrinkles or buckles caused by compressive loading or uneven settlement of the pipeline.

The lowest-resolution geometry tool is the gaging pig or single-channel caliper-type tool. This type of tool is adequate for identifying and locating severe deformation of the pipe cross section. A higher resolution is provided by standard caliper tools that record a channel of data for each caliper arm, typically 10 or 12 spaced around the circumference. This type of tool can be used to discern deformation severity and overall shape aspects of the deformation. With some effort, it is possible to identify sharpness or estimate strains associated with the deformation using the standard caliper tool output. High-resolution tools provide the most detailed information about the deformation. Some also indicate slope or change in slope, which can be useful for identifying bending or settlement of the pipeline. Third-party damage that has rerounded under the influence of internal pressure in the pipe may challenge the lower limits of reliable detection of both the standard and high-resolution tools. There has been limited success identifying third-party damage using magnetic-flux leakage tools. MFL tools are not useful for sizing deformations.

6.2.4 All Other Threats. In-line inspection is typically not the appropriate inspection method to use for all other threats listed in para. 2.

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

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

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

(2) Classification. Differentiation between types of anomalies.

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

(4) Location Accuracy. Enables location of anomalies by excavation.

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

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

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

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

(3) Pipe Cleanliness. Can significantly affect data collection.

(4) Type of Fluid. Gas or liquid, affecting the possible choice of technologies.

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

(6) Product Bypass/Supplement. Reduction of gas flow and speed reduction capability on the ILI tool may be a consideration in higher velocity lines. Conversely, the availability of supplementary gas where the flow rate is too low shall be considered.

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

(1) confidence level of the ILI method (e.g., probability of detecting, classifying, and sizing the anomalies)

(2) history of the ILI method/tool

(3) success rate/failed surveys

(4) ability of the tool to inspect the full length and full circumference of the section

(5) ability to indicate the presence of multiple cause anomalies

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

6.2.6 Examination and Evaluation. Results of in-line inspection only provide indications of defects, with some characterization of the defect. Screening of this information is required in order to determine the time frame for examination and evaluation. The time frame is discussed in para. 7. **(04)**

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

6.3 Pressure Testing

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

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

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

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

(04) **6.3.2 Manufacturing and Related Defect Threats.** Pressure testing is appropriate for use when addressing the pipe seam aspect of the manufacturing threat. Pressure testing shall comply with the requirements of ASME B31.8. This will define whether air or water shall be used. Seam issues have been known to exist for pipe with a joint factor of less than 1.0 (e.g., lap-welded pipe, hammer-welded pipe, and butt-welded pipe) or if the pipeline is comprised of low-frequency welded electric resistance welded (ERW) pipe or flash-welded pipe.

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

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

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

6.3.4 Examination and Evaluation. Any section of pipe that fails a pressure test shall be examined in order to evaluate that the failure was due to the threat which the test was intended to address. If the failure was due to another threat, the test failure information must be integrated with other information relative to the other threat and the segment reassessed for risk.

6.4 Direct Assessment

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

6.4.1 External Corrosion Direct Assessment (ECDA) for the External Corrosion Threat. External corrosion direct assessment can be used for determining integrity for the external corrosion threat on pipeline segments. The process integrates facilities data, and current and historical field inspections and tests, with the physical characteristics of a pipeline. Nonintrusive (typically aboveground or indirect) inspections are used to estimate the success of the corrosion protection. The ECDA process requires direct examinations and evaluations. Direct examinations and evaluations confirm the ability of the indirect inspections to locate active and past corrosion locations on the pipeline. Post-assessment is required to determine a corrosion rate to set the reinspection interval, reassess the performance metrics and their current applicability, and ensure the assumptions made in the previous steps remain correct.

The ECDA process therefore has the following four components:

(a) pre-assessment

(b) inspections

(c) examinations and evaluations

(d) post-assessment

The focus of the ECDA approach described in this Standard is to identify locations where external corrosion defects may have formed. It is recognized that evidence of other threats such as mechanical damage and stress corrosion cracking (SCC) may be detected during the ECDA process. While implementing ECDA and when the pipe is exposed, the operator is advised to conduct examinations for nonexternal corrosion threats.

The prescriptive ECDA process requires the use of at least two inspection methods, verification checks by examination and evaluations, and post-assessment validation.

For more information on the ECDA process as an integrity assessment method, see Nonmandatory Appendix B, para. B1.

6.4.2 Internal Corrosion Direct Assessment Process (ICDA) for the Internal Corrosion Threat. Internal corrosion direct assessment can be used for determining integrity for the internal corrosion threat on pipeline segments that normally carry dry gas but may suffer from short-term upsets of wet gas or free water (or other electrolytes). Examinations of low points or at inclines along a pipeline, which force an electrolyte such as water to first accumulate, provide information about the remaining length of pipe. If these low points have not corroded, then other locations further downstream are less likely to accumulate electrolytes and therefore can be considered free from corrosion. These downstream locations would not require examination.

Internal corrosion is most likely to occur where water first accumulates. Predicting the locations of water accumulation (if upsets occur) serves as a method for prioritizing local examinations. Predicting where water first accumulates requires knowledge about the multiphase flow behavior in the pipe, requiring certain data (see para. 4). ICDA applies between any feed points until a new input or output changes the potential for electrolyte entry or flow characteristics.

Examinations are performed at locations where electrolyte accumulation is predicted. For most pipelines it is expected that examination by radiography or ultrasonic NDE will be required to measure the remaining wall thickness at those locations. Once a site has been exposed, internal corrosion monitoring method(s) [e.g., coupon, probe, ultrasonic (UT) sensor] may allow an operator to extend the reinspection interval and benefit from real-time monitoring in the locations most susceptible to internal corrosion. There may also be some applications where the most effective approach is to conduct in-line inspection for a portion of pipe, and use the results to assess the downstream internal corrosion where in-line inspection cannot be conducted. If the locations most susceptible to corrosion are determined not to contain defects, the integrity of a large portion of pipeline mileage has been assured.

For more information on the ICDA process as an integrity assessment method, see Nonmandatory Appendix B, para. B2.

6.4.3 All Other Threats. Direct assessment is typically not the appropriate integrity assessment method to use for all other threats listed in para. 2.

6.5 Other Integrity Assessment Methodologies

Other proven integrity assessment methods may exist for use in managing the integrity of pipelines. For the purpose of this Standard, it is acceptable for an operator to use these inspections as an alternative to those listed above.

For prescriptive-based integrity management programs, the alternative integrity assessment shall be an industry-recognized methodology, and be approved and published by an industry consensus standards organization.

For performance-based integrity management programs, techniques other than those published by consensus standards organizations may be utilized; however, the operator shall follow the performance requirements of this Standard and shall be diligent in confirming and documenting the validity of this approach to confirm that a higher level of integrity or integrity assurance was achieved.

7 RESPONSES TO INTEGRITY ASSESSMENTS AND MITIGATION (REPAIR AND PREVENTION)

7.1 General

This paragraph covers the schedule of responses to the indications obtained by inspection (see para. 6), repair activities that can be affected to remedy or eliminate an unsafe condition, preventive actions that can be taken to reduce or eliminate a threat to the integrity of a pipeline, and establishing the inspection interval. Inspection intervals are based on the characterization of defect indications, the level of mitigation achieved, the prevention methods employed, and the useful life of the data, with consideration given to expected defect growth.

Examination, evaluation, and mitigative actions shall be selected and scheduled to achieve risk reduction where appropriate in each segment within the integrity management program.

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

Table 4 includes a summary of some prevention and repair methods and their applicability to each threat.

7.2 Responses to Pipeline In-Line Inspections

An operator shall complete the response according to a prioritized schedule established by considering the results of a risk assessment and the severity of in-line inspection indications. The required response schedule interval begins at the time the condition is discovered.

When establishing schedules, responses can be divided into the following three groups:

(a) immediate: indication shows that defect is at failure point

(b) scheduled: indication shows defect is significant but not at failure point

(c) monitored: indication shows defect will not fail before next inspection

Upon receipt of the characterization of indications discovered during a successful in-line inspection, the operator shall promptly review the results for immediate response indications. Other indications shall be reviewed within 6 months and a response plan shall be developed. The plan shall include the methods and timing of the response (examination and evaluation). For scheduled or monitored responses, an operator may reinspect rather than examine and evaluate, provided the reinspection is conducted and results obtained within the specified time frame.

7.2.1 Metal Loss Tools for Internal and External Corrosion. (04) Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. This would include any corroded areas that have a predicted failure pressure level less than 1.1 times the MAOP as determined by ASME B31G or equivalent. Also in this group would be any metal-loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding. The operator shall examine these indications within a period not to exceed 5 days 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.

Indications in the scheduled group are suitable for continued operation without immediate response provided they do not grow to critical dimensions prior to the scheduled response. Indications characterized with a predicted failure pressure greater than 1.10 times the MAOP shall be examined and evaluated according to a

Table 4 Acceptable Threat Prevention and Repair Methods

Prevention, Detection, and Repair Methods	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environment
	TPD(IF)	PDP	Vand	Ext	Int	Gask/ Oring	Strip/ BP	Cont/ Rel	Seal/ Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
Prevention/Detection																					
Aerial patrol	X	X	X	...	...	...	...	...	...	...	X	X	X	...	...	...	...	X	...	X	...
Foot patrol	X	X	X	X	...	...	...	...	...	...	X	X	X	...	...	...	...	X	...	X	...
Visual/mechanical inspection	...	...	...	...	...	X	X	X	X	...	X	...	...	...	...	X	...	...	...	...	...
One-call system	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Compliance audit	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...
Design specifications	...	...	...	X	X	X	X	X	X	...	...	...	...	...	...	X	...	X	X	X	X
Materials specifications	...	...	...	...	...	X	X	X	X	...	...	...	...	X	X	...	X	...	...	...	...
Manufacturer inspection	...	X	...	...	...	...	...	X	X	...	...	...	...	X	X	...	X	...	...	...	...
Transportation inspection	...	X	...	...	...	...	...	...	...	...	...	...	...	X	X	...	...	...	...	...	...
Construction inspection	...	X	...	...	...	X	X	X	X	...	...	...	...	...	X	X	X	X	X	...	X
Preservice hydrostatic test	...	X	...	...	...	...	...	...	...	...	...	...	...	X	X	X	X	X	X	...	...
Public education	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
O&M procedures	...	X	X	X	X	X	X	X	X	X	X	...	X	...	...	...	...	X	X	X	X
Operator training	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...
Increase marker frequency	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Strain monitoring	...	...	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	X	...
External protection	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Maintain ROW	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Increased wall thickness	X	X	X	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...
Warning tape mesh	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
CP monitor/maintain	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X
Internal cleaning	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Leakage control measures	...	X	X	X	X	X	X	X	X	...	...	...	...	...	...	...	...	X	...	...	...
Pig-GPS/strain measurement	...	...	...	...	...	...	...	...	...	...	X	...	X	...	...	...	...	...	...	X	...
Reduce external stress	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	X	X	X	X
Install heat tracing	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...
Line relocation	X	...	X	...	...	...	...	...	...	...	X	...	X	...	...	...	...	...	...	X	...
Rehabilitation	...	X	...	X	X	...	...	...	...	...	...	...	...	...	...	...	...	X	X	X	X
Coating repair	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X
Increase cover depth	X	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	X	...	...
Operating temperature reduction	...	...	...	...	...	X	...	...	X	...	...	...	...	...	...	...	...	...	...	...	X
Reduce moisture	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Biocide/inhibiting injection	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Install thermal protection	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...	...	...	...	...	...

Table 4 Acceptable Threat Prevention and Repair Methods (Cont'd)

Prevention, Detection, and Repair Methods	Third-Party Damage			Corrosion Related		Equipment				Incorrect Operation	Weather Related			Manufacture		Construction				O-Force	Environment
	TPD(IF)	PDP	Vand	Ext	Int	Gask/ Oring	Strip/ BP	Cont/ Rel	Seal/ Pack	IO	CW	L	HR/F	Pipe Seam	Pipe	Gweld	Fab Weld	Coup	WB/B	EM	SCC
Repairs																					
Pressure reduction	...	X	...	X	X	...	...	...	...	...	...	...	...	X	X	X	X	X	...	...	X
Replacement	...	X	X	X	X	X	X	X	X	...	X	X	X	X	X	X	X	X	X	X	X
ECA, recoat	...	...	...	X	X	...	...	...	...	...	...	...	...	...	...	X	...	...	...	...	...
Grind repair/ECA	...	X	X	...	...	...	...	...	...	...	...	...	...	X	X	X	X	...	...	...	X
Direct deposition weld	...	...	X	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Type B, pressurized sleeve	...	X	X	X	X	...	...	...	...	...	...	...	...	X	X	...	X	X	...	...	X
Type A, reinforcing sleeve	...	X	X	X	...	...	...	...	...	...	...	...	...	X	X	...	...	...	...	...	X
Composite sleeve	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...
Epoxy filled sleeve	...	X	X	X	...	...	...	...	...	...	...	...	...	X	X	X	X	X	X	...	...
Mechanical leak clamp	...	...	...	X	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...	...

GENERAL NOTE: The abbreviations found in Table 4 relate to the 21 threats discussed in para. 5. Explanations of the abbreviations are as follows:

Cont/Rel = Control/Relief Equipment Malfunction
Coup = Coupling Failure
CW = Cold Weather
EM = Earth Movement
Ext = External Corrosion
Fab Weld = Defective Fabrication Weld
Gask/Oring = Gasket or O-Ring
Gweld = Defective Pipe Girth Weld
HR/F = Heavy Rains or Floods
Int = Internal Corrosion
IO = Incorrect Operations Company Procedure
L = Lightning
PDP = Previously Damaged Pipe (delayed failure mode)
Pipe = Defective Pipe
Pipe Seam = Defective Pipe Seam
SCC = Stress Corrosion Cracking
Seal/Pack = Seal/Pump Packing Failure
Strip/BP = Stripped Thread/Broken Pipe
TPD(IF) = Damage Inflicted by First, Second, or Third Parties
Vand = Vandalism
WB/B = Wrinkle Bend or Buckle

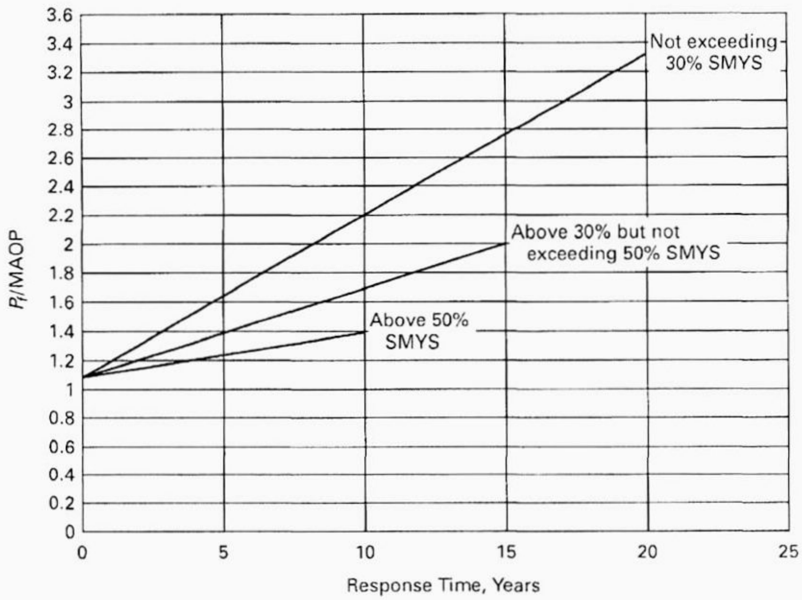


Fig. 4 Timing for Scheduled Responses: Time-Dependent Threats, Prescriptive Integrity Management Plan

schedule established by Fig. 4. 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.

Monitored indications are the least severe and will not require examination 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.

7.2.2 Crack Detection Tools for Stress Corrosion Cracking. All indications of stress corrosion cracks require immediate response. The operator shall examine and evaluate these indications within a period not to exceed 5 days following determination of the condition. After examination and evaluation, any defect found to require repair or removal shall be promptly remediated by repair, removal, or lowering the operating pressure.

7.2.3 Metal Loss and Caliper Tools for Third-Party Damage and Mechanical Damage. Indications requiring immediate response are those that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. These could include dents with gouges. The operator shall examine these indications within a period not to exceed 5 days following determination of the condition.

Indications requiring a scheduled response would include any indication on a pipeline operating at or above 30% of specified minimum yield strength (SMYS) of a plain dent that exceeds 6% of the nominal pipe diameter, 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. (For additional information, see ASME B31.8, para. 851.4.) The operator shall expeditiously examine these 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.

7.2.4 Limitations to Response Times for Prescriptive-Based Program. When time-dependent anomalies such as internal corrosion, external corrosion, or stress corrosion cracking are being evaluated, an analysis utilizing appropriate assumptions about growth rates shall be used to assure that the defect will not attain critical dimensions prior to the scheduled repair or next inspection. GRI-00/0230 (see para. 14) contains additional guidance for these analyses.

When determining repair intervals, the operator should consider that certain threats to specific pipeline operating conditions may require a reduced examination and evaluation interval. This may include third-party damage or construction threats in pipelines subject to pressure cycling or external loading that may promote increased defect growth rates. For prescriptive-based programs, the inspection intervals are conservative for potential defects that could lead to a rupture; however, this does not alleviate operators of the responsibility to evaluate the specific conditions and changes in operating conditions to insure the pipeline segment does not warrant special consideration (see GRI-01/0085).

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

7.2.5 Extending Response Times for Performance-Based Program. An engineering critical assessment (ECA) of some defects may be performed to extend the repair or reinspection interval for a performance-based program. ECA is a rigorous evaluation of the data that reassesses the criticality of the anomaly and adjusts the projected growth rates based on site-specific parameters.

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

7.3 Responses to Pressure Testing

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

7.3.1 External and Internal Corrosion Threats. The interval between tests for the external and internal corrosion threats shall be consistent with Table 3.

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

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

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

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

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

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

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

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

7.4 Responses to Direct Assessment Inspections

7.4.1 External Corrosion Direct Assessment (ECDA). (04) For the ECDA prescriptive program for pipelines operating at and above 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspection, and repairs all defects that could grow to failure in 10 years, then the reinspection interval shall be 10 years. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 5 years, provided an analysis is performed to ensure all remaining defects will not grow to failure in 10 years. The interval between determination and examination shall be consistent with Fig. 4.

For the ECDA prescriptive program for pipeline segments operating below 30% SMYS, if the operator chooses to examine and evaluate all the indications found by inspections and repair all defects that could grow to failure in 20 years, the reinspection interval shall be 20 years. If the operator elects to examine, evaluate, and repair a smaller set of indications, then the interval shall be 10 years, provided an analysis is performed to ensure all remaining defects will not grow to failure in 20 years (at an 80% confidence level). The interval between determination and examination shall be consistent with Fig. 4.

7.4.2 Internal Corrosion Direct Assessment (ICDA). For the ICDA prescriptive program, examination and evaluation of all selected locations must be performed within 1 year of selection. The interval between subsequent examinations shall be consistent with Fig. 4.

Figure 4 contains three plots of the allowed time to respond to an indication, based on the predictive failure pressure P_f divided by the MAOP of the pipeline. The three plots correspond to

(a) pipelines operating at or above 50% SMYS

(b) pipelines operating at or above 30% SMYS but at less than 50% SMYS

(c) pipelines operating at less than 30% SMYS

The figure is applicable to the prescriptive-based program. The intervals may be extended for the performance-based program as provided in para. 7.2.5.

7.5 Repair Methods

Table 4 provides acceptable repair methods for each of the 21 threats.

Each 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 B31.8 requirements.

7.6 Prevention Strategy/Methods

Prevention is an important proactive element of an integrity management program. Integrity management program prevention strategies should be based on data gathering, threat identification, and risk assessments conducted per the requirements of paras. 2, 3, 4 and 5. Prevention 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 utilized.

Operators who opt for prescriptive programs should use, at a minimum, the prevention methods indicated in Nonmandatory Appendix A under "Mitigation."

For operators who choose performance-based programs, both the preventive methods and time intervals employed for each threat/segment should be determined by analysis using system attributes, information about existing conditions, and industry-proven risk assessment methods.

7.7 Prevention Options

An 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 presented in para. 7 include information on the following:

(a) preventing third-party damage

(b) controlling corrosion

(c) detecting unintended releases

(d) minimizing the consequences of unintended releases

(e) operating pressure reduction

There are other prevention activities that the operator may consider. A tabulation of prevention activities and their relevance to the threats identified in para. 2 is presented in Table 4.

8 INTEGRITY MANAGEMENT PLAN

8.1 General

The integrity management plan is developed after gathering the data (see para. 4) and completing the risk assessment (see para. 5) for each threat and for each pipeline segment or system. An appropriate integrity assessment method shall be identified for each pipeline system or segment. Integrity assessment of each system can be accomplished through a pressure test, an in-line inspection using a variety of tools, direct assessment, or use of other proven technologies (see para. 6). In some cases, a combination of these methods may be appropriate. The highest-risk segments shall be given priority for integrity assessment.

Following the integrity assessment, mitigation activities shall be undertaken. Mitigation consists of two parts. The first part is the repair of the pipeline. Repair activities shall be made in accordance with ASME B31.8 and/or other accepted industry repair techniques. Repair may include replacing defective piping with new pipe, installation of sleeves, coating repair, or other rehabilitation. These activities shall be identified, prioritized, and scheduled (see para. 7).

Once the repair activities are determined, the operator shall evaluate prevention techniques that prevent future deterioration of the pipeline. These techniques may include providing additional cathodic protection, injecting corrosion inhibitors and pipeline cleaning, or changing the operating conditions. Prevention plays a major role in reducing or eliminating the threats from third-party damage, external corrosion, internal corrosion, stress corrosion cracking, cold weather-related failures, earth movement failures, problems caused by heavy rains and floods, and failures caused by incorrect operations.

All threats cannot be dealt with through inspection and repair; therefore, prevention for these threats is a key element in the plan. These activities may include, e.g., prevention of third-party damage and monitoring for outside force damage.

A performance-based integrity management plan, containing the same structure as the prescriptive-based plan, requires more detailed analyses based upon more complete data or information about the line. Using a risk assessment model, a pipeline operator can exercise a variety of options for integrity assessments and prevention activities, as well as their timing.

Prior integrity assessments and mitigation activities should only be included in the plan if they were as rigorous as those identified in this Standard.

8.2 Updating the Plan

Data collected during the inspection and mitigation activities shall be analyzed and integrated with previously collected data. This is in addition to other types of integrity management-related data that is constantly being gathered through normal operations and maintenance activities. The addition of this new data is a continuous process that, over time, will improve the accuracy of future risk assessments via its integration (see para. 4). This ongoing data integration and periodic risk assessment will result in continual revision to the integrity assessment and mitigation aspects of the plan. In addition, changes to the physical and operating aspects of the pipeline system or segment shall be properly managed (see para. 11).

This ongoing process will most likely result in a series of additional integrity assessments or review of previous integrity assessments. A series of additional mitigation activities or follow-up to previous mitigation activities may also be required. The plan shall be updated periodically as additional information is acquired and incorporated.

It is recognized that certain integrity assessment activities may be one-time events and focused on elimination of certain threats, such as manufacturing, construction, and equipment threats. For other threats, such as time-dependent threats, periodic inspection will be required. The plan shall remain flexible and incorporate any new information.

8.3 Plan Framework

The integrity management plan shall contain detailed information regarding each of the following elements for each threat analyzed and each pipeline segment or system.

8.3.1 Gathering, Reviewing, and Integrating Data. The first step in the integrity management process is to collect, integrate, organize, and review all pertinent and available data for each threat and pipeline segment. This process step is repeated after integrity assessment and mitigation activities have been implemented, and as new operation and maintenance information about the pipeline system or segment is gathered. This information review shall be contained in the plan or in a database that is part of the plan. All data will be used to support future risk assessments and integrity evaluations. Data gathering is covered in para. 4.

8.3.2 Assess Risk. Risk assessment should be performed periodically to include new information, consider changes made to the pipeline system or segment, incorporate any external changes, and consider new scientific techniques that have been developed and commercialized since the last assessment. It is recommended that this be performed annually but shall be performed after substantial changes to the system are made and before the end of the current interval. The results of this assessment are to be reflected in the mitigation and integrity assessment activities. Changes to the acceptance criteria will also necessitate reassessment. The integrity management plan shall contain specifics about how risks are assessed and the frequency of reassessment. The specifics for assessing risk are covered in para. 5.

8.3.3 Integrity Assessment. Based on the assessment of risk, the appropriate integrity assessments shall be implemented. Integrity assessments shall be conducted using in-line inspection tools, pressure testing, and/or direct assessment. For certain threats, use of these tools may be inappropriate. Implementation of prevention activities or more frequent maintenance activities may provide a more effective solution. Integrity assessment method selection is based on the threats for which the inspection is being performed. More than one assessment method or more than one tool may be required to address all the threats. After each integrity assessment, this portion of the plan shall be modified to reflect all new information obtained and to provide for future integrity assessments at the required intervals. The plan shall identify required integrity assessment actions and at what established intervals the actions will take place. All integrity assessments shall be prioritized and scheduled.

Table 3 provides the integrity assessment schedules for time-dependent threats for prescriptive plans. A current prioritization listing and schedule shall be contained in this section of the integrity management plan. The specifics for selecting integrity assessment methods and performing the inspections are covered in para. 6. A performance-based integrity management plan can provide alternative integrity assessment, repair, and prevention methods with different implementation times than those required under the prescriptive program. These decisions shall be fully documented.

8.3.4 Responses to Integrity Assessment, Mitigation (Repair and Prevention), and Intervals. The plan shall specify how and when the operator will respond to integrity assessments. The responses shall be immediate, scheduled, or monitored. The mitigation element of the plan consists of two parts. The first part is the repair of the pipeline. Based on the results of the integrity assessments and the threat being addressed, appropriate repair activities shall be determined and conducted. These repairs shall be performed in accordance with accepted standards and operating practices. The second part of mitigation is prevention. Prevention can stop or slow down future deterioration of the pipeline. Prevention is also an appropriate activity for time-independent threats. All mitigation activities shall be prioritized and scheduled. The prioritization and schedule shall be modified as new information is obtained and shall be a real-time aspect of the plan (see para. 7)

Tables 5, 6, and 7 provide an example of an integrity management plan in a spreadsheet format for a hypothetical pipeline segment (line 1, segment 3). This spreadsheet shows the segment data, the integrity assessment plan devised based on the risk assessment, and the mitigation plan that would be implemented, including the reassessment interval.

9 PERFORMANCE PLAN

9.1 Introduction (04)

This paragraph provides the performance plan requirements that apply to both prescriptive- and performance-based integrity management programs. Plan evaluations shall be performed at least annually to provide a continuing measure of integrity management program effectiveness over time. Such evaluations should

Table 5 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Segment Data: Line 1, Segment 3)

Segment Data	Type	Example
Pipe attributes	Pipe grade	API 5L-X42
	Diameter	24 in.
	Wall thickness	0.250 in.
	Manufacturer	A. O. Smith
	Manufacturer process	Low frequency
	Manufacturing date	1965
	Seam type	Electric resistance weld
Design/construction	Operating pressure (high/low)	630/550 psig
	Operating stress	72% SMYS
	Coating type	Coal tar
	Coating condition	Fair
	Pipe install date	1966
	Joining method	Submerged arc weld
	Soil type	Clay
	Soil stability	Good
	Hydrostatic test	None
Operational	Compressor discharge temperature	120°F
	Pipe wall temperature	65°F
	Gas quality	Good
	Flow rate	50 MMSCFD
	Repair methods	Replacement
	Leak/rupture history	None
	Pressure cycling	Low
	CP effectiveness	Fair
	SCC indications	Minor cracking

consider both threat-specific and aggregate improvements. Threat-specific evaluations may apply to a particular area of concern, while overall measures apply to all pipelines under the integrity management program.

Program evaluation will help an operator answer the following questions:

(a) Were all integrity management program objectives accomplished?

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

(04) **9.2 Performance Measures Characteristics**

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

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

9.2.1 Process or Activity Measures. Process or activity measures can be used to evaluate prevention or mitigation activities. These measures determine how well an operator is implementing various elements of the integrity management program. Measures relating to process or activity shall be selected carefully to permit performance evaluation within a realistic time frame.

9.2.2 Operational Measures. Operational measures include operational and maintenance trends that measure how well the system is responding to the integrity management program. An example of such a measure might be the changes in corrosion rates due to the implementation of a more effective CP program. The number of third-party pipeline hits after the implementation of prevention activities, such as improving the excavation notification process within the system, is another example. (04)

Table 6 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Integrity Assessment Plan: Line 1, Segment 3)

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

Table 7 Example of Integrity Management Plan for Hypothetical Pipeline Segment (Mitigation Plan: Line 1, Segment 3)

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

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

9.2.3 Direct Integrity Measures. Direct integrity measures include leaks, ruptures, injuries, and fatalities. In addition to the above categories, performance measures can also be categorized as leading measures or lagging measures. Lagging measures are reactive in that they provide an indication of past integrity management program performance. Leading measures are proactive; they provide an indication of how the plan may be expected to perform. Several examples of performance measures classified as described above are illustrated in Table 8.

9.3 Performance Measurement Methodology

An operator can evaluate a system's integrity management program performance within their own system and also by comparison with other systems on an industry-wide basis.

9.4 Performance Measurement: Intrasystem

(a) Performance metrics shall be selected and applied on a periodic basis for the evaluation of both prescriptive- and performance-based integrity management programs. Such metrics shall be suitable for evaluation of local and threat-specific conditions, and for evaluation of overall integrity management program performance.

(b) For operators implementing prescriptive programs, performance measurement shall include all of the

Table 8 Performance Measures

Measurement Category	Lagging Measures	Leading Measures
Process/activity measures	Pipe damage found per location excavated	Number of excavation notification requests, number of patrol detects
Operational measures	Number of significant ILI corrosion anomalies	New rectifiers and ground beds installed, CP current demand change, reduced CIS fault detects
Direct integrity measures	Leaks per mile in an integrity management program	Change in leaks per mile

threat-specific metrics for each threat in Nonmandatory Appendix A (see Table 9). Additionally, the following overall program measurements shall be determined and documented:

(1) number of miles of pipeline inspected versus program requirements

(2) number of immediate repairs completed as a result of the integrity management inspection program

(3) number of scheduled repairs completed as a result of the integrity management inspection program

(4) number of leaks, failures, and incidents (classified by cause)

(c) For operators implementing performance-based programs, the threat-specific metrics shown in Nonmandatory Appendix A shall be considered, although others may be used that are more appropriate to the specific performance-based program. In addition to the four metrics above, the operator should choose three or four metrics that measure the effectiveness of the performance-based program. Table 10 provides a suggested list; however, the operator may develop their own set of metrics. Since performance-based inspection intervals will be utilized in a performance-based integrity management program, it is essential that sufficient metric data be collected to support those inspection intervals. Evaluation shall be performed on at least an annual basis.

(d) In addition to performance metric data collected directly from segments covered by the integrity management program, internal benchmarking can be conducted that may compare a segment against another adjacent segment or those from a different area of the same pipeline system. The information obtained may be used to evaluate the effectiveness of prevention activities, mitigation techniques, or performance validation. Such comparisons can provide a basis to substantiate metric analyses and identify areas for improvements in the integrity management program.

(e) A third technique that will provide effective information is internal auditing. Operators shall conduct periodic audits to validate the effectiveness of their integrity management programs and ensure that they have been conducted in accordance with the written plan. An audit frequency shall be established, considering the established performance metrics and their particular time base in addition to changes or modifications made to the integrity management program as it evolves. Audits may be performed by internal staff, preferably by personnel not directly involved in the administration of the integrity management program, or other resources. A list of essential audit items is provided below as a starting point in developing a company audit program.

(1) A written integrity management policy and program for all the elements in Fig. 2 shall be in place.

(2) Written integrity management plan procedures and task descriptions are up to date and readily available.

(3) Activities are performed in accordance with the plan.

(4) A responsible individual has been assigned for each element.

(5) Appropriate references are available to responsible individuals.

(6) Individuals have received proper qualification, which has been documented.

(7) The integrity management program meets the requirements of this document.

(8) All required activities are documented.

(9) All action items or nonconformances are closed in a timely manner.

(10) The risk criteria used have been reviewed and documented.

(11) Prevention, mitigation, and repair criteria have been established, met, and documented.

(f) Data developed from program specific performance metrics, results of internal benchmarking, and audits shall be used to provide an effective basis for evaluation of the integrity management program.

Table 9 Performance Metrics

Threats	Performance Metrics for Prescriptive Programs
External corrosion	Number of hydrostatic test failures caused by external corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of external corrosion leaks
Internal corrosion	Number of hydrostatic test failures caused by internal corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of internal corrosion leaks
Stress corrosion cracking	Number of in-service leaks or failures due to SCC Number of repair replacements due to SCC Number of hydrostatic test failures due to SCC
Manufacturing	Number of hydrostatic test failures caused by manufacturing defects Number of leaks due to manufacturing defects
Construction	Number of leaks or failures due to construction defects Number of girth welds/couplings reinforced/removed Number of wrinkle bends removed Number of wrinkle bends inspected Number of fabrication welds repaired/removed
Equipment	Number of regulator valve failures Number of relief valve failures Number of gasket or O-ring failures Number of leaks due to equipment failures
Third-party damage	Number of leaks or failures caused by third-party damage Number of leaks or failures caused by previously damaged pipe Number of leaks or failures caused by vandalism Number of repairs implemented as a result of third-party damage prior to a leak or failure
Incorrect operations	Number of leaks or failures caused by incorrect operations Number of audits/reviews conducted Number of findings per audit/review, classified by severity Number of changes to procedures due to audits/reviews
Weather related and outside forces	Number of leaks that are weather related or due to outside force Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

9.5 Performance Measurement: Industry Based

In addition to intrasystem comparisons, external comparisons can provide a basis for performance measurement of the integrity management program. This can include comparisons with other pipeline operators, industry data sources, and jurisdictional data sources. Benchmarking with other gas pipeline operators can be useful; however, any performance measure or evaluation derived from such sources shall be carefully evaluated to ensure that all comparisons made are valid. Audits conducted by outside entities can also provide useful evaluation data.

9.6 Performance Improvement

The results of the performance measurements and audits shall be utilized to modify the integrity management program as part of a continuous improvement process. Internal and external audit results are performance measures that should be used to evaluate effectiveness in addition to other measures stipulated in the integrity management program. Recommendations for changes and/or improvements to the integrity management program shall be based on analysis of the performance measures and audits. The results, recommendations, and resultant changes made to the integrity management program shall be documented.

10 COMMUNICATIONS PLAN

10.1 General

The operator shall develop and implement a communications plan in order to keep appropriate company personnel, jurisdictional authorities, and the public informed about their integrity management efforts and

Table 10 Overall Performance Measures

Miles inspected vs. integrity management program requirement
Number of integrity management program changes requested by jurisdictional authorities
Jurisdictional reportable incidents/safety-related conditions per unit of time
Amount of integrity management program required activities completed
Fraction of system included in the integrity management program
Number of actions completed that impact safety
Number of anomalies found requiring repair or mitigation
Number of leaks repaired
Number of hydrostatic test failures and test pressures
Number of third-party damage events, near misses, damage detected
Risk reduction achieved by integrity management program
Number of unauthorized crossings
Number of precursor events detected
Number of right-of-way encroachments:
Number of pipeline hits by third parties due to lack of notification as locate request through the one-call process
Aerial/ground patrol incursion detections
Number of excavation notifications received and their disposition
Number and types of public communications issued
Effectiveness of communications
Public confidence in integrity management program activities
Effectiveness of the feedback process
Integrity management program costs
Integrity improvement through use of new technology
Unscheduled outages and impact on customers

the results of their integrity management activities. The information may be communicated as part of other required communications.

Some of the information should be communicated routinely. Other information may be communicated upon request. Use of industry, jurisdictional, and company websites may be an effective way to conduct these communication efforts.

Communications should be conducted as often as necessary to ensure that appropriate individuals and authorities have current information about the operator's system and their integrity management efforts. It is recommended that communications take place periodically and as often as necessary to communicate significant changes to the integrity management plan.

(04) 10.2 External Communications

The following items should be considered for communication to the various interested parties, as outlined below:

(a) *Landowners and Tenants Along the Rights-of-Way*

(1) company name, location, and contact information

(2) general location information and where more specific location information or maps can be obtained

(3) commodity transported

(4) how to recognize, report, and respond to a leak

(5) contact phone numbers, both routine and emergency

(6) general information about the pipeline operator's prevention, integrity measures, and emergency preparedness, and how to obtain a summary of the integrity management plan

(7) damage prevention information, including excavation notification numbers, excavation notification center requirements, and who to contact if there is any damage

(b) *Public Officials Other Than Emergency Responders*

(1) periodic distribution to each municipality of maps and company contact information

(2) summary of emergency preparedness and integrity management program

(c) *Local and Regional Emergency Responders*

(1) operator should maintain continuing liaison with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.

(2) company name and contact numbers, both routine and emergency

(3) local maps

(4) facility description and commodity transported

(5) how to recognize, report, and respond to a leak

(6) general information about the operator's prevention and integrity measures, and how to obtain a summary of the integrity management plan

(7) station locations and descriptions

(8) summary of operator's emergency capabilities

(9) coordination of operator's emergency preparedness with local officials

(d) *General Public*

(1) information regarding operator's efforts to support excavation notification and other damage prevention initiatives

(2) company name, contact, and emergency reporting information, including general business contact

It is expected that some dialogue may be necessary between the operator and the public in order to convey the operator's confidence in the integrity of the pipeline, as well as to convey the operator's expectations of the public as to where they can help maintain integrity. Such opportunities should be welcomed in order to help protect assets, people, and the environment.

10.3 Internal Communications

Operator management and other appropriate operator personnel must understand and support the integrity management program. This should be accomplished through the development and implementation of an internal communications aspect of the plan. Performance measures reviewed on a periodic basis and resulting adjustments to the integrity management program should also be part of the internal communications plan.

11 MANAGEMENT OF CHANGE PLAN

(a) Formal management of change procedures shall be developed in order to identify and consider the impact of changes to pipeline systems and their integrity. These procedures should be flexible enough to accommodate both major and minor changes, and must be understood by the personnel that use them. Management of change shall address technical, physical, procedural, and organizational changes to the system, whether permanent or temporary. The process should incorporate planning for each of these situations and consider the unique circumstances of each.

A management of change process includes the following:

(1) reason for change

(2) authority for approving changes

(3) analysis of implications

(4) acquisition of required work permits

(5) documentation

(6) communication of change to affected parties

(7) time limitations

(8) qualification of staff

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

(1) If a change in land use would affect either the consequence of an incident, such as increases in population near the pipeline, or a change in likelihood of an incident, such as subsidence due to underground mining, the change must be reflected in the integrity management plan and the threats reevaluated accordingly. **(04)**

(2) If the results of an integrity management program inspection indicate the need for a change to the system, such as changes to the CP program or, other than temporary, reductions in operating pressure, these shall be communicated to operators and reflected in an updated integrity management program.

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

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

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

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

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

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

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

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

12 QUALITY CONTROL PLAN

This paragraph describes the quality control activities that shall be part of an acceptable integrity management program.

12.1 General

Quality control as defined for this Standard is the "documented proof that the operator meets all the requirements of their integrity management program."

Pipeline operators that have a quality control program that meets or exceeds the requirements in this paragraph can incorporate the integrity management program activities within their existing plan. For those operators that do not have a quality program, this paragraph outlines the basic requirements of such a program.

12.2 Quality Management Control

(a) Requirements of a quality control program include documentation, implementation, and maintenance. The following six activities are usually required:

(1) identify the processes that will be included in the quality program

(2) determine the sequence and interaction of these processes

(3) determine the criteria and methods needed to ensure that both the operation and control of these processes are effective

(4) provide the resources and information necessary to support the operation and monitoring of these processes

(5) monitor, measure, and analyze these processes

(6) implement actions necessary to achieve planned results and continued improvement of these processes

(b) Specifically, activities that should be included in the quality control program are as follows:

(1) determine the documentation required and include it in the quality program. These documents shall be controlled and maintained at appropriate locations for the duration of the program. Examples of documented activities include risk assessments, the integrity management plan, integrity management reports, and data documents.

(2) the responsibilities and authorities under this program shall be clearly and formally defined.

(3) results of the integrity management program and the quality control program shall be reviewed at predetermined intervals, making recommendations for improvement.

(4) the personnel involved in the integrity management program shall be competent, aware of the program and all of its activities, and be qualified to execute the activities within the program. Documentation of such competence, awareness, and qualification, and the processes for their achievement, shall be part of the quality control plan. **(04)**

(5) the operator shall determine how to monitor the integrity management program to show that it is being implemented according to plan and document these steps. These control points, criteria, and/or performance metrics shall be defined.

(6) periodic internal audits of the integrity management program and its quality plan are recommended. An independent third-party review of the entire program may also be useful.

(7) corrective actions to improve the integrity management program or quality plan shall be documented and the effectiveness of their implementation monitored.

(c) When an operator chooses to use outside resources to conduct any process (for example, pigging) that affects the quality of the integrity management program, the operator shall ensure control of such processes and document them within the quality program.

13 TERMS, DEFINITIONS, AND ACRONYMS **(04)**

See Fig. 5 for the hierarchy of terminology for integrity assessment.

bell hole: excavation that minimizes surface disturbance yet provides sufficient room for examination or repair of buried facilities.

cathodic protection (CP): technique by which underground metallic pipe is protected against deterioration (rusting and pitting).

close interval survey (CIS): inspection technique that includes a series of aboveground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e., 2,100 ft) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

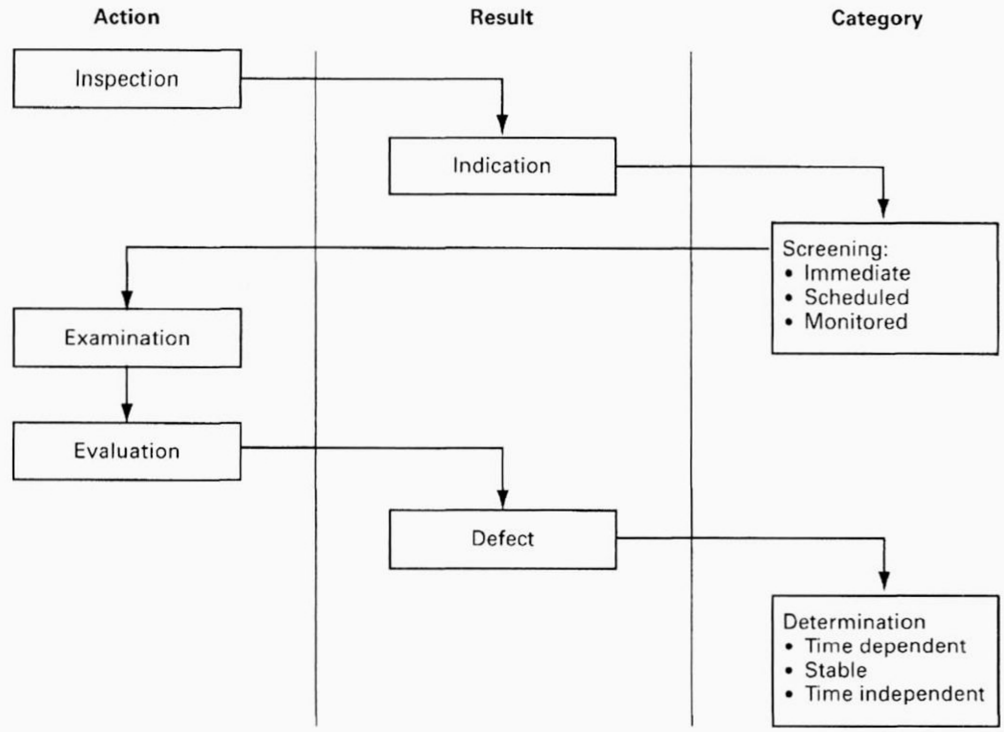


Fig. 5 Hierarchy of Terminology for Integrity Assessment

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

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

defect: imperfection of a type and magnitude exceeding acceptable criteria.

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

double submerged-arc welded pipe (DSAW pipe): pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc welded process.

electric resistance welded pipe (ERW pipe): pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of pressure and heat obtained from electrical resistance. ERW pipe forming is distinct from flash welded pipe and furnace butt-welded pipe as a result of being produced in a continuous forming process from coils of flat plate.

evaluation: analysis and determination of the facility's fitness for service under the current operating conditions.

examination: direct physical inspection of the pipelines by a person and may also include the use of nondestructive examination techniques (NDE).

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

fracture toughness: resistance of a material to failure from the extension of a crack.

gas: as used in this Standard, any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air.

geographic information system (GIS): system of computer software, hardware, data, and personnel to help manipulate, analyze, and present information that is tied to a geographic location.

global positioning system (GPS): system used to identify the latitude and longitude of locations using GPS satellites.

hydrogen-induced cracking (HIC): form of hydrogen-induced damage consisting of cracking of the metal.

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

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

indication: finding of a nondestructive testing technique. It may or may not be a defect.

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

inspection: use of a nondestructive testing technique.

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

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

location class: onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Class location units are categorized as Class 1 through 4. Class 1 locations are more rural and Class 4 locations are more urban.

magnetic flux leakage (MFL): type of in-line inspection technique that induces a magnetic field in a pipe wall between two poles of a magnet. Sensors record changes in the magnetic flux (flow) that can be used to evaluate metal loss.

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

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

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

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

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

nondestructive examination (NDE): inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic, and dye penetrant methods.

operator: entity that operates and maintains the pipeline facilities and has fiduciary responsibility for such pipeline facilities.

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

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

piggability: ability of a pipeline or segment to be inspected by an ILI device.

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

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

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

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

probability: likelihood of an incident occurring.

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

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

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

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

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

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

rupture: complete failure of any portion of the pipeline.

SCADA system: supervisory control and data acquisition system.

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

smart pig: industry term for a type of ILI device.

specified minimum yield strength (SMYS): minimum yield strength of the steel in pipe as required by the pipe product specifications, $lb/in.^2$

stress concentrator: discontinuity in a structure or change in contour that causes a local increase in stress.

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

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

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

third-party damage: damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this Standard, this also includes damage caused by the operator's personnel or the operator's contractors.

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

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

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

wrinkle bend: pipe bend produced by field machine or controlled process that may result in abrupt contour discontinuities on the inner radius.

14 REFERENCES AND STANDARDS

The following is a list of publications that support or are referenced in this Standard.

Common Ground: Study of One-Call Systems and Damage Prevention Best Practices

Publisher: Office of Pipeline Safety (OPS), Research and Special Programs Administration, U.S. Department of Transportation, 400 Seventh Street, SW, Washington, DC 20590

Guidelines for Technical Management of Chemical Process Safety

Publisher: Center for Chemical Process Safety (CCPS) of the American Institute of Chemical Engineers (AIChE), 3 Park Avenue, New York, NY 10016

Juran's Quality Control Handbook (4th Edition)

Publisher: McGraw-Hill Book Company, 1221 Avenue of the Americas, New York, NY 10020

Pipeline Risk Management Manual (2nd Edition)

Publisher: Gulf Publishing Company, P.O. Box 2608, Houston, TX 77252

ANSI/ISO/ASQ Q9004-2000, Quality Management Systems (Spanish Language Version): Guidelines for Performance Improvements

Publisher: American Society for Quality (ASQ), P.O. Box 3005, Milwaukee, WI 53201

API 1160, Managing System Integrity for Hazardous Liquid Pipelines

Publisher: American Petroleum Institute (API), 1220 L Street, NW, Washington, DC 20005

ASME B31.8, Gas Transmission and Distribution Piping Systems

ASME B31G, Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping

ASME CRTD-Vol. 40-1, Risk-Based In-Service Testing — Development of Guidelines, Volume 1: General Document

Publisher: The American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016-5990; Order Dept.: 22 Law Drive, Box 2300, Fairfield, NJ 07007-2300

GRI-00/0076, Evaluation of Pipeline Design Factors

GRI-00/0077, Safety Performance of Natural Gas Transmission and Gathering Systems Regulated by Office of Pipeline Safety

GRI-00/0189, Model for Sizing High Consequence Areas Associated With Natural Gas Pipelines

GRI-00/0192, GRI Guide for Locating and Using Pipeline Industry Research

GRI-00/0193, Natural Gas Transmission Pipelines: Pipeline Integrity — Prevention, Detection, & Mitigation Practices

GRI-00/0228, Cost of Periodically Assuring Pipeline Integrity in High Consequence Areas by In-Line Inspection, Pressure Testing and Direct Assessment

GRI-00/0230, Periodic Re-Verification Intervals for High-Consequence Areas

GRI-00/0231, Direct Assessment and Validation

GRI-00/0232, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines

GRI-00/0233, Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level

GRI-00/0246, Implementation Plan for Periodic Re-Verification Intervals for High-Consequence Areas

GRI-00/0247, Introduction to Smart Pigging in Natural Gas Pipelines

GRI-01/0027, Pipeline Open Data Standard (PODS)

GRI-01/0083, Review of Pressure Retesting for Gas Transmission Pipelines

GRI-01/0084, Proposed New Guidelines for ASME B31.8 on Assessment of Dents and Mechanical Damage

GRI-01/0085, Schedule of Responses to Corrosion-Caused Metal Loss Revealed by Integrity-Assessment Results

GRI-01/0111, Determining the Full Cost of a Pipeline Incident

GRI-01/0154, Natural Gas Pipeline Integrity Management Committee Process Overview Report

GRI-95/0228.1, Natural Gas Pipeline Risk Management, Volume I: Selected Technical Terminology

GRI-95/0228.2, Natural Gas Pipeline Risk Management, Volume II: Search of Literature Worldwide on Risk Assessment/ Risk Management for Loss of Containment

GRI-95/0228.3, Natural Gas Pipeline Risk Management, Volume III: Industry Practices Analysis

GRI-95/0228.4, Natural Gas Pipeline Risk Management, Volume IV: Identification of Risk Management Methodologies

Publisher: Gas Technology Institute (GTI), 1700 South Mount Prospect Road, Des Plaines, IL 60018

GPTC 2000-19, Technical Report—Review of Integrity Management for Natural Gas Transmission Pipelines

Publisher: Gas Piping Technology Committee (GPTC) of the American Gas Association (AGA), 400 N. Capitol Street, NW, Washington, DC 20001

NACE RP0169, Control of External Corrosion on Underground or Submerged Metallic Piping Systems

Publisher: National Association of Corrosion Engineers (NACE) International, 1440 South Creek Drive, Houston, TX 77084

PR-218-9801, Analysis of DOT Reportable Incidents for Gas Transmission and Gathering System Pipelines, 1985–1997

Publisher: Pipeline Research Council International, Inc. (PRCI), 1401 Wilson Boulevard, Arlington, VA 22209

Blue Ash & Col: Ex. 3

Exposed Duke Energy Pipelines

CALL

811

Know what's **below.**
Call before you dig.

Ohio: 800-362-2764
Indiana: 800-382-5544
Kentucky: 800-752-6007
N. Carolina: 800-632-4949
S. Carolina: 888-721-7877

UTILITY EMERGENCIES
Carolinas: 800-769-3766
Indiana: 800-343-3525
Kentucky/Ohio: 800-634-4300

It's Critical to Support and Protect Them

Natural gas and propane pipelines that are exposed due to construction activities can shift, separate, or be damaged when they are not adequately supported by the soil around them. Properly supporting and protecting these pipelines ensures their continued safe operation, and helps protect your crew and the public from the very serious risk of a fire or explosion.

There are several ways to safely support exposed pipelines. The best method for your jobsite depends on the type and condition of the pipeline, the depth of construction activity, and the surrounding soil. Please contact Duke Energy's Gas Engineering Department for recommendations specific to your jobsite in Ohio and Kentucky. They can be reached at 800–544–6300.

Work Carefully Around Exposed Pipelines

Once pipelines have been safely supported, exercise caution when working around them:

- **Do not walk on, climb on, strike, or attempt to move exposed pipelines.** Even a slight impact or load can separate pipeline joints, damage protective coatings, or destabilize supports.

- **Protect the pipeline's coating.** The coating on the pipeline is critical to preventing corrosion. Any wooden beams in contact with the pipeline must be structurally sound and free of nails, and they must be removed prior to backfilling. Cover or pad any support material like dense rubber or polyurethane padding.

- **Slings must be made from nylon and in good condition.** Each sling shall be properly rated for the load. All slings must be carrying equal loads at intervals no greater than the maximum allowed span of unsupported pipe.

Report All Damages

Even a slight gouge, scrape, or dent to a pipeline, its coating, or a wire attached to or running alongside the pipe, may cause a break or leak in the future. Check the pipeline regularly for nicks, dents, or other damage. When your excavation work is complete and before you backfill around the pipeline, check it again. Report any damages to Duke Energy so crews can inspect the line and make the necessary repairs.

Would You Like to Know More?

Additional pipeline protection guidelines, illustrations of proper support methods, case studies, instructional videos, and training tools can all be found, at no charge to you, on Duke Energy's e–SMARTworkers website.

Do you like this email series? Do you find the information helpful? We'd like to know. Please reply to this email and tell us what you think or let us know what topics you'd like to see in future emails.

For more contractor safety information, visit www.duke-energy.com

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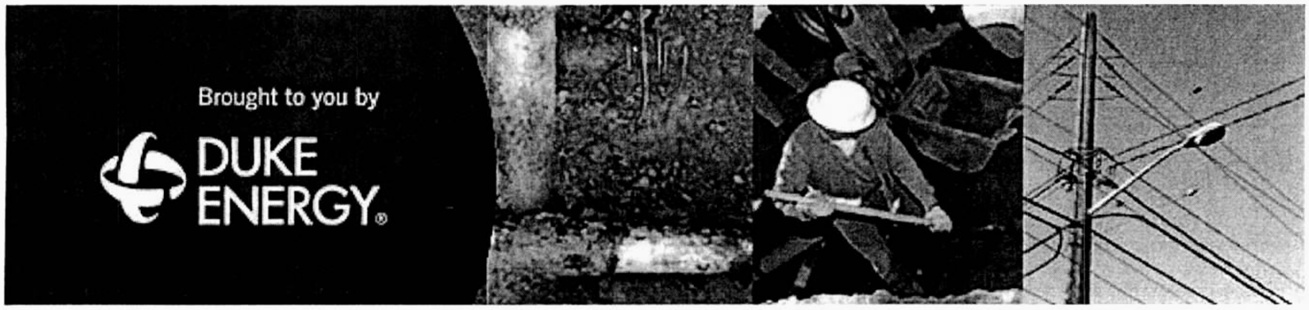

If You Suspect a Natural Gas Leak

Duke Energy Emergencies
Carolinas: 800-769-3766
Florida: 800-228-8485
Indiana: 800-343-3525
Kentucky/Ohio:
800-634-4300
Duke Energy Progress:
800-419-6356

CALL

811

Know what's below. Call before you dig.

Florida: 800-638-4097
Indiana: 800-382-5544
Kentucky: 800-752-6007
Ohio: 800-362-2764
N. Carolina: 800-632-4949
S. Carolina: 888-721-7877

FL 866-372-4663
IN 800-774-0246
Electric meter and service removal: Completed in 3 working days for residential or non-residential properties.

KY/OH 877-700-3853
Electric meter and service removal: Completed in 10 working days for residential properties and 14 working days for non-residential properties.

Gas meter removal:
Completed in 1-3 working days for residential or non-residential properties, with a minimum of 7 working days notice.

Abandoned gas service at main or curb valve:
Completed in 1-10 working days, with a minimum of 14 working days notice.

NC/SC 800-653-5307
Electric meter and service removal: Completed in 5 working days for residential or non-residential properties.

Recognizing Gas Leaks

If you're like most people, you've learned to rely on your sense of smell to detect a natural gas leak. In and around your home, that distinctive, sulfur-like odor is in fact a sure sign that natural gas is leaking from an appliance burner or pipe. But it's not the only sign, especially on the job site. And in some cases, natural gas leaks don't smell at all.

Duke Energy adds the odorant Mercaptan to natural gas. This odor, which is similar to sulfur or rotten eggs, helps most people smell a leak. But in some cases, the odor of natural gas can be masked by other smells, or the gas can be stripped of its odor. This is known as "odor fade."

So be sure to rely on your eyes and ears (not just your nose) to detect the warning signs of a gas leak. Be alert for hissing or roaring sounds, dirt spraying or blowing into the air, continuous bubbling in water, or dead/dying vegetation in an otherwise moist area over or near a pipeline.

If Equipment Contacts a Gas Line or You Suspect a Leak

Protect yourself, your coworkers, and the public by taking the following steps:

1. **Evacuate the area immediately,** including nearby buildings. Warn others to stay away.
2. **Leave the excavation open,** and do not attempt to stop the flow of gas or fix the pipeline.
3. **Do not light a match, start an engine, or operate any electrical device—even a phone.** A spark could ignite the gas.
4. **Abandon equipment.**
5. **From a safe location, call 911 and Duke Energy.** Call even if damage is a minor nick or scrape.
6. **Stay away from the area** until safety officials say it is safe to return.
7. **Report the incident to your supervisor.**

There's No Such Thing as Minor Damage

Even a slight gouge, scrape, or dent to a pipeline, its coating, or a wire attached to or running alongside the pipe may cause a break or leak in the future. Report ALL gas line contacts to Duke Energy so crews can inspect the line and make the necessary repairs.

Would You Like to Know More?

Additional digging and overhead guidelines, case studies, instructional videos, and training tools can all be found, at no charge to you, on Duke Energy's e-SMARTworkers website.

Do you like this email series? Do you find the information helpful? We'd like to know. Please reply to this email and tell us what you think, or let us know what topics you'd like to see in future emails.

For more contractor safety information, visit www.duke-energy.com.

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Blue Ash/Columbia
Ex. 5

Natural Gas and Safety

Protect yourself and your family

En Español | Duke Energy cares about your safety and wants you to enjoy the comforts and convenience that natural gas provides. We encourage you to read these important gas safety tips and share them with your family and friends.

If you suspect a natural gas leak or suspect that contact with a natural gas line has occurred:

Natural Gas Safety

If you suspect a natural gas leak or suspect that contact with a natural gas line has occurred:

Do:

- Know where your appliance and building gas shut-off valves are located
- Turn the shut-off valve(s) off if you can do so safely
- Evacuate everyone from the premise immediately
- Keep others a safe distance away
- From a safe location, call 911 and Duke Energy at 800.634.4300

Do Not:

- Operate electrical equipment that could create a spark, such as a cellphone, light switch or matches
- Operate pipeline system equipment
- Turn vehicles or equipment on or off
- Re-enter the home or building until cleared to do so by a Duke Energy representative

Call before you dig

One of the most potentially hazardous situations in residential areas, industrial plants and construction sites is accidental contact with underground electric power lines, natural gas lines, communication lines and other utility services.

To ensure you're working safely, contact the designated One Call Center for your state by calling 811. There's no charge for the service, and the call is free. Calling before you dig can not only save you money from a damage claim, it can also save your life.

All you have to remember is 811. That's the FCC-designated number to call before any digging project. 811 will connect you to the One Call Center in your respective state and notify area member utilities to mark the approximate location of underground lines. Duke Energy is a member of the One Call Center, but all not utilities are and may not receive notification by 811. Learn more about 811 and its members at this link.

Natural Gas Safety

Most state laws require at least a 48-hour notice; some may be longer. Call 811 or the numbers below for the best information for your state.

For information on gas line safety, you may also contact Duke Energy at 800.634.4300.

Know about gas safety

Natural gas is a safe and reliable fuel when used properly. But, escaping natural gas can signal danger. Natural gas is colorless and odorless, and it can penetrate walls even if your home or building is not supplied with gas.

As a safety precaution, Duke Energy adds a distinctive sulfur-like odor to natural gas so you can smell a leak immediately. For your safety, it is important that everyone in your family recognizes this odor.

If you smell sulfur near a natural gas appliance, check the pilot light. Most modern automatic equipment, like water heaters and furnaces, has safety shut-offs to control the escape of natural gas if the pilot goes out. Manually controlled appliances, like a natural gas range, may have a pilot light that does not turn off, but can be safely re-lit. All appliances should have a panel with the lighting instructions attached.

If you can't determine the source of a natural gas odor, and it is localized around an appliance, turn the natural gas to the appliance off at the shut-off valve and get a professional to look at the appliance.

If the source of the odor can't be determined or shut off, you have an emergency. As with any emergency, stay calm and follow these guidelines.

Learn more about natural gas odorant

FEEDBACK

Natural Gas Safety

Protect the pipeline

Pipelines are a safe way to transport energy across the country. While rare, pipeline incidents do happen. When natural gas systems leak, the gas normally rises away from the surface and dissipates. However, problems can occur if natural gas migrates underground and into buildings, sewers and duct systems such as those used for underground industrial lines.

To ensure the safety of our customers, employees and the public, Duke Energy has numerous pipeline programs, policies and procedures in place. Collectively, they work to make sure that the natural gas used to power your home or business is delivered safely and efficiently. Learn more about our approach, as well as what you can do to enhance and facilitate pipeline safety.

Know what's below – call 811

The majority of natural gas distribution incidents are caused by damage to natural gas lines from construction and other excavation activities. If lines are dug into, they may leak and create an emergency situation. To protect the public, laws are in place requiring contractors or landowners to locate underground utilities before excavating.

Even if you are simply installing a fence or planting a new tree in your yard, you must **always contact your state's Call Before You Dig program at 811** at least two working days before you dig. This free program will notify your local utility company to mark the location of underground lines so that you can dig safety and avoid a potential accident.

Learn more about Call Before You Dig.

Know where to dig

Natural gas is a safe, clean, and reliable energy source when treated and handled with respect. Working around gas lines requires a strong focus on safety.

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strong focus on safety.

Distribution pipeline systems are used to deliver natural gas. When natural gas systems leak, natural gas will normally rise away from the surface and dissipate. Trouble may occur, however, if natural gas migrates under the ground and into buildings, sewers and duct systems such as those used for underground telephone and electric lines. The majority of natural gas distribution incidents are caused by damage to natural gas lines from construction and other excavation activities. Unreported small leaks and sudden large leaks create emergency situations.

For the public's protection, our lawmakers require contractors and landowners to have underground utilities located before excavation activities begin. Our company, and other businesses with buried investments, are working together to provide locating services to anyone planning to excavate in the vicinity of underground gas, electric, telephone or other buried utilities.

Homeowners can protect themselves and their neighbors by asking excavators if they have called the appropriate locating services.

Homeowners should also call for their own projects. A task as simple as installing a fence or planting a new tree in the yard can turn out deadly if an underground gas or electric line is hit.

Call Before You Dig is a free service. Participating utilities will send someone out to mark the underground facilities. Be sure to call two days in advance.

Call before you dig. It's the law.

Dial 811 or contact your local Call Before You Dig centers at the following numbers:

Indiana: 800.382.5544
Kentucky: 800.752.6007
Ohio: 800.362.2764

Natural Gas Safety

If you have any questions about natural gas safety, or need more information, contact us at 800.634.4300.

Gas Emergencies

Call 800.634.4300

What's that smell

Natural gas is a colorless, odorless gas. Duke Energy odorizes the natural gas we deliver through our natural gas system to smell like sulfur or rotten eggs. This added odorant enables natural gas to be detected in the event a gas leak occurs.

Duke Energy routinely monitors odor concentration in the gas system for compliance with the regulatory requirements. Even so, you should not rely solely on your sense of smell to determine if a gas leak has occurred or is occurring.

Don't rely on sense of smell alone

In some situations, you may not be able to detect the odorant. Some people may have a diminished sense of smell. Physical conditions, including common colds, sinus conditions and allerges, can also temporarily impair your sense of smell. Sometimes the added odorant may be masked or overpowered by other odors. In rare incidences, odor fade (loss of odorant) may occur. This may cause the odor to diminish so that it is not detectable.

What causes odor fade?

Odor fade (loss of odorant) can occur when physical and/or chemical processes cause the level of odorant in the gas to be reduced. If a natural gas leak occurs underground, the surrounding soil may cause odor fade. Other factors that may cause odor fade include, but are not limited to:

- The construction and configuration of your gas facilities
- The presence of rust, moisture, liquids or other substances in the pipe
- Gas composition, pressure and/or flow

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intermittent, little or no gas flow over an extended period of time may also result in an initial loss of odorant that returns once the gas flow increases or becomes more frequent.

Carbon monoxide

When natural gas is burned completely, the products are carbon dioxide (the same chemical that makes bubbles in a soda) and water vapor. Both products are usually harmless.
However, incomplete combustion can create carbon monoxide, which can be dangerous. That's why it is important to have natural gas appliances routinely inspected and serviced to ensure proper operation, including a check of vents and flues.

In order for vents and flues to operate properly, you must allow air into the system. This air allows the vent or flue to draw air up and out similar to a fireplace chimney and allows for more complete combustion. High-efficiency furnaces have make-up air piped directly into the combustion area to enhance the fuel burn, which produces safe products that are vented from the furnace.

Without adequate ventilation, the natural gas may not burn completely producing carbon monoxide – a potentially deadly situation.

Is your family safe from carbon monoxide poisoning?

Carbon monoxide can be formed when any common fuel is burned, including natural gas, wood, oil or coal. As the weather gets colder, the risk of carbon monoxide (CO) poisoning increases. As many as one-quarter of patients who go to hospital emergency departments with flu-like or more severe symptoms may actually have been exposed to CO. High exposures may even cause brain damage or death.

Because CO is a colorless, odorless, tasteless, non-irritating gas, it can go undetected. With some understanding and prevention, you can protect your family from an unnecessary risk.

Have your heating equipment professionally inspected and serviced yearly by a certified heating contractor.

The effects of carbon monoxide

CO can build up in the body over time. Longer exposures to lower amounts may actually be worse than a short duration of a higher amount. Signs and symptoms of CO poisoning include:

- Headache
- Fatigue
- Nausea/vomiting
- Dizziness
- Shortness of breath
- Chest pain
- Confusion /poor judgment/memory loss
- Decreased motor function/ slower reaction time

If you suspect you have been exposed:

- Seek a well-ventilated area immediately.
- If symptoms are severe or persist, get medical attention or call 911.
- Call a service contractor to check your house for problems.

For more information on carbon monoxide, go to:

- Centers for Disease Control
- Consumer Product Safety Commission

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Flexible gas connectors

Flexible gas connectors are corrugated metal tubes used to attach natural gas appliances to a home or building's natural gas supply lines. Some older, uncoated brass flexible gas connectors can corrode or break and cause a serious gas leak, fire or explosion.

According to the U.S. Consumer Product Safety Commission, these uncoated brass flexible gas connectors have not been manufactured for more than 25 years, but many are still in use. If you have a natural gas appliance that is more than 20 years old, it is a good idea to have the gas connectors replaced by a qualified professional.

WARNING: Moving an appliance to check the gas connector may cause the connector to break, resulting in a gas leak, fire or explosion. DO NOT attempt to check the connectors yourself. Instead, have a qualified person, such as a professional plumber or HVAC or appliance repair contractor inspect your appliances and, if necessary, replace the connectors for you. The new connector should be certified by the American Gas Association and should be manufactured in conformance with the American National Standards Institute. Have all of your natural gas appliances inspected in accordance with the manufacturer's recommendations.

Read more about the U.S. Consumer Product Safety Commission.

Clearing a sewer line

A sewer lateral is an underground pipe that connects a residence or business to the main sewer line. Caution is required when doing repair work on a sewer lateral because these lines often run along other buried utilities, including natural gas lines. Rooter equipment used to clear lines of clogs and tree roots can break through the sewer line and damage gas lines.

Before **clearing out a sewer lateral, remember to**:

- Contact your state's Call Before You Dig service at 811 to locate underground utilities

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- Contact your state's Call Before You Dig service at 811 to locate underground utilities.
- Look for a sewer lateral tag on the sewer clean-out or under the kitchen drain pipe.
- If a tag is present, call Duke Energy for a free sewer line inspection.

Signs of damage to a natural gas line include, but are not limited to:

- Hissing sounds
- Natural gas odor (rotten eggs/sulfur)
- Blowing dirt
- Bubbling water

Damage to a natural gas service line is a serious hazard and can lead to a:

- Gas leak
- Fire
- Explosion

Duke Energy contact information

If you have any questions, please do not hesitate to contact Duke Energy toll-free at 800.634.4300.

System damage

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the surface and dissipate. Trouble may occur, however, if natural gas migrates under the ground and into buildings, sewers and duct systems such as those used for underground telephone and electric lines. The majority of natural gas distribution incidents are caused by damage to natural gas lines from construction and other excavation activities. When lines are dug into they may leak with no one reporting the damage, or leak in such large quantities that an instant emergency results.

For the public's protection, our lawmakers have made it mandatory for contractors or landowners to have underground utilities located before excavation activities can begin. Our company, and other businesses with buried investments, are working together to provide locating services to anyone planning to excavate in the vicinity of underground gas, electric, telephone or other buried utilities.

Homeowners can protect themselves and their neighbors by keeping an eye on things and by asking excavators if they have called the appropriate locating services.

Homeowners should also not forget to set a good example by calling for their own projects. A task as simple as installing a fence or planting a new tree in the middle of the yard can turn out deadly if an underground gas or electric line is hit.

It's a free service. Participating utilities will send someone out to mark the underground facilities if you call two days in advance.

Call before you dig. It's the law.

Call 811 or

Indiana: 800.382.5544
Kentucky: 800.752.6007
Ohio: 800.362.2764

Natural gas is a safe, clean and reliable energy source when treated and handled with respect; but like safety – it's something to think about

If you have any questions about natural gas safety, or need more information, contact us at 800.544.6900

Gas Emergencies
Call 800.634.4300

Hydrostatic pressure testing

At Duke Energy, we are committed to the safe operation of our natural gas pipeline. We want everyone to be safe each and every day -- in our homes, schools and businesses. Hydrostatic Pressure Testing is one of several methods a company may use to confirm the structural integrity of its natural gas pipeline.

About hydrostatic pressure testing

Pipeline testing involves pressurizing a section of the pipe with water to a much higher level than the pipe will ever operate with natural gas, thus validating the safe operating pressure of the pipeline.

In an emergency call **911**, call 800.634.4300. For questions about testing, call 513.287.2110 or email pipelinetesting@duke-energy.com.

Frequently Asked Questions

Why is testing done?

Public safety is our number one priority. Assessing the strength and durability of the pipeline will help prevent leaks or ruptures and help us determine areas that may need repair. Testing with water is a safe and effective way to find and correct any problem areas in the pipeline.

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How it is done?

First, the pipeline is taken out of service and residual gas is safely vented. The pipeline is closed at each end using welded steel caps. The section of pipe that is being tested is then filled with water until a pressure is reached that exceeds the pressure that the pipeline would experience during normal operation with natural gas. This allows us to test the pipeline's durability and determine a safe level of pressure for the pipeline to operate. It's also a way to find any defects and make repairs. After a successful test, the pipeline is drained of water, dried thoroughly and returned to service.

What to expect

Alternate sources of natural gas will be provided prior to testing to ensure you receive the natural gas you need. You may experience a short interruption in your gas supply during the changeover process. During testing you may notice the following:

- Temporary traffic and detour signs
- Pipeline workers and personnel onsite
- Pipes above ground and visible during testing
- Machinery such as excavators and water tanks in the area
- Standing water or puddles of water that may be dyed with a nontoxic colorant

What happens during a test?

1. Duke Energy notifies neighbors of testing dates.
2. Some customers will need to be connected to an alternate source of natural gas during testing.
3. Pipeline section is taken out of service and sealed on both ends.
4. Pipeline is filled completely with water.
5. The section is pressurized to a level higher than normal operating pressure.
6. The pressure is held for a set period of time, typically eight or more hours.

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7. Any pipeline sections that leak or rupture are repaired or replaced with new pipe.
8. Once a section passes the test, the pipeline is emptied of water, dried and put back into service. Work can continue up to four weeks depending on test results. Some work may occur at night to ensure pressure is held for the recommended time limit.

Is testing safe?

Hydrostatic pressure testing is a very common and safe way to test pipelines. If a pipeline were to fail during testing, it would only leak water. Testing with water is an excellent way to ensure the integrity of the pipes and fix areas in question before an emergency happens.

Delivering natural gas safely from 1837 to today

Natural gas was first available in the Cincinnati area in 1837 when the Cincinnati Gas Light and Coke Company was granted a charter to light the streets, homes and businesses in what is now the downtown area. Although electricity now powers most of our lights, the old gas company has grown into a modern natural gas distribution system that provides about one-third of all the energy used by residential, commercial and industrial applications in the Greater Cincinnati and Northern Kentucky.

Like any other source of energy, natural gas can be hazardous if not managed properly.

One simple safety procedure that is used to help avoid these problems is the odorization of natural gas. Learn more about odorant and odorant fade.

Pipeline safety

To ensure the safety of our customers, employees and the public, Duke Energy has numerous pipeline programs, policies and procedures in place. Collectively, they work to make sure that the natural gas used to power your home or business is delivered safely and efficiently. Learn more about our approach, as well as what you can do to enhance and facilitate pipeline safety.

Regulatory requirements

The U.S. Department of Transportation's Office of Pipeline Safety (OPS) regulates the safety, design, construction, operation and maintenance of interstate natural gas transmission pipelines. Their job is to make certain the U.S. pipeline system is both safe and reliable. Each year, our pipeline system is inspected by the OPS and/or state pipeline safety representative to ensure we are in compliance with all pipeline safety regulations. Duke Energy responds promptly to any findings and recommendations as a result of these inspections.

Integrity management

All natural gas pipeline operators are required to develop and maintain integrity management programs for gas transmission pipelines. Duke Energy's Integrity Management Program defines its procedures and practices to help our personnel identify and address threats and to ensure that our pipelines remain structurally sound.

This program includes plans for areas that:

- Meet U.S. Department of Transportation's Office of Pipeline Safety's criteria of population density
- Include populations with impaired mobility, such as schools or hospitals
- Attract large groups of people, such as ball fields and parks

Learn more about integrity management on the Department of Transportation's Integrity Management website.

Mapping the pipeline

A Geographic Information System (GIS) is a computer database capable of organizing and relating information according to its geographic location. At Duke Energy, we use GIS to record and analyze up-to-date pipeline information throughout our system. We

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geographic location. At Duke Energy, we use GIS to record and analyze up to date pipeline information throughout our system. We include specific pipe statistics, such as size, coating, construction and testing information, along with pipeline routes with topographical, weather and community-based data. Using a GIS, Duke Energy can learn more about factors that affect pipelines and possibly forecast when issues may occur.

Pipeline rights of way are marked with signs showing the pipeline's approximate location, name of the pipeline company and a telephone number where company representatives can be reached. For security reasons, detailed maps of the pipeline are not publicly available.

You can access the National Pipeline Mapping System Web site and the link Find Who's Operating Pipelines in Your Area to find out which operators have pipelines near you.

Protecting natural gas metering equipment in winter

While heavy snow and ice storms are infrequent in southwest Ohio and Northern Kentucky, excessive snowfall and abnormal icy weather have the potential to damage natural gas meters, regulators and pipes outside homes and businesses.

Damage can occur from:

- additional loading of heavy ice and snow
- clearing of snow from around natural gas facilities
- snow and ice falling from roofs, either from melting or someone shoveling snow off the roof
- ice forming in or on natural gas meters

In addition, exterior vents for natural gas appliances can become blocked with heavy snow and ice. This could shut down heating [illegible] carbon monoxide back into the home.

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Keep your family safe and warm during the winter by taking some protective measures.

- Conduct regular visual checks of your natural gas meter to see that it's free of ice and snow, especially if the meter is exposed to melting precipitation.
- If your natural gas meter is completely encased in snow or ice, or if you think there may be a problem, call Duke Energy at 800.634.4300.
- Always keep a clear path to your natural gas meter to allow quick access in an emergency.
- Vents for natural gas appliances should be cleared following a major snow or ice storm to allow for proper venting and to prevent carbon monoxide accumulation.
- Do not pile snow against your natural gas meter, gas piping or the venting pipes from gas appliances when shoveling driveways or walkways.
- If possible to do so safely, remove icicles from overhead eaves and gutters so dripping water does not splash and freeze on your meter.
- Never kick, hit or apply any type of heat source to your natural gas meter to break or clear ice.

Important Reminders

- If your natural gas meter is completely encased in snow or ice, or if you think there may be a problem, call Duke Energy at 800.634.4300.
- If you smell a natural gas odor, leave the area immediately. From a safe location, call 911 and Duke Energy at 800.634.4300. Wait until a Duke Energy representative arrives before returning to the area.

Excess flow valves

An excess flow valve is designed to permit normal operation of the service line. But, when activated, an excess flow valve may

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An excess flow valve is designed to permit normal operation of the service line. But, when activated, an excess flow valve may lessen the buildup of natural gas in the service line and may decrease the possibility of accidents caused by such buildup. However, an excess flow valve does not protect against customer appliance malfunction, customer houseline leaks, or small leaks on service lines or gas meters. Learn more https://www.duke-energy.com/safety-and-preparedness/natural-gas-safety