Managing System Integrity for Hazardous Liquid Pipelines

API STANDARD 1160
FIRST EDITION, NOVEMBER 2001
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Approved American National Standard
ANSI

American Petroleum Institute

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Pipeline Segment

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FOREWORD

Regulatory Requirements for Pipeline Integrity Management

This standard—Managing Pipeline System Integrity for Hazardous Liquid Pipelines—provides guidance to the pipeline industry for managing integrity. It is important that operators using this standard understand the Federal pipeline safety requirements for pipeline integrity management in high consequence areas when establishing or enhancing their integrity management programs. Although pipeline operators must comply with the pipeline safety regulations, a robust, high quality pipeline integrity program requires more than a compliance approach to managing pipeline integrity. Operators should build upon the foundation established by the regulations to develop an integrity management program that best serves their unique operational needs. To assist users of the standard, this foreword provides a summary of the regulatory requirements for integrity management.

Effective May 29, 2001, the *Code of Federal Regulations (CFR)* governing hazardous liquid pipeline operation and maintenance was amended to establish new requirements for "*Pipeline Integrity Management in High Consequence Areas*" (49 *CFR* 195.452, referred to here as "the rule")[1] . The purpose of these new requirements is to enhance and validate pipeline integrity, and provide improved protection for high consequence areas that could be affected by an unintended release of hazardous liquids from a pipeline system.

High consequence areas are defined in 49 *CFR* 195.450 as:

1. A *high population area*, which means an urbanized area, as defined and delineated by the U.S. Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.
2. An *other populated area*, which means a place, as defined and delineated by the U.S. Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.
3. A *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists. These waterways are identified in the National Waterways Network, a geographic database created by the National Waterways GIS Design Committee.
4. An *area of the environment that has been designated as unusually sensitive to oil spills* (an "unusually sensitive area" or USA). USAs are defined in 49 *CFR* 195.6.

This API standard includes guidance for complying with these requirements based on proven industry practices for managing pipeline system integrity. The following discussion provides a description of the requirements in 49 *CFR* 195.452, and identifies the location in this standard where guidance and information is provided to facilitate operator compliance.

The rule requires that operators develop and implement a written integrity management program. This integrity management program must include:

- An identification of all pipeline segments that could affect a high consequence area in the event of a pipeline failure.
- A plan for conducting baseline assessments of the line pipe in these segments.
- A framework that addresses how each element of the operator's integrity management program will be implemented.

Pipeline segments that could impact high consequence areas must be identified by December 31, 2001. The Baseline Assessment Plan and framework must be completed by March 31, 2002. Section 5 of this standard provides an overview of a pipeline integrity management program, and the steps necessary to craft the required framework.

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[1]This rule applies to operators who own or operate 500 or more miles of hazardous liquid pipeline. At the time this standard was being prepared, a similar rule covering other hazardous liquid pipeline operators was in preparation.

The Baseline Assessment Plan for assessing the condition of line segments that could affect high consequence areas must:

1. Identify all line segments that could affect a high consequence area. Section 6 of this standard describes where to get information on the location of high consequence areas and how to determine if a line or line segment could affect a high consequence area.
2. Specify the method(s) used to assess pipeline integrity for each segment. The acceptable methods for conducting integrity assessments are pressure testing, instrumented internal inspection[2], or another technology that the operator demonstrates can provide an equivalent understanding of the pipe's condition.
3. Provide a schedule for completing the initial integrity assessment for each segment.
4. Explain the technical basis for the integrity assessment method(s) selection and the evaluation of risk factors considered in scheduling the assessment. Sections 7 and 8 of this standard provide guidance for selecting important risk factors and prioritizing segments for scheduling integrity assessments. Section 9 describes the different integrity assessment methods and tools, and important considerations in determining the appropriate approach for a particular situation.

The Baseline Assessment Plan must be available for review by the U.S. DOT Office of Pipeline Safety (OPS) during inspections. Operators should periodically review this plan to be sure it continues to reflect the appropriate priorities in conducting integrity assessments for line segments that may impact high consequence areas. If necessary, the Baseline Assessment Plan may be revised to reflect new operating experience, the insights gained from the initial integrity assessments, and other maintenance and surveillance data.

Although the rule requires a Baseline Assessment Plan only for segments that could affect high consequence areas, an operator may find that such a plan is useful for its entire system, and could expand the scope of its program accordingly. The guidance provided in this standard is suitable for complete pipeline systems and is not limited to high consequence areas.

The rule requires operators to perform a baseline integrity assessment by March 31, 2008 for all pipeline segments that could affect a high consequence area. Furthermore, fifty percent of this pipeline mileage must be assessed by September 30, 2004, beginning with the highest risk segments. Operators, who have performed and documented integrity assessments after January 1, 1996, may use these assessments to validate line integrity if the assessment approach and documentation are consistent with the provisions of the rule.

In evaluating the results of the integrity assessment, operators must integrate information from other relevant sources with the inspection or testing results to fully identify and characterize the potential threats to pipeline integrity. Other information sources might include cathodic protection system data, close interval surveys, results of previous internal inspections, operating and leak history, patrolling reports, exposed pipe reports, etc. Section 7 of this standard addresses gathering, reviewing, and integrating information and data. From this evaluation, the operator should identify the location, nature, and relative risk of features that could threaten pipeline integrity. Operators must use a risk-based approach in prioritizing repair and mitigation activities, in which any defects or other features that have the potential to result in a near-term leak or failure are addressed promptly. The rule establishes specific time limits by which certain anomalies identified by in-line inspection must be repaired or mitigated. Section 9 provides additional guidance for prioritizing and scheduling anomalies.

As an integral part of a continuing integrity management program, the rule also requires that operators periodically reassess pipeline integrity on line segments that could affect high consequence areas at intervals not to exceed five years. The risk represented by the segment should be used to establish the appropriate assessment interval within this five-year period. Operators may be allowed variances from this five-year interval if a reliable engineering evaluation in combination with other activities such as external monitoring provide a compa-

[2]For low frequency, electric resistance welded (ERW) pipe or lap welded pipe subject to longitudinal seam failures, an operator must select a method capable of assessing seam integrity, and capable of detecting corrosion and deformation anomalies.

rable understanding of the pipe's condition. The risk assessment methods described in Section 8 provide one approach for establishing a technical justification for longer inspection intervals. Variances may also be allowed if a particular assessment technology desired for a given segment(s) is not available (e.g., new, more sophisticated internal inspection devices). Operators requesting such variances must notify OPS in advance and maintain documentation justifying these decisions.

After completing a baseline assessment, an operator must conduct a risk analysis for the line segments that could affect high consequence areas. This analysis should identify and evaluate the need for additional preventive and mitigative actions to protect high consequence areas. Such actions might include enhancing damage prevention programs, improved cathodic protection monitoring, reducing surveillance and inspection intervals, enhanced training, conducting drills with emergency responders, and other management controls. Section 10 describes a number of common preventive and mitigative risk control measures that can be used to provide additional protection. Operators must also explicitly evaluate the need for Emergency Flow Restricting Devices and enhancements to leak detection systems to protect high consequence areas. The rule provides important factors to be considered in performing these evaluations.

As noted previously, the rule requires an operator to develop and implement an integrity management program. This program must include the following elements:

- A process for determining which pipeline segments could affect a high consequence area (Section 6 of this standard).
- A Baseline Assessment Plan (Section 9).
- A process for periodic integrity assessment and evaluation of segments that could affect high consequence areas (Sections 9 and 11).
- An analytical process that integrates all available information about pipeline integrity and the consequences of a failure (Section 7 discusses information sources, and Section 8 describes a risk assessment process that integrates this data to identify pipeline risks).
- Repair or mitigation to address issues identified by the integrity assessment method (Section 9).
- A process to identify and evaluate preventive and mitigative measures to protect high consequence areas (Section 8 describes a risk-based process for making these determinations).
- Methods to measure the integrity management program's effectiveness (Section 13).
- A process for review of integrity assessment results and data analysis by a qualified individual.

An operator's approach for developing and implementing each of these elements must be addressed in the framework.

Finally, the rule identifies records that must be maintained by the operator. An operator must have a written integrity management program description that includes how each element of its integrity management program is implemented. Documentation supporting the decisions and analyses performed as part of the program are also identified. It is important that the operator have documented technical justification for key integrity management decisions, as well as for any variances or deviations allowed by the rule.

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1 Introduction

1.1 PURPOSE AND OBJECTIVES

The goal of the operator of any pipeline is to operate the pipeline in such a way that there are no adverse effects on employees, the environment, the public, or their customers as a result of their actions. They do this while they fill the needs of the customer and earn a reasonable return on their investment. The goal is error-free, spill-free, and incident-free operation of the pipeline.

An integrity management program provides a means to improve the safety of pipeline systems and to allocate operator resources effectively to:

- Identify and analyze actual and potential precursor events that can result in pipeline incidents.
- Examine the likelihood and potential severity of pipeline incidents.
- Provide a comprehensive and integrated means for examining and comparing the spectrum of risks and risk reduction activities available.
- Provide a structured, easily communicated means for selecting and implementing risk reduction activities.
- Establish and track system performance with the goal of improving that performance.

This standard outlines a process that an operator of a pipeline system can use to assess risks and make decisions about risks in operating a hazardous liquid pipeline in order to reduce both the number of incidents and the adverse effects of errors and incidents. Section 5 describes the integrity management framework that forms the basis of this standard. This framework is illustrated schematically in Figure 5-1. This standard also supports the development of integrity management programs required under Title 49 *CFR* 195.452 of the federal pipeline safety regulations.

This standard is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. Typically a team would include engineers, operating personnel, and technicians or specialists with specific experience or expertise (corrosion, in-line inspection, right-of-way patrolling, etc.). Users of this standard should be familiar with the pipeline safety regulations (Title 49 *CFR* Part 195), including the requirements for pipeline operators to have a written pipeline integrity program, and to conduct a baseline assessment and periodic reassessments of pipeline management integrity.

1.2 GUIDING PRINCIPLES

In developing this standard on managing pipeline system integrity, certain guiding principles underlie the entire document. These principles are reflected in many of the sections and are provided here to give the reader the sense of the need to view pipeline integrity from a broad perspective.

Integrity must be built into pipeline systems from initial planning, design, and construction. Integrity management of a pipeline starts with the sound design and construction of the pipeline. Guidance for new construction is provided in a number of consensus standards, including ASME B31.4, as well as the pipeline safety regulations. As these standards and guidelines are applied to the design of a pipeline, the designer must consider the area the pipeline traverses and the possible impacts that the pipeline may have on that area and the people that reside in its vicinity. New construction is not a subject of this standard, but the design specifications and as-built condition of the pipeline provide important baseline information for an integrity management program.

System integrity is built on qualified ***people****, using defined* ***processes*** *to operate maintained* ***facilities****.* The integrity of the physical facility is only part of the complete system that allows an operator to reduce both the number of incidents and the adverse effects of errors and incidents. The total system also includes the people that operate the facility and the work processes that the employees use and follow. A comprehensive integrity management program should address people, processes, and facilities.

An integrity management program must be flexible. An integrity management program should be customized to support each operator's unique conditions. Furthermore, the program must be continually evaluated and modified to accommodate changes in the pipeline design and operation, changes in the environment in which the system operates, and new operating data and other integrity-related information. Continuous evaluation is required to be sure the program takes appropriate advantage of improved technology and that the program remains integrated with the operator's business practices and effectively supports the operator's integrity goals.

Operators have multiple options available to address risks. Components of the facility or system can be changed; additional training can be provided to the people that operate the system; processes or procedures can be modified; or a combination of actions can be used that will have the greatest impact on reducing risk.

The integration of information is a key component for managing system integrity. A key element of the integrity management framework is the integration of all available information in the decision making process. 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 integrating all of the available information, the operator can determine where the risks of an incident are the greatest, and make prudent decisions to reduce these risks.

Preparing for and conducting a risk assessment is a key element in managing pipeline system integrity. Risk assessment is an analytical process through which an operator determines the types of adverse events or conditions that might impact pipeline integrity, the likelihood that those events or conditions 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 and analysis of design, construction, operating, maintenance, testing, and other information about a pipeline system. Risk assessments can have varying scopes, varying levels of detail, and use different methods. However, the ultimate goal of assessing risks is to identify and prioritize the most significant risks so that an operator can make informed decisions about these issues.

Assessing risks to pipeline integrity is a continuous process. Analyzing for risks in a pipeline system is an iterative process. The operator will periodically gather additional information and system operating experience. This information should be factored into the understanding of system risks. As the significance and relevance of this additional information to risk is understood, the operator may need to adjust its integrity plan accordingly. This may result in changes to inspection methods or frequency, or additional modifications to the pipeline system in response to the data. As changes are made, different pipelines within a single operating company and different operators will be at different places with regard to the goal of incident-free operation. Each pipeline system and each company will need specific goals and measures to monitor the improvements in integrity and to assess the need for additional changes.

Mitigative actions are taken for injurious defects. Operators should take action to address integrity issues raised from assessments and information analysis. Operators should evaluate anomalies and identify those that are injurious to pipeline integrity. Operators should take action to mitigate or eliminate injurious defects.

New technology should be evaluated and utilized, as appropriate. New technology must be understood and incorporated into integrity management programs. Such new technology can enhance an operator's ability to assess risks and the capability of analytical tools to assess the integrity of system components.

Operators should periodically assess the capabilities of new technologies and techniques that may provide improved understanding about the pipe's condition or provide new opportunities to reduce risk. Knowledge about what is available and effective will allow the operator to apply the most appropriate technologies or techniques to a specific risk to best address potential impacts.

Pipeline system integrity and integrity management programs should be evaluated on a regular basis. The Office of Pipeline Safety provides a periodic review of the integrity management program for the operator through its enforcement personnel. Operators are encouraged to perform internal reviews to ensure the effectiveness of the integrity management program in achieving the program's goals. Some operators may choose to use the services of third parties to assist with such evaluations

2 Scope

This standard is applicable to pipeline systems used to transport hazardous liquids as defined in Title 49 *CFR* 195.2. The use of this standard is not limited to pipelines regulated under Title 49 *CFR* 195.1, and the principles embodied in integrity management are applicable to all pipeline systems.

This standard is specifically designed to provide the operator with a description of industry proven practices in pipeline integrity management. The guidance is specific to the line pipe along the right-of-way, from scraper trap to scraper trap, but the process and approach can and should be applied to all pipeline facilities, including pipeline stations, terminals and delivery facilities associated with pipeline systems. Certain sections of this standard provide guidance specific to pipeline stations, terminals, and delivery facilities.

3 References

3.1 REFERENCED CODES, GUIDES, AND STANDARDS

API

Std 5T1	*Imperfection Terminology*
RP 1110	*Pressure Testing Liquid Pipelines*
Publ 1156	*Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines*
RP 579	*Fitness for Service*
Std 653	*Tank Inspection, Repair, Alteration, and Reconstruction*
API 570	*Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems*

DOT[1]

49 *CFR* Part 195	*Transportation of Hazardous Liquids by Pipeline*

ASME[2]

B31.4	*Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*

[1]U.S. Department of Transportation, 400 7th Street, S.W., Washington D.C. 20590.
[2]ASME International, 3 Park Avenue, New York, New York 10016-0518.

B31G	*Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping*
NACE[3]	
35100	*Technical Committee Report, "In-line Nondestructive Inspection of Pipelines"*
RP 0169	*Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

3.2 OTHER REFERENCES

1. *Pipeline (In-service) Repair Manual*, Pipeline Research Council International, Project PR-218-9307, Dec. 94, Kiefner, J. F., Bruce, W. A., Stephens, D. R. (www.prci.com)

2. "Hazardous Liquid Pipeline Risk Assessment," California State Fire Marshall, March 1993

3. Kiefner, J. F., and Vieth, P. H., "A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe," Final Report to the Pipeline Corrosion Supervisory Committee of the Pipeline Research Committee of the American Gas Association, December 22, 1989

4. "Common Ground: Study of One Call and Damage Prevention Best Practices," U.S. DOT Office of Pipeline Safety, August 1999 (www.commonground.com)

5. "National Pipeline Mapping System," U.S. DOT Office of Pipeline Safety (www.npms.rspa.dot.gov)

6. "Guidelines for the Assessment of Dents on Welds," Pipeline Research Council International, Project PR-218-9822, Dec. 99, Rosenfeld, M. J. (www.prci.com)

4 Terms, Definitions, and Acronyms

anomaly: A possible deviation from sound pipe material or weld. Indication may be generated by non-destructive inspection, such as in-line inspection. Definition based on NACE Technical Committee Report, "In-line Nondestructive Inspection of Pipelines." Also see, defect; imperfection.

current established maximum operating pressure: The actual maximum operating pressure (MOP) of the pipeline, sometimes different from the design MOP. The current established MOP may be set due to the necessity to derate a pipeline or for other reasons.

current operating pressure: Pressure (sum of static head pressure, pressure required to overcome friction losses, and any backpressure) at any point in a piping system when the system is operating under steady state conditions.

defect: An imperfection of a type or magnitude exceeding acceptable criteria. Definition based on API 570. Also see, anomaly; imperfection.

final in-line inspection report: A report provided by the in-line inspection vendor that provides the operator with a comprehensive interpretation of the data from an in-line inspection. Also see, preliminary in-line inspection report.

HCA: High consequence area.

high consequence areas: Those locations where a pipeline release might have a significant adverse effect on an unusually sensitive area (see 49 *CFR* 195.6), a high population area, an other populated area, or a commercially navigable waterway. This definition is specific to the federal regulations in the United States, see 49 *CFR* 195.

imperfection: A flaw or other discontinuity noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis. Definition based on API 570. Also see, anomaly; defect.

indication: A finding of a nondestructive testing or inspection technique. Definition based on NACE Technical Committee Report, "In-line Nondestructive Inspection of Pipelines."

maximum steady state operating pressure: Maximum pressure (sum of static head pressure, pressure required to overcome friction losses, and any backpressure) at any point in a piping system when the system is operating under steady state conditions.

mitigation or mitigative action: Taking appropriate action based on an assessment of risk factors to reduce the risk level of a given injurious anomaly. Such action may consist of, but is not limited to, further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, administrative/procedural changes, or repairs.

MOP: Maximum operating pressure.

normal operating pressure: The predicted pressure (sum of static head pressure, pressure required to overcome friction losses, and any backpressure) at any point in a piping system when the system is operating under a set of predicted steady state conditions.

operator: A person who owns or operates pipeline facilities. Definition based on 49 *CFR* Part 195.

P&ID: Piping and instrumentation diagram.

PLC: Programmable logic controller.

[3] NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, P.O. Box 218340, Houston, Texas 77218-8340.

preliminary in-line inspection report: A report, usually produced in a short amount of time, that provides the operator with a list of defects considered to be an immediate hazard to pipeline safety. Typically, the operator defines the actual reporting parameters. Also see, final in-line inspection report.

risk: A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

risk assessment: A systematic, analytical process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are determined. Risk assessments can have varying scopes, and be performed at varying levels of detail depending on the operator's objectives (see Section 8).

risk management: An 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.

safe operating pressure: The pressure, calculated using remaining strength of corroded pipeline formulas, where all corroded regions will withstand a pressure equal to a stress level of 1.39 times the maximum operating pressure (MOP).

SCADA: Supervisory control and data acquisition.

SCC: Stress-corrosion cracking.

shall: The term "shall" is used in this standard to indicate those practices that are mandatory.

should: The term "should" is used in this standard to indicate those practices which are preferred, but for which operators may determine that alternative practices are equally or more effective, or those practices for which engineering judgement is required.

stand-up (operational) test: A pressure test to determine the leak tightness of a pipeline or pipeline segment. This test is typically conducted with product (or water) at a pressure significantly less than hydrostatic test pressure required by 49 *CFR* 195.304 (1.25 times maximum operating pressure [MOP]) and does not exceed the MOP of the pipe. A pipeline company may conduct this test after a pipeline is lined up but prior to beginning the movement (delivery).

TPD: Third-party damage.

5 Integrity Management Program

5.1 GENERAL CONSIDERATIONS

Although all pipeline systems have design features and operating characteristics that are unique to each individual system, an effective pipeline system integrity management program should have a solid foundation comprised of several key elements. This section describes a program framework that includes these key elements. Figure 5-1 illustrates this integrity management program framework.

Developing and implementing an integrity management program is required under the federal pipeline safety regulations in 49 *CFR* 195.452. The foreword to this standard describes the rule. The rule requires that each operator initially prepare a framework describing how its integrity management program will address several key elements. The framework presented in this standard provides recognized industry practices for developing these elements in the context of establishing a comprehensive integrity management program.

The framework shown in Figure 5-1 provides a common structure upon which to develop an operator-specific integrity management program. In developing an integrity management program, pipeline operators should consider their unique integrity management goals and objectives, and then use existing approaches or develop new processes to assure these goals are achieved. There are many different approaches to implementing the different elements identified in Figure 5-1, ranging along a continuum from relatively simple to highly sophisticated and complex. There is no "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 guidance commensurate with this need.

It is important to recognize that an integrity management program should be a highly integrated and iterative process. Although the elements depicted in Figure 5-1 are shown sequentially for ease in illustration, there is a significant amount of information flow and interaction between the different steps. For example, the selection of a risk assessment approach depends in part on what integrity related data and information is available. Conversely, while performing a risk assessment, additional data needs are usually identified to better address potential integrity issues. Thus the data gathering and risk assessment elements are tightly coupled and may require several iterations until an operator is satisfied that the risk assessment appropriately characterizes pipeline system risks.

A brief overview of the individual framework elements is provided in this section, as well as a road map to the more specific and detailed description of the individual elements that comprise the remainder of this standard. References to the specific detailed sections in the standard are provided in Figure 5-1 for the reader's convenience.

5.2 FRAMEWORK ELEMENTS

Identify potential pipeline impacts to HCAs. This framework element involves the identification of pipeline segments that could affect high consequence areas (HCAs) in the event of a release. HCA impact identification involves accessing

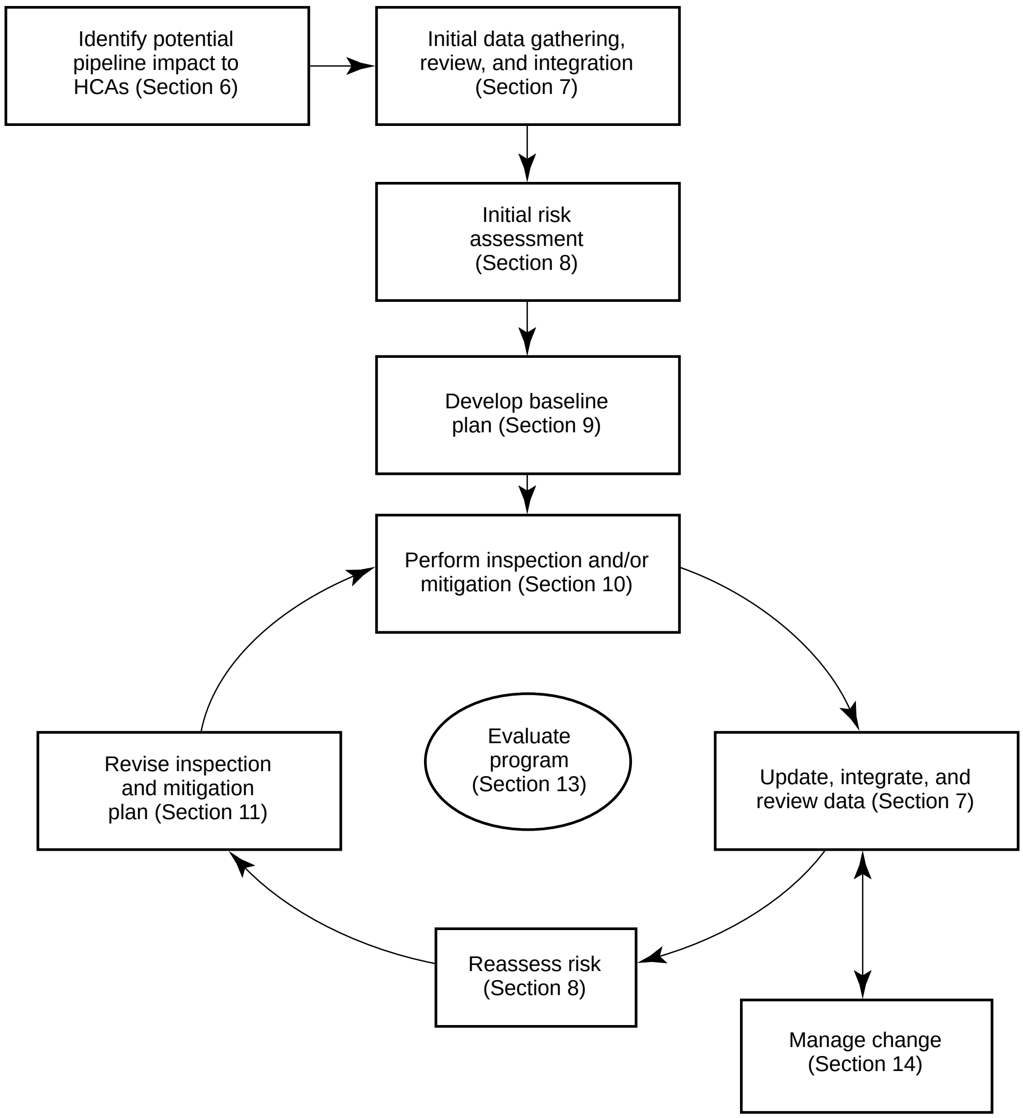

Figure 5-1—Framework for an Integrity Management Program

information that identifies HCAs on a map, overlaying the pipeline system on this map, and determining at which locations a release could impact the HCAs that lie within or near the pipeline system corridor. This analysis is required by 49 *CFR* 195.452. Guidance for making these determinations is provided in Section 6 of this standard.

Initial data gathering, review, and integration. The first step in understanding the potential integrity threats both in HCAs and elsewhere along the pipeline system is to assemble information about potential risks. In this element, the operator performs the initial collection, review, and integration of data that is needed to understand the condition of the pipe and identify the location-specific threats to its integrity. The types of data to support a risk assessment include information on the operation, maintenance, and surveillance practices, pipeline design, operating history, and the specific failure modes and concerns that are unique for each system and segments within a system. Section 7 provides a summary of useful data sources, common data elements that are typically used in risk analyses, and approaches to data review and integration. For operators that are just formalizing an approach to integrity management, the initial data gathering may be focused on a limited number of parameters so that a screening for the most significant integrity threats can be readily identified.

Initial risk assessment. In this element, the data assembled from the previous step is used to conduct a risk assessment of the pipeline system. The risk assessment begins with a systematic and comprehensive search for possible threats to pipeline or facility integrity. The identification of potential threats should not be limited to a review of known risk categories, but should include steps to look for new or unique manifestations of risks. Through the integrated evaluation of the information and data collected in the previous step, the risk assessment process identifies the location-specific events or conditions, or combinations of events and conditions that could lead to loss of pipeline integrity, and provides an understanding of the likelihood and consequences of these events. The output of a risk assessment should include the nature and location of the most significant risks on the pipeline system.

There is a significant variation in the detail and complexity associated with different risk assessment methods. Some operators, without formal risk assessment processes, have found that an initial screening level risk assessment can be beneficial in terms of focusing resources on the most important areas. During a screening risk assessment, an operator may limit the scope of the system to those portions of the system where a failure could have the most severe consequences (i.e., an HCA). Similarly, risk assessment and data collection may be focused to support identification of the most likely failure mechanisms in those pipeline segments, without going into extensive detail. Because of the limited time in which to prepare the Baseline Assessment Plan required by 49 *CFR* 195.452, some operators may find a screening approach as the most practical approach to prioritize line segments for integrity assessment.

After identifying the most significant risks on the system, the next step is to determine what preventive or mitigative actions might be desirable to reduce risk, and where assessment techniques such as internal inspection and pressure testing would be of the most value in identifying potential integrity-threatening defects. The risk control and mitigation process involves:

- Identification of risk-control options that lower the likelihood of a pipeline system incident, reduce the consequences, or both.
- A systematic evaluation and comparison of those options.
- Selection and implementation of the optimum strategy for risk control.

There are a number of methods that can be employed to conduct a risk assessment and identify risk control activities. Section 8 provides guidance for developing and implementing a useful risk assessment approach.

Develop baseline assessment plan. Using the output of the risk assessment (or a screening assessment), a plan is developed to address the most significant risks and assess the integrity of the pipeline system. This plan should address integrity assessment activities (e.g., internal inspection or pressure testing), as well as any preventive and mitigative risk control actions identified in the risk assessment process. For pipeline segments that could affect HCAs, 49 *CFR* 195.452 requires that a documented baseline assessment plan be prepared which identifies the internal inspection technique(s), pressure testing, or other technology that will be used to assess the line's integrity, the schedule for conducting these assessments, and the justification for the integrity assessment method selected. Section 9 provides a description of the various internal inspection techniques available, and guidance to assist operators in selecting an integrity assessment method and establishing a schedule for periodic inspection or pressure testing.

Inspection and/or mitigation. In this element, the baseline assessment plan activities are implemented, the results are evaluated, and the necessary repairs are made to assure defects that might lead to pipeline failure are eliminated. Section 9 provides guidance for prioritizing features identified by internal inspection for examination and repair. Appendix B provides a description of commonly used repair techniques to address the different type of defects that might be discovered during integrity assessment.

As noted previously, a risk assessment may identify other risks that should be addressed. For example, if damage from excavation was identified as a significant risk in a particular area, the operator may elect to conduct additional patrolling, increase public communication, improve line marking, improve right-of-way clearance, actively engage local planning commissions, and/or enhance its excavator awareness program to reduce the likelihood of third-party damage (TPD) to their line. A menu of risk control activities and mitigative options to address common integrity threats is also provided in Section 10.

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 line. This information is retained and added to the database of information used to support future risk assessments and integrity evaluations. Furthermore, as the system continues to operate, additional operating, maintenance, surveillance, and other data is collected, thus expanding and improving the historical database of information to support integrity management.

Reassess risk. Risk assessments should be performed periodically to factor in recent operating data, consider changes to the pipeline system design (e.g., new valves, newly replaced pipeline segments or rehabilitation projects, etc.) and operation (e.g., a change in flow or the hydraulic pressure profile), and analyze the impact of any external changes that may have occurred since the last risk assessment (e.g., population encroachment in new areas). The results of integrity assessments, such as internal inspection or pressure testing, should also be factored into future risk assessments, to assure the analytical process reflects the latest understanding of pipe condition.

Revise mitigation and inspection plan. The baseline assessment plan should be transformed into an on-going integrity assessment plan that is 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 preventive or mitigative actions to address these risks should be performed, as appropriate. Furthermore, the updated risk assessment results should also be used to support scheduling of future integrity assessments. Section 11 discusses updating the integrity assessment plan. Section 9 provides a discussion of methods to plan internal inspection and pressure testing frequency.

Evaluate program. The operator should collect performance information and periodically evaluate the success of its integrity assessment techniques, pipeline repair activities, and other preventive and mitigative risk control activities. The operator should also evaluate the effectiveness of its management systems and processes in supporting sound integrity management decisions. Section 13 provides guidance for developing performance measures to evaluate program effectiveness, and guidance for conducting audits of integrity management programs.

Manage change. Pipeline systems and the environment in which they operate are never static. A systematic process should be used to ensure that changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts prior to implementation, and to ensure that changes in the environment in which the pipeline operates are evaluated. Furthermore, after these changes have been made, they should be incorporated, as appropriate, into future risk assessments to be sure the risk assessment process addresses the system as it is currently configured, operated, and maintained. Section 14 discusses the important aspects of managing changes as they relate to integrity management.

As this final element indicates, managing pipeline integrity is not a one-time process. As implied by the loop in the lower portion of Figure 5-1, an integrity management program involves a continuous cycle of monitoring pipeline condition, identifying and assessing risks, and taking action to minimize the most significant threats. Risk assessments must be periodically updated and revised to reflect current pipeline conditions so operators can most effectively use their finite resources to achieve the goal of error-free, spill-free operation.

Finally, Section 12 of this standard identifies some of the special considerations for pipeline system facilities other than line pipe, such as pump stations and terminals that should be considered in developing a comprehensive system-wide integrity management program. While the same framework as depicted in Figure 5-1 applies to these facilities, there are some considerations associated with integrity assessment, risk assessment, testing, and preventive and mitigative actions that are unique. Section 12 provides guidance specific to pump stations and terminals.

6 High Consequence Areas

6.1 IDENTIFYING HIGH CONSEQUENCE AREAS

High consequence areas, commonly called HCAs, are those locations where a pipeline spill might have significant adverse impacts to population, the environment, or commercial navigation. HCAs are defined under 49 *CFR* Part 195.450 and are described in the foreword to this standard. The definitions for various types of HCAs are periodically reevaluated and operators should be familiar with the current regulations for managing pipeline system integrity and the definitions of HCAs. The federal government, through the Office of Pipeline Safety (OPS), makes maps and databases describing HCAs available to the pipeline industry and to the public through the OPS website[4]. An operator must consider the federally prescribed HCAs in developing a pipeline integrity management program. The physical location of some HCAs will change over time as new population and environmental resource data becomes available. Accordingly, the maps delineating the locations of HCAs are expected to be updated. Hence, it is important that the operator periodically ensure that its integrity management program considers the most recent HCA location information provided by the government.

6.2 USING HCA INFORMATION

Information about HCAs is used in several key elements of an integrity management program.

- Data gathering.
- Risk assessment.
- Inspection and mitigation.

HCA information should also be incorporated into an operator's response plan.

6.3 DETERMINING WHETHER A PIPELINE SEGMENT COULD AFFECT A HIGH CONSEQUENCE AREA

As part of the data gathering and integration, pipeline operators must determine the likelihood that a particular pipeline segment, segments, or system will affect an HCA in the event of a spill. Operators must look at HCAs that the pipeline segment crosses, as well as those HCAs in proximity to the segment or system. In addition to the pipeline right-of-way, operators need to evaluate any impact zones for the pipeline and associated pump station and delivery locations. Impact zones will vary in size and complexity. When determining a potential impact zone, operators should consider:

[4]http://ops.dot.gov

1. The health and safety consequences of a release, including the possible need for evacuation.
2. The nature and characteristics of the product or products transported (refined products, crude oil, highly volatile liquids, etc.).
3. The operating conditions of the pipeline (pressure, temperature, flow rate, etc.).
4. The topography of the land associated with the HCA and the pipeline segment.
5. The hydraulic gradient of the pipeline.
6. The diameter of the pipeline, the potential release volume, and the distance between isolation points.
7. The type and characteristics of the HCA crossed or in proximity to the segment.
8. Potential physical pathways between the pipeline and the HCA.
9. Potential natural forces inherent to the area (flood zones, earthquake zones, subsidence areas, etc.).
10. Response capability (time to detect, confirm and locate a release; time to respond; nature of response; etc.).

Developing an understanding of the potential impact zone ensures that operators include the appropriate HCA information for use in the risk assessment.

6.4 DOCUMENTING HCA INFORMATION

HCA maps and databases provided by the Office of Pipeline Safety will include information about the quality of the HCA map or data. Commonly called "meta data" or data about the data, operators should document the meta data for the HCA information at the time they acquire the HCA information from the Office of Pipeline Safety or other sources.

In addition to HCA information obtained from OPS, operators must document any HCA areas identified during routine operator conducted risk assessments, right-of-way surveillance or other activity related to HCAs.

7 Data Gathering, Review, and Integration

The objective of this section is to provide a systematic methodology for pipeline operators to obtain the data needed to manage the integrity of their pipeline system. Most operators will find that many of the data elements suggested here are already being collected. This section provides a systematic review of potentially useful data to support an integrity management program. However, it should be recognized that all of the data elements delineated in this section are not necessarily for all systems.

The types of data required depend on the types of defects and failure modes that are anticipated. The operator should consider not only the failure modes currently suspected in the system, but also consider whether the potential exists for other failure modes not previously experienced in the system. This section includes lists of many types of data elements. These lists have been organized using failure mode (or potential defects) as an organizational tool that can be helpful in defining and utilizing the information. As different types of data are listed, common types of related defects and failure modes are indicated. The purpose of indicating defects and failure modes is to help the user understand the need and importance for the related type of data. All possible defects and failure modes are not necessarily listed, so the operator is responsible for evaluating its system to identify those that may be of concern.

This section covers the gathering, review, and integration of data for pipeline integrity management. The discussion is separated into five subsections that address sources of data, identification and location of data, establishment of a common reference system, data collection and review, and data integration.

7.1 DATA SOURCES

The first step in gathering data is to identify the sources of data needed for pipeline integrity management. These sources can be divided into five different classes.

Design, material, and construction records. Design information is used to identify the design pressure and other loads, nominal pipe diameter, and design wall thickness. The material information should include the grade of steel, type of weld, type of welding procedure, type of coating, and pipe manufacturer, as well as all available material certification records. Important construction records include as-built drawings, pipe laying procedures, procedures for making field bends and welds, type of backfill, and depth of cover. The over pressure protection logic for steady state and transient conditions is also valuable.

Right-of-way records. Current right-of-way records are used to identify the location of the pipeline. This information is essential for determining areas that may be affected by the pipeline, establishing patrolling programs, and for protecting the pipeline from TPD.

Operation, maintenance, inspection, and repair records. Operating data and control procedures are used to identify maximum operating pressures (MOPs) and pressure fluctuations, commodities transported, operating temperatures, control and communications hardware and software, operator qualification and training, etc. Maintenance records are used to determine the effectiveness of corrosion protection and other activities to assure pipeline integrity. In-line and other inspection data are used to identify areas of corrosion, dents, cracks, and other defects. Repair records identify problems that have occurred in the past and could potentially occur in the future. These records also identify the specific locations where these problems have been eliminated in the system.

Records for determining portions of pipeline that may affect high consequence or other sensitive areas. This information is used to develop impact zones and the relationship of such impact zones to various areas along the pipeline (see

Section 6). Any reports assessing environmental impacts should be included as one of the data sources.

Incident and risk reports. The impacts of an unintended release on the environment and population are essential to a complete consequence analysis. Safety and emergency response concerns should be included.

7.2 IDENTIFICATION AND LOCATION OF DATA

7.2.1 Identifying Data Needs

The type and quantity of data to be gathered will depend on the individual pipeline system, the risk assessment methodology selected, and the decisions that are to be made. The data collection approach will follow the risk assessment path determined by the initial expert panel assembled to identify the data needed for the first pass at risk assessment (see Section 8).

The quantity of pipe to be evaluated and the resources available may prompt the risk analysis team to begin their work with an overview or screening analysis of the most critical issues that impact the pipeline with the intent of highlighting the highest risks. Therefore, the initial data collection effort will only include the relevant information necessary to support this risk analysis. As the risk analysis process evolves, the scope of the data collection will be expanded to support a more detailed analysis and improve results. Thus, as the operator reviews this section, a sampling of potential data types are presented to help readers formulate their plans when embarking on the identification of pipeline data sources.

7.2.2 Locating Required Data

Operator data are available in different forms and format. They may not be physically stored and updated at a single location based on the current use or need for the information. The first step is to make a list of all data required for integrity assurance and locate them. The data generally include:

- Piping and instrumentation diagrams (P&ID).
- Pipeline alignment drawings.
- Pipeline aerial maps.
- Facility layouts and maps.
- As-built drawings.
- Survey reports and drawings.
- Operating and maintenance procedures.
- Emergency response procedures.
- Inspection records.
- Incident and risk data.
- Repair and maintenance records.
- Test reports and records.
- Incident reports and operation history.
- Regulatory and compliance records.
- Pipeline design and engineering reports.
- Technical studies.
- Operator standards and specifications.
- Equipment dossiers.
- Industry standards and specifications.

7.3 ESTABLISHING A COMMON REFERENCE SYSTEM

As part of the data assembly process, data units from multiple sources with multiple reference standards need to be translated and correlated to a consistent referencing system so that data features can be aligned for observation of coincident events and locations.

Common references (examples in parentheses) that are used to tie together information associated with pipelines include:

- GPS coordinates (longitude, latitude).
- Odometer readings (100,387 meters).
- Milepost (10.5 miles).
- Engineering station (136 + 20).
- Surface references (300 ft north of FM 12).

Data accuracy concerns will be dictated by the resolution of the risk analysis process (discussed later in Section 8). The accuracy of the common reference system should be in accordance with the accuracy of the data sources. Being able to put collected data into a common reference system is essential to integrating or overlaying the data for analysis as discussed in Section 7.5.

7.4 DATA COLLECTION

As the collection effort begins, every effort should be made to collect data of the highest quality and consistency. When data of suspect quality or consistency are encountered, such data should be flagged so that during the analysis process appropriate consideration can be given to these concerns. No decision should be addressed solely on suspect data.

Resolution of the input data should also be taken into account. Data resolution addresses the specific length over which data impacts the pipeline and is recorded. Every effort should be made to utilize data as it actually exists along the pipeline (i.e., do not assume an entire system has uniform properties when more localized information is known). Widespread data assumptions should be minimized, as they will not increase the overall accuracy of the analysis. The resolution will be handled during the risk analysis (see Section 8).

In the event that the risk analysis approach needs input data that are not readily available, the operator should flag the absence of information. The risk assessment team can then discuss the necessity and urgency of collecting the missing information.

Data that are typically collected can be divided into five groups as indicated in Table 7.1. In this table, types of data that many pipeline operators have found to be useful in integrity management and important factors for consideration in relationship to those data are listed. An individual pipeline operator usually will not need to collect every type of data listed in the table. Furthermore, an operator may need to collect types of data that are not listed. The types of data to be collected should be based on the risk analysis methodology selected (see Section 8) and the specific integrity threats that are appropriate to a particular pipeline system.

7.5 DATA INTEGRATION

The quality of an ongoing risk assessment, as well as a data maintenance program relies strongly on the use of available information and on monitoring conditions over a period of time.

A substantial amount of inspection and monitoring data is collected over the life of a pipeline. Examples of such data are cathodic protection station checks, close interval potential surveys, in-line inspection results, pipeline coating inspections, valve data including closure rate, test data for leak tight closure, estimated spill volumes, etc. These data may reside within various departments and considerable effort can be involved to collect, collate, and arrange these data in a format that allows ready comparison.

The number of data points may become large, especially with the application of a risk-based assessment system and the pipeline repair, maintenance, inspection, and monitoring data. Integrity data should be stored in an electronic database. Design of reports and data output is an important consideration in designing the database. This greatly simplifies the comparison of measured values against design values during pipeline integrity assessment.

The strength of a risk assessment is in its ability to compare the existing data for the coincident occurrence of suspected high-risk conditions or events. The user will be collecting data that indicates risk-increasing conditions, as well as activities that will confirm or deny the impact of suspect risk conditions. Integration of data is an integral part of this approach.

Shown below is an example of how integration of data is used to answer the question, "What is the likelihood of TPD at a location on the pipeline?"

Integration Example: Potential for TPD	
Risk-increasing Indicators	Confirmation Activities (Confirm or Deny)
Patrol Frequency Depth of Cover Construction or Farm Activity Third-party Leak History One-call Activity	In-line Inspection (ILI) Dent Survey Third-party Leak History Pipe Exposure Reports
Question: What is the Likelihood Of TPD at a Specific Location Along the Pipeline?	

Additional advantages of using a data management system for data integration include:

- Vast amounts of in-line inspection and non-inline inspection information can be stored.
- Keeping track of changes and updating reference points is easier.
- Data from different tools can be cross-referenced (e.g., a pipe containing a dent can in addition be corroded, which would increase the severity of the dent).
- Information can be combined more readily between in-line inspection results and other inspection or evaluation techniques (e.g., corrosion in a river crossing or close to high power cables).
- Information and data can be sorted, filtered, or searched (e.g., list all corrosion defects with depths > 40% in HCAs).
- Discovering and identifying data needed for the risk assessment process is made easier.
- The capability to import documents, photographs, videos, drawings, etc., allows user-friendly visualization of locations of anomalies (displays of aerial pictures of terrain with superimposed maps and drawn in pipeline with depicted selected defects).
- Integration of defect assessment (including operating pressure calculations) modules allows sorting and prioritizing anomalies based on the MOP calculations.
- Anomalies can be prioritized based on combined information (e.g., a corrosion spot in a specific location and in conjunction with a gouge).
- Integrity data can be compatible with other data management systems.
- Integrated data can be used in employee, contractor, and public education and training.

Building the databases in accordance with a company-wide or industry-wide data standard offers numerous advantages in allowing operators to compare their own performance with comparable companies or across the pipeline industry (also see Section 13).

8 Risk Assessment Implementation

8.1 DEVELOPING A RISK ASSESSMENT APPROACH

When establishing a risk assessment program, a pipeline operator should consider many features that are unique to its systems and operations to determine which approach is most appropriate. The ultimate goal of risk assessment is to identify and prioritize risks in the system so the pipeline operator can determine how, where, and when to allocate risk mitigation resources to improve pipeline system integrity. The operator must decide what information could be useful in performing the assessment and how that information can be used to maximize the accuracy and effectiveness of the risk assessment.

Table 7-1—Types of Data to Collect

Type of Data	Example Factors
Design, Material, and Construction Data	
Pipeline segment name/id	Identification labels
Pipeline route coordinates	HCA, engineering stationing, GPS, mileposts
Pipe diameter	Stress, potential spill volume
Pipe wall thickness	MOP, TPD
Pipe grade	MOP
Design operating pressure and safety factors	MOP, TPD
Pipe type —electric resistance welded (ERW) —high frequency welds are used in modern line pipe —DC or low frequency welds were used in older line pipe —flash welds were used in older line pipe —submerged arc welded (SAW) —double submerged arc welds (DSAW) are used in modern line pipe —single submerged arc welds (SSAW) were used in older line pipe —seamless pipe sees limited use in pipelines	Toughness, crack-like flaws, metallurgical anomaly
Pipe manufacturer and production date	Historical problems
Construction date or age	State of art
Weld quality and inspection	Weld failure
Coating type	External corrosion, SCC
Coating condition	External corrosion
Cathodic protection type	External corrosion
Cathodic protection condition	External corrosion
Pump station, booster station, and terminal	Potential spill volume
Valve locations, testing requirements, and closure times	Potential spill volume
Type of soils (sand, rock, clay, etc.)	External corrosion, stress
Appurtenances, flanges, fittings, deadlegs, and instrumentation lines	Corrosion, correct ratings
Right-of-way Data	
Width of right-of-ways	TPD
Depth of burial	TPD
Condition of right-of-way	TPD, ingress/egress
Frequency of patrolling —line flying —driving —walking	TPD
Encroachment check and mitigation	TPD
Pipeline markers and signage	TPD
List of legal description and land owners	Public education
Description of land use—rural, urban, farm, industrial	TPD
Highway and railroad crossings—cased, uncased	External corrosion, TPD
River, creek and lake crossings	Consequence, spill control
Pipeline and other utility crossings, sharing right-of-way corridor	Corrosion interference, TPD
Community relationship	Public education, TPD
Public awareness of pipeline	Public education, TPD
One-call system use, effectiveness, and response timing	TPD
Operator personnel presence during excavations	Condition of pipe, external corrosion, TPD
Pipeline exposure reports	Condition of pipe, external corrosion, TPD
Operation, Maintenance Inspection and Repair Data	
In-line inspection (ILI) results	Condition of pipe, external corrosion, TPD
Results of ILI anomaly assessment	Condition of pipe, external corrosion, TPD
Hydrostatic pressure testing data	Condition of pipe, failures during testing
SCADA and leak detection	Potential spill volume, response time, release prevention
Procedure for control room and field coordination	Operator error
Emergency response plan, drill and training	Response time, minimize release

Table 7-1—Types of Data to Collect (Continued)

Type of Data	Example Factors
Spill management plan	Spill control, consequence, HCA
Backup plan for communication and power failures	Operator error
Operators qualification and training plan	Operator error
Line pressure content or service (crude oil, gasoline, jet fuel, HVL)	Consequence
Pressure cycles and pressure profile	Pipe failure, fatigue, overpressure protection
Operating temperature	Pipe failure, coating damage, SCC
Ambient temperature	Release properties—vapor cloud, product flow characteristics
Atmospheric condition and data	External corrosion
Pipe to soil readings	External corrosion
Close interval survey	External corrosion
Coating condition and inspection	External corrosion
Cathodic protection inspection	External corrosion
Depth of burial inspection	TPD
Re-route, replace section, line lowering	TPD
Pipeline protection in river, creek, lakes and water ways	TPD, consequence
Pipeline protection and monitoring in unstable ground	Release prevention
Records for Determining Portions of Pipeline that May Affect Sensitive Areas	
Proximity to drinking water: within 500 ft, 2500 ft, 1 mile, 5 – 10 miles	Consequence, HCA
Proximity to populated areas	Consequence, HCA
Proximity to habitats	Consequence, HCA
Proximity to recreation water	Consequence, HCA
Proximity to other water use and water ways	Consequence, HCA
Proximity to farms	Consequence, HCA
Proximity to parks and forests	Consequence, HCA
Proximity to commercial fishing waters	Consequence, HCA
Proximity to sensitive areas	Consequence, HCA
Proximity to other important areas	Consequence, HCA
Incidents and Risk Data	
Past history of incidents, leaks, and near misses —location —failure causes and root causes —consequences —remedial action —repair history —encroachment history	Failure mode, release prevention and control
Air, soil and water sampling program	Consequence, corrosion
Potential for human safety	Consequence, HCA
Potential for releases in canyons	Consequence
Potential for environmental impact (air, soil and water)	Consequence, HCA
Potential for fire	Consequence, HCA
Potential for financial losses —human safety, injury and fatality —damage to air, soil and water —functional losses, legal expenses, fines and punitive damages Costs of alternate drinking water supply, pipeline downtime, and fuel shortages	Consequence, HCA
History on other company and industry systems	Failure mode

Notes:
HCA = High consequence area
MOP = Maximum operating pressure
TPD = Third-party damage
SCC = Stress-corrosion cracking
This table lists data that various operators have used for pipeline integrity management. An individual operator is not likely to need all of the listed types of data. Furthermore, an operator may need some types of data not listed in this table. Examples of relevant factors are given to help illustrate why the data are needed. The operator should consider factors for its system in deciding what type of data to collect.

A risk management program is a continuous process that is most effective if completely integrated into a company's daily operation. The benefits of effective data integration (comparing the results of in-line inspection anomaly locations, cathodic protection test station performance, close interval survey results, proximity to HCAs, and risk studies, etc.) will greatly enhance an operator's ability to plan effective maintenance and mitigation activities as well as identify circumstances that could result in an unintentional release. Operators need to evaluate the scope of the initial data entry, as well as the ongoing update of data, the effective analysis of the data by a qualified individual, and the design and implementation of risk reduction activities. In selecting the types of data that the operator will use for the risk assessment the operator should consider the following (see also Table in Section 7):

The completeness of the data. For a set of data to be useful for an assessment, the data set should be as complete and consistent as possible across the portion of the pipeline system within the scope of the assessment. Using incomplete data will introduce uncertainty into the assessment, possibly resulting in poor and misleading results. However, some preliminary risk assessments may be performed with minimal or incomplete information to quickly screen a large collection of assets, and to focus the initial risk analysis on the areas of highest concern. The use of incomplete data should be tempered appropriately based on the intent of the analysis. This initial risk assessment, or risk screening, step may be used, for example, to develop a baseline inspection plan and/or to prioritize pipeline systems or portions of systems for more complete risk assessments. The scope, purpose, and objectives of such an assessment should be clearly communicated so that decision-makers do not interpret the results of a screening risk assessment to have a higher degree of accuracy than is possible, given the information considered in the assessment.

The quality of the data. Data that has not been consistently and regularly prepared, updated, and maintained may also introduce error into the assessment that may be detrimental to achieving the objective. Operators should strive to use data that best reflects the known, actual location-specific conditions on the pipeline. Where possible, operators should avoid the use of global data assumptions (such as, one-call effectiveness in entire system is defined as "good"). This will support a risk assessment that discriminates potential problematic areas in the system, and allows risk-results to be based on the changing "actual" conditions along the pipeline length.

The timeliness of the data. Conditions along the pipeline change over time. Information types such as population density and third-party excavation activity should be monitored and updated for use in risk assessments. Similarly cathodic protection data that is collected periodically and reviewed annually should be incorporated into risk assessments. The user must take into account the changing conditions of key data when performing and using the results of risk assessments in decision making.

The importance of specific pipeline data. Not all information about a pipeline is considered of equal value in a risk assessment. The pipeline operator must decide what level of importance will be placed on specific pipeline data. Risk assessment methods should consider the historical failure mechanisms of the specific system, tempered with broader industry and other proven engineering practices and technical guidance.

Risk assessment is a very important analytical process in an integrity management program. Although there are a number of different methods for performing risk assessments, all approaches should answer the following basic questions:

- What kind of events and/or conditions might lead to a loss of pipeline system integrity?
- How likely are these events and/or conditions to occur?
- What is the nature and severity of the consequences if these events and/or conditions occur?
- What overall risks do these events and/or conditions present?

In selecting an appropriate risk assessment method, an operator must answer a few key questions:

- What management decisions will be made based on the results of the risk assessment?
- What specific results are required from the risk assessment to support the decision making process?
- What level of commitment and resources (both internal and external) are required for successful implementation?
- How quickly do results need to be available?

8.2 DEFINITION OF PIPELINE RISK

The overall risk to a pipeline is a function of the *likelihood* of an event or condition to lead to a release (e.g., severe corrosion damage), and the *consequence* in the event of a release (e.g., crude entering a waterway). Both components of risk must be considered when conducting a risk assessment and in making prudent risk-based decisions. Figure 8-1 provides a simple depiction of risk.

8.3 ESTIMATING RISK USING RISK ASSESSMENT METHODS

Many pipeline risk and integrity management programs use risk assessment methods that collect and logically process data to arrive at a risk estimation result. Risk assessment methods are tools that define a relationship between the threats that can reduce the system integrity (i.e., corrosion, outside force) and the consequences in the event of a release through a variety of data and assumptions about how the system is designed, constructed, operated, and maintained, as well as the environmental and external factors that can affect risk. Risk assessment methods "predict" the value of the output variable (e.g., risk) based on the input values of more eas-

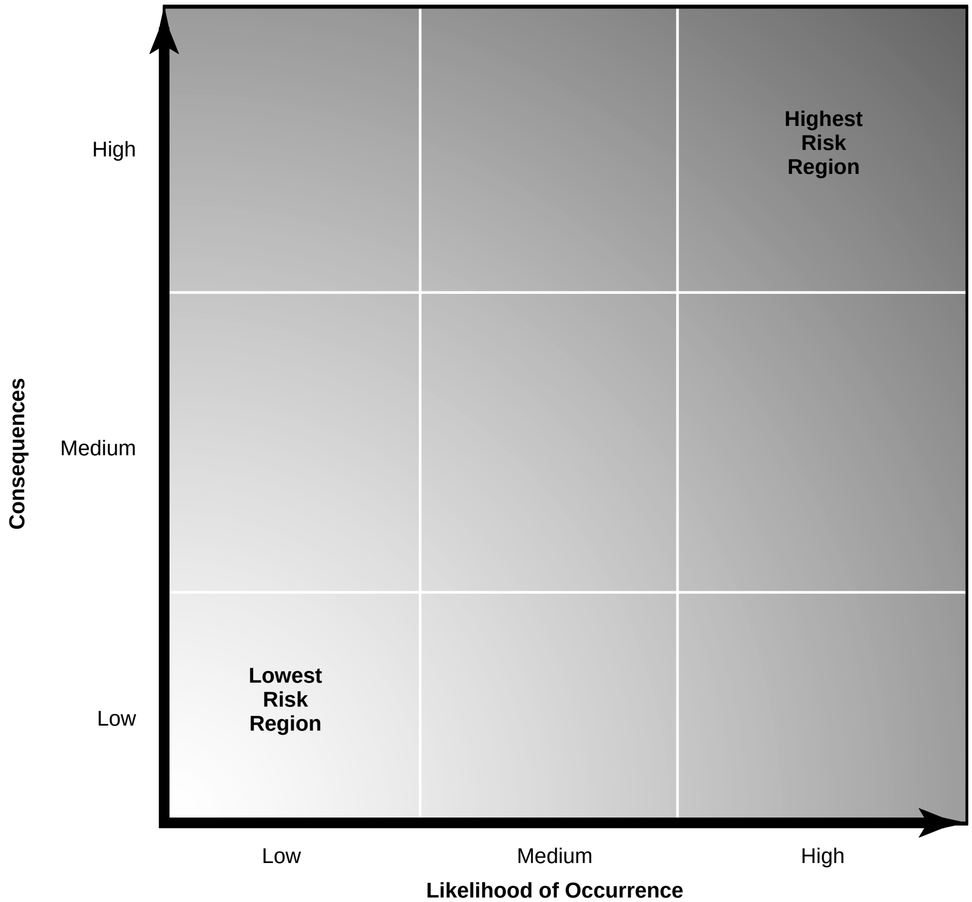

Figure 8-1—Simplified Depiction of Risk

ily measured or evaluated variables (e.g., pigging results, soil conditions, pipe wall thickness, coating condition, etc.). The quality of the prediction is dependent on the quality of the inputs and the soundness of the logical relationships inherent in the risk assessment method used to evaluate the input and output conditions.

It is important to distinguish between a risk management process and a risk assessment method. Risk assessment is the estimation of risk for the purposes of decision making. Risk management is the overall process that includes the risk assessment, maintenance activity, and reintegration of data into subsequent risk assessments. Risk assessment methods can be very powerful analytical tools to integrate data and information, and help understand the nature and locations of risks along a pipeline. However, risk assessment methods alone should not be relied upon to establish risk, nor solely determine decisions about how risks should be addressed. Risk assessment methods should be used as part of a process that involves knowledgeable, experienced personnel that critically review the input, assumptions, and results. This review should integrate the risk assessment output with other factors not considered by the tool, the impact of key assumptions, and the impact of uncertainties created by the absence of data or the variability in assessment inputs before arriving at decisions about risk and actions to reduce risk.

A variety of different approaches to risk assessment have been employed in the pipeline as well as other industries. The major differences among approaches are associated with:

- The relative "mix" of knowledge, data, and their logical relationships within the risk assessment methods.
- The complexity and detail of the risk assessment method.
- The nature of the output (probabilistic versus relative measures of risk).

Independent of the risk assessment method used, all techniques incorporate the same basic components:

1. Identify potential events or conditions that threaten the system's integrity.
2. Determine risk represented by these events or conditions by determining the likelihood of a release and the consequences of a release.
3. Rank risk assessment results.
4. Identify and evaluate risk mitigation options (both net risk reduction and benefit/cost analyses).

5. Integrate maintenance project data (i.e., a feedback loop).
6. Re-assess risk.

Ultimately, it is the responsibility of the operator to apply the risk analysis method(s) that best meets the requirements of the risk assessment task. Therefore, it is in the best interest of the pipeline operator to develop a thorough understanding of the various risk assessment methods in use and available, as well as the respective strengths and limitations of the different types of methods, before developing a long-term strategy.

8.4 CHARACTERISTICS OF A SOUND RISK ASSESSMENT APPROACH

A risk assessment should be:

Structured. The underlying methodology is structured to provide a thorough analysis. Some methodologies employ a more rigid structure than others do. More flexible structures may be easier to use; however, they generally require more input from subject matter experts. However, all risk assessment methods identify and use logic to determine how the data considered contributes to risk in terms of affecting the likelihood and/or consequences of potential incidents.

Given adequate resources. Appropriate personnel and adequate time must be allotted to fit the detail level of the analysis.

Experience-based. The frequency and severity of past events (in the subject or a similar system) should be considered. The risk assessment should understand and account for any corrective actions that have been made to prevent similar mishaps. The risk assessment should consider the system-specific operating history and other knowledge about the system that has been acquired by field, operations, and engineering personnel.

Predictive. A risk assessment should be investigative in nature, seeking to identify previously unrecognized threats to pipeline integrity. It should make use of previous events, but focus on the potential for future mishaps, including scenarios that may never have happened before.

Use appropriate data. Some risk analysis decisions are judgment calls. However, relevant data and particularly data about the system under review should affect the confidence level placed in the decisions.

Able to provide for and identify means of feedback. Risk analysis is an iterative process. Actual field events and data collection efforts should be used to validate (or invalidate) assumptions made.

8.5 FIRST STEP IN THE RISK ASSESSMENT PROCESS

A common step in approaching risk assessment is to collect a representative group of company experts to identify potential events or conditions that could lead to pipeline failure, the consequences of these failures, and risk reduction activities for the operator's system. These experts draw on the years of experience, practical knowledge, and observations from experienced engineers, pipeline operation controllers, field operations and maintenance personnel in understanding where the integrity threats may reside and what can be done about them. Such a group typically consists of representation from: risk management, operations, corrosion control, engineering and construction, maintenance, safety, environmental, regulatory compliance and right-of-way management departments. This group of experts will focus on the potential problems and risk control activities that would be effective in a risk management program and not become encumbered by the presence or absence of data on hand. During a later step in the risk assessment method development process, the availability of data, and the incremental value of collecting specific data, will be handled. The primary goal of this group is to capture and build into the risk assessment method, the experience of this diverse group of individual experts so that the risk assessment process will capture and incorporate information that may not be available in operator databases.

There are a number of techniques employed by these expert panels that have proven useful in assuring a systematic and thorough review. These include:

- Free-form brainstorming of issues and potential risks.
- Conducting a segment-by-segment review along the line using pipeline alignment sheets or maps.
- Using checklists or structured question sets designed to elicit information on a comprehensive list of potential risks and integrity issues.
- Using simple risk matrices to qualitatively portray and communicate the likelihood and consequences of different events.

8.6 RISK ASSESSMENT

Each of the risk assessment methods commonly used has its own strengths and limitations. Some approaches are well suited to particular applications and decisions, but may not be as helpful in other situations. In selecting or applying risk assessment methods, there are a number of questions that should be considered. Some of the more significant ones are summarized below:

- Does the scope of the risk assessment method encompass significant failure causes and risks along the pipeline system? If not, how can the risks that are not included in the risk assessment method be assessed and integrated in the future?
- Will all data be assessed as it really exists along the pipeline? (Data should be location specific so that additive effects of the various risk variables can be determined). Can the analysis resolution be altered (i.e., station by station, mile by mile) dependent on the evaluation needs?

- What is the logical structure of variables that are evaluated to provide the quantitative results of the risk assessment? Does this provide for straightforward data collection and maintenance?
- Does the risk assessment method use numerical weights and other empirical factors to derive the risk measures and results? Are these weights based on the operational experience of the system, operator, or industry?
- Do the basic input variables of the risk assessment method require data that are available to the operator? Do operator data systems and pipeline data updating procedures provide sufficient support to apply the risk assessment method effectively? What is the process for updating the risk assessment data to reflect changes in the pipeline condition, new operating experience, and other new data? How are the input data validated to ensure that the most accurate, up-to-date depiction of the pipeline system is reflected in the risk assessment?
- Does the risk assessment output provide adequate support for the technical justification of risk-based decisions? Are the risk assessment results and output documented adequately to support technical justification of the decisions made using this output?
- Does the risk assessment method allow analysis of the effects of uncertainties in the data, structure, and parameter values on the method output and decisions being supported? What sensitivity or uncertainty analyses are supported by the risk assessment method?

8.7 CORE RISK ASSESSMENT METHODOLOGY COMPONENTS

This section describes the common characteristics of the various risk assessment methods that are currently used to assess pipeline system risk. There are many techniques and methods available but they all have common elements.

A risk assessment technique is typically based on a logically structured process that collects and analyzes data for the common causes of pipeline failure, as well as failure consequences along the pipeline. Figure 8-2 provides a simplified example of the logical hierarchy showing the relationship between variables in many risk assessment methods.

The risk assessment methods typically include a number of different design, operation, and maintenance variables that can be important in affecting the likelihood of pipeline failure, as well as variables that reflect conditions in the surrounding area (e.g., population density, sensitive environmental resources, etc.). Variable scores or values are assigned based on the presence or absence of these variables for each pipeline segment. These variables are assessed according to their importance and combined to determine the degree of risk represented by that segment.

Risk estimation is the process of combining frequency and severity estimates into a risk value. The frequency and consequence estimated for each of the various identified events, or sequences of events, are combined into a risk value for that event sequence. The risk values for all identified event sequences can be combined into an overall risk value for the pipeline system or segment. The risk values may be qualitative, quantitative, or a combination of both, depending upon the processes used for frequency and consequence analysis, and the goals of the operator's risk management program.

The sensitivity of risk assessment methods is a function of the number of variables and the ability to estimate the changing risk along the length of the line. Some techniques require the user to evaluate long sections of line using a uniform set of characteristics, while others integrate the localized effect of changing performance data (i.e., cathodic protection values, number of in-line inspection anomalies, etc.).

In many risk assessment methods, the likelihood is estimated using a combination of variables in categories such as the following:

- External corrosion
- Internal corrosion
- TPD
- Ground movement
- Design and materials
- System operations

The consequence is estimated as a combination of variables in categories such as:

- Environmental receptors
- Population
- Business interruption
- Spill size
- Spill spread
- Product hazard

The values used in a risk assessment method are determined based on the pipeline operator's knowledge and experience with systems involving the risk increasing or decreasing performance of a variable. For example, an operator may consider an older coating a higher risk than a newer coating, or a higher-pressure line higher risk than a low-pressure line. For relative risk estimation, the numerical value assigned to a condition is not critical; however, an operator should take care to assure that the relative values assigned to different conditions reflect its best understanding of the relative contributions of different conditions to risk. The risk assessment method is looking for the coincident occurrence of multiple risk increasing features. Risk assessment methods may consider very few or many variables in the analysis depending on the available data, the purpose of the risk assessment and resource availability for the risk assessment. The risk levels can be qualitative if only a limited number of variables are used. The risk levels can become more quantitative as the number of variables used in the analysis increase. The quantitative accuracy can be further enhanced by over-

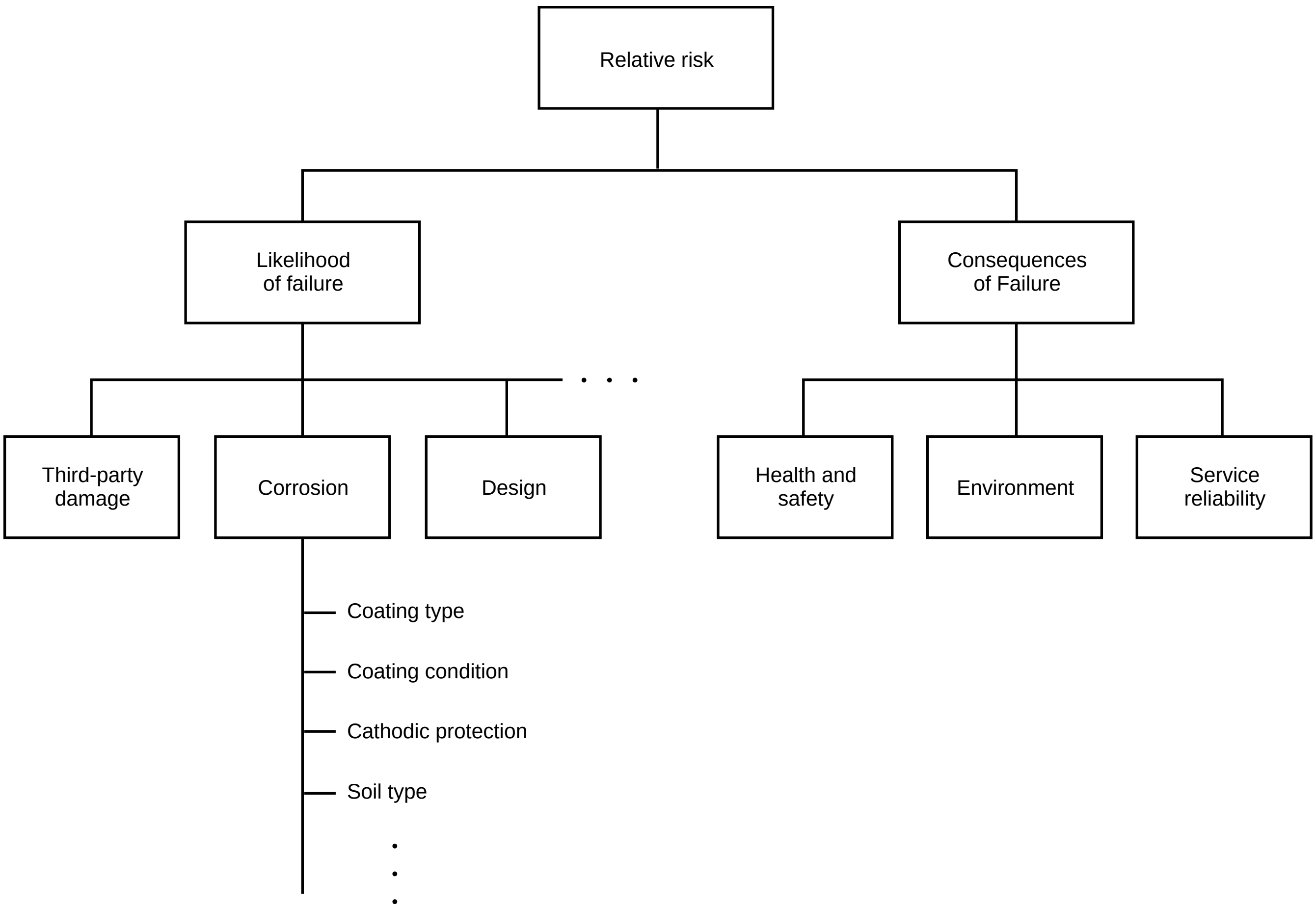

Figure 8-2—Simplified Risk Assessment Hierarchy

riding the effect of assumptions (i.e., effect of soil type, coating age, pipe age, etc.) when performance data are collected that suggests a specific failure mechanism is not active (i.e., close interval survey indicates adequate performance or in-line inspection results do not indicate anomalies).

The quantitative risk assessment methods are those where the characteristics of segments of the pipeline and the surrounding area are used to derive an actual estimate of the risk for that segment. Likelihood is estimated as the probability of failure along the segment over a given period of time (typically per year). Actual expected levels of consequences in different categories (human, environmental, economic) are estimated and may be combined using some common metric (e.g., equivalent dollar cost). The total risk for the segment is estimated as the product of the likelihood of failure and the expected consequences given failure. Some risk assessment methods calculate the likelihood of different pipeline failure modes (e.g., small leak, large leak, rupture), and then estimate the total risk by summing the product of the likelihood of failure in each failure mode and the expected consequences given failure in that mode.

Once a risk assessment method has been developed, the operator will organize and incorporate the information known about the pipeline system into the risk analysis process. When assessing the risks of a group of assets operated by a single company, those assets may be divided into distinct segments to enable the comparison of the relative risks of those segments across the company. This will enable the operator to allocate resources using risk-based prioritization to reduce overall risk in the most effective manner. Similarly, when assessing the risks of a single large asset such as a cross-country pipeline, the system may be divided into geographic or organizational segments to compare the risks of respective pipeline segments to determine how to allocate resources across the pipeline system. The operator decides how long the segments will be and the logical location of boundaries between segments. Factors that drive these decisions include:

- Scope of the risk assessment: i.e., which assets are included/excluded from the assessment.
- Equipment boundaries such as pump stations or block valves.
- Geographical boundaries such as state lines or rivers.

- Desired minimum/maximum length of any one segment (i.e., ft, mile, etc.).
- How system databases are set up and organized; this is important since data will be transferred from one or several databases into the risk assessment method.
- Design changes (i.e., grade, wall thickness, coating type, etc.).
- Population density/type changes.
- The presence of environmentally sensitive or population sensitive (i.e., schools, churches, etc.) areas.

Once data for each pipeline segment has been collected and assembled, the risk assessment method can be used to analyze risk factors in many different ways. First, the individual segments can be ranked: by total risk level, by individual likelihood category, or by consequence level. A varying risk profile along the pipeline can be created, highlighting areas susceptible to particular threats. These rankings can be used by an operator to focus attention on potential problem areas. A number of comparative analyses can be performed, such as:

- Comparison of risks from different failure causes (e.g., corrosion) along the pipeline.
- Comparison of pipeline risks by geographic region.
- Comparison of different pipeline system risks within a company.
- Comparison of pipeline risk profile with a predefined standard, such as compliance with regulations or an operator defined standard.

Some additional criteria to evaluate the results of a risk analysis:

- Are the data and analyses handled competently and consistently throughout the system? (Can the logic be readily followed?)
- Is the analysis presented in an organized and useful manner?
- Are all assumptions identified and explained?
- Are major uncertainties (e.g., due to missing data) identified?
- Do evidence, analysis, and argument adequately support conclusions and recommendations?

8.8 IDENTIFY AND GATHER DATA REQUIRED FOR RISK ASSESSMENT

For each potential pipeline failure mechanism or risk factor (i.e., external corrosion, internal corrosion, etc.), the characteristics or variables that potentially could impact risk (both beneficially and adversely) are identified. During the risk assessment process, specific risk-increasing characteristics of the pipeline are generally either environmental variables (i.e., outside influences acting on the pipeline system) or design variables (i.e., characteristics associated with the physical properties or installation practices used to fabricate the pipeline). In either case, these variables are features of the in-service pipeline system and are not easily altered. A sample list is shown in Tables 8-1 and 8-2, categorized by influencing factor type.

Variables should be considered individually based on how they impact a specific risk factor. This means that variables could be used in different ways, and with potentially contradictory influences within the risk assessment. For those variables whose characteristics change with time, (e.g., pressure, product type, flow rate) the operator is advised to consider the reasonable worst case value for those variables. Below are a few examples illustrating the importance of considering the different impacts a single variable can have on risk.

Once the likelihood of risk increasing features are evaluated, the next step is to incorporate pipeline inspection results (i.e., cathodic protection measurements, in-line inspection results, ground movement monitoring equipment, corrosion coupons, visual inspection results, etc.) into the likelihood of failure (LOF) estimation. Direct integrity variables have the ability to either increase the LOF (i.e., if corrosion damage is identified) or decrease the LOF in the event that no adverse anomalies or conditions are identified.The impacts on risk should be based on sound engineering fundamentals.Total risk is determined by combining the factors that affect the LOF with the impact associated with the consequence of failure. The overall process of *proactively* evaluating and identifying the potential of risk-increasing conditions *prior* to the onset of a release is the primary objective of risk assessment.

8.9 VALIDATION AND PRIORITIZATION OF RISKS

Independent of the process used to perform a risk assessment, the operator must perform a quality control review of the output to ensure that the methodology has produced results consistent with the objectives of the assessment. This can be achieved through a review of the risk assessment data and results by a knowledgeable and experienced individual, or, preferably, by a cross-functional team consisting of a mixture of personnel with skill sets and experience-based knowledge of the pipeline systems or segments being reviewed. This validation of the risk assessment method should be performed to ensure that the method has produced results that make sense to the operator. The operator may wish to perform sensitivity or uncertainty analysis to ensure that decisions are robust and can withstand technical scrutiny. If the results are not consistent with the operator's understanding and expectations of system operation and risks, the operator should explore the reasons why and make appropriate adjustments to the method, assumptions, or data.

Once the risk assessment method and process has been validated, the operator has the necessary information to prioritize risks. To do this, the operator sorts the pipeline segments in order of overall risk level of each segment. The higher risk level pipeline segments should be given higher priority when deciding where to implement risk mitigation actions. To determine what risk mitigation actions to take, the operator

Table 8-1—Sample Environmental Variables

Risk Factor	Variable	Example Characteristics			
External Corrosion	Soil type	Clay	Loam	Sand	Rock
Internal Corrosion	Internal water content	None	< 0.5%	< 1%	> 1%
Third-party Impact	Ground cover depth	< 12"	12" – 24"	24" – 36"	> 36"

Table 8-2—Sample Design Variables

Risk Factor	Variable	Example Characteristics			
External Corrosion	Coating type	FBE	Coal tar	Tape wrap	Bare
Ground Movement	Seismic faults	Yes	No		
System Operations	Valves & relief	No relief	SCADA	Mainline valve closer	Remote closer

Table 8-3—Variables Affecting Pipeline Risk (Partial List)

Variable	Variable Impact
Soil Type	• The resistivity of the soil impacts both the current distribution and effectiveness of the cathodic protection system. • The texture of the soil can affect coating damage and premature corrosion. • Acidity in the soil can attack the coating and greatly increase corrosion rate. • Although not preferred for the above reasons, more stable soils such as rock may be preferable in ground movement prone areas.
Wall Thickness	• Increased wall thickness increases resistance to TPD and extends the depth of pitting before a release occurs. • Increased wall thickness is preferred over casings at road crossings for cathodic protection. • Increased D/t ratios increase the potential for damage from ground movement.
Weights/Hold-downs	• Weights increase potential for crevice corrosion, coating abrasion, and cathodic protection shielding. • Weights and hold-downs reduce risk of ground movement associated with buoyancy issues and hillside instability.

considers which pipeline systems (or segments of systems) have the highest risk and then looks at the reasons the risks are higher for these assets. These risk factors are known as risk drivers since they drive the risk to a higher level for some assets than others do.

For example, when considering a pipeline segment that has the highest overall risk, the operator found that two risk factors had a much greater influence on the risk determination than any of the other risk factors. For this segment, the factors that drove the risk to a higher level than the rest of the segments considered were external corrosion and population density. The risk assessment identified a higher LOF due to external corrosion because the pipeline has older, poorer quality coating when compared to the rest of the pipeline system's segments. Also, the risk assessment identified a higher potential consequence of failure due to a large residential housing development in the immediate vicinity of this pipeline segment. These risk drivers were combined in the risk assessment method to result in the highest overall risk level for the assets considered. This information about risk drivers can then be used to plan what risk mitigation activities would be effective in reducing risk for this specific pipeline segment. This process is discussed in the following section.

The risk assessment process or risk assessment methods can be applied at different stages of the integrity assessment and evaluation process. For example, it can be applied to help select, prioritize, and schedule the locations to conduct internal inspections. It can also be performed after the internal inspection is completed to conduct a more comprehensive risk assessment that incorporates more accurate information about pipe condition.

8.10 RISK CONTROL AND MITIGATION

Risk assessment methods also are important tools to help operators make cost-effective and sound decisions to control risks on their systems. Once a potential risk has been identified, risk assessment methods can be used to predict the expected risk reduction or benefits that will be achieved. The process typically mimics an operator's current workflow when proposing maintenance projects. When combined with project cost estimates, the risk assessment methods can compare the cost/benefit results of several proposed projects to help a company determine if the project will be the best solution for the time period under consideration. Potential capital and maintenance improvement activities can be prioritized to support management decision-making. This section provides an overview of this process.

After the results of the risk assessment are available, the next step is to examine the most significant risks on the system, as well as other opportunities to more efficiently control risks and determine what preventive or mitigative actions might be desirable. It should be noted that many risk mitigation activities may not require a thorough or extensive evaluation and may be implemented as deemed appropriate by the operator. The risk control and mitigation evaluation process may involve the following steps:

- Identification of risk control options that lower the likelihood of a pipeline system incident, reduce the consequences, or both (i.e., preventive or mitigative activities).
- A systematic evaluation and comparison of those options to quantify the risk reduction impact of the proposed project.
- Selection and implementation of the optimum strategy for risk control.

This process is described briefly below:

Typically there are many ways to address a particular risk. For example, improvements or modifications can be made to the system hardware or equipment configuration, operation and maintenance practices, inspections and testing practices, personnel training, pipeline control and monitoring methods, emergency response, and interface with the public and other external organizations. Section 10 of this standard provides a discussion of risk control options that are frequently used to reduce pipeline integrity threats. In order to find the optimum approach to risk control, it is important that a variety of options, and perhaps combinations of activities, be considered, rather than just taking the first idea that is proposed or doing what has always been standard practice. This allows management to consider innovative solutions and perhaps new technologies that may be more effective in addressing risk. Many operators have found that a structured process for identifying risk control options and encouraging innovative solutions has produced unique insights and contributed to more effective risk management.

After identifying the risk control options available, the next step is to evaluate and compare the effectiveness of the different alternatives. This evaluation and comparison is often performed at more than one level. For example, a company may desire to select the best approach among several options to address a specific risk. However, on a broader scale, the company may need to evaluate the relative benefits of a number of risk-reduction projects and activities as part of its budget process. In each case, the basis for comparison and ranking should consider both the magnitude of risk reduction benefits expected as well as the resources expended. Many operators use a benefit-to-cost ratio (where the benefit is the expected risk reduction) to evaluate and rank potential risk control projects. This can provide a simple, easy-to-understand metric that allows projects with diverse benefits to be compared.

When conducting a ranking of projects based on a benefit-to-cost approach, a comprehensive evaluation and comparison process should also include a review of the pipeline system risks to be sure that relatively high risks are not overlooked simply because the risk control projects proposed don't have a high benefit-to-cost ratio. This may signal the need to consider other risk control options[5]. The process should also consider the amount of risk reduction being achieved to be sure the most effective projects are being proposed. There are many other practical factors that are typically considered when evaluating and prioritizing activities. These can include:

- Uncertainties in both the risk reduction and cost estimates.
- Technological value of a particular option (e.g., employing a new generation internal inspection device).
- Long-term, strategic value of the pipeline asset to the company.
- Human resource and equipment constraints.
- Logistical and implementation issues (e.g., delay in ability of vendor to supply necessary equipment or inability to access the pipeline during a particular season due to weather or environmental resource concerns).
- Concerns of government organizations and other external stakeholders.

Many operators have found that a structured and consistent methodology for evaluating the relative benefits of different options or activities has led to more effective use of resources in their organizations. There are a number of ranking and prioritization tools and approaches that are employed to provide

[5]Although summarized in a linear fashion for this standard, the risk control and mitigation process, like the risk assessment process, is highly interactive in nature.

structure and consistency to this evaluation process. These include expert panel reviews, risk assessment methods, priority matrices, and multi-attribute utility models. Whatever approach is used, it is important that the process consistently uses defined inputs, specific analytical steps, established and clear decision criteria, and documented output.

The integrity inspection and risk mitigation decisions that are produced by this process are used to prepare the baseline plan, or modify the existing plan, as described in Section 9.

8.11 CONTINUOUS RISK ASSESSMENT

Risk assessment is not a one-time event and there must be an established process to repeat the risk assessment at some operator-defined frequency.

The process and methods used to perform the risk assessment should be reviewed periodically to ensure that the process is appropriately rigorous and yields results consistent with the objectives of the operator's integrity management program. The method used to perform the risk assessment will be adjusted and improved with each use as the operator incorporates more detailed and current information about the pipeline system.

The pipeline operator learns more about the risks of the pipeline system with each risk assessment. Using this knowledge, the operator must periodically review and alter, as needed, a schedule for re-assessment of each pipeline system or segment. Some of the factors an operator should consider in determining when to perform a re-assessment of a specific pipeline system or segment include:

- Number of repairs required during the previous inspection, testing, and mitigation activity.
- Type of defects found during previous inspections and testing.
- Causes of defects found during previous inspections and testing.
- Rate of degradation of the pipeline (when known).
- Potential consequences of the most likely pipeline failures.
- Quantity and quality of information known about the pipeline. (The less information that is available means a greater uncertainty in understanding the risk. Hence, potentially significant risks could be unrecognized).
- Pipeline sections exhibiting characteristics in common to newly discovered pipeline releases.
- Change in service or significant change in operating parameters.

9 Initial Baseline Assessment Plan Development and Implementation

9.1 INITIAL BASELINE PLAN

The baseline plan is developed as a result of initial data gathering and risk assessment (see Sections 7 and 8), and consists of an initial inspection plan and possibly some mitigation activities including a schedule for these activities. To develop the baseline plan, the most appropriate inspection technique(s) must be identified for each asset, and the work must be prioritized and scheduled. Inspection of each asset or pipeline segment could be accomplished by hydrostatic testing, in-line inspection, other equivalent technologies, or a combination of these techniques. The initial risk assessment will provide guidance to determine what factors to consider (see Section 8). This section provides information about inspection techniques. The baseline plan, once developed, will identify what to inspect, how to inspect and when to inspect.

The initial baseline plan may also include a list of mitigation activities. These are actions, identified during the initial risk assessment, that will improve pipeline reliability/integrity and/or reduce risk, and do not require additional inspection data to determine if they are justified. These actions could include activities to prevent spills, provide early detection of spills, or minimize consequences. Section 10 also provides information to assist in development of mitigation strategies.

The operator should consider the following factors in developing the baseline plan:

1. Pipeline anomalies that can adversely affect pipeline integrity.
2. Various inspection techniques typically used for underground pipelines.
3. Methodology for evaluation of in-line inspection data.
4. Pipeline repair methodologies, and other mitigation activities that can improve pipeline integrity.

9.2 PIPELINE ANOMALIES AND DEFECTS

Appendix A outlines the various pipeline anomalies that can occur in a pipeline system. An understanding of pipeline anomalies, and the conditions under which they can occur is essential in order to select the most appropriate inspection technique(s). Table 9-1 contains a matrix of pipeline defects and appropriate inspection technologies available to detect them.

9.3 PIPELINE INTERNAL INSPECTION AND TESTING TECHNOLOGY

This section presents an overview of two pipeline integrity assessment techniques; in-line inspection (commonly called smart pigging) and hydrostatic testing. The operator is encouraged to consult NACE Technical Committee Report, "In-line Nondestructive Inspection of Pipelines" and API 1110 *Pressure Testing Liquid Pipelines*, for more detailed information.

In-line inspection technology is constantly evolving and the only reliable way to determine the state-of-the-art is to keep in touch with vendors, technology center researchers, and other operators.

9.3.1 Internal Inspection Tools

Since the 1960s, the pipeline industry has been using and developing pipeline in-line inspection tools ("smart pigs") to identify pipeline anomalies. The first tools developed addressed corrosion and pipe deformation and these tools had limited capabilities. Advances in technology have improved the range, applicability, and accuracy of corrosion and deformation tools and have made it possible to identify other anomalies such as cracks.

Prior to running a baseline assessment on a pipeline segment, a pipeline operator should examine the history of the segment and consider the root cause of failures, if any. The operator should also consider other factors, such as the type and age of pipe and coating, operating pressure, performance of cathodic protection systems and environmental issues before selecting an internal inspection tool or a combination of tools for an assessment.

An internal in-line inspection is one method to assess the integrity of a pipeline. Different in-line inspection technologies exist for different kinds of anomalies. When in-line inspection is selected to verify the integrity of a pipeline segment, the inspection should be conducted using the appropriate technology to detect anomalies that the operator has reason to believe may exist on a given pipeline. Multiple inspection runs using different tools should prove to be beneficial over running any single tool to detect defects and anomalies.

In-line inspection tools are only available in certain sizes and some line segments cannot accommodate them. In that case, alternate inspection techniques shall be considered. Accuracy and reliability of in-line inspection tools varies with each tool, pipeline conditions and other factors. In conducting an in-line inspection program, the operator should evaluate the capabilities of the available inspection tools for the intended application and formulate a plan to validate the results. Sufficient verification excavations should be made to show that the tool is accurate and reliable. Then and only then, can the operator have adequate confidence that the critical injurious anomalies will be found so that they can be removed or repaired.

9.3.1.1 Metal Loss Tools (Corrosion Tools)

Standard resolution magnetic flux leakage. The first generation of internal inspection corrosion tools used either permanent magnets or electromagnets to induce an axially oriented magnetic field in the pipe wall as the tool traversed the pipeline. Sensors measure the magnetic flux leakage (MFL) from the pipe wall into the interior of the pipe and record any deviation in flux density. Such deviations are an indicator of a change in wall thickness or other anomaly that causes a disturbance of the magnetic field, such as ferrous metal in proximity to the pipeline. This is an inferential method since the characteristics of the anomalies have to be inferred from the characteristics of the flux leakage. There are certain limitations to detection and the ability to quantify longitudinally oriented metal loss using this technique.

This tool reports likely corrosion anomalies as light, moderate, or severe based on estimated depth of the anomaly, e.g., light being 10% to 30% of wall thickness, moderate 30% to 50%, and severe being over 50%.

Standard resolution corrosion tools have been in use for a number of years and have proven to be effective. Most operators that use standard resolution tools excavate and examine the severe and moderate anomalies reported.

High resolution MFL. High resolution magnetic flux corrosion tools work on the same principles as the standard resolution tools with the difference being that high resolution tools have more sensors with closer spacing to measure deviations in the magnetic field. This allows the tool to collect and store more precise length and depth data for each anomaly. Using remaining strength of corroded pipeline calculations, the MFL data can be utilized to determine the approximate remaining strength of the pipe. High-resolution tools can also determine if a corrosion anomaly is internal or external to the pipe wall. There are limitations to detection of longitudinally oriented metal loss using this technique.

The advantage of high-resolution corrosion tools is an improved measurement of corrosion and other metal loss anomalies. This improvement results in a more accurate and reliable assessment of pipeline integrity; allowing an operator to focus efforts and resources on repairing those anomalies that do, in fact, have a deleterious effect on pipeline integrity. Usually, an operator will have to perform fewer excavations and repairs, an important consideration in areas of limited or difficult access.

Ultrasonic. Ultrasonic corrosion tools work by using transmit/receive transducers to transmit an ultrasonic pulse into the pipe wall, and record the times of reflection from both its internal and external surfaces, allowing for direct measurement of the wall thickness and internal/external defect discrimination.

Ultrasonic tools provide direct and linear measurement of wall thickness that can be used to approximate, with appropriate calculations, the remaining strength of corroded pipe. The tools have the advantage of being a more direct description of an anomaly as compared to the magnetic flux tool, which is an inferred measurement of an anomaly. With an ultrasonic tool, it is critical that the signal be acoustically coupled to the ID of the pipe. This can be an issue in some crude oil lines with a paraffin build on the pipe ID, and some liquids with unsuitable ultrasonic properties such as ethanol.

9.3.1.2 Crack Detection Tools

In-line crack inspection tools have been recently developed to detect longitudinally oriented cracks and crack like features, such as stress corrosion cracks and long seam cracks.

These tools use either ultrasonic shear waves or circumferential (transverse) magnetic flux technology.

Ultrasonic crack detection. Ultrasonic tools operate by introducing an ultrasonic pulse into the pipe wall at an angle such that it generates a shear wave travelling circumferentially through the pipe wall as it is reflected off the pipe's ID and OD surfaces. If the pulse encounters a crack, it is reflected back along the same path and is received at the transducer. The ultrasonic tool is capable of detecting defects such as lack of fusion, hook cracks, stress-corrosion cracking, and voids, as well as narrow axial corrosion. The level of detection, discrimination, and sizing that has been achieved by such tools is superior to hydrostatic testing.

By rotating the transducers by 90°, the tools can be modified to detect circumferential cracks and crack like features.

Transverse MFL. Transverse MFL tools magnetize the pipe wall circumferentially and have detected cracks and lack of fusion. These tools can also detect longitudinally oriented seam corrosion. Although this technology is evolving rapidly, the use of this technology requires more detailed assessment of the anomaly.

9.3.1.3 Geometry Tools

Geometry tools are typically used to find deviations in geometry (deformation), mechanical damage, bend radius, subsidence and pipeline movement. These tools are also used to map pipelines using GIS technology, as well as to determine if passage of in-line inspection tools such as MFL and ultrasonic tools is possible.

Caliper tools. Caliper tools measure deviations in the geometry of a pipeline's diameter. Caliper tools use a set of mechanical fingers (arms) that ride against the ID of the pipe or electromagnetic methods to sense the ovality of the pipe. Any change in the geometry of the diameter of the pipe will cause a relative movement of the arms or a change in the electromagnetic reading and will be recorded. Changes in the pipe diameter geometry can be due to pipe bends, dents, buckles, gate or check valves, or changes in wall thickness.

Caliper tools are used to verify that pipelines are capable of passing other tools such as corrosion tools and to inspect for buckles or dents in the pipe. Buckles and dents can be the result of pipe settlement during or after construction, or the result of TPD.

Caliper tools can determine if a dent is a "smooth dent" which is generally not a concern or a "sharp dent" which may be a concern, particularly if there is an associated gouge that could eventually fail due to fatigue.

Deformation tools. Deformation tools provide the same type of information as caliper tools with the addition of circumferential location of the dent or other anomaly. Deformation tools can provide high-resolution data, resulting in more accurate measurement of smaller and more complexly shaped dents.

Mapping tools. Mapping tools are based on inertial navigation using built-in gyroscopes and accelerometers and establish the geographical coordinates of the pipeline. The information includes the coordinates of girth welds and is useful for creating pipeline alignment maps, populating GIS information systems and determining pipeline ground movement.

9.4 DETERMINATION OF INSPECTION INTERVAL/ FREQUENCY

9.4.1 Initial Inspections

In deciding if and when to conduct an initial inspection, the operator should consider the results of risk assessment and the type or types of anomalies suspected.

External corrosion. When considering the need for an initial inspection for external corrosion, the operator should consider the age of the pipeline; wall thickness; type of coating, condition of the coating as revealed either by direct observations or by electrical surveys or cathodic-protection-current requirements (or by all of these), status of the cathodic protection as revealed by test lead readings, pipe-to-soil potential readings, current requirements, anode consumption (or all of the foregoing), operating temperature of the pipeline; soil type especially noting conditions that might cause shielding of cathodic protection such as rock trenches, and the history of previous leaks or ruptures caused by external corrosion. Note that pipeline risers in wet-soil conditions are prone to external corrosion due to lack of coating integrity at the soil/ air interface.

Internal corrosion. When considering the need for an initial inspection for internal corrosion, the operator should consider the age of the pipeline, the wall thickness, the nature of the product transported especially taking note of the possible presence of water, water salinity, CO_2, H_2S, bacteria, or sediment, the status of corrosion probes or coupons, whether or not cleaning pigs have been used at regular intervals, the amounts of corrosion products recovered when cleaning pigs have been run, the flow-rates in the pipeline, especially noting idle periods with product in the pipeline, the use or non-use of inhibitors or biocides, and the history of previous leaks or ruptures caused by internal corrosion.

Dents or buckles. When considering the need for an initial inspection for dents or buckles, the operator should consider the age of the pipeline, the backfill conditions, the diameter-to-wall-thickness ratio, the wall thickness, the range and number of service pressure cycles applied to the pipeline, and the history of previous leaks or ruptures caused by dents or buckles. It should be noted that additional information on dents and buckles may be obtained from tools run for other purposes such as those designed to detect metal loss or longitudinal cracks. Cross correlating information from multiple types of inspection devices may provide essential information on the severity of dents, in particular. The operator should

Table 9-1—Anomaly Types and Tools to Detect Them

ILI PURPOSE	METAL LOSS TOOLS			CRACK DETECTION TOOLS		GEOMETRY TOOLS	
	Magnetic Flux Leakage (MFL)		Ultrasonic (Compression Wave)	Ultrasonic (Shear Wave)	Transverse MFL	Caliper	Mapping
	Standard Resolution (SR) MFL	High Resolution (HR) MFL					
METAL LOSS (CORROSION) External Corrosion Internal Corrosion	Detection[1], Sizing[3, 10] No ID/OD Discrimination	Detection[2] Sizing[3]	Detection[2] Sizing[3]	Detection[2] Sizing[3]	Detection[2] Sizing[3]	No Detection	No Detection
NARROW AXIAL EXTERNAL CORROSION (NAEC)	No Detection	No Detection[4]	Detection[2] Sizing[3]	Detection[2] Sizing[3]	Detection[2] Sizing[3]	No Detection	No Detection
CRACKS AND CRACK-LIKE DEFECTS (axial) Stress Corrosion Cracking Fatigue Cracks Longitudinal Seam Weld Imperfections Incomplete Fusion (Lack of fusion) Toe-cracks	No Detection	No Detection	No Detection	Detection[2] Sizing[3]	Detection[2] Sizing[3]	No Detection	No Detection
CIRCUMFERENTIAL CRACKING	No Detection	Detection[5] and Sizing[5]	No Detection	Detection[2] and Sizing[3] if Modified[6]	No Detection	No Detection	No Detection
DENTS WRINKLE BENDS BUCKLES	Detection[7]	Detection[7] Sizing Not Reliable	Detection[7] Sizing Not Reliable	Detection[7] Sizing Not Reliable	Detection[7] Sizing Not Reliable	Detection[8, 10] Sizing	Detection, Sizing Not Reliable
	In Case of Detection, Circumferential Position is Provided						
GOUGES	Detection[1, 2] but No Discrimination as Gouges						No Detection
LAMINATION OR INCLUSION	Limited Detection	Limited Detection	Detection and Sizing[3]	Detection and Sizing[3]	Limited Detection	No Detection	No Detection
PREVIOUS REPAIRS	Detection of Steel Sleeves and Patches, Others Only with Ferrous Markers		Detection Only of Steel Sleeves and Patches Welded to Pipe	Detection Only of Steel Sleeves and Patches Welded to Pipe	Detection Only of Steel Sleeves and Patches, Others Only with Ferrous Markers	No Detection	No Detection
MILL-RELATED ANOMALIES	Limited Detection	Limited Detection	Detection	Detection	Limited Detection	No Detection	No Detection
BENDS	No Detection	No Detection	No Detection	No Detection	No Detection	Detection and Sizing[3]	Detection and Sizing[3]
OVALITIES	No Detection	No Detection	No Detection	No Detection	No Detection	Detection and Sizing[3, 11]	Detection and Sizing[3, 9]
PIPELINE COORDINATES	No Detection	No Detection	No Detection	No Detection	No Detection	No Detection	Detection and Sizing[3]

Notes:
1. Limited by the minimum detectable metal loss
2. Limited by the minimum detectable depth, length, and width of the defects
3. Defined by the specified sizing accuracy of the tool
4. If the width is smaller than the minimum detectable defect width for the tool
5. Reduced Probability of Detection (POD) for tight cracks
6. Transducers to be rotated by 90°
7. Reduced reliability depending on the size and shape of the dent
8. Depending on the configuration of the tool, also circumferential position
9. If equipped for ovality measurement
10. Available in tethered tool
11. If equipped for bend measurements

also consider the value of conducting an inspection of a new pipeline in order to locate construction damage, bends with slight ripples, and places where the pipeline may be impinging on rocks. More information can be found in API 1156 *Effects of Smooth and Rock Dents on Liquid Petroleum Pipelines*.

Longitudinal cracks, seam defects, selective seam corrosion. When considering the need for an initial inspection for longitudinal cracks, seam defects, or selective seam corrosion, the operator should consider the age of the pipeline, metallurgy, mechanical properties, the type of longitudinal seam, the range and number of pressure cycles, the pressure levels of previous hydrostatic tests and times of the tests, the type of coating, and the history of previous leaks and ruptures caused by longitudinal cracks, seam defects, and/or selective seam corrosion. Fracture-mechanics models are available for assessing the effects of pressure-cycle-induced fatigue on the growth of longitudinal cracks. These may be used to assess the need for inspection.

Stress corrosion cracking (SCC). This is a form of environmentally assisted cracking. The factors that influence this type of anomaly include the age of the pipeline, type of coating, cathodic protection system conditions and levels, soil stresses, drainage type and degree of pressure cycles. These factors along with the excavation data, if any, will allow identification of any susceptibility of a pipeline. Fracture mechanics models can be utilized with crack growth rate to assess the need and timing of inspection if the pipeline has stress corrosion cracks.

9.4.2 Setting Re-inspection Intervals

Ongoing modes of deterioration such as external and internal corrosion and the growth of defects as the result of pressure-cycle-induced fatigue or environmental cracking will necessitate repeated inspection. Examples of methods for determining re-inspection intervals follow. Other methods for setting re-inspection intervals may be appropriate.

External or internal corrosion. Excavations in response to an initial metal-loss inspection will reveal the locations affected by corrosion and the nature and extent of the metal loss. Based on actual depths of metal loss, and subsequent re-inspections, the operator may be able to estimate a corrosion rate. Based on these estimated rates, re-inspection intervals should be scheduled based on the calculation of not more than half the remaining life of the deepest unremoved or unrepaired corrosion metal loss unless other factors or critical assessments indicate that an alternate inspection frequency is appropriate. Other factors that may influence re-inspection intervals include product transported, potential for development of isolated pitting into pitting networks, maintenance pigging, inhibitor usage, cathodic protection and coatings system quality, age of the pipe/pipe wall thickness, pipe size (potential spill size), location related to potential ground movement, hydraulic profile (operating pressure), HCA/USA locations, leak history, operating stress, leak detection, physical support of a segment, and other factors that could change the rate of metal loss. API 570 *Piping Inspection Code,* Section 7.1—Corrosion Rate Determination, offers guidance in this area. At this point, the operator has several options such as:

- Reinspect the pipeline.
- Reduce the MOP of the pipeline.
- Perform additional repairs.

After a second inspection has been carried out, especially if the same technology is used for both inspections, comparisons of the same unremediated anomalies as they appear on both inspection records may provide information about additional metal-loss.

Longitudinal cracks. Where there is a concern that undetected longitudinal cracks are being enlarged by pressure-cycle-induced fatigue, fracture-mechanics models can be used to assess the appropriate interval for re-inspection. It is beyond the scope of this document to provide guidance on the use of fracture-mechanics models.

Stress corrosion cracks. Re-inspection should be determined by fracture mechanics based models and excavation data. Following a second inspection, if there are no new SCC sites developing in the pipeline, it is possible the inspection may be suspended or postponed. There are two types of SCC, high pH and near neutral pH SCC. The type of SCC could affect the approach taken for integrity management. See Appendix A for a more complete description of pipeline SCC mechanisms.

Geometry tools. Re-inspection intervals for geometry tools such as mapping tools and caliper tools depend on an assessment of the likelihood of additional activity in the area which could lead to third-party mechanical damage, known seismic events and soil stability issues. Re-inspection using deformation type in-line inspection tools is based on the results of risk assessment.

9.5 HYDROSTATIC TESTING

9.5.1 Value of Hydrostatic Testing

Hydrostatic testing has long been accepted as a method of integrity testing of pipelines. Hydrostatic testing lines that have been in service is complicated due to interruption of service and difficulty in acquiring permits to acquire, treat, and dispose of water that may have been contaminated by the product being transported. However, hydrostatic testing remains a viable alternative to be considered by an operator for integrity testing if the pipeline cannot accommodate passage of an in-line inspection tool, the segment history shows anomalies that are not detectable by internal inspection tools or other assessment methodology inspection methods do not provide satisfactory confidence in the integrity of the line.

Hydrostatic testing validates integrity at the time of the test by demonstrating the integrity of a pipeline with respect to the established MOP and the leak tightness of a pipeline. Within limits, the greater the ratio of test pressure to operating pressure, the more effective the test. ASME B31.4 currently requires a test pressure of not less than 1.25 times MOP for not less than four hours when the pipe is visually inspected during the test, and not less than an additional four hours at 1.1 times MOP when the pipe is not visually inspected during the test. An alternative test commonly called a "spike test "is conducted at 1.39 times MOP for approximately 30 minutes to detect linear type defects associated with longitudinal seams.

As an integrity tool, there are situations where hydrostatic testing can be beneficial and can be used to either substitute for or complement other techniques such as in-line inspection. In-line inspection is well regarded as the tool of choice to detect internal and external corrosion. With respect to detection of cracks and crack-like defects, in-line inspection is able to provide a threshold of detection lower than hydrostatic testing, which allows detection of sub-critical cracks and crack-like defects as shallow as 10% through wall. When tools are not available to detect non-corrosion defects due to technology or line size limitations, and localized damage is a concern, hydrostatic testing can be used in conjunction with an in-line inspection corrosion detection tool or other assessment methodology.

9.5.2 Limitations of Hydrostatic Testing

Hydrostatic testing is valuable as a tool to *destructively remove critical defects*. Not all anomalies will be removed during a test; only those defects that reach a critical size will be removed during a test. Testing a pipeline above the operating pressure will demonstrate the absence of defects that could result in failure up to the test pressure. The "damaging aspect" of pressure testing has two components; pressure reversal and time-dependent defects. A pressure reversal can occur when a previous hydrostatic test causes a defect to grow nearly to failure and when additional defect extension occurs during pressure unloading. If this occurs, then the line can fail at a pressure lower than the previous hydrostatic test pressure.

The second damaging aspect, time-dependent defects, can occur when pipeline defect growth takes place due to fatigue, SCC, or corrosion. Although this type of crack growth can occur regardless of hydrostatic test history, it is possible that a hydrostatic test could initiate crack growth that can become susceptible to continued time-dependent growth. In this case, to prevent future in-service failures, continued hydrostatic testing would be required to remove defects that have extended over time.

Hydrostatic testing is not nearly as valuable when used to identify corrosion, particularly localized corrosion. Localized pitting can maintain a high failure pressure due to restraint around a pit and depending on the size of the pit, almost to the point where the defect is through the pipe wall. Unless the corrosion depth is nearly through-wall at the time of the hydrostatic test, the line will hold. A line with localized pitting can pass a hydrostatic test and maintain the MOP until it leaks. In-line inspection is a much more effective tool for detection of corrosion damage since tools can find sub-critical defects.

When an operator chooses to use hydrostatic testing as its integrity assessment tool, the quality and effectiveness of the pipeline corrosion control program must be demonstrated. This includes data such as release history, cathodic protection annual survey results, pipeline current demand, results of cathodic protection close interval survey data, coating integrity and results of open hole (open assessment) reports.

9.5.3 Determination of Inspection Interval/ Frequency

A hydrostatic test is one method to assess the integrity of a pipeline. When hydrostatic testing is selected to verify the integrity of a pipeline segment, tests should be conducted at intervals sufficient to eliminate or prove the absence of critical defects before they reach a condition that can cause an unintentional release.

9.5.3.1 Deciding When to Test

In deciding whether or not a hydrostatic test is the appropriate method to verify the integrity of a pipeline segment, the operator should consider the types of defects that might be a threat to the integrity of the pipeline and the time frame within which a defect may affect the integrity of the pipeline. Generally, defects such as corrosion-caused metal loss, dents, buckles, and some types of longitudinal cracks can be dealt with more effectively by using an appropriate in-line inspection technology followed by appropriate and timely remediation. If the types of defects suspected cannot be found reliably by means of in-line inspection, or if the segment of pipeline cannot accommodate an in-line inspection tool, a hydrostatic test may be used to validate a safe operating pressure level for a specific period of time. If the margin of safety assured by the test erodes with the passage of time because of the time-dependent enlargement of defects, which are too small to fail at the time of the first test, a hydrostatic retest becomes necessary.

9.5.3.2 Retesting Frequency

The frequency of hydrostatic retesting required to assure continued serviceability of a pipeline segment depends on the test-pressure-to-operating-pressure ratio, and the rates of growth of the particular type of defects that exist in the pipeline. Typical defects that tend to become larger with the passage of time are: external and internal corrosion-caused metal loss, stress-corrosion cracks, and any longitudinally oriented crack-like defect that is subjected to pressure-cycle-induced fatigue crack growth. A method to estimate the retest interval is to calculate the sizes of defects that will just survive the proposed or historic hydrostatic test pressure level and the sizes of defects that will cause a leak or a rupture at the MOP level. The operator can then use a realistic defect growth rate to estimate the time required for the just-surviving defects to grow large enough to fail in service.

Rates of corrosion-caused metal loss can be estimated from historic records of pit depths after various times in service. Stress-corrosion crack growth rates (maximum rates) may be found in the technical literature on the phenomenon. Fatigue crack growth rates are available in the literature for various environments, and linear elastic fracture-mechanics models are available to calculate the amounts of crack growth that will occur in response to a specific pressure-cycle spectrum over a period of time. The operator should select an interval for retesting that will be significantly shorter than the minimum calculated time to failure for the most severe defect that could have survived the previous test.

Integration of baseline integrity assessment data into the risk assessment model will assist with determining a re-inspection interval.

9.6 STRATEGY FOR RESPONDING TO ANOMALIES IDENTIFIED BY IN-LINE INSPECTIONS

Due to the complexity of raw in-line inspection data, the tool vendor typically evaluates this information and provides the pipeline operator with the results. It is then the responsibility of the operator to review and evaluate these interpretations and develop a repair and mitigation strategy. The following will assist the operator in developing a strategy for evaluation of anomalies identified by an in-line inspection tool.

An operator shall take action to address pipeline integrity concerns identified during the evaluation of in-line inspection data. If a condition exists on the pipeline that presents an "immediate concern" (defined below), the operator shall initiate mitigative actions within five days in order to continue to operate the affected part of the system. Mitigation action is based on regulatory requirements, company guidelines, and assessment of risk.

When a pipeline is inspected by an in-line inspection tool, the final results of the inspection should be provided to the operator within six months. However, certain types of potential defects should be brought to the operator's attention through a preliminary report. The following could present an "immediate concern" and should be reported by the in-line inspection vendor as soon as possible, but within thirty days.

- Metal loss greater than 80% of nominal wall regardless of dimensions. These anomalies can be temporarily mitigated by on-site monitoring, leak test, pressure reduction, or other mitigative actions until the anomaly has been excavated, assessed, and repaired, if necessary.
- Remaining strength of the pipe results in a predicted burst pressure that is less than the MOP at the location of the anomaly using a suitable remaining strength calculation method. Temporary mitigative actions include reduction in operating pressure with concurrent resetting of pressure relief device setpoints, or other mitigative actions until the anomaly can be excavated, assessed and repaired if necessary[6].
- Top of the line dents (above four and eight o'clock positions) with any indicated metal loss. Temporary mitigative actions include reduction in operating pressure with concurrent resetting of pressure relief device setpoints, or other mitigative actions until the anomaly can be excavated, assessed, and repaired if necessary.
- Significant anomaly meeting other criteria established by the operator for immediate action.

Mitigative action for the above conditions shall be based on in-line inspection data analysis without excavation verification. Temporary mitigative action(s) shall be initiated as soon as possible; within five days of receipt of the preliminary in-line inspection report and shall remain in place until the anomaly can be excavated and assessed. Permanent mitigative action such as repairs, if required, should be accomplished within thirty days[7] of receipt of the preliminary in-line inspection report.

The following areas should be evaluated, repaired or otherwise mitigated, if necessary, within six months[7] of receipt of the final in-line inspection report. Mitigative actions, if necessary, for these defects can be taken after the defect is evaluated by excavation:

- Dents with metal loss or dents that affect pipe curvature at a girth or detected longitudinal seam weld.
- Dents located on the top of the line pipe between four and eight o'clock where the dent depth exceeds:
  i. 2% of the pipe diameter for NPS 12 and larger.
  ii. 0.250 in. for pipe diameters less than NPS 12.
- Dents with reported depths greater than 6% of the pipe diameter.
- Remaining strength of the pipe results in a safe operating pressure that is less than the current established MOP at the location of the anomaly using a suitable safe

[6]It is understood that not all in-line inspection vendors are able to provide this level of analysis for all types of tools in a preliminary report. The intent of this bullet item is to identify in an expeditious manner metal loss that is likely to result in an estimated/predicted burst pressure less than the MOP.

[7]Operators may incorporate information on regulatory requirements, existing public policies such as acquisition of local permits, or other extreme circumstances such as severe weather that could act as barriers to the inspection, repair or replacement of pipelines when compliance with all the above specific time lines is not possible.

Table 9-2—Summary of Commonly Used Permanent Pipeline Repairs[9]

Anomalies		PRIMARY REPAIR STRATEGIES[1]				
		Weld Metal Deposition[2]	Type A Sleeve	Type B Sleeve	Composite Reinforcement	Hot Tap
External Metal Loss ≤ 80% w.t.	Pipe Seam	Yes	Yes	Yes	Yes	No
	Girth Weld	Yes	Yes	Yes	Yes	No
	Pipe Body	Yes	Yes	Yes	Yes	Yes
	Bend	Yes	Yes[3]	Yes[3]	Yes[4]	Yes
Internal Metal Loss ≤ 80% w.t.	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	Yes
	Bend	No	No[3]	Yes[3]	No	Yes
External Metal Loss > 80% w.t.	Pipe Seam	Yes	No[8]	Yes	No[8]	No
	Girth Weld	Yes	No[8]	Yes	No[8]	No
	Pipe Body	Yes	No[8]	Yes	No[8]	Yes
	Bend	Yes	No[8]	Yes[3]	No[8]	Yes
Internal Metal Loss > 80% w.t.	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	Yes
	Bend	No	No[3]	Yes[3]	No	Yes
Leaks, Cracks, Arc Burns and Girth Weld Flaws[12]	Pipe Seam	No	No	Yes	No	No
	Girth Weld	No	No	Yes	No	No
	Pipe Body	No	No	Yes	No	No[10]
	Bend	No	No	Yes[3]	No	No[10]
	Thread Collar	No	No	Not Practical	No	No
Dents with Stress Concentrators	Pipe Seam	No	Yes[5,6]	Yes[6]	No	No
	Girth Weld	No	Yes[5,6]	Yes[6]	No	No
	Pipe Body	No	Yes[5,6]	Yes[6]	No	Yes[11]
	Bend	No	Yes[3,5,6]	Yes[3,6]	No	Yes[11]
Plain Dents	Pipe Seam	No	Yes[5]	Yes	No[7]	No
	Girth Weld	No	Yes[5]	Yes	No[7]	No
	Pipe Body	No	Yes[5]	Yes	No[7]	Yes[11]
	Bend	No	Yes[3,5]	Yes[3]	No	Yes[11]

Notes: 1. Pipe replacement is always an effective repair.

2. Use of weld deposition requires a minimum pipe wall thickness and control of welding parameters to prevent burn thru. This generally prevents use of this technique in pipes with external metal loss > 80% wall thickness except in heavy wall pipelines. At this time we do not recommend use of this technique for wall < 0.181".

3. Metallic sleeves both bolted and weld-on are available for bends and fittings.

4. Special techniques utilizing multiple overlapping sleeves are required for bends.

5. A hardenable incompressible filler shall be used to fill the annular space between the dent and the sleeve.

6. Mechanical damage in a dent must be removed by grinding prior to installation of the sleeve.

7. Only certain types of composite repairs when used with an incompressible filler are adequate for the repair of dents and such repairs must show by reliable engineering tests and analysis to permanently restore the serviceability of the line pipe.

8. Conservative industry practice is to limit the use of Type A and composite sleeves to external metal loss ≤ 80% of nominal wall. For the case of external metal loss > 80%, a minimum wall must be present for Type A sleeves and composite reinforcement repair techniques. At this time, we recommend a minimum wall of 50 mils, precise non-destructive testing of pit depth, no internal corrosion and sound engineering practice.

9. Other repair methods may be used provided they are based on sound engineering practice.

10. Cracks that are not leaking can be hot tapped to remove the crack.

11. If entire dent can be removed.

12. Arc burns and girth-weld flaws can be repaired by grinding out the defect and/or Type A or B sleeves as long as the repairs are based on sound engineering practice.

operating pressure calculation method (e.g., B31G, modified B31G, RSTRENG).

- Predicted metal loss of > 50% of nominal wall at foreign line crossings.
- Predicted metal loss > 50% in areas with widespread circumferential corrosion, i.e. the type of corrosion where axial loading may be a concern or where mitigation of continued corrosion may be important to maintain MOP.
- Weld anomalies with a predicted metal loss > 50% of nominal wall.
- Indications of probable cracks that upon excavation are determined to be cracks.
- Selective seam corrosion of or along detected seam welds.
- Possible gouges or grooves greater than 12.5% of nominal wall.

An operator should take into consideration the in-line inspection vendor's stated statistical accuracies, analysis techniques, and the operator's experience in determining an effective anomaly investigation program.

Once all above metal loss anomalies are addressed, the operator shall document all remaining indications and integrate this information into the risk assessment model.

Anomalies located in or near casings, near foreign pipeline crossings, areas with suspect cathodic protection, or HCAs should take precedence over other pipeline locations with similar indications. Mechanical damage and corrosion associated with a longitudinal seam should generally take priority over corrosion damage.

ASME/ANSI B31.4 Section 451.6 provides specific limits for disposition of certain defects. 49 *CFR* Part 195.452 provides specific limits for the disposition of certain defects.

9.7 REPAIR METHODS

Inspections conducted per an operator's integrity management plan will identify anomalies that must be evaluated. A number of these anomalies will require repair. This section and Appendix B provide guidance for repair. The information in this standard should not be considered a complete summary of every type of repair, but an overview of some of the more frequently used techniques in the industry today. In the absence of detailed company procedures for pipe replacement or repair, the "Pipeline In-service Repair Manual" should be consulted.

Table 9-2 provides a ready reference for individuals determining the appropriate repair strategy for a certain type of defect in a certain location (seam, body, girth weld) of line pipe.

All repairs will be made with materials that meet or exceed the MOP of the impacted portion of the pipeline and comply with applicable regulations.

10 Mitigation Options

An operator's integrity management program will include applicable mitigation activities to prevent, detect, and minimize the consequences of unintended releases. Mitigation activities do not necessarily require justification through additional in-line inspection data. Mitigative actions can be identified during normal pipeline operation, during the initial risk assessment, during implementation of the baseline inspection plan, or during subsequent testing.

The mitigation activities presented in this section include information on:

- Preventing TPD.
- Controlling corrosion.
- Detecting unintended releases.
- Minimizing the consequences of unintended releases.
- Operating pressure reduction.

Operators should thoroughly understand the strengths and limitations in the application and performance of mitigation options.

10.1 PREVENTION OF THIRD-PARTY DAMAGE

TPD is a major cause of pipeline releases. Current US DOT data indicates that roughly one-quarter of all reported pipeline incidents are caused by TPD. The following mitigation activities should be considered.

10.1.1 One-call Utility Location Systems

Pipeline operator participation in one-call utility location systems is very important. Presently, every state except Hawaii and the District of Columbia has an underground facility damage prevention law to govern the activities of operators and excavators of most buried utilities. In order for this system to be effective, a pipeline operator must ensure that all pipelines in the system are included in appropriate one-call jurisdiction maps and documentation, and that designated personnel are equipped and trained to accurately locate and mark the pipeline in response to each one-call inquiry.

Note: Presently, all but seven states (Connecticut, Iowa, Massachusetts, Maryland, Maine, New Hampshire, and Vermont) have granted exceptions to a variety of organizations. In general, exempt organizations are not required to participate in a state's excavation damage prevention program. Exemptions have been granted to state transportation departments; railroads; mining operations; city, state, and federal governments; cemeteries; military bases; and Native American lands.

10.1.2 Improved Line Marking

Line marking is part of the first line of defense against third-party incidents. Additional markers make the pipeline more visible to third parties working in the vicinity. Line markers should generally be required on both sides of each road, highway, railroad, and water crossing. In areas of high third-party activity, intermediate line markers should be installed such that at least two markers are visible from any location along the line. Line markers in other areas should be spaced so that the line location is accurately known. Aerial line markers should also be utilized, where applicable, to provide markings for periodic aerial right-of-way inspections. Surface line markers should be labeled with the pipeline operator's 24-hour emergency telephone number.

10.1.3 Optical or Ground Intrusion Electronic Detection

These systems include a fiber optic or metallic cable, usually installed twelve to twenty-four in. above the pipeline that are continuously monitored by optical or metallic instruments. Should the cable become damaged or severed, the monitoring device(s), which are integrated into the pipeline programmable logic controllers (PLCs) and supervisory control and data acquisition (SCADA) system, issue an alarm and identify the location of the cable damage.

Optical or electronic ground intrusion detection systems, may reduce the consequences of third-party intrusion in three ways:

1. *Damage prevention*—The system may reduce the frequency of third-party incidents by alerting the operator of the location of potential third-party intrusions before the pipeline is damaged.
2. *Prevention of unintended releases*—A system alarm may reduce the likelihood of a leak in the event the pipeline is damaged, but not ruptured by third parties. This allows the operator to respond and perform an immediate inspection and/or repair, at the location the damage occurred.
3. *Spill minimization*—In the event third-party intrusion results in an immediate rupture, the intrusion alarm, coupled with a release alarm, will allow response to occur more quickly, and potentially reducing the volume released significantly.

10.1.4 Increased Depth of Cover

Increasing the pipeline depth of cover (e.g., five or six ft below ground surface) may place the pipe below many normal excavation and agricultural activities, thereby reducing the chance of third-party intrusions. This is also an important consideration at stream and other crossings. For example, the depth of scour should be evaluated at major stream crossings. The pipeline should then be buried well beneath the potential scour depth of active streams. When increased depth of burial or increased cover is desired but not practical, mitigation options include concrete caps, increased line marking, electronic warning tapes as well as plastic tape and mesh marking above the line or fencing off areas particularly susceptible to TPD.

Note: Excessive depth of burial can be detrimental to pipeline operation and safety. Locations of unintended releases can be difficult to isolate, excavations can be more hazardous, lines are more difficult to locate and repairs can become more complex.

10.1.5 Improved Public Education

Pipeline operators currently implement educational and public awareness programs designed to also meet requirements of current federal regulations. These programs educate the public, emergency responders, and persons engaged in excavation related activities as to the whereabouts, potential dangers, and appropriate emergency responses associated with the pipeline facilities. These programs can help reduce a pipeline operators' exposure to TPD and enhance emergency response in the event of an incident. An operator should consider improving public education beyond the minimum regulatory requirements to reduce third-party exposure where such risks are high.

10.1.6 Right-of-way Maintenance

Having a plan to protect pipelines and rights-of-way will reduce the chance of TPD and enhance the ability for response to an emergency. Development of guidelines addressing the following maintenance issues will reduce the consequence of third-party intrusion.

- Control of vegetation in the right-of-way.
- Removal of trash, brush, and other items near the pipeline.
- Control of impediments constructed above or below ground near the pipeline (including, but not limited to, buildings, engineered structures, pavement, pools, fences, etc.).
- Operation of heavy equipment over the pipeline.
- Blasting near the pipeline.
- Crossing the pipeline.
- Excavation or boring near the pipeline.

Further, by providing regular maintenance (e.g., brush clearing, line marker replacement, etc.), the pipeline corridor is more obvious to third parties.

10.1.7 Improved or More Frequent Right-of-way Inspections

Current federal pipeline regulations require regular right-of-way inspections and maintenance. These regular inspections enable the pipeline operator to identify activities that may encroach upon their right-of-way before the pipeline facility can be impacted. An operator may wish to make these inspections more frequently, or take other actions to make the pipeline more visible, in areas subject to a high level of third-party activities. Pipeline operators should also be in touch with land-use planners and other governmental agencies to minimize encroachments of right-of-ways.

10.1.8 Mechanical Pipe Protection

Mechanical protection, designed to shield a pipeline from TPD, may be accomplished in two ways. This would normally only be considered for new pipeline systems.

First, a segment of pipeline can be coated with reinforced concrete, installed over the top of the external corrosion coating. The external concrete coating can be installed at most coating plants and is intended to provide mechanical protection from excavation equipment, or from gouges and punctures from other external forces.

CAUTION: Concrete in contact with the steel pipe may change the pH and cause an increase in corrosion of the pipe surface.

Alternately, a concrete cap can be installed above the pipeline to provide a physical barrier to excavation and other equipment digging above a pipeline. Selection of this approach needs to carefully consider the areas of high risk, along with other factors such as reducing access for ordinary repairs, etc. It is important that the concrete cap not contact the pipeline.

10.1.9 Additional Pipe Wall Thickness

Additional pipe wall thickness may increase the resistance of a pipeline to TPD. This option is normally only a consideration during the initial construction of a pipeline. The additional pipe wall thickness may provide mechanical protection against a puncture and allow the pipe to be gouged, with less chance of immediate leakage. The lower stress that results with a thicker wall also makes the pipe less prone to rupture.

For relatively short, small diameter pipelines, additional pipe wall thickness can be provided at relatively minimal additional cost. For long, large diameter pipelines, heavier wall pipe may be considered at locations with higher exposures to TPD (e.g., road crossings, water crossings, etc.).

10.1.10 Pipeline Marker Tape or Warning Mesh Installed Over Pipeline

Marker tape or warning mesh installed above a pipeline is an additional measure to protect against TPD. This option is generally implemented during installation of the pipeline. The brightly colored tape or plastic mesh should typically be installed approximately one or two ft above the pipeline and appropriately labeled (e.g., hazardous liquid pipeline/operator name).

10.2 CONTROL OF CORROSION

10.2.1 Monitor and Maintain Cathodic Protection

Pipe coating systems, combined with cathodic protection, provide effective corrosion control of the external pipeline surfaces. Pipeline cathodic protection shall be installed, monitored, and maintained in compliance with federal requirements and NACE International (National Association of Corrosion Engineers) Recommended Practice RP-O1-69. Cathodic protection system data should be integrated with in-line inspection data, and other information as described in Section 7.

Additional monitoring of cathodic protection systems utilizing close interval potential surveys and/or coating integrity surveys should be considered. Risk assessment, in-line inspection data, results of routine system monitoring, open hole inspections and release history are factors which may indicate that a close interval potential survey is needed.

10.2.2 Rehabilitation of Pipeline Coatings

External pipe coating systems should be evaluated, monitored, and maintained. Control of corrosion is highly dependent on the integrity of the external coating system. NACE provides a great deal of information on this and other corrosion engineering topics.

The combinations of a substandard coating system, the inability of cathodic protection to effectively and efficiently mitigate corrosion, a significant release history or the results of open hole reports may prompt an operator to rehabilitate or replace a section of pipe line.

10.2.3 Pipeline Maintenance Cleaning

Periodic maintenance cleaning of a pipeline is at times an effective method to minimize internal corrosion as well as improve pipeline flow characteristics.

10.3 DETECTING AND MINIMIZING UNINTENDED PIPELINE RELEASES

In the event of an unintended product release from within a pipeline system, the consequences can be minimized by:

- Reducing the time required for detection of the release.
- Reducing the time required to locate the release.
- Reducing the volume that can be released.
- Reducing emergency response time.

10.3.1 Reducing Volumes Lost from Unintentional Releases

The role of release detection is to minimize the time required to detect product that is actively being released from a pipeline system. It is important to evaluate and understand the potential volume of pipeline product that might be released prior to an alarm event from a release detection system. Release detection technology and equipment provide a wide range of sensitivity and reliability. In order to achieve site specific, and pipeline segment specific, release detection objectives, it may sometimes be necessary to utilize complimentary release detection technologies.

Selection of a release detection system is dependent upon the specific pipeline application required. Factors to be considered prior to selection and implementation include: length and size of pipeline, type of products contained in the pipeline, complexity of installation and maintenance, HCAs, acceptable release detection system performance criteria, risk assessment results and other integrity management data such as in-line inspection results. Since excessive false alarms erode confidence in release detection performance, the potential for false alarm events should also be considered with any system.

Release detection system manufacturers, and/or manufacturer's representatives, should provide pipeline operators with written descriptions of system capabilities and performance expectations for each specific pipeline segment application. The performance expectations should be described in terms of product volume released versus time for detection. Potential release detection system limitations, or concerns for specific service suitability, should also be provided to the pipeline operator.

The performance and reliability of the communications system(s) may significantly affect the performance and response times of some release detection systems. The operator should evaluate the communications process for critical systems, where action must be taken within relatively short timeframes. Where applicable, improvements to these systems can reduce the time required to detect and respond to an unintended release, thus reducing the consequences.

All personnel responsible for monitoring release detection system data/alarm functions should be properly trained in the operation and maintenance of the system. Pipeline controller training should include the process to recognize and analyze release detection alarms and basic concepts of pipeline hydraulics (steady state and transient).

The technology to detect unintended releases from pipelines is undergoing continual development and improvement. Therefore, new and improved technology should be considered with any release detection decision.

10.3.2 Types of Release Detection Systems

A brief description of current release detection systems includes:

Dynamic flow modeling. This model basically simulates the operating conditions of the pipeline through hydraulic calculations, then compares the computed pressures (based on flow rate, temperature, pipe profile, and density) against real time data obtained from various measuring points along the pipeline. Deviations are compared against alarm set points. When the deviations exceed the set points, the system alarms. These systems are normally integrated with the pipeline SCADA communications technology. Leak location information is not provided.

Tracer chemical. This approach requires mixing a very small amount (ppb to ppm of total volume) of a specific volatile chemical tracer with the contents of a pipeline. The chemical tracer is not a component of the pipeline contents and does not occur naturally in the soil. After inoculation of the pipeline with the tracer chemical, samples of the vapor contained in the soil outside the pipeline are collected. The soil vapor samples are obtained from probes or other devices installed intermittently along the pipeline. The vapor samples are analyzed by a gas chromatograph for the specific tracer chemical that was mixed with the pipeline contents. Presence of the tracer chemical in the sample can only occur through an active release of pipeline product mixed with the tracer into the soil. These systems are able to provide single or continuous liquid tightness tests and will provide release location information.

Release detection cable. Release detection sensing cables are designed to alarm after contact with liquid hydrocarbons at any point along their length. The presence of hydrocarbons creates a circuit between two sensing wires and triggers an alarm. Typically, leak detection cable is installed in slotted PVC conduit that is buried in the pipe trench along or below the pipeline. These systems provide continuous monitoring via electronic control units capable of interfacing with SCADA technology and are able to provide leak location information.

Shut-in (static) release detection. This technique basically consists of a pressure test, with the pipeline filled with its normal contents. Between shipments, the pipeline is pressured against a closed valve(s). This release detection tool allows the operator to analyze the pipeline in a static (no flow) mode, without the complications of pipeline operations. With the pipeline blocked, the pressure (compensated for temperature fluctuations) in a section should remain constant. The pressure is then monitored for any unexplained pressure losses. This test does not provide leak location information.

Pressure point analysis release detection software. Software for this system incorporates two independent methods of release detection: pressure point analysis and mass balance. Pattern recognition algorithms that distinguish normal operating events from leaks are used. When used with a communications system, pressure point analysis can provide the calculated location of a release.

10.3.3 Improved Emergency Response

Information about active unintended release events occurring on a pipeline may be presented to an operator through pipeline system operation alarms, release detection testing, third-party observations, emergency response agencies, etc. It is important to develop response procedures for each. These procedures should define an action plan that includes:

- Definition of organizational lines of responsibility and notification for response to unintended releases.
- Training of all personnel responsible for unintended release events.
- Immediate verification of unintended releases, if necessary.

- Isolation and control of the unintended release source.
- Control of the released product according to procedures developed for specific environmental impacts and unintended release volumes.

10.3.4 Organizational Lines of Responsibility and Notification for Unintended Release Response

All pipeline operational personnel involved with an unintended release need to have clear definition of their personal authority and responsibility. They then need to know exactly which operator personnel and outside agencies to notify with specific unintended release event information.

10.3.5 Training of All Personnel Responsible for Unintended Releases

Personnel should be trained to act in response to a variety of potential unintended releases that might occur within their areas of responsibility. The training should be comprehensive to include:

- Procedures for notification of company personnel and outside agencies.
- Technology, equipment, and procedures used to minimize the consequence of an unintended release.
- Additional resources available for control and mitigation of an unintended release.

Response drills should be conducted with established response teams to provide training for both operator and outside agency personnel.

10.3.6 Release Verification

Procedures for verifying unintended release alarms and notifications need to be well defined and practiced. If verification is necessary, the process should be completed in the shortest possible time. There should then be no hesitation by the operator to enact control measures for active releases.

10.3.7 Isolation and Control of the Release Source

The source of an active unintended release needs to be immediately controlled. Control measures may vary depending on the release volume, rate, location, and pipeline operational capabilities. Pipeline operators shall have procedures that address each of these issues for all pipeline segments.

The primary methods of source control for an active unintended release are:

- Reduction of pipeline operating pressure.
- Total shutdown of pipeline product flow and closure of release source area line valves, when applicable.
- Isolation of pipeline segment containing the release by closing main line block valves or other mechanisms.

Operator personnel with authority and responsibility to reduce operating pressures and/or stop flow of pipeline product need to be clearly defined and accessible at all times. Criteria for restricting or stopping flow of pipeline product during an unintended release event should be clear and concise. Flow restriction should then be implemented immediately when the situation warrants.

10.3.7.1 Block or Check Valves

Block or check valves (one type of emergency flow restricting device) can serve to restrict flow to a release location. However, it should be noted that block or check valves are only capable of minimizing one unintended release volume component - the drain down volume. In many situations, segmenting the pipeline can reduce the unintended release volume. This can be done by adding intermediate block or check valves, but such decisions are made depending on many factors such as terrain, access, products, etc.

10.3.7.2 Emergency Flow Restricting Devices (EFRD)

EFRDs such as mainline valves (both manual and remotely operated), and check valves can be used to minimize the size of an unintended release. In the event of an unintended release, the resulting volume is dependent upon a number of variables: the physical characteristics of the fluid released, the volume of contents within the pipeline, the pipeline profile (ground topography), the volume of pipeline drain down, etc. Since natural terrain and other factors affect pipeline locations differently, segments of pipeline should be analyzed for a range of release flow rates. However, if the resulting unintended release volumes are unacceptable, additional block valves should be considered, along with the method of valve actuation.

10.3.7.3 Limitations on EFRDs

Remotely actuated or automatic valves may cause additional unintended releases themselves since the valves sometimes leak or malfunction. Further, the valves could be closed unintentionally, as a result of a malfunctioning automatic or remote closing apparatus, causing other operational problems including over pressurizing and possible rupture of the pipeline.

A 1993 California State Fire Marshall study of over 7,000 miles of regulated interstate and intrastate hazardous liquid pipelines analyzed block valve effectiveness. This study found that there was little statistical correlation between block valve spacing and the resulting spill size. The study found that for 50% of the incidents, the spill volume was less than 1% of the total volume between the adjacent block valves. Only 4.6% of the incidents resulted in spill volumes, which exceeded the maximum potential drain down spill volume between adjacent block valves. In the cost benefit analysis, the study found that there may be some justification for additional block valves on long segments of pipe (over about ten miles). However, the study noted that natural terrain and other factors (e.g., proximity to dense populations, environmentally sensitive areas, etc.) would affect each pipe segment differently.

10.3.8 Control of the Released Product

When the volume and location of an unintended release warrants immediate on-site control measures, operator response teams and third-party response teams need to be dispatched. Maximum time-to-respond criteria should be developed for all pipeline sections. The teams should be equipped and trained, or have access to contract resources, to contain unintended releases of various volumes.

Operator personnel or outside agencies designated for command authority may vary according to factors such as unintended release volume, location, potential environmental impacts, potential impacts to the public and outside agency jurisdictions. Therefore, procedures to identify and maintain personnel in command of an unintended release at various locations should be developed and communicated to all potential parties in order to eliminate disputes and indecision during an active release event. This is usually accomplished using an incident or unified command system.

10.4 PIPELINE OPERATING PRESSURE REDUCTION

Operating pressure reduction is used as both a temporary and occasionally permanent measure to reduce risk. Operating pressure reduction is a temporary, but immediate mitigative action, to reduce risk until a defect can be evaluated by excavation, repaired or removed. In some cases, an operator may determine that the consequences of a failure are significant enough to design for a higher level of safety than normally afforded by ASME B31.4. An operating pressure reduction can provide benefit similar to a hydrostatic test, but a larger margin of pressure reduction may be necessary.

11 Revision of the Integrity Management Plan

Inspections conducted under an operator's integrity management plan will result in data that must be analyzed and integrated with previously collected data. This is in addition to the other types of integrity management related data that is constantly being gathered, updated, reviewed and integrated into the operator's database (see Section 7). The result of this ongoing data integration, and periodic risk assessment will result in revision of the plan in the form of new or modified mitigation plans and subsequent integrity assessments.

Analysis of inspection data will most likely result in a series of additional mitigation activities. Some of these mitigation activities may require immediate action while others may be scheduled in a long-term plan. The criticality of mitigation actions and how they are scheduled will depend on the results of integrating this information into an operator's risk assessment.

12 Integrity Management of Pipeline Pump Stations and Terminals

Conceptually, managing the integrity of pipeline stations and terminals is similar to main line cross-country pipe. The framework elements described in Section 5 apply to pipeline stations and terminals, as well as to the pipeline itself. However, some aspects of data gathering, risk assessment, inspection tools and techniques, and mitigation are specific to pipeline stations and terminals. Section 12 addresses aspects of pipeline integrity that are specific to pipeline stations and terminals.

Any of the risk methods used to assess the risk of a pipeline may be applied to pipeline stations and terminals. The data used in a facility model will vary from that used to model a pipeline. The fact that facilities occupy a limited geographic area make risk assessment an easier task as compared to risk assessment of a geographically dispersed asset like a cross country pipeline. On the other hand, the relatively more complex nature of facility piping including manifolds, numerous valves, flanged connections, complex cathodic protection systems, dead legs/low flow piping legs, and auxiliary and instrumentation piping make integrity assessment a greater challenge than cross country pipelines, which consist of pipe with an occasional valve.

12.1 DATA GATHERING

12.1.1 Incident History

The risk assessment process for a pipeline facility should include a thorough review of the incident history of the facility and facilities of similar design on the pipeline system. The nature and characteristics of releases at pipeline facilities differ and are more varied than those of cross country pipelines. Corrosion, which is one of the two leading causes of pipeline releases, is also an issue with facilities but ranks third behind operating errors and non-pipe equipment failures. Non-pipe equipment failures include leaks from pump seals, valve stem seals and threaded fittings. TPD, the leading cause of releases on cross-country pipelines is rare at facilities because access by third parties is severely limited by fencing and other security measures.

A thorough analysis of the incident history at a facility, including root cause analysis, is important in understanding the probability and consequences of failures as well as determining mitigating action.

12.1.2 Facility Data

The following types of data are useful in conducting a risk assessment for stations and terminals:

- Design data. Data may be gathered from original and revised drawings and specifications if available, otherwise a site visit will provide much information. Design data includes:
  - —Design operating pressure
  - —Normal operating pressure
  - —Operating temperature
  - —Pipe data, including manufacturer, wall thickness, grade, notch toughness, and manufacturing process
  - —Material compatibility
  - —Appurtenance data (flanges, fittings, etc.), including ANSI pressure ratings
  - —Piping location—above or below ground
  - —Piping connections—welded, flanged, or threaded
  - —Valves—manual, electric, or hydraulic operators
  - —Tanks—type, construction, capacity, age, venting and vapor control systems
  - —Age of piping, tanks, and appurtenances
  - —Coating
  - —Cathodic protection
  - —Relief devices
  - —Protective devices—control valves, pressure switches, and level alarms
  - —Oil/water separators
  - —Spill containment—dikes and retention ponds
  - —Storm water drainage/collection
  - —Auxiliary piping and instrumentation tubing
  - —Equipment seals and seal leak containment
  - —Distances from equipment and piping to property lines
- Corrosion data. Information must also be gathered about the nature and effectiveness of corrosion control. Corrosion data includes:
  - —Pipe coating, type, age, condition
  - —Corrosion mechanism and monitoring results
  - —Pipe insulation, type, age, condition
  - —Cathodic protection system, age and condition
  - —Close interval survey results
  - —Aboveground paint and coating systems
- Security information. Such information includes:
  - —Fences
  - —Security monitoring systems
  - —Lighting
  - —Surroundings
  - —Visibility
  - —Signage
- Information about the physical environment of the facility. Such information includes:
  - —Soil types
  - —Soil gas surveys
  - —Depth to groundwater
  - —Down-gradient receptors such as ponds, lakes, streams, or wetlands
- Groundwater monitoring well locations
  - —Water quality
  - —Wildlife habitat in vicinity
  - —Drinking water sources in vicinity
  - —Storm sewer and sanitary sewer locations
- Information about environmental concerns near the facility. Such information includes:
  - —Population in vicinity down-gradient and/or downwind
  - —Public buildings
  - —Public roads and highways
  - —Evacuation routes
  - —Commercially navigable waterways
  - —Groundwater monitoring well locations
  - —Water Quality
- Information about the operating characteristics of the facility. Such information includes:
  - —Product types and characteristics
  - —Normal operating pressures
  - —Man/unmanned status
  - —Operating procedures
  - —Frequency of facility visual inspections
  - —Operator training
  - —Operating error and near miss history
  - —Preventive maintenance records
  - —Pipe inspection reports
  - —Equipment failure reports
- Information about the capabilities for emergency response at the facility. Such information includes:
  - —Firefighting capability at facility, including equipment and training
  - —Local fire departments, capabilities, and location

12.2 CONCERNS UNIQUE TO MITIGATION OPTIONS

Risk mitigation at facilities involves addressing both the probability and the consequence side of risk. Managing the probability of a failure is addressed by leak prevention. Managing the consequence side is addressed through release detection, containment, response, and remediation.

For example, seal leaks are one of the leading causes of unintentional releases at facilities. Managing the probability of a seal leak can include replacement with a more robust seal of a different material or design, or periodic replacement prior to failure using predictive maintenance techniques.

12.3 MITIGATION OPTIONS

Mitigation options to reduce the consequences of an unintentional release may include:

- A liquid collection system such as one that collects product leaking by a valve or instrument connection that directs it to a sump or other collection device.
- Periodic visual inspection of a facility to discover seal leaks, while any quantity of product that might have escaped into the environment is small, and recovery and remediation are relatively easy.
- Instrumentation or systems that detect the presence of product once it has escaped from the piping.

12.3.1 Inspections

API 570 is an acceptable guiding document to help an operator develop an inspection strategy.

Periodic visual inspections can be scheduled for the facility. An on-site visual inspection of a facility should include the following:

- Obvious leaks or indications of a leak such as stains around valves or flanges or stained soil or gravel.
- Inspection of instrument wells for sign of leakage at tubing connections or corrosion of piping or auxiliary piping.
- Evidence of excessive vibration of pipe or auxiliary piping that could result in fatigue related failures.
- Sumps for product levels.
- Loose connections of threaded or flanged fittings.
- Oil/water separators.
- Product sheens on retention ponds.
- Condition of security fencing, signs of vandalism or unauthorized access.
- Piping air-soil interface corrosion.

Facility piping can be scheduled for periodic non-destructive testing, including radiography, ultrasonic and other appropriate techniques.

12.3.2 Routine Maintenance of Protective Devices

Facilities include a broad range of protective devices, including pressure regulators such as control valves and pressure switches, and product level gages, switches and alarms. These devices must be periodically inspected, calibrated, and tested to ensure they perform their intended function.

12.3.3 Corrosion Control

Cathodic protection systems should be maintained. Close interval surveys can be used to evaluate the effectiveness of cathodic protection. The integrity of coating systems should be evaluated. If internal corrosion is an issue, the need for inhibitors and biocide treatments should be evaluated. Dead leg piping should be identified and the potential for internal corrosion evaluated.

12.3.4 Tanks

API 653 *Tank Inspection, Repair, Alteration, and Reconstruction* should be consulted for guidance on inspection, maintenance, and repair of tanks.

12.3.5 Leak Detection

Potential mitigative actions to detect releases and reduce their consequences include:

- Installation of hydrocarbon sensing cables/devices.
- Installation of gas sensors to detect combustible vapors.
- Integrity testing (leak test/stand-up test, hydrostatic test, pneumatic test, tracer chemicals).

12.3.6 Emergency Response Capability

Potential mitigative actions to improve emergency response capabilities to reduce the consequences of unintentional releases include:

- On-site spill containment equipment and material.
- Pre-determined product containment recovery sites.
- Participation in joint response groups.
- Emergency response training including participation in periodic emergency drills.

12.3.7 Facility Design Considerations

As new facilities are built, or when existing facilities are refurbished or reconfigured, improved design features can be incorporated into facilities, such as:

- Make piping accessible for inspection such as limiting the amount of buried piping.
- Avoid buried flanged or threaded connections.
- Avoid low flow and dead legs.
- Minimize the number of small taps which are subject to damage.
- Install impervious barriers or linings under tanks and piping.
- Route surface drainage through underflow retention ponds.
- Install remote tank gauging.

13 Program Evaluation

The intent of this section is to provide system operators with a methodology that can be used to evaluate the effectiveness of integrity management. The goal of the operator of any pipeline is to operate the pipeline in such a way that there are no adverse effects on employees, the environment, the public, or their customers as a result of their actions. Evaluations need to be performed on a periodic basis to review the effectiveness of the operator's integrity management program. In the most basic sense, a program evaluation should help an operator answer the following questions:

- Did you do what you said you were going to do?

- Was what you said you were going to do effective in addressing the issues of integrity in your pipeline system?

13.1 PERFORMANCE MEASURES

The operator shall collect performance information and periodically evaluate the effectiveness of its integrity assessment methods, and its preventive and mitigative risk control activities, including repair. The operator should also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions. A combination of performance measures and system audits is necessary to evaluate the overall effectiveness of a pipeline integrity program.

Each operator shall have a minimum of 10 performance measures. These ten performance measures shall include a distribution of leading, lagging, and deterioration measures (see 13.2 for a discussion of the types of performance measures). These ten performance measures shall be part of the operator's integrity management program, and shall be based on an understanding of the failure mechanisms or threats to integrity for each pipeline system operated.

Of the ten required performance measures the following shall be included:

1. A performance measurement and a goal to reduce the total volume from unintended releases with an ultimate goal of zero.
2. A performance measurement and a goal to reduce the total number of unintended releases (based on a threshold of five gallons) with an ultimate goal of zero.
3. A performance measurement and a goal that documents the percentage of integrity management activities completed during the calendar year.
4. A performance measurement and a goal to track and evaluate the effectiveness of the operator's community outreach activities.
5. A narrative description of pipeline system integrity, including a summary of performance improvements, both qualitative and quantitative, to an operator's integrity management program, prepared periodically.

Of the ten required performance measures the remaining five should include at least the following types:

1. A performance measure based upon internal audits of the operator's pipeline system per 49 *CFR* Part 195.
2. A performance measure based upon external audits of the operator's pipeline system per 49 *CFR* Part 195.
3. A performance measure based on operational events (e.g., relief occurrences, unplanned valve closure, SCADA outages, etc.) that have the potential to adversely affect pipeline integrity.
4. A performance measure to demonstrate that the operator's integrity management program reduces risk over time with a focus on high-risk items.
5. A performance measure to demonstrate that the operator's integrity management program for pipeline stations and terminals reduces risk over time with a focus on high risk items.

13.2 PERFORMANCE MEASUREMENT METHODOLOGY

All of the risk-assessment and mitigation methods discussed earlier in this standard are put forth with the intent of reducing the likelihood and consequences of a product release. Ultimately, the performance measurement of an operator's integrity management program is the degree to which unintended releases are eliminated. However, a typical integrity management program will contain many elements, and the program will operate over long time horizons. Thus, an integrity management program cannot be evaluated based on any one measure. This section describes an approach to monitoring performance of the components of an integrity program with the expectation that component progress will correlate with overall program success. Performance measures actually form a continuum from leading indicators (before releases or failures) to lagging (after releases or failures), and include process measures, measures of deterioration and measures of actual failures or releases. The distinction between many of these measures will not always be clear.

Selected process measures. Metrics that monitor the surveillance and preventive activities undertaken by the operator. These measures indicate how well an operator is implementing the various elements of the integrity management program. These measures answer the question: "Once the program has been defined, how well are the details being executed?" Activity measures must be thoughtfully selected since not all activity measures will effectively measure performance.

Deterioration measures. Operational and maintenance trends that indicate when the integrity of the system is reduced despite preventive measures. Some performance measures of this type may indicate that the system condition is deteriorating despite well-executed preventive activities. For example, other performance measures may indicate that predicted rates of wall loss from corrosion are within expected parameters or they are not within expected parameters. Deterioration measures should be evaluated over time to understand trends.

Failure measures. Examples include leak history, incident response, clean-up costs, product loss, and recovery percentage, etc. These measures are clear indications that the ultimate objective of the program has not yet been achieved, but hopefully will indicate progress towards fewer spills, less damage, faster response, and more effective cleanup. Failure measures should be evaluated over time to understand trends.

Table 13-1 is a chart that shows examples of the relationship of performance measures along the continuum from leading to lagging. This chart also illustrates the relationship of the three categories of performance measures and suggests an approach to developing performance measures in relationship to pipeline failure mechanisms. Operators are encouraged to generate their own performance measures.

13.3 MEASURING PERFORMANCE USING INTERNAL COMPARISONS

Every operator should evaluate their current performance against past performance and set specific goals. Internal comparisons over time are suitable for analyzing trends. For example, miles of pipe inspected during the last twelve months can be plotted on a rolling basis once per quarter. An increasing trend would indicate that the average age of inspection data is improving. Percent of system hydrostatically tested or inspected using in-line inspection tools within the last five years plotted on a quarterly basis would give a similar indication of the currency of test and inspection data.

Internal comparisons of one portion of a pipeline system against another portion of the same pipeline system (e.g., portions of the system within designated HCAs versus other portions outside designated HCAs) may be used to evaluate the effectiveness of specific preventive or mitigative actions.

Internal comparisons from one geographic region to another geographic region within the same operating company, or from one business unit to another business unit may be helpful ways to identify areas with deficiencies.

13.4 MEASURING PERFORMANCE USING EXTERNAL COMPARISONS

External comparisons may be more difficult to obtain. This is particularly true for the metrics related to preventive and mitigation actions. Benchmarking among operators may prove practical when those operators are not in direct competition. Care needs to be taken to ensure that benchmarking is conducted such that information is comparable among the benchmarking operators or systems.

Operators should also conduct periodic evaluations of their own performance in comparison with industry-wide data sources. For example, an operator should periodically review its performance in comparison with the database managed by the Office of Pipeline Safety based on 49 *CFR* Part 195 incident reporting requirements. Operators may also take advantage of voluntary performance tracking programs such as that of the American Petroleum Institute through its Pipeline Performance Tracking Initiative.

In order to ensure that operators have access to external databases, operators need to participate in data initiatives, both operator benchmarking and industry wide databases. The pipeline industry has created a voluntary performance tracking database, called the Pipeline Performance Tracking Initiative. A copy of the standard set of incident data fields is attached as Appendix C to this standard. Individual operators should collect internal incident information using the standard incident data fields even if they do not choose to contribute operator information to external databases[8]. Only by using standard data fields can comparisons be made external to individual operators.

In order to conduct trend analysis of incidents, system characteristics also need to be captured using a standard format (miles, miles by diameter, miles by decade of construction, miles by pipe size, miles by operating pressure, and volumes moved). The pipeline industry has developed standard data fields for system characteristics. Those standard data fields for system characteristics (also called infrastructure data) are provided in Appendix D to this standard. Operators should collect infrastructure data for trend analysis using the standard data fields even if they do not choose to contribute system infrastructure information to external databases.

13.5 AUDITS

Audits of integrity management programs are an important element of evaluating program effectiveness and identifying areas for improvement. Audits may be performed by personnel with the organization (self assessments), or by auditors from outside organizations. Examples of questions that integrity management program audits should address include:

- Are activities being performed as outlined in the operator's program documentation?
- Is someone assigned responsibility for each subject area?
- Are appropriate references available to those who need them?
- Are the people who do the work trained in the subject area?
- Are qualified people used when required by code or regulation?
- Are activities being performed using an appropriate integrity management framework as outlined in this standard (API 1160)?
- Are all required activities documented by the operator?
- Are action items followed-up?
- Is there a formal review of the rationale used for developing the risk criteria used by pipeline operator?
- Are there established criteria for repairing, re-rating, replacing, or rerouting damaged pipelines? Are criteria established for these activities stated above for terminals, pump stations, associated piping and relief systems?

[8]Other industry data activities exist; for example, The Pipeline Open Data Standard (PODS) is a relational database being designed for use by the pipeline industry. It is designed to support natural gas and liquid pipelines as well as their vendors and software application developers and data suppliers. PODS is managed by the pipeline industry for the pipeline industry. Interested pipeline operators, vendors, and data suppliers are asked to designate representatives to serve on committees, which work to build and maintain the model. (Further information is available via the internet: http://www.pods.org/)

Table 13-1—Example Performance Measurement Categories

	Leading ← – – – – – Indicators – – – – – → Lagging		
Failure Mechanism	Selected Process Measures	Deterioration Measures	Failure Measures
Third-party Damage			
Third-party excavation, construction or other work at the time of failure	• Compliance with 195.442 • Compliance with "common ground" • Number of one-calls	• Aerial patrol reports with no one-call • Inadequate one-call follow-up • Pig run with indicated damage	• Leak due to TPD
Third-party excavation, construction or other work activity occurring at some time prior to failure		• Aerial patrol reports with no one-call • Inadequate one-call follow-up	• Pig run with indicated damage • Notification of pipeline damage by TPD
Other TPD, including vandalism, third-party vehicle contact with facility, and other intentional or unintentional acts	• Compliance with 195.442	• Aerial patrol reports • Pig run with indicated damage	• Leak due to TPD
Corrosion			
External corrosion	• Compliance with 195.236, 238, 242, 244, 416 • Compliance with NACE RPO 169	• Pig run with indicated corrosion • Annual cathodic protection exception reports • Close interval surveys • Interference testing	• Leak due to corrosion
Internal corrosion	• Water content • H_2S content • CO_2 content	• Coupon tests • Pig run with indicated corrosion • Time interval between scraper runs	• Leak due to corrosion
Material Failures			
Pipe materials, pipe seam, pipe weld or repair weld failure	• Review of material properties	• ILI tool run results • Hydro-test blowouts	• Leak or rupture
Equipment Failure			
Equipment malfunction or failure of non-pipe component	• Inappropriate specifications • Inappropriate materials • Efficiency testing of pumps • Maintenance training • Root cause failure analysis for systemic problems • Maintenance procedures	• Testing of control valves • Testing of high pressure shutdown devices • Testing of relief valves • Corrosion failure • API 653 inspections • API 570 inspections	• Leaks due to gasket and packing failures • Leaks due to tank failure • Sump tank leaks
Operational Error			
Excavation or physical damage to facility or pipeline by operator or operator's contractor	• Proper training • Internal one-calls	• Number of near misses reported	• Leaks • Pipe damage from pig run
Valve left or placed in wrong position		• Relief valve failure • Contamination	• Over pressure • Leaks
Pipeline or equipment over-pressured	• Compliance with 195 • Training program reviews	• Number of relief valves operating	• Leak

Table 13-1—Example Performance Measurement Categories (Continued)

	Leading ← – – – – – Indicators – – – – – → Lagging		
Motor vehicle			
Tank overfilled	• Operating procedures are adequate • Shipper schedule changes or unscheduled deliveries	• Alarm maintenance	
Other human error		• Isolation of relief valves and shutdown devices for long periods of time	• Leaks
Natural Forces			
Cold Weather			
Heavy rains/flooding	• Water crossing inspections	• Exposed pipes • Washout	• Rupture
Lightning	• # of station shutdowns due to groundfaults		• Fire
Earth movement	• # of earthquakes	• Ground sloughing	• Rupture
Other			
Other			

- Is there a formal review of the data provided by federal data sources, such as the U.S. DOT Office of Pipeline Safety concerning HCAs (locations/sizes) that may have changed and what is the frequency of that review?

13.6 PERFORMANCE IMPROVEMENT

Program evaluation shall be conducted on an ongoing basis. Information shall be accumulated and documented over time. Since the details of operator integrity management programs will vary, so too will the appropriate set of performance measures. Section 13.1 identifies performance measures to be used by all operators. Many operators will elect to have more than ten performance measures.

Internal audits and external audits should be used as additional information sources for understanding the effectiveness of pipeline integrity programs. Recommendations for integrity management program improvement shall be developed based on the results of performance evaluation, including performance measures and audits. The performance measurement and audit results shall also be factored into future risk assessments.

The results of performance measurement and audits, including all follow-up recommendations, shall be reported to those individuals within an operating company who are responsible for pipeline integrity and operations. Performance should be reviewed at least annually and issues addressed.

14 Managing Change in an Integrity Program

Once a pipeline integrity program is established, it is critical that the pipeline operator continuously monitors and improves the program. Changes to the pipeline made by the operating company, and changes affecting the pipeline made by others, could affect the priorities of the integrity program and the risk control measures employed. To ensure continued validity of the program, operators must:

- Recognize changes before or shortly after they occur.
- Ensure that those changes do not unnecessarily increase risks.
- Update the affected portion(s) of the pipeline integrity program.

Operators with an existing management of change (MOC) program should verify that the types of changes mentioned in this section are included in their MOC program. For other operators, a system should be established to recognize and manage changes relevant to their pipeline integrity program.

14.1 RECOGNIZING CHANGES THAT AFFECT THE INTEGRITY PROGRAM

To keep the pipeline integrity program current, the operator should identify the ways a pipeline may be modified that could impact any of the risk factors identified in the pipeline integrity program. Examples of such changes are:

- Adding, deleting, or otherwise modifying the pipeline equipment.
- Changes in the fluid transported and/or its operating conditions in the pipe that may also affect the risk prioritization and any spill control or other mitigation measures employed.
- Changes to flow rate and/or operating pressure.
- Restarting equipment or systems that have been out of service for an extended time and/or systems that have not been maintained.
- Changes to existing procedures, or addition of new procedures.

- Changes along the right-of-way, such as changes in land use.
- Regulatory changes.

The operator is responsible for recognizing these changes and ensuring that the changes are appropriately reviewed.

14.2 UPDATING THE PIPELINE INTEGRITY PROGRAM

A change may impact any or all of the pipeline integrity program. Sections 6 through 13 of this document address elements of the program that may be impacted by a change. As part of managing a change, the operator should evaluate integrity program issues such as:

- Have the potential impacts or affected impact zones been altered? (Section 6)
- Should data be added, deleted, or modified? (Section 7)
- Does this change impact data that was input or assumptions that were made during the risk assessment? (Section 8)
- Does this change affect inspection, prevention, or mitigation plans? (Sections 10)
- Should this change lead to a revision of the integrity management plan? (Section 11)
- Does this change impact the integrity program for pipeline stations, terminals, and/or delivery facilities? (Section 12)
- Does this change impact any performance indication or auditing criteria? (Section 13)

Any change that affects the pipeline integrity program shall be documented. Affected parts of the pipeline integrity program shall be modified as necessary to reflect the change.

APPENDIX A—ANOMALY TYPES, CAUSES, AND CONCERNS

A.1 Metal Loss (Corrosion)

Corrosion is defined as the deterioration of a material, usually a metal, by reaction with its environment. The rate in which a metal will deteriorate (corrode) is primarily governed by the environment it has been placed in and also by the preventative measures that have been put in place to mitigate the reaction.

Almost all types of corrosion attack (external or internal) can be listed under several major categories. Perhaps the most striking feature of corrosion is the immense variety of conditions in which it occurs and the large number of forms in which it appears. Although there are several different forms of corrosion each share some common factors.

- An anode.
- A cathode.
- A metallic path connecting the anode and cathode (typically the pipe itself).
- An electrolyte (typically the soil and groundwater).

Although this is a simplification, no matter what type of corrosion is present, each of the four items listed above are always present. Eliminating any of the four will stop the electrochemical corrosion reaction. The elimination of one of the four common factors is the basis for a corrosion control program.

The most common methods of corrosion control are proper material selection, protective paints and coatings, corrosion treatment chemicals, dielectric insulation, and cathodic protection. Each of these methods has distinct advantages and disadvantages. All should be considered when planning a comprehensive corrosion control program.

A.1.1 EXTERNAL CORROSION

When a pipeline is placed in the ground, it typically develops both anodic and cathodic sites, which were created by the steel manufacturing process, the surrounding environment, other buried facilities, and other factors. The pipeline itself is the metallic path and the soil is the electrolyte. Typically, external corrosion on pipelines can be categorized as "general corrosion" or "localized pitting."

Localized pitting is normally confined to a small area or several interconnected small areas. Localized (or pitting corrosion) may be individual or multiple pits surrounded by pipe that is at or near full wall thickness. Localized corrosion is evaluated using depth and length measurements to determine the remaining strength of the steel. Bacteria, differential oxygen concentrations, stray interference currents, or simply interaction between galvanic cells can cause localized pitting. Localized corrosion causes concern for the integrity of a pipeline since the area being attacked can be very small and the corrosion rate, in some situations, can be extremely high.

External corrosion is controlled on buried pipelines by the combined use of protective coatings and cathodic protection. Protective coatings form a barrier between the pipe steel and the soil thus, isolating the pipe from the electrolyte. Cathodic protection is used in combination with coatings to provide corrosion control where there are holidays or damage to the protective coating, such that the steel pipe is exposed to the corrosive electrolyte. Cathodic protection essentially changes anodic areas on the steel surface to cathodic areas, transferring corrosion to an external, non-pipeline structure that can easily and periodically be replaced. Stray current corrosion is corrosion (usually pitting) caused by the influence of outside sources of electrical currents.

A.1.2 SELECTIVE ERW SEAM CORROSION

Selective ERW seam corrosion, also called preferential seam corrosion, is created when the pipe is experiencing corrosion caused metal loss, either internal or external, across or adjacent to an ERW seam. The corrosive action attacks the seam bond region at a higher rate than the surrounding metal. The result is often a V-shaped crevice or groove within the bond line. In some ERW materials, this bond region exhibits low fracture toughness. Selective seam corrosion and low toughness creates a serious defect that is more likely to cause a rupture than coincident corrosion in the body of the pipe.

A.1.3 NARROW AXIAL EXTERNAL CORROSION

While not unique to pipe longitudinal seams, narrow axial external corrosion (NAEC) is often found at pipeline double submerged arc welded seams coated with polyethylene tape. The "tenting" allows the intrusion of water and provides an environment that could shield the external surface of the pipe from cathodic protection. This shielded area is axially oriented and limited to the area immediately adjacent to the seam weld. The resultant groove-like defect is more likely to rupture than typical blunt corrosion.

A.1.4 INTERNAL CORROSION

Internal corrosion follows the same basic principles as external corrosion. Refined petroleum products and crude oil can contain water, bacteria, chemical contaminants and debris that can create a corrosive environment on the internal pipe. Like external corrosion, localized pitting and general corrosion are the typical forms of corrosion attack.

Cathodic protection applied to the external surface is ineffective in mitigating internal corrosion attack. While cathodic protection applied internally can be effective in mitigating internal corrosion (such as inside a water tank), it is typically not used internally in pipelines due to difficulties in application, disruption of pipe flow, presence of valves, inaccessibility, etc. Corrosion treatment chemicals such as inhibitors, bactericides are often used to combat internal corrosion. Pigging at regular intervals, and often in conjunction with chemical treatment, is an effective technique for removing water and debris from a pipeline and helps prevent internal corrosion.

A.1.5 UNDER-DEPOSIT CORROSION

Under-deposit corrosion is a form of internal corrosion usually found on the bottom quadrant of the pipe and may or may not act in conjunction with bacterial corrosion. Pools of water, especially in pipelines transporting under-treated crude oil, provide the electrolyte for the corrosion process and contain dissolved corrodents such as chlorides and sour gases. Water that pools in low areas also acts as a medium for supplying nutrients for sulfate reducing bacterial growth.

Localized corrosion occurs under these conditions through several mechanisms:

- Adherent deposits permit the formation of anodic and cathodic regions, which drive the corrosion process.
- Chlorides in brines breakdown passive layers and hydrolyze to form acid conditions.
- Dissolved gases create acidic solutions and provide anodic reactants to the corrosion cell.

The development of these concentration cells beneath a deposit can lead to accelerated corrosion usually in the bottom of the pipeline. This type of corrosion is difficult to control because the deposit helps prevent corrodents from being removed by flow forces and prevents inhibitors from filming the corroding areas. This shielding also keeps biocides from contacting corrosive microorganisms.

A.1.6 OTHER TYPES OF CORROSION

As mentioned above, there are several different types of corrosion attacks. The type of attack that a pipeline may encounter depends primarily on the environment. Listed below are some examples of other types of corrosion.

A.1.6.1 Bacterial Corrosion (Microbiologically Influenced Corrosion)

Bacteria are found in essentially all soil and water, and some of them do not present problems insofar as corrosion of metals is concerned. However, there are important exceptions. The two basic categories of bacteria are aerobic (oxygen using) and anaerobic (non-oxygen using). Both types can be present in the same environment depending on temperature, moisture, nutrient supply, etc. Aerobic bacteria will be more abundant where oxygen is plentiful, and anaerobic bacterial will be more abundant in oxygen deficient environments. Members of both groups can contribute to conditions that cause external and internal corrosion of pipelines.

A consortium of microorganisms typically influences corrosion of ferrous metals. These bacteria are hydrogen consuming, sulfate-reducing bacteria and are commonly referred to as sulfate-reducing bacteria or SRBs. The bacteria do not directly attack the steel, but create changes in the electrolyte that increases corrosion activity. Not only do they convert sulfides into sulfuric acid, which attacks the pipe, but they also consume hydrogen, which destroys the polarization film on cathodically protected structures and increases the current requirement for effective cathodic protection.

Anaerobic bacteria are found in stagnant bodies of water, both fresh and salt, in heavy clay soils, swamps, bogs, and in most areas that have moisture, organic materials, low oxygen, and some form of sulfates. Anaerobic bacteria are also found in salt water bearing formations several thousand ft deep, and in many areas are the major factor in well-casing corrosion.

Aerobic bacteria can also create corrosive environments for buried steel structures when sufficient organic matter is available for a food supply. Various organic acids can be formed depending on the type of bacteria and the available organic material. When bacteria produce carbon dioxide, it combines with the available water to form carbonic acid and ammonia compounds, which are oxidized into nitrous, and nitric acid. Other acids that can be formed under the proper conditions are lactic, acetic, citric, oxalic, butyric, and possible others.

Aerobic bacteria are known to attack some pipeline coating materials made from organic materials and use them as a "food" source; these include asphalt coatings and primers, tape adhesives, Kraft paper, and pipeline felts.

A.1.6.2 Galvanic

Galvanic corrosion is defined as corrosion associated with the current resulting from the coupling of two or more dissimilar metals in contact with a common electrolyte. One metal will be anodic (the anode) the other will be cathodic (the cathode). As mentioned above, a piece of steel has anodic and cathodic areas. These areas exist when different alloys such as copper and stainless steel are in contact with steel, or a new piece of pipe is in contact with older pipe. Galvanic corrosion cells may also be created due to dissimilar metals used when welding on pipe.

Additionally, galvanic corrosion can also occur as a result of the introduction of stress on the pipe such as at weld joints, mechanical pipe bends, or on pipe that has been damaged by backhoe teeth. In addition, the presence of concrete on portions of the pipeline, such that some areas of steel are concrete coated and other areas are not concrete coated, can lead to galvanic corrosion.

A.1.6.3 Stress Corrosion

Stress corrosion cracking (SCC) is a form of environmentally assisted cracking, wherein small cracks lengthen and deepen slowly over a period of years. The individual cracks, which may occur in colonies, may eventually join together to form larger cracks. SCC may be present on a pipe for many years without causing problems, though once a crack becomes large enough the pipeline could leak or rupture.

Three conditions must be present for SCC to occur: a susceptible microstructure, a conducive environment, and a tensile stress.

1. *Microstructure*—All commonly used line pipe steels are susceptible, though susceptibility may increase with tensile strength.
2. *Environment*—Specific forms of SCC are associated with specific terrain and soil types, particularly those having alternating wet-dry conditions and those that tend to damage or disbond coatings. However, SCC can occur in almost any soil type since the local electrochemistry at the pipe surface may be isolated from the surrounding conditions. Thus, pipe coating type and condition can be an important factor.
3. *Stress level*—Susceptibility to SCC increases with stress level, though there may be no lower threshold stress level. Conducive stress levels may occur at local structural discontinuities (e.g., weld toes) or sites of deformation due to outside forces (e.g., rock dents). Some amount of stress cycling can promote SCC growth by breaking the oxide film that forms on the crack surface, re-exposing the crack tip to the environment. Cyclic loading seems to be an important factor in the initiation of SCC.

Two forms of SCC have been identified: high-pH (classical) and near-neutral pH (non-classical) SCC. The high-pH form tends to occur within a narrow cathodic potential range and at a local pH over 9. It is associated with increased pipe operating temperatures. Cracks tend to be narrow and primarily intergranular. Pipe with coal tar and asphalt coatings are sometimes susceptible to this type of cracking.

Near-neutral pH SCC tends to occur at a local pH of 5.5 to 7.5. It is associated with mild concentrations of CO_2 in ground water and colder climates. Cracks are generally transgranular, wide, and more corroded than those found in high pH SCC. Generally, tape coated systems are susceptible to this type of environment.

A.2 Construction Damage/Third-party Damage

Pipe and pipe welding defects can occur during new construction or maintenance. These defects vary in type: dents, gouges, undercut, lack of fusion, lack of penetration, or cracks.

TPD and outside forces, such as earth movement and excavation equipment may cause dents, gouges, scratches, loss of pipeline support, change in pipeline alignment and loss of cover.

A.2.1 DENT

Dents can be separated into two basic types, plain dents and dents that include a stress concentrator.

A.2.1.1 Plain Dents

Plain dents are a local change in surface contour but not accompanied by a stress concentrator, rocks in the backfill or mechanical impact. Plain dents may be analyzed by existing fatigue techniques.

A.2.1.2 Dents with a Stress Concentrator

This type of defect is a dent with stress concentrators such as cracks, gouges, grooves, or arc burns, located within the dent. These dents can provide the beginning point for a pipe failure. This type of defect may pose a potentially serious integrity problem for a pipeline. Dents with a stress concentrator shall be repaired.

A.2.1.3 Double Dents

Double dents consist of two dents that overlap along the axis of the pipe creating a central area of reverse curvature in the longitudinal direction. Fatigue cracks develop in the saddle region between the two dents and often develop to critical proportions faster than fatigue cracks in single dents.

A.2.1.4 Dents that Affect Welds

Dents that affect welds either longitudinal pipe seams or girth welds may be analyzed by existing fatigue techniques such as PRCI Report PR-218-9822 "Guidelines for the Assessment of Dents on Welds" for purposes of assessing risk and repair priority.

A.2.2 GOUGES

Gouges are elongated grooves or cavities caused by mechanical removal of metal. A gouge can be recognized by the sharpness of its edges. Gouges can be very detrimental to the integrity of a pipeline. Corrosion typically has a rounded or parabolic shape, while gouges have more defined edges.

A.2.3 ARC BURNS

Arc burns are sometimes referred to as contact burns. Usually a series of small pits or indentations adjacent to or on the weld surface caused by arcing between the welding electrode (welding rod) or ground and the pipe surface.

A.2.4 APPURTENANCES WELDED TO LINE

An appurtenance welded to the pipeline is any metallic structure attached to the line, i.e. stopple fitting, branch connection, taps, etc.

A.2.5 WRINKLE BENDS / BUCKLES

Wrinkle is a local deformation of the pipe wall caused by longitudinal compressive stress on the pipe, characterized by minor outward bulging or inward asymmetry.

Buckle is a wrinkle that has advanced well into the post wrinkle regime. A buckle is characterized by large deformation of the pipe wall with amplitudes greater than 1 in.

A.2.6 PREVIOUS REPAIRS

Some procedures used in the past to repair pipe defects are not recommended today. For example, “puddle” welding was used to replace lost or damaged metal and restore pipe continuity. Puddle welding should not be confused with the current deposited weld metal technology, which has been shown to produce repairs of acceptable quality.

Patches and half wraps may have been used to repair leaking pipelines. These repairs are no longer recommended for high-strength line pipe because of the potential weak point at the juncture between the longitudinal fillet weld and the patch or half wrap.

A.2.7 CRACKS

Cracks are stress-induced separation of the metal, which, without any other influence, are not large enough to cause the complete rupture of the material. Because of the potential for crack growth in liquid pipeline service through fatigue and intergranular corrosion, cracks represent a major concern to pipeline operators.

A.2.8 MILL-RELATED ANOMALIES

Pipe defects may occur during the manufacturing process. These defects include but are not limited to those named below:

Blister. A raised spot on the surface of the pipe caused by expansion of gas in a cavity within the pipe wall.

Expander marks. Expander marks are due to cold working of the steel in the mill. These marks are usually less than $^1/_8$ in. and normally do not affect the service life of the pipeline.

Ovality. Pipe that is oval or egg shaped and on which the major and/or minor axes are respectively in excess or less than the tolerances permitted in the pipe standard designated in the purchase order specifications.

Lamination or inclusion. An internal metal separation creating layers generally parallel to the surface. Some laminations are caused by a shrinkage cavity in the upper part of an ingot. If oxides form on the surface of this cavity, the surfaces will not weld together during subsequent rolling operations. Since the shrinkage cavity starts in the center of an ingot, it will remain in the center of the resulting slab, plate, and pipe. Laminations that break the surface may behave much like cracks. Laminations in pipe carrying hydrogen sulfide or sour contents may be sites for hydrogen build-up and subsequent cracking or blistering.

Incomplete fusion. A lack of complete coalescence of some portion of the metal in the weld joint.

Burnt pipe. Sometimes appearing in lap-weld pipe, “burnt pipe” is a condition that occurred when the edges of the skelp were heated to too high a temperature and austenite grain-boundary sulfides formed. These layers are characterized as very brittle and susceptible to cracks after the material had cooled. It is believed that “burnt pipe” and inadequate bonding due to oxide entrapment in the lap-weld itself account for the inability for some lap-welded pipe to develop to its full strength.

Hook cracks (upturned fiber imperfection). A hook crack or upturned fiber imperfection is defined in API Bulletin 5TL as, “Metal separations resulting from imperfections at the edge of the plate or skelp, parallel to the surface, which turn toward the inside diameter or outside diameter pipe surface when the edges are upset during welding.” Hook cracks are not a welding problem per se although they do not exist other than at an upset weld such as an ERW seam. They arise from nonmetallic inclusions or laminations in the skelp that normally are parallel to the surfaces and do not affect the tensile strength of the skelp. The shear stresses between the layers as the fibers are bent causes the nonmetallic layers to rupture resulting in hook-shaped or J-shaped cracks near the bondline. Sometimes the cracks do not occur until the pipe is subjected to a large internal pressure, such as in the mill or field hydrostatic test. Hook cracks not exposed by a hydrostatic test would seldom be expected to cause problems in service unless extended by fatigue crack growth from large numbers of significant-size pressure cycles. Hook crack failures during the re-testing of some older ERW pipelines are fairly common.

Hard spots. Hard spots are high hardness areas created during hot rolling of plate by localized quenching. These hard spots are circular in shape and in various diameters. Hardness readings, as indicated, reach a tensile strength ranging from 130,000 to 200,000 psi in center portion of the spot and consist of untempered martensite, and low and high temperature bainite. Another source of excessively hard material in the line pipe could be an inadequately post-weld heat treated ERW seam. Any type of hard zone (untempered martensite) regardless of its origin may become cracked if exposed to atomic hydrogen from sour products or cathodic protection.

A.2.9 FIELD BEND MANDREL MARKS

Field bend mandrel marks are associated with pipe bending. Field bends may contain mandrel marks up to $^1/_8$ in. without affecting the service life of most pipelines.

APPENDIX B—REPAIR STRATEGIES

B.1 General

Inspections conducted per the operator's integrity management plan will result in anomalies that must be evaluated. A number of these anomalies will require repair and this appendix provides guidance to develop repair strategies. The information provided in this appendix should not be considered a complete summary of every type of repair, but an overview of some of the more frequently used techniques in the industry today. In the absence of detailed company procedures for pipe replacement or repair, the "Pipeline In-service Repair Manual" should be consulted. Table 9-2 (see Section 9) contains a list of anomalies and acceptable repair strategies for these anomalies, and provides a ready reference for individuals determining the appropriate repair strategy for a certain type of defect in a certain location (seam, body, and girth weld) of line pipe.

ASME B31.4 Section 451.6—Pipeline Repairs—describes thresholds for repair of specific defects.

49 *CFR* Part 195 describes rules for repair. The current rule states that repairs can be "made by a method that reliable engineering tests and analysis show can permanently restore the serviceability of the pipe." This gives the operator the flexibility to use new or innovative repair technologies.

All repairs will be made with materials that have properties that meet or exceed the MOP of the affected line segment and comply with applicable regulations.

B.2 Pipe Replacement

If a section of pipe is found to have a severe anomaly, or anomalies, or a steel reinforcement sleeve will not fit, or a composite reinforcement sleeve will not fit, the replacement of a defective section of pipe with another pipe section may be required. The replacement must have a design strength at least equal to the pipe that is being replaced.

B.3 Re-coat and Backfill

After an external anomaly has been evaluated and determined to not require a repair, the anomaly may be re-coated and backfilled. By completing a re-coat, the anomaly will be once again under the protection of coating and cathodic protection. However, if the pipe was previously coated and cathodically protected, some determination of the root cause of the corrosion anomaly should be made and mitigative measures taken so as to preclude re-occurrence or an increase in severity of the anomaly.

B.4 Pipe Sleeves

Steel full encirclement sleeves are one of the most widely used methods of general repair of defects in pipelines. In the early 1970s, the American Gas Association funded a major project on the effectiveness of various repair methods, with special emphasis on full-encirclement sleeves. This work showed that a properly fabricated sleeve will restore the strength of a defective piece of pipe to at least 100% SMYS.

There are many types and configurations of steel full encirclement sleeves that can be used, dependent upon the configuration of the pipeline segment and the defect area to be repaired.

A Type A sleeve consists of two halves of a pipe cylinder or two curved plates placed around the carrier pipe at the defective area and joined by either welding the side seams via a full penetration groove weld or via a single fillet weld. The ends are not welded to the carrier pipe, but should be sealed to prevent migration of water between the pipe and reinforcing sleeve. It cannot contain pressure and can only be used on non-leaking defects. To be effective, the Type A sleeve must reinforce the defective area, restraining it from bulging radially as much as possible. Reduction in operating pressure while the sleeve is being installed makes for a more effective repair. This is also true for using incompressible resin filler in the annular space.

Advantages

1. There is no welding to the carrier pipe.
2. Longitudinal welds can be made with cellulose rods, if necessary.

Disadvantages

1. The repair is not recommended for circumferentially oriented defects.
2. It cannot be used to repair any leaking anomalies or anomalies that will eventually leak.

Another type of steel sleeve used to repair defects in pipelines is the Type B sleeve in which the ends are fillet-welded to the carrier pipe. The Type B sleeve consists of two halves of a pipe cylinder or two curved plates fabricated and positioned in the same manner as a Type A sleeve. A Type B sleeve may contain pressure and/or carry substantial longitudinal stress imposed on the pipeline by lateral loads. It is used to repair leaks and strengthen circumferentially oriented defects. Sometimes Type B sleeves used to repair non-leaking defects are pressurized by hot tapping through the sleeve and the pipe to relieve hoop stress from the defective area. The Type B sleeve must be fabricated using full penetration welds for the side seam. Only Type A sleeves that have butt welded longitudinal sleeves may be made into Type B sleeves.

Advantages

1. It can be used on most every type of anomaly, including leaking defects.
2. It can be used for circumferentially oriented anomalies.
3. The repair is easily detected by a metal-loss in-line inspection tool.

4. Annular space between the sleeve and the carrier pipe is protected from corrosion.

Disadvantages

1. There is a potential for delayed cracking associated with the circumferential fillet-welds if the welds are made while the line is in service using a non low hydrogen welding process.
2. Reductions in flow rate and/or operating pressure should be considered during repair.

B.5 "Pumpkin" Sleeve

In many older pipelines, joints were made by mechanical compression type couplings. These couplings usually included longitudinal bolts and collars used to compress packing or gaskets to seal against the pipe. They provided negligible longitudinal stress transfer along the pipeline so they were subject to "pull-out" incidents when unusual longitudinal loads were imposed upon the pipeline. To overcome the pullout problem and leakage problem, a "pumpkin" sleeve is installed over the coupling and fillet-welded to the pipe on both ends. The side seams are also welded so the sleeve can contain pressure. Pumpkin sleeves may also be used to repair buckles, ovalities, and wrinkle bends because they can fit over such anomalies. This type of pumpkin sleeve should be installed in the same manner as a conventional Type B sleeve. Because pumpkins typically have a diameter significantly larger than the carrier pipe, they need to be thicker or of higher grade than the carrier pipe to carry the design pressure; therefore, a thorough technical design check should be carried out prior to the installation of a pumpkin.

Another type of pumpkin may be installed over a leaking tap. A small piece of pipe (pup) with a cap welded to the end is welded to the pipe to prevent any possible leaking from the tap. The pumpkin has typically been used only as a last resort technique when a Type A or Type B steel reinforcement sleeve proves to be inadequate.

Pumpkin sleeves or attachments should only be used as a last resort and typically are considered temporary.

B.6 Split Sleeve Reinforcement Clamp (SSRC) (or Bolt-on Clamps)

SSRCs are a widely used method to repair anomalies to restore full pipeline MOP and may be considered a permanent repair in most situations. They can be used on both high and low pressure pipelines carrying oil, gas, or products. Typically, bolt-on clamps are quite thick and heavy due to the large bolts needed to ensure adequate clamping force. Although there are many types of commercially available bolt-on clamps, there are two basic installation configurations: (1) elastomeric sealing only, and (2) elastomeric sealing with welding. The elastomeric seal is designed to contain the pressure if the defect is leaking. The welding option is designed as a back-up device. If the elastomeric seal should fail, the welded clamp is designed to seal the leak and continue to contain the pressure. The "welded-up" option should be chosen on an individual case basis, but great care must be taken when welding bolt-on clamps, especially due to wall thickness mismatch. In addition, packing materials must not be overheated, yet fusion to the heavy wall must be obtained.

Advantages

1. Clamps are cost effective.
2. There is no required welding to the carrier pipe.

Disadvantages

1. The short length prevents use on larger anomalies although custom sleeves can be fabricated in longer lengths.
2. Typically used on straight sections of pipe but custom applications for elbows and fittings are available.

B.7 Leak Clamps

Leak clamps are used to repair leaking external corrosion pits. They are widely used on isolated pits but are considered temporary repairs lasting only until the pipe segment can be replaced. Leak clamps are distinguished from pipe clamps or sleeves due to their temporary nature. They should be used only if analysis shows that the rupture of general corrosion around the leak is impossible, or if the pressure level will remain lowered until a permanent repair is made. Leak clamps include lightweight metal bands with single draw bolts to tighten them onto a pipeline. They also include a threaded fitting located 180° from the draw bolt which is used to force a neoprene cone into the leaking pit.

B.8 Non-metallic Reinforcement Sleeve

Non-metallic reinforcement sleeves are used as a reinforcement and repair alternative to split steel sleeves for non-leaking defects. They are designed to repair blunt corrosion defects and are available in a variety of technologies. The structure resulting from a non-metallic sleeve provides circumferential reinforcement. An operator must investigate each technology to ensure that reliable engineering tests and analysis show the repair can permanently restore the serviceability of the pipe.

Advantages

1. There is no welding to the carrier pipe.
2. The overall cost of the repair technique is less than a Type A sleeve.

Disadvantages

1. The material cost is higher than steel sleeves.
2. The repair cannot be seen by an in-line inspection tool without the installation of a marker, such as a steel band.

B.9 Other Repairs

Weld Deposit Repairs

Repairing a pipeline by means of deposited weld metal involves replacing lost or damaged metal with a filler metal to restore the continuity of the pipe. This type of repair requires special procedures.

Hot Tapping

Some defects, leaking or non-leaking, may be removed on an in-service pipeline by hot tapping a fitting over the defect and cutting out the defect. This type of repair also requires special procedures.

Incompressible Resin-filled Sleeve

This system uses a metallic shell filled with epoxy grout. The technique is considered to be a permanent repair for gouges, corrosion, dents, circumferential, or girth-weld defects, without any welding on the carrier pipe.

Grinding Repairs

Grinding by hand filing or power disk grinding is widely accepted for repairing superficial defects and some more significant defects such as gouges.

APPENDIX C—STANDARD DATA FIELDS FOR TRACKING PIPELINE RELEASES

The oil pipeline members of the American Petroleum Institute and the Association of Oil Pipe Lines began in-depth tracking of pipeline industry environmental and safety performance and created the Pipeline Performance Tracking System in 1998. The PPTS uses a standard set of data fields for tracking releases based on a reporting threshold of 5 gallons. Participation in PPTS is voluntary. API periodically prepares analyses based on the aggregated industry data. This appendix is provided to share the standard data fields used by PPTS and to encourage the use of these standard fields by all liquid pipeline operators.

RELEASE RECORD – HAZARDOUS LIQUID PIPELINE FACILITY

API-assigned User Name ___________________________

PART DS. DESCRIPTION OF RELEASE

Date of release: __/__/__

Is pipeline or facility: ☐ interstate
☐ intrastate

Is pipeline or facility: ☐ a gathering line (based on function, not Part 195 definition)
If so, is it ☐ regulated under Part 195 or its state equivalent
☐ unregulated under Part 195

Was or will a DOT 7000-1 report be submitted? ☐ Yes ☐ No ☐ Don't know

Was or will a telephonic or written release report be made to any State agency?
☐ Yes ☐ No ☐ Don't know

Was a telephonic report made to the National Response Center for this incident?
☐ Yes ☐ No ☐ Don't know

Transported commodity released (check one):
☐ HVLs or other flammable or toxic fluid which is a gas at ambient conditions
☐ CO_2, N_2 or other non-flammable, non-toxic fluid which is a gas at ambient conditions
☐ Gasoline, diesel, fuel oil, or other petroleum product which is a liquid at ambient conditions
☐ Crude oil

Approximate size range of release: ☐ < 1 gal sheen on water → *PART SM*
☐ 1 gal – 4.99 bbls → *PART SM*
☐ ≥ 5 bbls

Estimated size of release: ____________ bbls

Amount of commodity recovered: ____________ bbls

Is recovery of additional commodity anticipated? ☐ Yes ☐ No ☐ Don't know

Did release occur: ☐ Onshore ☐ Offshore

Onshore	Offshore
State ______ Did release occur in "non-rural" area (Part 195 definition)? ☐ Yes ☐ No ☐ Don't know	☐ Federal OCS waters ☐ State waters Offshore area (without block number e.g., Ship Shoal) _________________ Approximate water depth: _______ ft.

PART CQ. CONSEQUENCE OF RELEASE

Was there a fire? ☐ No ☐ Yes

Was there an explosion? ☐ No ☐ Yes

Any deaths or injuries? ☐ No ☐ Yes *If Yes* → *Complete also PART PB*

Public evacuation necessary? ☐ No ☐ Yes *If Yes* → *Complete also PART PB*

Was the area affected by the release contained on the company-controlled facility (excluding right-of-way)? ☐ Yes ☐ No ☐ Don't know

Type of water impacted (check all that apply):

- ☐ None
- ☐ Surface water *if checked,* was an intake shutdown? ☐ Yes ☐ No ☐ Don't know
- ☐ Groundwater *if checked,* was a well shutdown? ☐ Yes ☐ No ☐ Don't know
- ☐ Drinking water for human consumption

Type of ecology impacted (check all that apply):

- ☐ None
- ☐ Vegetation/plant life
- ☐ Fish/aquatic life (excluding livestock)
- ☐ Birds (excluding livestock)
- ☐ Other wildlife (excluding livestock)
- ☐ Livestock such as commercially raised fish, animals, birds and other livestock

Remediation activities undertaken related to the following (check all that apply):

- ☐ None needed
- ☐ Vegetation/plant life
- ☐ Soil
- ☐ Surface water
- ☐ Groundwater
- ☐ Drinking water for human consumption
- ☐ Fish/aquatic life
- ☐ Birds
- ☐ Other wildlife (excluding livestock)
- ☐ Livestock such as commercially raised fish, animals, birds and other livestock

Were other environmental projects performed which are not listed above?

☐ No ☐ Yes ☐ Unknown at this time

If Yes → Is it: ☐ Underway ☐ Anticipated ☐ Planned

Were threatened or endangered species or plants injured (animal, plant, fish, or bird)?

☐ No ☐ Yes ☐ Don't know

Has a Natural Resources Damage Assessment been performed? ☐ No ☐ Yes ☐ Don't know

If Yes → Corrective action performed or planned? ☐ No ☐ Yes

Public or commercial property disrupted or damaged? ☐ No ☐ Yes ☐ Don't know

If Yes, check all that apply:

- ☐ Homes and/or personal property
- ☐ Businesses/commercial
- ☐ Farming/agricultural business
- ☐ Recreational resources
- ☐ Commercial navigation

PART FA. FACILITY INVOLVED

Part of system involved (check one main category and one subcategory):

☐ Aboveground storage tank
- ☐ Atmospheric or low pressure
- ☐ Pressurized

→ *Go to PART TK for cause of release*

☐ Cavern or other belowground storage facility
- ☐ Sub-surface facility
- ☐ Wellhead equipment

☐ Pump/meter station; terminal/tank farm piping & equipment, including sumps

Does facility operate above 20% SMYS? ☐ Yes ☐ No
- ☐ Aboveground equipment or pipe
- ☐ Belowground equipment or pipe
- ☐ At aboveground/belowground transition

☐ Onshore pipeline, including valve sites

Does facility operate above 20% SMYS? ☐ Yes ☐ No
- ☐ Belowground equipment or pipe
- ☐ At unintentional exposure of buried pipe
- ☐ At designed aboveground/belowground transition
- ☐ Aboveground equipment or pipe

☐ Offshore pipeline, including platforms

Does facility operate above 20% SMYS? ☐ Yes ☐ No
- ☐ Shoreline crossing or shore approach
- ☐ Below water
- ☐ Splash zone
- ☐ Above water

If Station/Terminal/Tank Farm, Onshore Pipeline, or Offshore Pipeline, complete "Item involved"

Item involved (check one): ☐ Pipe or Pipe Seam → *Also complete PART PI*
☐ Weld, including heat-affected zone → *Also complete PART WL*

☐ Valve ☐ Pump ☐ Meter/Prover ☐ Scraper Trap ☐ Sump/Separator
☐ Weld Fitting ☐ Repair Fitting ☐ Threaded or Other Fitting ☐ Other

Year item was installed (actual or estimated if necessary) ___________

PART CA. CAUSE OF RELEASE

Primary cause of release (check one):

☐ Third party damage (current or past)	*PART TP*
☐ Corrosion	*PART CR*
☐ Pipe material, pipe seam, pipe weld or repair weld failure	*PART PW*
☐ Equipment malfunction or failure of non-pipe component	*PART EQ*
☐ Operator error or other incorrect operation	*PART OP*
☐ Natural forces	*PART NF*
☐ Other	*PART OT*

Part CD NOT to be completed when the facility involved is an Aboveground Storage Tank, a Cavern or Other Belowground Storage Facility, or Sumps/Separators.

PART CD. CONDITIONS RELATED TO RELEASE

Maximum operating pressure of failed component (psig): __________ ☐ Don't know
Estimated pressure at time and location of failure (psig): __________ ☐ Don't know

System Tests and Inspections

Had there been a pressure test on the system? ☐ Yes ☐ No ☐ Don't know

If Yes → Duration of most recent test (hrs.) __________ ☐ Don't know
Maximum pressure of most recent test (psig) __________ ☐ Don't know
Year of most recent test _____ ☐ Don't know

Had there been an in-line internal inspection device run at the point of failure ?
☐ Yes ☐ No

If Yes → Type of device run (check all that apply including combination tools):

☐ High resolution magnetic flux tool	Year of latest in-line inspection: _________
☐ Low resolution magnetic flux tool	Year of latest in-line inspection: _________
☐ UT tool	Year of latest in-line inspection: _________
☐ Geometry tool	Year of latest in-line inspection: _________
☐ Caliper tool	Year of latest in-line inspection: _________
☐ Crack tool	Year of latest in-line inspection: _________
☐ Hard spot tool	Year of latest in-line inspection: _________
☐ Other	Year of latest in-line inspection: _________

Leak Detection

Was the release initially detected by? (check one):

- ☐ CPM/SCADA-based system with automated leak detection (alert/alarm)
- ☐ Remote operating personnel, including controllers
- ☐ Static shut-in test or other pressure or leak test
- ☐ Local operating personnel, procedures, or equipment
- ☐ Air patrol or ground surveillance
- ☐ A third party
- ☐ Other

Was the presence of the release confirmed by? (check one):

- ☐ CPM/SCADA-based system with automated leak detection (alert/alarm)
- ☐ Remote operating personnel, including controllers
- ☐ Static shut-in test or other pressure or leak test
- ☐ Local operating personnel, procedures, or equipment
- ☐ Air patrol or ground surveillance
- ☐ A third party
- ☐ Other

Did the applied leak detection tools perform as expected? ☐ Yes ☐ No ☐ Don't know

If No → Reason for non-performance (check one):

- ☐ Field instrumentation failure
- ☐ Communications failure
- ☐ Software failure
- ☐ Human error
- ☐ Other

Emergency Response

Did the Federal Government take control of the response? ☐ Yes ☐ No ☐ Don't know

If: 1) the volume released is greater than or equal to 50 bbls; and 2) the release involved an Onshore or Offshore Pipeline, complete "Isolation Response" section below:

Isolation Response

Was there an isolation? ☐ Yes ☐ No *(if No, skip remainder of section)*

What is the approximate distance between valves which were closed for the initial isolation?

______ miles ☐ Don't know

How long did it take from release detection/confirmation to perform this initial isolation?

______ minutes ☐ Don't know

What is the approximate distance between valves which were closed for the final isolation, if needed?

______ miles ☐ Don't know

How long did it take from release detection/confirmation to perform this final isolation, if needed?

______ minutes ☐ Don't know

These instructions should appear as one of the first screens the User sees upon entering the Release Record program

Feedback or Suggested Improvements

This section describes a feature which is built into the database program which allows you to provide valuable feedback and suggested improvements to this Release Record Form "online". As you enter the data, a "Feedback" menu item is continuously available to you. This menu item can be activated while you are entering data for any data field. It will then allow you to make either: 1) a comment relating to that particular data field; or, 2) a more general comment relating to the overall database program. Selecting the "Feedback" menu item will activate the following pop-up screen where you will be able to register your feedback or suggested improvements:

- ☐ General comment on overall database program
- ☐ A definition is needed for this term
- ☐ The definition which exists is not clear enough
- ☐ This data element or question is not appropriate
- ☐ This data element or question needs to be stated more clearly
- ☐ A new data element or question needs to be added
- ☐ Other feedback or suggested improvement

Explain your selection above:

____
____
____
____
____
____
____
____
____
____
____
____
____

Definitions – Terms contained in the Release Record program should be bolded to indicate that a definition and/or explanation is available via a pop-up screen.

POP-UP SCREEN FOR SMALL RELEASES

PART SM. SHORT FORM FOR SMALL RELEASES

Any deaths or injuries? ☐ No ☐ Yes *If Yes* → *return to Long Form*

Fire or explosion? ☐ No ☐ Yes *If Yes* → *return to Long Form*

Did release occur: ☐ Onshore ☐ Offshore

If onshore:

Was the area affected by the release contained on the company-controlled facility (excluding right-of-way)? ☐ Yes ☐ No ☐ Don't know

Did release occur in "non-rural" area (Part 195 definition)? ☐ Yes ☐ No ☐ Don't know

Type of water impacted (check all that apply):

- ☐ None
- ☐ Surface water *if checked,* was an intake shutdown? ☐ Yes ☐ No ☐ Don't know
- ☐ Groundwater *if checked,* was a well shutdown? ☐ Yes ☐ No ☐ Don't know
- ☐ Drinking water for human consumption

Part of system involved (check one):

- ☐ Aboveground storage tank
- ☐ Cavern or other belowground storage facility
- ☐ Pump/meter station; terminal/tank farm piping & equipment, including sumps
- ☐ Onshore pipeline, including valve sites
- ☐ Offshore pipeline, including platforms

Cause of release (check one):

- ☐ Third-party damage (current or past)
- ☐ Corrosion
- ☐ Pipe material, pipe seam, pipe weld or repair weld failure
- ☐ Equipment malfunction or failure of non-pipe component
- ☐ Operator error or other incorrect operation
- ☐ Natural forces
- ☐ Other

POP-UP SCREEN FOR DETAILS OF PUBLIC SAFETY CONSEQUENCES

PART PB. DETAILS OF PUBLIC SAFETY CONSEQUENCES

Fatalities and/or injuries:

Number of operator employees	______ killed	______ injured
Number of contractor employees working for the operator	______ killed	______ injured
Number of others	______ killed	______ injured
Total	______ killed	______ injured

Public evacuation undertaken (check all that apply):

- ☐ Precautionary evacuation undertaken by company
- ☐ Evacuation required by or initiated by a public official

POP-UP SCREENS WHEN PIPE OR WELDS ARE INVOLVED

PART PI. DETAILS WHEN PIPE IS INVOLVED

Nominal pipe size ______ in. ☐ Don't know

Wall thickness ______ in. ☐ Don't know

SMYS (psi) ______________ ☐ Don't know

Type of pipe (check one):

☐ Seamless	☐ Flash welded	☐ Spiral welded SAW
☐ ERW	☐ Butt-welded	☐ Spiral welded ERW
☐ Single SAW	☐ Lap-welded	☐ Plastic/non-metallic
☐ DSAW	☐ Continuous welded	☐ Other
		☐ Unknown

Manufacturer (if known) ____________________ ☐ Don't know

Year of manufacture (if known) ________ ☐ Don't know

Was this a seam-related failure? ☐ Yes ☐ No ☐ Don't know

Nature of failure (check one):

- ☐ Pinhole leak or crack
- ☐ Rupture
- ☐ Puncture
- ☐ Other

PART WL. DETAILS WHEN A GIRTH WELD OR FABRICATION OR REPAIR WELD IS INVOLVED

Nature of failure (check one):

- ☐ Pinhole leak or crack
- ☐ Total separation of weldment
- ☐ Partial separation of weldment

Was this an acetylene weld? ☐ Yes ☐ No ☐ Don't know

POP-UP SCREENS FOR ABOVEGROUND STORAGE TANKS

PART TK. CAUSE OF RELEASE—ABOVEGROUND STORAGE TANKS

Description of failure (check one):

- ☐ Single bottom system failure
- ☐ Double bottom system failure
- ☐ Shell or head failure
- ☐ Overfill/overpressure (check one)
  - ☐ Operator error
  - ☐ Equipment malfunction
  - ☐ Other
- ☐ Appurtenance failure (check one)
  - ☐ Roof drain failure
  - ☐ Other
- ☐ Damage by third-party → Go to PART TP
- ☐ Damage by operator → Go to PART OP
- ☐ Damage by natural force → Go to PART NF
- ☐ Other failure

Was this a catastrophic failure? ☐ Yes ☐ No ☐ Don't know

Was the tank hydrotested or otherwise pressure tested upon construction or major repair?
☐ Yes ☐ No ☐ Don't know

Is the tank bottom cathodically protected? ☐ Yes ☐ No ☐ Don't know

Is the tank bottom internally lined or coated? ☐ Yes ☐ No ☐ Don't know

Year of most recent API 653 internal tank inspection or equivalent __________ ☐ Don't know

Year of most recent API 653 shell thickness external tank inspection or equivalent
_________ ☐ Don't know

POP-UP SCREENS FOR THIRD-PARTY DAMAGE

PART TP. THIRD-PARTY DAMAGE

Failure occurred due to (check one):

- ☐ Third-party excavation, construction, or other work activity occurring at the time of the failure → *#1 Pop-up screen below*
- ☐ Third-party excavation, construction, or other work activity occuring at some time prior to the failure → *#2 Pop-up screen below*
- ☐ Other, including vandalism, third-party vehicle contact with facility, and other intentional or unintentional acts. → *#3 Pop-up screen below*

#1 POP-UP SCREEN—OCCURRING AT TIME OF FAILURE

Damaging party or activity (check one):

- ☐ Pipeline operator or their contractor → *Will be recorded as "Operator Error," and NOT "Third-party Damage"*
- ☐ Other liquid or gas transmission pipeline operator or their contractor
- ☐ Other underground facility operator or their contractor (check one):
  - ☐ Power or electric company
  - ☐ Gas distribution
  - ☐ Cable television
  - ☐ Telecommunications
  - ☐ Water utility
  - ☐ Sewer utility
  - ☐ Other industry or party
- ☐ Farming or agricultural business
- ☐ Homeowner or other activity related to homeowner's residence
- ☐ Residential or commercial development
- ☐ Road construction or maintenance, including ditch grading, traffic light construction, etc.
- ☐ Railroad construction, maintenance, or repair
- ☐ Waterway or reservoir construction or maintenance, including dredging
- ☐ Some type of offshore oil production, maritime, shipping, or fishing activity or equipment
- ☐ Some type of inland waterway oil production, maritime, shipping, or fishing activity or equipment

Other damaging party or activity

If on land, depth of cover at site of damage: ______ in. ☐ Don't know

Did damage result from (check one):
- ☐ Drilling, boring, augering
- ☐ Blasting, tunnelling, mining
- ☐ Trenching, grading, backfilling
- ☐ Other

Was One-call system utilized? ☐ None available ☐ Yes ☐ No

Pipeline operator‘s response to one-call notification (check all that apply):
- ☐ Marked or staked centerline of pipe
- ☐ Provided on-site representation during excavation
- ☐ Excavated own line for the third-party
- ☐ Pipeline operator was unaware of excavation activity

Patrol frequency: ☐ Weekly ☐ Bi-weekly ☐ Other

Was pipeline right-of-way permanently marked and visible to third-party at the site?
☐ Yes ☐ No ☐ Don’t know

Was there a job-specific excavation plan in effect? ☐ Yes ☐ No ☐ Don’t know

Apparent primary cause of damage (check one):
- ☐ Failure of third-party to utilize one-call system
- ☐ Failure of third-party to wait the proper time
- ☐ Failure of third-party to respect pipeline company directions or procedures
- ☐ Failure of third-party to take reasonable care to protect facilities
- ☐ Failure of pipeline operator to respond or to properly mark the pipeline
- ☐ Other

<u>#2 POP-UP SCREEN—PRIOR DAMAGE</u>

Possible or probable cause of damage (check one):
- ☐ Some type of onshore construction, boring, or excavation equipment
- ☐ Some type of offshore or inland waterway oil production, maritime, shipping, or fishing activity or equipment
  - Approx. water depth: _______ ft ☐ Don’t know
- Other source
- ☐ There are no clues as to the possible cause

Evidence of damage (check one):
- ☐ Coating damage only
- ☐ Dent or buckle without metal loss
- ☐ Gouge or other metal loss (with or without dent or buckle)
- ☐ Other

Position of damage on pipe (check one):
- ☐ Top (10 – 2 o’clock position)
- ☐ Side (8 – 10 & 2 – 4 o’clock position)
- ☐ Bottom (4 – 8 o’clock position)

If onshore, depth of cover at site of damage: ______ in. ☐ Don’t know

#3 POP-UP SCREEN—OTHER

Cause of third-party damage (check one):

- ☐ Vandalism/theft/mischief
- ☐ Sabotage
- ☐ Vehicle impact
  - *If checked,* was vehicle driven by:
    - ☐ A direct employee of the operator or a contract employee engaged by the operator
      If checked → *retrace your steps, this is an operator error, not a third-party damage*
    - ☐ Other party
- ☐ Fire
- ☐ Other

POP-UP SCREENS FOR CORROSION

PART CR. CORROSION

Location of corrosion: ☐ External ☐ Internal

If External corrosion, complete the following:

Type of corrosion (check one):

☐ Galvanic
☐ Atmospheric
☐ Stray current corrosion
☐ Other
☐ Microbiologically-induced corrosion
☐ Stress corrosion cracking
☐ Selective seam corrosion

Facility externally coated or painted? ☐ Yes ☐ No ☐ Don't know

If Yes → Type of coating (check one):

☐ Coal tar
☐ Tape
☐ Extruded plastic
☐ Fusion-bonded epoxy
☐ Paint
☐ Other
☐ Unknown

Was shielding, tenting, or disbonded coating a factor in this failure? ☐ Yes ☐ No ☐ Don't know

Was damaged coating a factor in this failure? ☐ Yes ☐ No ☐ Don't know

Was the pipeline or equipment at the site of the failure operating above 100°F? ☐ Yes ☐ No ☐ Don't know

Facility under cathodic protection? ☐ Yes ☐ No ☐ Don't know
Year that CP was installed: ________

Has a Close Interval CP Survey been performed? ☐ Yes ☐ No ☐ Don't know
Year of most recent CIS: ________

Did failure occur within or just outside of a road crossing casing? ☐ Yes ☐ No ☐ Don't know

---

If Internal Corrosion, complete the following:

Were inhibitors being injected, dewatering pigs run, or other internal corrosion mitigation systems or procedures employed? ☐ Yes ☐ No ☐ Don't know

Year since mitigation system or procedures have been continuously employed: ________ ☐ Don't know

POP-UP SCREENS FOR PIPE & MATERIAL FAILURES AND EQUIPMENT & OPERATIONS FAILURES

PART PW. DETAILS OF PIPE, PIPE MATERIAL, & WELD FAILURE

Failure occurred due to (check one):

- ☐ Defective pipe body
- ☐ Defective pipe seam
- ☐ Defective girth weld
- ☐ Defective fabrication weld or repair weld
- ☐ Original construction or fabrication damage or defect
- ☐ Pipe transport damage
- ☐ Prior third-party damage → *Go to PART TP*
- ☐ Other defective weld or material

What other factors do you suspect played a role in the incident? (check all that apply)

- ☐ Fatigue crack growth
- ☐ Overpressurization
- ☐ Ground settling or other loss of support
- ☐ Other factors
- ☐ None

PART EQ. DETAILS OF EQUIPMENT & NON-PIPE COMPONENT FAILURE

Failure occurred due to (check one):

- ☐ Malfunction of control or relief equipment
- ☐ Stripped threads, defective or loose fitting or tubing, failed coupling
- ☐ Seal or packing failure
- ☐ Gasket or O-ring failure
- ☐ Other equipment or non-pipe component failure

POP-UP SCREENS FOR NATURAL FORCE DAMAGE AND OTHER CAUSES

PART OP. OPERATOR ERROR OR INCORRECT OPERATION

Nature of the failure (check one):

- ☐ Excavation or physical damage to facility or pipeline by operator or operator's contractor
- ☐ Valve left or placed in wrong position
- ☐ Pipeline or equipment overpressured
- ☐ Motor vehicle
- ☐ Tank overfilled
- ☐ Other human error

Was the individual involved: ☐ A direct employee of the operator
☐ A contract employee engaged by the operator

PART NF. NATURAL FORCE DAMAGE

Which of the following natural forces were involved in this failure (check all that apply):

- ☐ Landslide or mudslide
- ☐ Earthquake
- ☐ Subsidence or other earth movement
- ☐ Wind, hurricane, or tornado
- ☐ Cold weather
- ☐ Frostheave
- ☐ Lightning
- ☐ Heavy rains or floods including washout
- ☐ Riverbed or seabed scouring
- ☐ Other

PART OT. OTHER CAUSE

Which of the following best describes this failure cause (check one):

- ☐ The cause of failure is unknown at this time
- ☐ The cause of failure could not be determined
- ☐ The cause of failure does not fit in any of the other classifications

APPENDIX D—STANDARD DATA FIELDS FOR PIPELINE INFRASTRUCTURE INFORMATION

The oil pipeline members of the American Petroleum Institute and the Association of Oil Pipe Lines began in-depth tracking of pipeline industry environmental and safety performance and created the Pipeline Performance Tracking System in 1998. The PPTS uses a standard set of data fields for pipeline infrastructure. Participation in PPTS is voluntary. API periodically prepares analyses based on the aggregated industry data. This appendix is provided to share the standard data fields used by PPTS and to encourage the use of these standard fields by all liquid pipeline operators.

INFRASTRUCTURE INFORMATION

Bold and Italic fields are automatically filled by API

YEAR _____

SYSTEM MILEAGE

1. Total number of miles operated in interstate commerce	
2. Total number of miles operated in intrastate commerce	
3. Total System Mileage (Line 1 + Line 2 or Line 4 + Line 5)	
4. Total number of miles operated offshore	
5. Total number of miles operated onshore	

6. Mileage by State ***(Total of all states = Line 3)***

Please specify “federal offshore” as a separate state. Electronic form will accept entries for any number of states.

State	Interstate miles	Intrastate miles
Total	***Equal line 1***	***Equal line 2***

7. Onshore Mileage Operated in Non-rural Areas	
8. Onshore Mileage Operated in Rural Areas (Line 5 – Line 7)	

9. Mileage by Decade (actual or estimated)

Decade of Construction	Onshore Miles	Offshore Miles
Pre – 1920		
1920 – 1929		
1930 – 1939		
1940 – 1949		
1950 – 1959		
1960 – 1969		
1970 – 1979		
1980 – 1989		
1990 – 1999		
2000 –		

10. Mileage by Operating Pressure

Pressure Rating	Onshore Miles	Offshore Miles
≤ 20% SMYS		
> 20% SMYS		
Total	***Equal line 5***	***Equal line 4***

11. Mileage by Nominal Pipe Size (actual or estimated)

NPS	Onshore Miles	Offshore Miles
< 8 NPS		
8 NPS		
10 NPS		
12 NPS		
14 NPS		
16 NPS		
18 NPS		
20 NPS		
22 NPS		
24 NPS		
26 NPS		
28 NPS		
30 NPS		
32 NPS		
34 NPS		
36 NPS		
38 NPS		
40 NPS		
42 NPS		
44 NPS		
46 NPS		
48 NPS		
> 48 NPS		

SYSTEM COMPONENTS OTHER THAN LINE PIPE

12. Total number of atmospheric storage tanks (tanks operated at atmospheric pressure)	
13. Total number of low pressure storage tanks (tanks operated at pressures up to 15 psig)	
14. Total number of high pressure storage tanks (those used for storing HVLs)	
15. Total number of any other storage tanks not meeting the definitions of lines 12, 13 or 14)	
16. Total number of cavern or other below ground storage facilities (excluding sumps)	
17. Total number of pump stations	
18. Total number of meter stations	

VOLUMES MOVED IN _____ (last full year for which information is available)

19. Total volume in barrel-miles of HVLs or other flammable or toxic fluid which is a gas at ambient conditions	
20. Total volume in barrel-miles of CO_2, N_2 or other nonflammable, Non-toxic fluid which is a gas at ambient conditions	
21. Total volume in barrel-miles of gasoline or other petroleum product which is a liquid at ambient conditions	
22. Total volume in barrel-miles of crude oil	

23. USE OF INTERNAL INSPECTION DEVICES FOR ______ (last full year for which information is available)

Please provide the system mileage in which each device (including combination tools) was run

Device	Mileage
High resolution magnetic flux tool	
Low resolution magnetic flux tool	
UT tool	
Geometry tool	
Caliper tool	
Crack tool	
Hard spot tool	
Other internal inspection device	

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