Managing System Integrity for Hazardous Liquid Pipelines

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Foreword

This recommended practice (RP) provides guidance to the pipeline industry for managing pipeline integrity. Pipeline operators are obligated to protect the public, their employees, private property, and the environment from the effects of unintentional releases of petroleum or petroleum products. As part of their commitment to error-free, spill-free operation of liquid petroleum pipelines, operators comply with consensus standards and government regulations in the design, construction, operation, and maintenance of their facilities. Beyond these basic requirements, however, experience has shown that periodic assessment of pipeline integrity (e.g. hydrostatic testing, in-line inspection) and a robust program of preventive and mitigative measures are necessary to minimize the frequency and severity of pipeline releases. The RP presents detailed guidance for developing a pipeline integrity management program. The program involves defining the critical locations along the pipeline and near pipeline facilities that would be most affected by an unintended release, defining the threats to the integrity of pipelines and pipeline facilities, calculating the risk of a release as it varies from one pipeline segment to another, prioritizing the segments for assessment by risk, assessing the segments for anomalies that could threaten integrity, and mitigating the risk by removing or repairing injurious defects. The program further involves the following:

1) calculating the remaining lives of anomalies that may remain in the system so that reassessment can be carried out to reevaluate the anomalies and remediate if necessary,

2) developing preventive and mitigative measures for integrity threats that cannot be effectively managed by periodic integrity assessment.

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Purpose and Objectives

The goal of the operator of any pipeline is to operate the pipeline so that there are no adverse effects on public/employees, the environment, or customers. 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 recommended practice (RP) 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 achieve a number of goals, including reducing both the number and consequences of incidents. Section 4 describes the integrity management program that forms the basis of this RP. This program is illustrated schematically in Figure 2. This RP also supports the development of integrity management programs required under 49 *CFR* 195.452 of the U.S. federal pipeline safety regulations.

This RP is intended for use by individuals and teams charged with planning, implementing, and improving a pipeline integrity management program. A team could 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 RP should be familiar with applicable pipeline safety regulations (e.g. 49 *CFR* 195).

Guiding Principles

The development of this RP was based on certain guiding principles. 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 should 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 should 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 RP, but the design specifications and as-built condition of the pipeline provide important baseline information for an integrity management program.

Effective integrity management 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 should be flexible. An integrity management program should be customized to support each operator’s unique conditions. Furthermore, the program should 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 to optimize risk reduction.

The integration of information is a key component for managing system integrity. A key element of the integrity management program is the integration of all relevant 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 relevant information, the operator can determine where the risks of an incident are relevant and 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 and refreshed information and system operating experience. This information should be factored into the understanding of system risks. As the significance and relevance of this newer 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 should implement specific goals and measures to monitor the improvements in integrity and to assess the need for additional changes.

Remedial 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 potentially injurious to pipeline integrity. Operators should take action to remediate or eliminate injurious defects.

New technology should be evaluated and utilized, as appropriate. New technology incorporated into integrity management programs should be understood. 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 continual basis. 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.

Managing System Integrity for Hazardous Liquid Pipelines

1 Scope

This recommended practice (RP) is applicable to pipeline systems used to transport “hazardous liquids” as defined in U.S. Title 49 *CFR* Part 195.2. The use of this RP is not limited to pipelines regulated under 49 *CFR* 195, and the principles embodied in integrity management are applicable to all pipeline systems.

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

2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Standard 5T1, *Standard on Imperfection Terminology*

API Standard 579-1/ASME FFS-1, *Fitness-For-Service*

API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*

API Recommended Practice 1109, *Marking Liquid Petroleum Pipeline Facilities*

API Recommended Practice 1166, *Excavation Monitoring and Observation*

ASME B31G [1], *Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping*

ASME B31.4-2009, *Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids*

ASME B31.8S-2004, *Managing System Integrity of Gas Pipelines*

ASTM E1049-85 [2], *Standard Practices for Cycle Counting in Fatigue Analysis*

NACE SP0204 [3], *Stress Corrosion Cracking (SCC) Direct Assessment Methodology*

NACE SP0169, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

NACE SP0208, *Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines*

NACE SP0502-2002, *Pipeline External Corrosion Direct Assessment Methodology*

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1 ASME International, 3 Park Avenue, New York, New York 10016-5990, www.asme.org.
2 ASTM International, 100 Barr Harbor Drive, PO Box C700, West Conshohocken, PA, 19428-2959, www.astm.org
3 NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, Houston, Texas 77218-8340, www.nace.org.

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

For the purposes of this document, the following definitions apply.

3.1.1
actionable anomaly
An anomaly that may exceed acceptable limits based on the operator's anomaly and pipeline data analysis (see API 1163).

3.1.2
anomaly
A possible deviation from sound pipe material or weld. See also **defect** and **imperfection**.

NOTE 1 Indication may be generated by nondestructive inspection, such as in-line inspection (NACE 35100).

NOTE 2 Alternatively: An unexamined deviation from the norm in pipe material, coatings, or welds (API 1163).

3.1.3
assessment
See **integrity assessment**.

3.1.4
assessment plan
A written plan produced by the operator that as a minimum:

1) identifies all segments of a pipeline system that could impact a critical location;

2) identifies the specific integrity assessment method(s) to be applied to those segments;

3) specifies the schedule by which those integrity assessments will be performed; and

4) provides the technical justification for the selection of the integrity assessment method(s) and the risk basis for establishing the assessment schedule.

NOTE This includes baseline assessment plans.

3.1.5
cathodic protection
Technique by which underground metallic pipe is protected against external corrosion.

3.1.6
check valve
A valve that permits fluid flow in only one direction.

NOTE Should the direction of flow reverse (e.g. after a failure), the valve contains a mechanism that automatically prevents flow in the opposite direction.

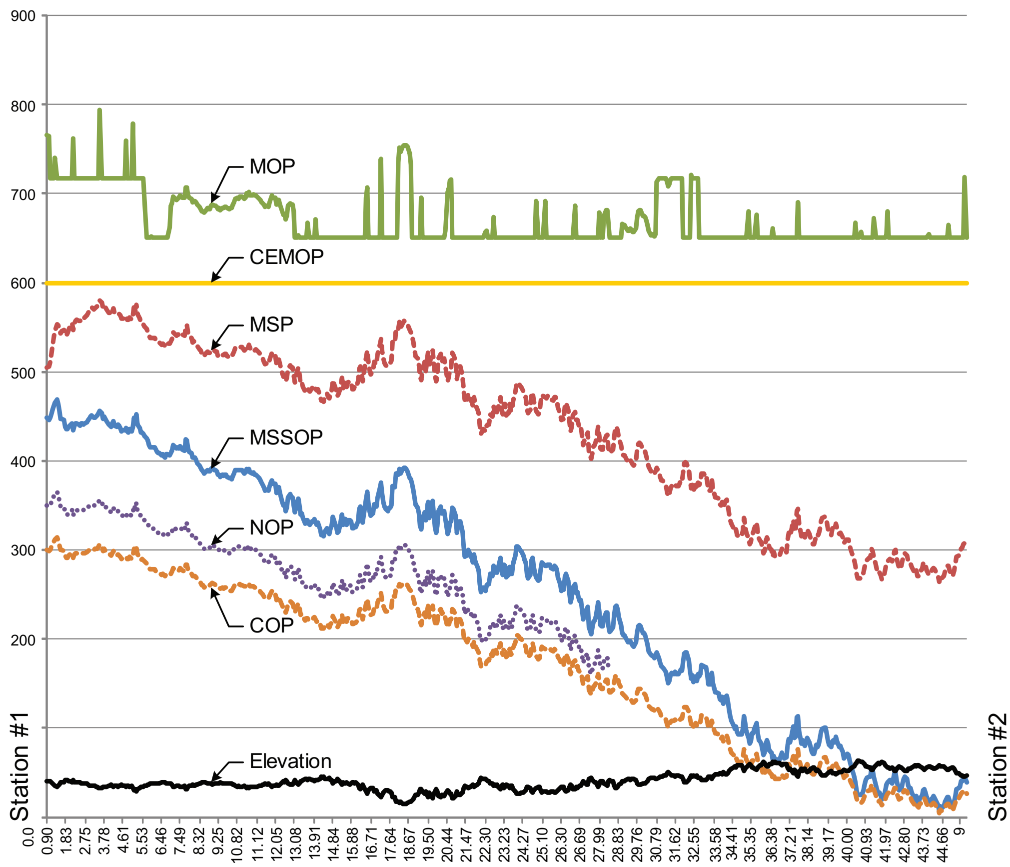
3.1.7
critical location
Locations such as populated areas, commercially navigable waterways, drinking water resources, or ecologically sensitive areas. See also **high consequence area**.

3.1.8
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 (see Figure 1).

3.1.9
current operating pressure

Pressure (sum of static head pressure, pressure required to overcome friction losses, and any back pressure) at any point in a piping system when the system is operating under steady state conditions at the current moment (see also **maximum steady state operating pressure**) (see Figure 1).



Legend

MOP	maximum operating pressure	MSSOP	maximum steady state operating pressure
CEMOP	current established maximum operating pressure	NOP	normal operating pressure
MSP	maximum surge pressure	COP	current operating pressure

Figure 1—Schematic of Various Pipeline Pressures

3.1.10
defect

An imperfection of a type or magnitude exceeding acceptable criteria (API 570); alternatively, a physically examined anomaly with dimensions or characteristics that exceed acceptable limits (see API 1163). See also **anomaly** and **imperfection**.

3.1.11
design pressure
At any point along a pipeline, the larger of the maximum allowed steady state operating pressure at that point under steady state conditions or the static head pressure at that point in a static condition (see ASME B31.4-2009, Paragraph 401.2.2).

3.1.12
direct assessment
Integrity assessment processes for detecting time-dependent degradation of a pipeline caused by external corrosion, internal corrosion, or stress corrosion cracking that involve making certain measurements, conducting certain analyses, and excavating the pipeline where appropriate to examine its condition (see **external corrosion direct assessment**, **internal corrosion direct assessment**, and **stress corrosion cracking direct assessment**).

3.1.13
discovery of a condition
Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. An operator should promptly, but no later than six months after an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator can demonstrate that the six-month period is impracticable.

3.1.14
double submerged arc welded pipe
DSAW pipe
Pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc process.

3.1.15
electric resistance welded pipe
ERW pipe
Pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of mechanical force and heat obtained from electric resistance.

3.1.16
emergency flow restriction device
EFRD
See **check valve** or **remotely controlled valve**.

3.1.17
external corrosion direct assessment
An integrity assessment process for locating possible external corrosion, damaged coating, or deficiencies in cathodic protection on a pipeline by making aboveground measurements and following up with excavations to examine the pipe where appropriate (see NACE SP0502).

3.1.18
final in-line inspection report
A report provided by the ILI vendor that provides the operator with a comprehensive interpretation of the data from an ILI. See also **preliminary in-line inspection report**.

3.1.19
guided wave ultrasonic testing
GWUT
A technique for detecting anomalies in a pipeline that involves introducing mechanical stress waves that propagate axially from a circumferential array of low-frequency transducers placed around the pipeline at a fixed location.

NOTE 1 The wall thickness of the pipe serves as a wave guide, and the locations of anomalies are established by the timing of the arrival of a wave reflected from the anomaly back to the location of the emitting device.

NOTE 2 The technique is applicable for distances up to several hundred feet.

3.1.20
hard heat-affected zone
The heat-affected zone of an ERW seam that has a high hardness as the result of inadequate postweld heat treatment.

3.1.21
hard spot
A localized increase in hardness through the thickness of a pipe, produced during hot rolling as a result of localized quenching.

3.1.22
high consequence area
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.

NOTE This definition is specific to the federal regulations in the United States, see 49 *CFR* 195.

3.1.23
hydrogen-induced cracking
HIC
A form of cracking that may occur in line pipe steels that contain manganese sulfide inclusions when such steels are used in sour service.

3.1.24
hydrogen stress cracking
A form of cracking that may occur in localized hard spots or hard heat-affected zones in a line pipe steel if those zones are exposed to atomic hydrogen generated at the surface of the pipe by a cathodic reaction.

3.1.25
hydrostatic test
A means of assessing the integrity of a new or existing pipeline, as detailed in API 1110 that involves filling the pipeline with water and pressurizing to a level significantly in excess of the MOP of the pipeline to demonstrate that the pipeline is fit for service at the MOP.

NOTE The test pressure is held for a period of time to establish that the pipeline is free of leaks.

3.1.26
imperfection
A flaw or other discontinuity noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis (API 570); or alternatively, an anomaly that has characteristics that do not exceed acceptable limits (see API 1163). See also **anomaly** and **defect**.

3.1.27
indication
A finding of a nondestructive testing or inspection technique (NACE 35100); or alternatively, a signal from an ILI system. An indication may be further classified or characterized as an anomaly, imperfection, or defect (see API 1163).

3.1.28
in-line inspection
ILI
An inspection of a pipeline from the interior of the pipe using an ILI tool.

3.1.29
integrity assessment
A method for determining the pipe's current condition. Methods include ILI, pressure testing, direct assessment, or other technologies that can demonstrate the integrity of the pipe.

3.1.30
integrity management program
A documented set of policies, processes, and procedures that includes, at a minimum, the following elements:

— a process for determining which pipeline segments could affect a critical location;

— a baseline assessment plan;

— a process for continual integrity assessment and evaluation;

— an analytical process that integrates relevant information about pipeline integrity and the consequences of a failure;

— repair criteria to address issues identified by the integrity assessment method and data analysis (49 *CFR* 195.452 provides minimum repair criteria for certain, higher-risk, features identified through internal inspection);

— a process to identify and evaluate preventive and mitigative measures to protect critical locations;

— methods to measure the integrity management program's effectiveness;

— a process for review of integrity assessment results and data analysis by a qualified individual.

3.1.31
internal corrosion direct assessment
ICDA
An integrity assessment process conducted for the purpose of locating and remediating anomalies arising from internal corrosion of a pipeline (see NACE SP0208).

3.1.32
maximum operating pressure
MOP
The MOP that a pipeline or segment of a pipeline may be normally operated under 49 *CFR* 195 (see Figure 1).

3.1.33
maximum steady state operating pressure
MSSOP
The sum of static head pressure, pressure required to overcome friction losses, and any back pressure at each point in a piping system while the system is operating under steady state conditions (see ASME B31.4-2009, Paragraph 401.2.2).

NOTE The MSSOP is limited by physical controls on the pipeline such as discharge pressure, relief pressure, shutdown settings, etc. (see Figure 1).

3.1.34
mitigation or mitigative action
Taking appropriate action based on an assessment of risk factors to reduce the level of a pipeline integrity risk in order to reduce the amount of risk either from a probability or consequence standpoint.

3.1.35
normal operating pressure
The predicted pressure (sum of static head pressure, pressure required to overcome friction losses, and any back pressure) at any point in a piping system when the system is operating under a set of predicted steady state conditions (see Figure 1).

3.1.36
operator
A person who owns or operates pipeline facilities (49 *CFR* 195).

3.1.37
piping circuit
A section of piping that has all points exposed to an environment of similar threat state and that is of similar design conditions and construction material (adapted from API 570).

3.1.38
preliminary in-line inspection report
A report, usually produced in a short amount of time, that provides the operator with a list of anomalies considered to be an immediate hazard to pipeline safety. See also **final in-line inspection report**.

NOTE Typically, the operator defines the actual reporting parameters.

3.1.39
preventive and mitigative measures
Activities designed to reduce the likelihood of a pipeline failure (preventive) and/or minimize or eliminate the consequences of a pipeline failure (mitigative).

NOTE 1 Examples of preventive measures include enhanced damage prevention practices, conducting periodic close interval surveys, or inspecting pressure relief devices more frequently. Examples of mitigative measures include the installation of emergency flow restricting devices, improving leak detection system capability, or conducting drills with local emergency responders.

NOTE 2 Reducing operating pressure is a measure that might impact both the likelihood and the consequences of a pipeline failure.

NOTE 3 Mitigative and remedial actions can be considered preventive and mitigative measures in some instances.

3.1.40
remediation or remedial action
Taking appropriate action to remove one or more causes of pipeline risk or of an injurious anomaly consisting of, but not limited to, further testing and evaluation, changes to the physical environment, operational changes, continued monitoring, and administrative/procedural changes. Includes repairs of defects.

3.1.41
remotely controlled valve
Any valve that is operated from a location remote from the valve site with actuation that is usually achieved by signals initiated by the control center operator or the supervisory control and data acquisition (SCADA) system.

3.1.42
risk
A measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

3.1.43
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.

NOTE Risk assessments can have varying scopes and be performed at varying levels of detail depending on the operator's objectives (see Section 7).

3.1.44
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.

3.1.45
safe operating pressure
The failure pressure, calculated via an industry-accepted method (i.e. B31G, RSTRENG, etc.) for a defect and divided by 1.39 for which the location of the defect can safely be operated. The safe operating pressure of a defect should be compared to the current operating pressure, normal operating pressure, MSSOP, and MOP of the location to determine the seriousness of the defect and its priority for action.

3.1.46
selective seam corrosion
External or internal corrosion-caused metal loss that proceeds at a higher rate at and near the bondline of the ERW or flash-welded (FW) longitudinal seam (e.g. A.O. Smith) of a pipe than the rate observed in the nearby base metal.

3.1.47
spike test
A short-term hydrostatic test wherein the pressure level is increased beyond the level that might normally be considered adequate, the purpose of which is to achieve an increased level of confidence in the serviceability of the pipeline or an increased interval until the next assessment than would be achieved by the normally adequate level of testing.

3.1.48
stand-up (operational) test
A pressure test to determine the leak tightness of a pipeline or pipeline segment, typically conducted with product (or water) at a pressure significantly less than hydrostatic test pressure required by 49 *CFR* 195.304 (1.25 times MOP) and does not exceed the MOP of the pipe.

NOTE A pipeline company may conduct this test after a pipeline is lined up but prior to beginning the movement (delivery).

3.1.49
stress corrosion cracking direct assessment
A direct assessment conducted for the purpose of locating and remediating anomalies arising from stress corrosion cracking (SCC) of a pipeline (see NACE SP0204).

3.1.50
surge pressure (transient pressure)
Pressure produced by a change in the velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

3.1.51
transit fatigue
End damage, abrasion, or peening of, or the development of longitudinal fatigue cracks in line pipe as the result of transportation by rail car, truck, or marine vessel.

3.2 Acronyms and Abbreviations

AC	alternating current
CEPA	Canadian Energy Pipeline Association
CUI	corrosion under insulation
DC	direct current
DC-ERW	direct current welded electric resistance welding
DIRT	Damage Incident Reporting Tool
DSAW	double submerged arc welding
ECDA	external corrosion direct assessment
EFRD	emergency flow restriction device
EMAT	electromagnetic acoustic transducer
ERW	electric resistance welding
FW	flash welded
GWUT	guided wave ultrasonic testing
HF-ERW	high-frequency welded electric resistance welding
HIC	hydrogen-induced cracking
HSAW	helical seam double submerged arc welding
HVL	highly volatile liquid
ICDA	internal corrosion direct assessment
ILI	in-line inspection
IMP	integrity management plan
LF-ERW	low-frequency welded electric resistance welding
LW	lap welded
MIC	microbially induced corrosion
MFL	magnetic flux leakage
MOP	maximum operating pressure
MSSOP	maximum steady state operating pressure
NDE	nondestructive examination
NPS	nominal pipe size
PPTS	Pipeline Performance Tracking System
PT	liquid-penetrant testing
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SME	subject matter expert
SOHIC	stress-oriented hydrogen-induced cracking
UT	ultrasonic testing

4 Integrity Management Program

4.1 General Considerations

A pipeline integrity management program should facilitate appropriate and timely actions on the part of a pipeline operator to assure that a pipeline system is continually operated in a manner that minimizes risk to the public/ employees, the environment, or the customers. It is the intent of this document to provide a guideline for pipeline operators to use in developing their pipeline integrity management plans (IMPs).

In simplest terms a pipeline integrity management program should:

— identify threats to pipeline integrity,

— identify potential consequences to the public and the environment in the event of a release,

— rank segments of the pipeline system according to the risk each poses,

— provide for assessment of the integrity of each segment in a timely manner based on identified threats and the risk to minimize the possibility of a release,

— specify repairs or mitigative actions to carry out in a timely manner to prevent releases,

— establish reassessment frequencies,

— define preventive and mitigative measures to address relevant threats including those not covered by integrity assessments,

— use the findings of integrity assessments to update and improve the integrity management process.

The program process flow shown in Figure 2 provides a common structure upon which to develop an operator-specific integrity management program [4]. As implied by the feedback loop in Figure 2, an integrity management program involves a continuous cycle of monitoring pipeline condition, identifying and assessing risks, and taking action to minimize the most significant risk. Risk assessments should be periodically updated and revised to reflect current conditions so operators can most effectively use their finite resources to achieve the goal of error-free, spill-free operation.

4.2 Elements of Integrity Management

Identify Potential Pipeline Impacts to Critical Locations—This program element involves the identification of pipeline segments that could affect critical locations in the event of a release. Identification of critical locations involves evaluating populated, environmentally sensitive and navigable water areas information, integrating this information with pipeline mapping data, and determining at which locations a release could impact these areas. The identified critical locations may change with time or with changes to the pipeline system. Therefore, critical locations need to be reviewed from time to time. Guidance for making these determinations is provided in Section 5 of this RP.

Data Gathering, Review, and Integration—To understand the potential threats to the integrity of a pipeline segment and to determine the extent to which the segment could affect a critical location, should a spill occur, an operator needs to gather, review, and integrate relevant information. Such information generally consists of the design of the pipeline, the attributes of the pipeline, the operational history including operating pressure ranges and past releases if any, the results of prior inspections and assessments including any in-line inspections (ILIs) or hydrostatic tests, previously made repairs or other mitigative responses, corrosion and cathodic protection surveys, and measures taken to prevent releases or the effects of a release. An operator should also consider gathering, reviewing, and

[4] Operators may access the essential elements of integrity management required by 49 *CFR* 195.452 at http://primis.phmsa.dot.gov/iim/flowchart1.htm.

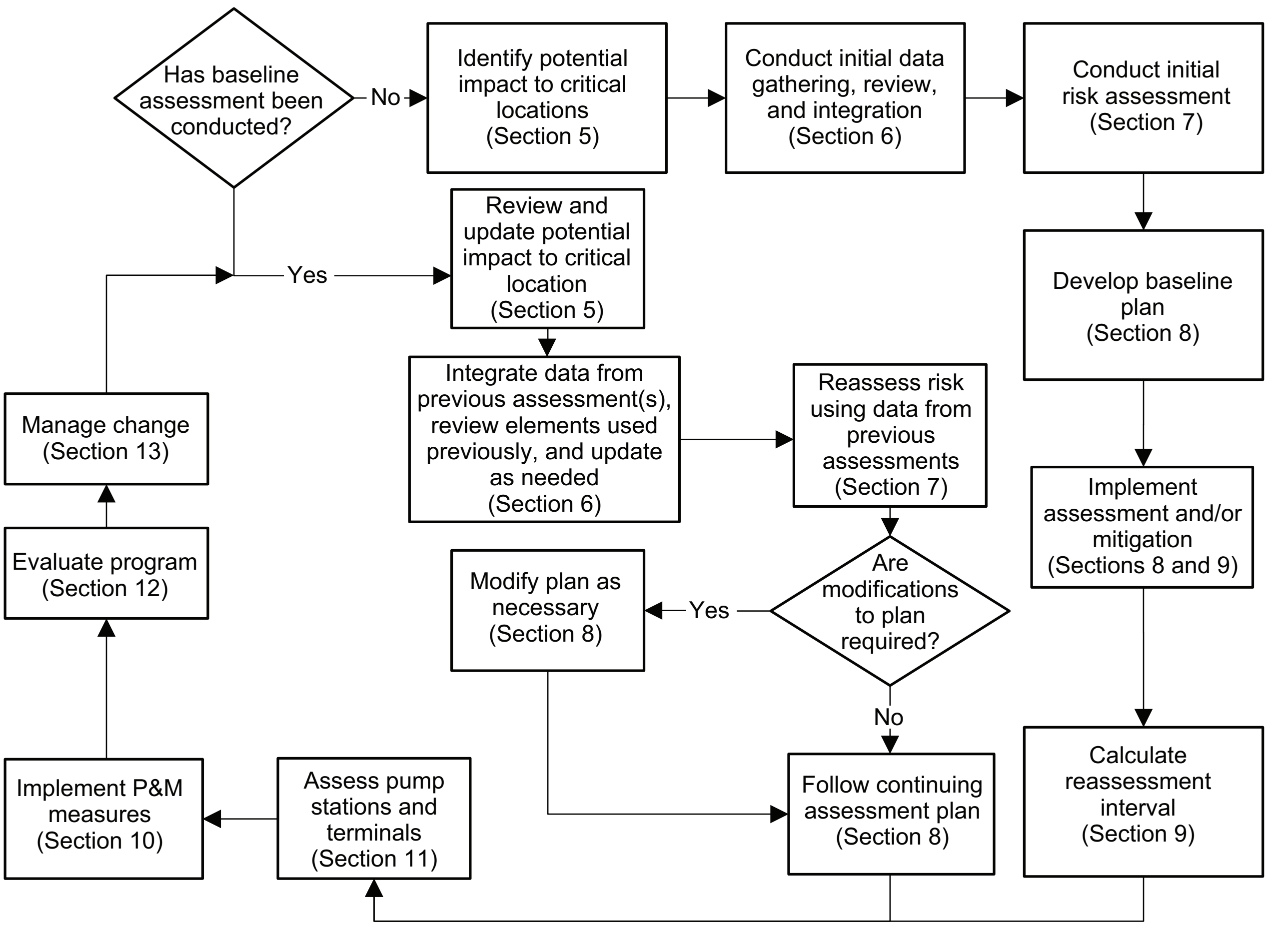


Figure 2—Process Flow for an Integrity Management Program

integrating applicable industry trends, regulatory notices, and other operators' experiences where applicable. Section 6 provides a summary of the data sources, common data elements that are typically used in risk analyses, and approaches to data review and integration.

Risk Assessment—Data assembled from the previous steps are used to conduct a risk assessment of the pipeline system. The risk assessment begins with a systematic and comprehensive consideration of potential threats to the integrity of the pipeline or facility.

The pipeline industry through the Pipeline Research Council International (PRCI) has classified pipeline incidents into 22 categories, each of which represents a threat to pipeline integrity. Pipeline integrity management entails addressing each of these 22 threats and taking appropriate measures to mitigate those that are found relevant to any particular pipeline segment. The 22 categories are:

1) external corrosion;

2) internal corrosion;

3) SCC;

4) defective pipe seam;

5) defective pipe;

6) defective pipe girth weld (circumferential including branch and T joints);

7) defective fabrication weld;

8) wrinkle bend or buckle;

9) stripped threads/broken pipe/coupling failure;

10) gasket or O-ring failure;

11) control/relief equipment malfunction;

12) seal/pump packing failure;

13) miscellaneous (failure of valve or other component);

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

15) previously damaged pipe such as dents and/or gouges (delayed failure);

16) vandalism;

17) incorrect operational procedure;

18) cold weather;

19) lightning;

20) heavy rains and floods;

21) earth movement;

22) unknown (root cause of failure was not determined).

ASME B31.8S recommends that pipeline operators address in their IMPs the first 21 of these 22 threats. The category of "unknown" [Threat 22)] is not included in the list of threats to be addressed for the obvious reason that prevention and mitigation of an unknown threat is not possible. Per ASME B31.8S, the 21 threats are grouped as time dependent, stable, or time independent, and certain failure modes are grouped under one heading as follows.

Time-dependent threats:

— external corrosion,

— internal corrosion,

— SCC.

Stable threats:

— defective pipe seams;

— defective pipe;

— welding/fabrication related threats: defective pipe girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure;

— equipment threats: gasket or O-ring failure, control/relief equipment malfunction, seal/pump packing failure; and

— miscellaneous.

Time-independent threats:

— third-party/mechanical damage threats: damage inflicted by first, second, or third party (instantaneous/immediate failure);

— previously damaged pipe;

— vandalism;

— incorrect operational procedure;

— weather-related and outside force threats: cold weather, lightning, heavy rains or floods, and earth movement.

Operators of hazardous liquid pipelines should address these threats as well in their IMPs. However, the fact that there are both physical and regulatory differences between gas and liquid pipelines makes it necessary to alter the threat categories to some extent. For one thing, the potential for pressure-cycle-induced fatigue is much greater for liquid pipelines than it is for gas pipelines. The threat of any one of several types of defects becoming enlarged by pressure-cycle-induced fatigue becomes an additional threat category for liquid operators to consider. In addition, 49 *CFR* 195 requires special consideration of seam integrity assessment for certain types of seams. As a result selective seam corrosion, which is a subset of the external and internal corrosion threats identified in ASME B31.8S, becomes a separate threat category in this RP. Lastly, the threat of "transit fatigue" is added because of its being historically a problem in some hazardous liquid pipelines due to pressure-cycle-induced fatigue.

The threats for hazardous liquid pipelines that operators should address can be characterized as follows:

1) external corrosion;

2) internal corrosion;

3) selective seam corrosion (external or internal);

4) SCC;

5) manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots);

6) construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure);

7) equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous);

8) mechanical damage (causing an immediate failure or from vandalism);

9) mechanical damage (previously damaged pipe causing a delayed failure or vandalism);

10) incorrect operations;

11) weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement);

12) the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue).

Threats 1), 2), 3), 4), and 12) are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. Threats 5), 6), and 9) are considered possibly time-dependent threats because of the potential for their enlargement by pressure-cycle-induced fatigue. For the latter threats, the pipeline operator will be called upon to judge the need for continuing assessments or monitoring. Threats 7), 8), 10), and 11) are considered time independent because they involve random events for which the time of occurrence is usually not predictable. Management of the latter class of threats involves employing preventive and mitigative measures.

It is recognized that not all 12 may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 12 threats are discussed in detail in Annex A of this RP.

Next the possible consequences of a release should be assessed. Consequences include impacts to critical locations. Risk is generally taken to be the combination of probability of an event and the consequence of such an event. Both the threats and the consequences may vary from point to point along a pipeline, so risk assessment should be done either incrementally along the pipeline or by discrete segments of the pipeline. The risk analysis for each segment can be used to prioritize or rank the segments. Risk should be reassessed periodically and prior to reassessment of pipeline integrity. Information gathered, analyzed, and acted upon during any previous assessments of pipeline integrity should also be taken into account in the risk reassessment. Section 7 provides guidance for developing and implementing a risk assessment approach.

Development of a Pipeline Integrity Assessment Plan—The pipeline operator should develop a plan to assess the integrity of the pipeline system, or modify as appropriate, an existing plan that has been followed previously. The order of assessment should be based as nearly as practical on the results of the risk rankings established during risk assessment, starting with the most significant risks. For pipeline segments that could affect critical locations, the pipeline operator's plan should identify the internal inspection technique(s), pressure testing, or other technology that will be used to assess the integrity of the pipeline. It should also establish the schedule for conducting these assessments, the justification for the integrity assessment method(s) selected, and mitigative measures that will be employed. Section 8 provides guidance for conducting integrity assessments, and Annex B provides a description of the various internal inspection techniques available and guidance to assist operators in selecting an integrity assessment method.

Inspection, Mitigation, and/or Remediation—The pipeline operator should implement the pipeline integrity assessment plan, evaluate the results, and make any necessary repairs, all in a timely manner, to assure that anomalies that pose an integrity threat are eliminated or remediated. For pipeline segments that could affect critical locations, the operator should establish reasonable and technically justifiable time limits for the examination of several classes of anomalies detected by ILI. This schedule should consider applicable regulatory statutes. Section 8 provides guidance for prioritizing features identified by ILI for examination and repair. Annex C provides a description of commonly used repair techniques to address the different types of defects that might be discovered during integrity assessment.

Revise Integrity Assessment Plan and Continue to Assess Periodically—The pipeline operator should conduct integrity assessment on a periodic basis. The pipeline operator should develop a schedule for reassessments that considers items such as the rates of deterioration, the consequences of an event, and other risk factors. Section 9 provides guidelines for scheduling reassessments. Examples of how one might go about calculating reassessment intervals are presented in Annex D.

Establish and Implement Preventive and Mitigative Measures—A pipeline operator should establish and implement a process to evaluate the need for additional measures to protect pipelines. The following list provides some examples of potential measures.

— Preventing mechanical damage. Generally, this involves participating in “one-call” systems, locating and marking a pipeline segment when excavation is to take place on the right-of-way, monitoring contractors working on the right-of-way, establishing and maintaining a public awareness program, maintaining visible rights-of-way, and conducting periodic aerial and/or ground surveillance of the rights-of-way.

— Establishing and maintaining a corrosion mitigation program.

— Installing emergency flow restriction devices (EFRDs) at appropriate locations.

— Developing emergency response plans to limit the amounts of unrecovered product in the event of a release.

The various preventive and mitigative measures are described in Section 10.

Evaluate Program—The pipeline operator should identify, collect, and periodically evaluate metrics that indicate the effectiveness of the integrity management program. For pipeline segments that could affect critical locations, pipeline operators should develop a process for assessing the effectiveness of their integrity management programs. Section 12 provides guidance for developing performance measures to evaluate program effectiveness and for conducting audits of integrity management programs.

Manage Change—Pipeline systems and the environment in which they operate are not 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 13 discusses the important aspects of managing changes as they relate to integrity management.

Update, Integrate, and Review Data—After an integrity assessment has been performed, the operator should add the information acquired through the assessment to the database of information used to assess risk. In addition, as the system continues to be operated, the accumulated operating, maintenance, and surveillance data should be collected for input into the next scheduled reevaluation of risk prior to the next integrity assessment. As part of this process, the operator should determine whether any circumstances have changed that would either add or remove pipeline segments from the population of segments that could affect critical locations.

Reassess Risk—Risk reassessments should be performed at established intervals to factor in recent operating data and to 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). Changes in population, changes that could alter the segments that could affect critical locations, and the results of previous integrity assessments and the impacts of repairs and mitigative measures should be taken into account in these risk reassessments as well. The aim should be to assure that the analytical process reflects the latest understanding of pipe condition.

Integrity Management of Pipeline Pump Stations and Terminals—Section 11 of this RP identifies attributes of 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 program depicted in Figure 2 applies to these facilities, the specific aspects of integrity assessment applicable to these facilities tend to be somewhat unique.

5 Identifying Critical Locations with Respect to the Consequences of a Release

5.1 General

Because the main goal of pipeline integrity management is to minimize risk to the public/employees, the environment, and the customers, a pipeline operator should place a high priority on the inspection, evaluation, and maintenance of pipeline segments in areas where the consequences of a spill would be most likely to affect a critical location. Note that commercial software including geographic information system (GIS) technology is available to perform many of the tasks described in the following sections. This technology is available from numerous commercials service providers. Information about pipeline segments and facilities that could affect critical locations is used in several key elements of an integrity management program, such as:

— data gathering,

— risk assessment,

— inspection and mitigation,

— decisions on placement of EFRDs,

— installation and utilization of leak detection systems,

— development and implementation of spill response plans.

5.2 Determining Whether a Release from a Pipeline Segment or a Facility Could Affect a Critical Location

5.2.1 General

As part of the data gathering and integration of information into a pipeline IMP, a pipeline operator should determine the likelihood that a particular pipeline segment or facility (e.g. pump station, delivery terminal) could affect a critical location in the event of a release. Operators should consider critical locations that are in proximity to the segment or facility as well as those that the pipeline segment actually crosses. Below is a list of items for consideration when determining a potential impact zone:

1) the proximity of the pipe to identified critical locations;

2) the nature and characteristics of the product or products transported [refined products, crude oil, highly volatile liquids (HVLs), etc.];

3) the operating conditions of the pipeline (pressure, temperature, flow rate, etc.);

4) the topography of the land associated with the critical location and the pipeline segment;

5) the hydraulic gradient of the pipeline;

6) the diameter of the pipeline, the potential release volume (including drain out), and the distance between isolation points;

7) the type and characteristics of the critical location crossed or in proximity to the segment;

8) potential physical pathways between the pipeline and the critical location, including overland spread, water transport by streams and rivers, or air dispersion in the case of an HVL;

9) response capability (time to detect, confirm, and locate a release; time to respond; nature of the response; etc.).

An outline of the process is shown in Figure 3.

5.2.2 Identifying Segments or Facilities Located Within Critical Locations

By comparing a map of the pipeline's route to an appropriate map of the critical location, the operator should establish the points where the segment enters and leaves the critical location. Any facility lying within the boundaries of a critical location should be noted as well. This process will identify the segments or facilities where a release will directly affect the critical location.

5.2.3 Determining Critical Locations

The boundary of each critical location should be defined taking into account the amount of product that could be released, the means by which the product could spread, and the potential for personal injuries or property damage associated with a spreading plume of product in the soil, air dispersion of an HVL, pooling or spreading of liquid on the surface, or ignition of a fire or explosion. Allowance should be made for any possible inaccuracies of the locations of the boundaries.

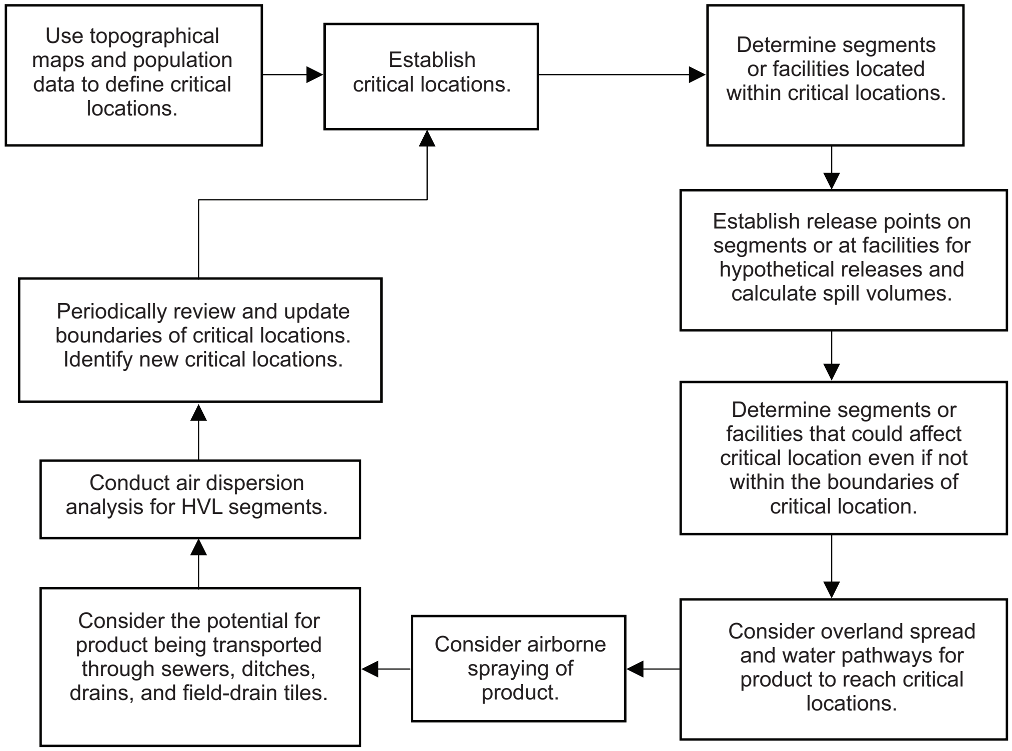


Figure 3—Identifying Pipeline Segments or Facilities That Could Affect Critical Locations

5.2.4 Identifying Segments or Facilities That Could Affect a Critical Location When Such Segments or Facilities Are Not Located Within the Boundaries of the Critical Location

It should be recognized that a release from a pipeline segment or a facility could affect a critical location even if the segment or the facility is not within the boundaries of the critical location. To identify such segments or facilities, the operator should determine the extent to which released product or the effects of the release can be transported to the critical location. For example, the operator should consider that released product could be transported by overland spread, by water, or by aerial dispersion of a vapor cloud and that the effects of ignition or explosion could be widespread. Operators may also consider that released product could be transported by spraying of product into the air.

Using topographical maps, maps of populated areas, and knowledge possessed or acquired by the operator's personnel in the area, the operator should consider scenarios for released product being transported to a critical area. Each scenario should be based on postulating a release from a point along the pipeline segment or from key points such as breakout tanks within a facility. Successive "release" points along a pipeline segment at some reasonable spacing should be considered. Any point where the release scenario evaluation(s) indicates product reaching a critical location should be identified as one that could affect the critical location. In a similar manner, the operator should identify each facility as one that could affect a critical location if the release scenario for any key point within that facility results in product being transported to the critical location.

Factors for consideration in establishing release scenarios include the following:

— pipeline diameter;

— topography and volume of drain out;

— internal pressure and its effect on spraying product into the air;

— flow rate;

— extremes in ambient temperature;

— tank volume for tanks at facilities;

— time to detect a large release such as a rupture;

— time to detect a small release such as a leak that is just at the threshold of the leak-detection system;

— time to isolate the segment or facility;

— time for gravity drain-down to occur;

— viscosity and vapor pressure of the product;

— terrain;

— water pathways (surface and underground);

— ditches, sewers, and drain tiles;

— wind direction for aerial dispersion;

— porosity and permeability of soil.

Additional considerations for HVLs include the following:

— aerial dispersion analysis for an HVL vapor cloud;

— effect that a vapor cloud fire, a pool fire, or a vapor cloud explosion would have on the critical location.

5.3 Documentation and Updating

The operator should document all pipeline segments and facilities that could affect critical locations. Supporting analyses should be made available to subject matter experts (SMEs) or others who will conduct risk assessments and for prioritizing integrity assessments. Periodically, the operator should conduct a review to see if any changes in segments or facilities that could affect critical locations have occurred. Alternatively, the operator may establish a process to identify changes during the conduct of typical operations and maintenance activities (e.g. aerial patrols, locate requests, management of change, right-of-way maintenance). Any new segments or facilities so identified should be added to the list of segments and facilities that could affect critical locations.

6 Gathering, Reviewing, and Integrating Data

6.1 General Considerations

The objective of Section 6 is to provide an overview of considerations to assist in the identification of data to be gathered and utilized to manage the integrity threats on a pipeline system. The approach described herein recognizes that users of this RP will have numerous data sources on their pipeline systems managed through existing processes. However, these data may need to be gathered and organized differently for integrity management purposes.

Data quality and consistency are significant issues; as such, the operator should gather data of sufficient quality and consistency to support the analyses that will leverage the available data. When the data are not sufficient for this task, the risk process needs to account for the additional uncertainty. The use of default values in the absence of actual data may be necessary at times, but the acquisition of actual data should be pursued and the use of a default value needs to be identified.

The analyst should avoid the temptation to make assumptions in the absence of data and should consider the benefit of gathering missing information.

The data to be gathered and integrated should be of sufficient quality and breadth so that it can be used in the risk assessment to help identify relevant threats that could affect the integrity of the pipe. Examples of these data include

— the attributes of each pipeline segment that bear on the susceptibility to various integrity threats,

— construction factors that could affect the susceptibility to various integrity threats,

— operating parameters that could affect the susceptibility to various integrity threats,

— assessment histories that may indicate susceptibility to various integrity threats,

— release history.

6.2 Data Integration

Data integration generally refers to the process of utilizing two or more data sets to identify conditions of interest on the pipeline. Some examples of data sets include ILI, cathodic protection annual survey, close interval survey, depth of cover, and EFRD locations. In more advanced applications, the data integration process may include computer applications that spatially align and correlate the available data along the pipeline. Classic examples of data integration are the overlaying of ILI data from two or more different types of tools and the overlaying of data from an ILI with other information. In the first instance, an overlaying of data from a metal loss inspection with a geometry tool inspection may show that an anomaly revealed by the metal loss tool coincides with a geometric anomaly suggesting a dent. The implication is that the anomaly is likely mechanical damage rather than corrosion-caused metal loss. In such a case, the operator may elect to investigate the anomaly even though as a metal loss anomaly only, its magnitude would not warrant investigation. In the second instance, it has occurred that overlaying ILI data showing a metal loss anomaly with the knowledge from aerial surveillance records that a utility company had been seen installing poles and guy wires near the right-of-way at that location resulted in the finding of mechanical damage from the pole auger.

6.3 Data Maintenance

Various data elements used to assess the applicability of a threat and its potential for failure may change with time. These changes may be caused for various reasons including modifications to operating practices, changes in land use, as well as new pipe properties associated with replacements, reroutes, and new lines. The pipeline operator should be alert to these types of changes and make certain that the data used for threat and risk assessment reflect the current conditions of the pipeline.

6.4 Types of Data Used to Assess Risk

6.4.1 General

The types of data used to assess the threats and associated risk to a pipeline segment or facility can be broadly categorized as pipe attributes, construction factors, operating parameters, and assessment history.

6.4.2 Pipeline Attributes

Pipeline attributes are typically contained on alignment sheets or system maps. The following is a representative list of these data elements:

— diameter;

— wall thickness;

— grade;

— manufacturer;

— year of manufacture;

— type of pipe (seamless, low-frequency or DC welded ERW seam, high-frequency welded seam, single or double submerged arc welded seam, FW seam);

— coating type;

— MOP, MSSOP;

— valve locations, types, and performance characteristics;

— types and locations of appurtenances, flanges, fittings, dead-legs, and instrumentation lines;

— locations of pump stations, booster stations, and terminals;

— highway and road crossings, cased and uncased;

— river, creek, and lake crossings;

— pipeline and other utility crossings, shared rights-of-way.

6.4.3 Construction Factors

Construction factors can typically be sourced from design, and construction, records. The following is a representative list of these data elements:

— year of construction;

— weld quality and inspection;

— coating installation method (over-the-ditch versus factory coating of pipe and field coating of joints);

— coating type;

— soil type (sand, silt, clay, rock);

— soil resistivity;

— depth of burial;

— width of right-of-way;

— land use;

— terrain;

— special protection (directional drills, concrete coating, barriers, warning strips).

6.4.4 Operating Parameters and History

Pipeline operating data elements can be found in the operator's "operation and maintenance" manuals, "standard operating procedures," and/or operator training materials. Others, such as representative pressure histories, test lead survey reports, valve inspection reports, river crossing inspection reports, and the actual records of aerial or ground patrols, will be contained in operating and maintenance records. The following is a representative list of these data elements:

— type(s) of liquids transported;

— bulk flow velocity;

— representative pressure histories;

— operating temperature range;

— SCADA and leak detection attributes;

— emergency response plans;

— test lead surveys;

— river crossing inspections;

— valve inspections;

— signage and markers;

— inhibitor/biocide program;

— cleaning pig frequency;

— aerial and ground patrol frequencies;

— public awareness program;

— one-call systems;

— excavation monitoring policy;

— qualifications and training of operators;

— failure investigations, incident reports, near-miss reports, soil and water sampling reports, corrosion coupons and resistance measurements;

— quality assurance practices.

6.4.5 Integrity Assessment History

Pipeline Integrity assessments will be contained in documents describing specific tests or inspections and the results. The following is a representative list of these data elements:

— pressure levels achieved in previous hydrostatic test and test failure history;

— anomaly lists from previous ILIs along with disposition of anomalies;

— results of any additional assessments such as close-interval pipe-to-soil potential surveys, DCVG surveys, pipeline current surveys, soil resistivity surveys, direct visual inspections of the pipe and the coating, right-of-way condition surveys, and depth-of-burial surveys;

— previous repair types and practices.

7 Risk Assessment Implementation

7.1 General Considerations

Risk to a liquid pipeline system arises from the combination of the probability that the system will sustain damage from one or more of the 12 threats listed in Section 4 and the consequences (in terms of effects to critical locations as defined in Section 5) if the damage is sufficient to cause a release. Risk is commonly described as the product of the likelihood of a release times the consequences of the release. The higher the product of these two quantities, the higher the risk as depicted in Figure 4. By assessing risk as it varies throughout a pipeline system, a pipeline operator can identify and numerically categorize locations according to risk. Prioritizing or ranking the calculated risks allows the operator to direct risk mitigation resources to various parts of the system in a manner that has the most impact on system integrity. Risk can be described in either relative or absolute terms. Relative risk considers how the identified risk ranks compared to other risks identified on the system or segment. Absolute risk considers the expected consequences based on occurrence of the identified risk element.

When developing a risk assessment approach, it is important to understand the end use of the assessment. Risk assessments should be used for determining the type and order of integrity assessments (see Section 8) and preventive and mitigative action implementation (see Section 10). The need for the risk assessment to identify which threats are relevant to the asset in question and also to prioritize the order in which follow-up activities are implemented should be considered when the risk assessment approach is designed.

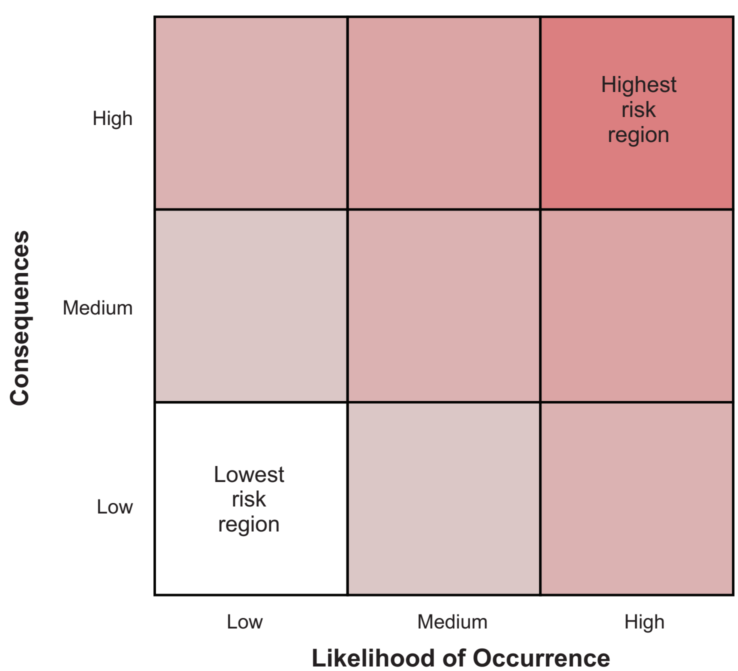


Figure 4—Simplified Depiction of Risk

7.2 Developing a Risk Assessment Approach

The goals of risk assessment are as follows:

— to identify the threats to pipeline integrity;

— to determine the risk represented by these threats and the consequences to critical locations;

— to rank segments of a pipeline system in the order of greatest need for integrity assessment or mitigative action;

— to compare different integrity assessment or mitigation options in terms of the risk reduction benefits and costs;

— to facilitate reassessment and reranking once the integrity assessments and mitigative actions have been completed.

A pipeline risk assessment process should address the following questions.

1) What kind of events and/or conditions might lead to a loss of system integrity?

2) How likely, in a relative or absolute sense, are these events and/or these conditions to occur?

3) What are the nature and the severity of the consequences if these events and/or conditions occur?

4) What risks are associated with these events and/or conditions either in a relative sense and/or an absolute sense?

Several approaches to implementing a risk process can be taken, each of which will provide answers to Questions 1) through 4). The approaches vary in complexity depending on the complexity of the asset in question, the data needed to complete the process, and the quality and quantity of data available. The use of SMEs to design and implement risk processes is critical regardless of approach taken. The following are generally accepted approaches:

1) using SMEs,

2) relative risk assessment,

3) scenario-based model,

4) probabilistic risk assessment.

Using SMEs—Typically, SMEs will be experienced company personnel who specialize in the subjects of relevance to pipeline integrity such as design, construction, corrosion mitigation, inspection and testing, maintenance, risk management, right-of-way maintenance, and operations. They will have detailed knowledge of the systems including size and nature, the critical locations (see Section 5), which of the 13 threats to pipeline integrity may be applicable to the system, and the types of data outlined in Section 6 (i.e. the pipeline attributes, the construction factors, the operational factors, and the assessment history). The SMEs jointly evaluate the threats to each pipeline segment, and considering the boundaries of critical locations, they estimate the risk for each segment and provide a relative ranking of segments for integrity assessments. The SMEs may or may not request assistance from an outside consultant, but usually review relevant technical literature, and where possible, industry-wide data sources to aid them in their evaluations of threats to pipeline integrity.

Relative Risk Assessment—In a relative risk assessment, an arithmetic model is developed or an existing model is purchased that allows numerical scores to be calculated for each pipeline segment based on the identified threats to pipeline integrity and the nature and distribution of critical locations that could be affected by a release. Probabilities and consequences are expressed as equations containing the relevant parameters that are typically multiplied by weighting factors that have been validated by sensitivity studies and comparisons to historic situations. Typically, these models provide algorithms for calculating the risk score associated with each individual threat. And also, typically, these models provide for calculating the effects of integrity assessments and mitigation on the basis of the score of a given segment. Thus the value of potential integrity assessment methods and mitigative actions appropriate for addressing a particular threat can be compared prior to their selection and use. The scores that result provide comparisons that are relative to each other; hence, the method is termed "relative" risk assessment. Pipeline segments can be ranked according to the calculated scores with the highest relative risk sections being scheduled first for assessment and mitigation. Reranking of segments can also be carried out after a round of assessments has been completed, and this allows the operator to plan the next assessment on the basis of the reranking.

Scenario-based Models—This approach involves considering events or sequences of events that lead to the risk of a release. A probability is assigned to the each event based on a historical rate of occurrence. A fault tree is constructed from the interaction of individual events that leads to a calculated probability of a release. Fault trees can be constructed for each of the 13 threats listed in Section 4 that is considered to be applicable to a given pipeline segment. The probability that releases of different types will occur within the boundaries of a segment where it could affect a critical location and the associated costs can be considered by means of a fault tree as well. By multiplying the probability of the release occurring within a critical location times the cost of potential damage and cleanup following a release, the operator obtains an "expectation" in cost terms for each scenario. The operator calculates expectations for all applicable scenarios and compares the results to determine which segments need integrity assessment soonest.

Probabilistic Risk Assessment—This method requires the consideration of probabilities of undesirable events (such as a release or the remaining pressure carrying capacity of the pipe falling below the MOP of the pipeline in a segment located within the boundaries of a critical location) and their associated costs and carrying out integrity assessments on the segments for which the calculated risk (probability times cost) of the undesirable event is unacceptably high. Probabilistic risk assessment requires large amounts of reliable data to establish credible probabilities of events and situations. An example is the use of probability-of-exceedance (POE) for mitigating external corrosion following an ILI. Each anomaly identified through the inspection has length and depth dimensions, as predicted by the inspection technology, which are used to calculate a safe pressure based on the properties and operating parameters of the pipe. The uncertainty embodied in the tool error allows the calculation of the probability that a detected and sized anomaly will leak or fail at the MOP at the location of the anomaly. The operator then should choose a probability level and remediate anomalies having a higher probability.

7.3 Characteristics of Risk Assessment Approaches

A pipeline operator needs to be aware of certain characteristics of risk assessment methods in order to use them appropriately. One is that they are data driven. As shown in Section 6, system data consisting of pipeline attributes, construction factors, operational factors, and assessment histories should be available to assess the levels of each threat to pipeline integrity. The nature and extent of the critical locations should be well defined in order to determine the ways in which a release from a point in a segment can affect a critical location as outlined in Section 5. The quality of the risk assessment is related to the quality of the data and the expertise provided by the operator.

Probabilities of releases and consequences to critical locations can be meaningfully combined to calculate risk for a specific location only if the data used in the calculation apply specifically to the location. Therefore, all data should be available and valid for the location to which the calculations apply. Some models use dynamic segmentation, which provides for a continuous interrogation of the pipeline data along the route, calculating a new value of risk every time any input variable changes. Other models use fixed segmentation, which is designed to calculate risk for a specific set of data applied to a predefined segment with constant values of the input data. In the case of dynamic segmentation, points of data change should be provided. In the case of fixed segmentation, the user should define segments for which the data remain constant.

In some situations, data weaknesses may lead to risk scores being driven by a single variable in a way that creates doubt about the reliability of the risk scores. For example, if a model shows the probability of external corrosion to be based on coating type, coating condition, soil type, age, and pipe-to-soil potential readings and the assumption is made that coating type, coating condition, soil type, and age are constant throughout the segment, the risk will be totally controlled by the pipe-to-soil potential readings. It is unlikely that coating condition and soil type are constant over long distances, so to obtain a more reliable calculation of the corrosion threat, the operator could invest in efforts to determine how coating condition and soil type vary along a pipeline. For each risk calculation, threat by threat, the operator needs to examine both the data being used and the output calculations to be sure that they agree with experience.

To determine the rate of mitigation needed to avoid a failure within an unassessed segment, the operator who uses relative risk scores should review the results of the assessments, remediations, and mitigations from the first few segments with the highest scores. Working through the first few segments provides an indication of the reliability of the risk assessment. The operator can then adjust the rate of integrity assessment and preventive and mitigative measure implementation accordingly.

Because the scenario-based approach and the probabilistic approach to risk assessment tend to give risk values in terms of probability of failure, the user has to decide how much risk to accept for a given period of time. For example, a probability of failure of 10^{-6} might indicate that a segment could go X years before needing an integrity assessment whereas a probability of failure of 10^{-3} might suggest a need for integrity assessment within Y years where Y is considerably less than X.

Risk assessment is not static and does not deliver absolute certainty with regard to scheduling integrity assessments or other preventive and mitigative activities. However, it does offer a methodology with which to start an integrity assessment program, and if allowed to evolve with experience, it becomes a tool for continual planning of integrity assessments. Risk assessment should also continually identify those preventive and mitigative measures an operator should be considering for implementation. As integrity assessments, remediations, and mitigative actions are carried out, the particular model used by an operator can be validated, improved, or replaced if necessary to conform with the experience gained through integrity management activities. The properly evolving risk assessment model will remain an essential tool for planning integrity assessments and preventive and mitigative actions in the future in a manner that assures the continued integrity of the system.

The experience that comes from carrying out integrity assessments and mitigative actions should be fed back into the risk assessment process in order for an operator's risk assessment process to remain reliable. Data that should be gathered for future integration and should be considered in reassessing risk (that may necessitate modifications to the risk assessment approach) are as follows:

— number of repairs required during the previous inspection, testing and mitigative activity;

— type of defects found and their significance to pipeline integrity;

— causes of defects found;

— rate of degradation;

— different assessment technologies and improvements in technology used;

— changes in pipeline attributes and pipeline operations;

— alignment of findings from inspections and tests with what the model predicted;

— results of preventive and mitigative actions.

8 Integrity Assessment and Remediation

8.1 General

This section of the RP provides guidance on integrity assessment methods and repair methods and includes the following topics:

— appropriate ILI techniques for the various pipeline integrity threats,

— schedules for dealing with anomalies found by ILI,

— benefits and limitations of hydrostatic testing,

— various types of other technologies for finding anomalies,

— seam integrity assessment for lap-welded (LW) and ERW pipe,

— SCC,

— various types of repair methods that can be used to restore the serviceability of pipe affected by defects.

To reiterate what was explained in Section 4, the threats for hazardous liquid pipelines that operators should address can be characterized as follows:

1) external corrosion;

2) internal corrosion;

3) selective seam corrosion (external or internal);

4) SCC;

5) manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots);

6) construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure);

7) equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous);

8) mechanical damage (causing an immediate failure or from vandalism);

9) mechanical damage (previously damaged pipe causing a delayed failure or vandalism);

10) incorrect operations;

11) weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement);

12) the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue).

Threats 1), 2), 3), 4), and 12) are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. Threats 5), 6), and 9) are considered possibly time-dependent threats because of the potential for their enlargement by pressure-cycle-induced fatigue. For the latter threats, the pipeline operator will be called upon to judge the need for continuing assessments or monitoring. Threats 7), 8), 10), and 11) are considered time independent because they involve random events for which the time of occurrence is usually not predictable. Management of the latter class of threats involves employing preventive and mitigative measures.

It is recognized that not all 12 may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 12 threats are discussed in detail in Annex A of this RP.

If no prior integrity assessment has been performed for a pipeline system or facility, an initial integrity assessment plan should be developed based on identifying critical locations (Section 5), initial data gathering (Section 6), and risk assessment (Section 7). If prior integrity assessments have been performed, the integrity assessment plan going forward should be modified by reviewing critical locations for possible changes or additions (Section 5); reviewing and updating data in response to changes in attributes, changes in operations, knowledge gained from company and industry failure reports, and the results of prior assessments (Section 6); and by reassessing risk and reprioritizing segments for future integrity assessments. ILI, which is discussed in 8.2, is one method of assessing pipeline integrity. This method involves running one or more internal inspection tools capable of locating and characterizing anomalies associated with one or more of the threats discussed in Annex A through the pipeline on-stream with the product. A list of available ILI technology types and the types of anomalies for which each is appropriate is given in Table 1. These ILI tools for integrity assessment are described in Annex B.

Guidelines for responding to the results of an internal inspection by means of ILI are provided in 8.3. The responses involve examining the inspection records to evaluate and rank anomalies by severity, mitigating those that might immediately threaten the integrity of the pipeline, and establishing a schedule to respond in a timely manner to those that might become a threat to the integrity of the pipeline with the passage of time. Guidelines for establishing scheduled response times (i.e. remaining life assessments) are presented in Section 9. Repair methods for anomalies are discussed in 8.7, and the details of various commonly used repair methods are described in Annex C.

Pipeline integrity can also be assessed by means of hydrostatic pressure testing. A hydrostatic test involves taking a pipeline segment out of service, replacing the product with water, pressurizing the pipeline to a pressure level well in excess of its MOP to intentionally fail defects with failure pressures near MOP, repairing the failed defects, retesting after the repairs, removing the water, and restoring the pipeline to product service. Guidelines for using a hydrostatic test to assess pipeline integrity are given in 8.4.

Finally, single-threat integrity assessments can be made by other means such as by external corrosion direct assessment (ECDA). Guidance for using other techniques for integrity assessments are given in 8.5.

It is expected that the appropriate pipeline integrity assessments will be performed periodically and remediation activities will be carried out at intervals that are appropriate to prevent releases that might result from time-dependent deterioration (especially for the time-dependent threats described previously). Reassessments are discussed in Section 9 and guidance for calculating reassessment intervals is given in Annex D.

8.2 In-line Inspection (ILI)

This section presents guidelines for the use of ILI technology to assess pipeline integrity. The generic classes of ILI tools and a brief overview of their capabilities are shown in Table 1, and detailed descriptions of the various ILI technologies appear in Annex B. Neither the information in the Table 1 nor in Annex B should be considered all-inclusive of every tool and capability that is available. For example, using two types of tools and overlaying the results can provide useful information on combinations of threats such as metal loss or cracking within a dent or cracking in combination with metal loss. Moreover, ILI technology evolves rapidly such that tools may exist that are not covered in this RP. Therefore, a pipeline operator would be well advised to keep in touch with ILI vendors, technology center researchers, industry conferences, and other pipeline operators. Also, pipeline operators are encouraged to consult other industry standards on ILI including:

— NACE SP0102,

— API 1163,

— ASNT ILI-PQ,

— POF's *Specifications and requirements for intelligent pig inspection of pipelines*.

A pipeline operator contemplating the use of ILI for integrity assessment should first determine whether or not the pipeline to be assessed can accommodate ILI tools. To accommodate ILI tools, the pipeline should be equipped

Table 1—In-line Inspection Tools and Capabilities

Integrity Assessment Detection/Sizing Objective	MFL Tools				Ultrasonic Tools (UT)			Geometry Tools		Pipeline Profile and Alignment Tools
	Axial MFL	Circumferential MFL (Transverse Field)	Helical MFL (Spiral Field)	Residual or Low Field MFL	Normal Beam UT (Wall Thickness)	Angle Beam Shear Wave UT (Crack Detection)	EMAT GWUT (Crack) Detection)	Caliper	High Resolution	Inertial Mapping
Metal loss external and/or internal	S [a]	S	S		S	D [b]	D		D (internal)	
Selective seam corrosion external and/or internal		D	D			S	D			
Axially oriented SCC						S	S			
Axially oriented stress fatigue cracking and other cracks						S	S			
Axially oriented cracklike manufacturing defects (i.e. hook cracks, cold welds)		D	D			S	D			
Circumferential cracking						S—with axially angled	S—with special setup			
Dents	D	D	D		D	D	D	S	S	
Wrinkles and buckles	D	D	D		D	D	D	D	S	
Expanded pipe								D	S	
Laminations	D	D	D		S	S	D			
Hard spots				D			S			
Evidence of strain				D					S [c]	S [c]
Bends and curvatures	D	D			D	D	D	S	S	S

NOTE Operators are encouraged to discuss improved inspection technologies with their vendors.

[a] S is detection capability with sizing specified by vendor.

[b] D is detection capability with limited or no sizing.

[c] Requires offline calculation.

either permanently or temporarily with the means to launch and receive tools, ideally, without taking the pipeline out of service. An appropriate tool should be available for the diameter of the segment to be assessed. The pipeline should contain no diameter or ovality restrictions or short-radius fittings that would interfere with the passage of the tool. Dual diameter lines can be inspected, but getting full assessment data can be problematic. Full-opening tees should be fabricated with bars that prevent a tool from turning into the branch. The fluid should be compatible with the tool both from the standpoint of not damaging the tool and from the standpoint that the fluid is capable of signal transmission if the technology relies upon signal transmission through the fluid. The cleanliness of the pipeline may be a factor in the effectiveness of an ILI assessment. Wax and solid debris may degrade the performance of an ILI tool. Lastly, capabilities of a tool for locating and sizing the target anomalies may vary with tool speed. In some instances, a tool can collect accurate data at flow rates faster than it can reliably survive the wear and tear of an inspection. Long runs and the presence of fittings can damage the tool. Therefore, in selecting tool speed, the run length and the number of fittings (check valves, tees, etc.) should be considered. The pipeline operator may have to reduce bulk flow velocity to achieve satisfactory results. The operator should review relevant aspects of the pipeline with the potential ILI vendors before committing to use ILI tools (or sets of tools).

Different tools are designed to address anomalies created by different threats; no one tool is capable of addressing all threats to pipeline integrity. The pipeline operator should carry out the data analyses outlined in Section 6 and the risk assessment outlined in Section 7 to identify any threats that could affect the segment to be inspected. Only then can an informed decision be made as to which ILI tools are appropriate for integrity assessment of a particular pipeline segment.

While many ILI technologies have proven to be effective at locating and characterizing injurious anomalies in pipelines, the pipeline operator should be aware of the limitations on any given ILI technology.

First, although the tools typically measure distance traveled, the operator should work with the vendor to place aboveground marking equipment to “mark” the data as the tool passes particular locations. These marks along with the known locations of other physical features are needed to calibrate the distance measurements recorded for each anomaly for later use in finding the location of the anomaly if necessary for visual inspection. Some tools offer global positioning system (GPS) location technology to increase accuracy and ease of locating actionable anomalies. Inertial guidance tools discussed in Annex B can be attached to the tools to obtain more accurate positioning measurements leading to GPS coordinates.

Second, most technologies will have a threshold anomaly detection size. Detectability will be less than 100 % certain for anomalies below the threshold size, and the user of the technology should understand these limitations of each type of tool prior to its use.

Third, many tools have the ability to characterize the sizes of anomalies within a certain stated tool tolerance; and as such, the anomaly sizing found upon excavation and measurement are often different to some degree from the sizes predicted by the tools. The operator should determine the amount of tool error associated with a particular tool run by excavating and examining a representative number of anomalies also considering field measurement error. The statistical distribution of error should be considered in the evaluation of the tool's performance and the evaluation of other anomalies for remedial action.

In some cases, special ILI tools can be set up to locate certain types of anomalies. For examples, if pipe body hard spots are suspected, a magnetic flux leakage (MFL) ILI tool can be used in a special setup to locate them. For additional information, see A.7.

Lastly, the pipeline operator should be aware that the routine grading of anomalies provided by an ILI vendor may not be sufficient to satisfactorily assess certain anomalies. In such cases, the operator may find it advantageous to request a reexamination by the vendor of the raw data acquired by the tool. Analysis of the raw data by the vendor’s experts may help in assessing a particular anomaly where the normally reported data were insufficient to resolve the nature of the anomaly particularly when detailed data integration is needed to identify threats.

8.3 Responding to Anomalies Identified by ILIs

8.3.1 General

In order for operators to most effectively respond to anomalies found by ILIs, they should have a fundamental understanding of not only the abilities and limitations of the ILI technology used but, more importantly, the operating parameters of the pipeline in question. This operating knowledge should be known about the specific location of the anomaly as much as practical. Critical parameters, such as the permissible pressure at that location (sometimes called maximum operating pressure or MOP), potential pressure at that location during a transient or abnormal event, or maximum potential pressure achievable during steady state operations (sometimes called maximum steady state operating pressure or MSSOP) should all be known in order to correctly categorize the severity of anomalies found. Hydraulic gradients and pressure surges can cause these critical parameters to vary widely from location to location, and an operator should know the differing level of risk when comparing the safe pressure capacity of anomalies to these different parameters.

Pipeline operators are reminded that some regulatory jurisdictions have requirements for the examination and repair of certain injurious defects and that the recommended timing for examination and repair listed below may differ. In addition, certain regulations also contain reporting requirements when certain conditions are found.

"Discovery" of Condition—Discovery of a condition occurs when an operator has adequate information about the condition to determine that the condition presents a potential threat to the integrity of the pipeline. Operators should establish a reasonable process and timeline for discovery (e.g. six months after completion of the tool run).

In general, an operator, upon becoming aware of an integrity-threatening condition, should take appropriate action within a reasonable amount of time to confirm the status of the condition by further analysis and to remediate the condition, if necessary, so that the integrity of the pipeline is no longer threatened. Discovery includes receiving dimensions of an anomaly from an ILI vendor that indicate the existence of an integrity-threatening anomaly. For example, the operator receives information that a particular metal loss anomaly exists that has ILI-indicated dimensions that result in a calculated failure pressure that is at or below the MSSOP at the location of the anomaly. Similarly, the finding based on geometry tool data, of a dent on the top side of the pipe that has a depth exceeding 6 % of the diameter of the pipe constitutes discovery of a potentially integrity-threatening condition. Discovery could also mean finding upon overlaying data from a geometry tool and a crack-detection tool that a crack coincides with a dent creating a potentially integrity threatening condition. Operators should establish a communications protocol with the vendor for timely reporting of anomalies that may require urgent action. The pipeline operator should excavate and examine those anomalies that appear on the basis of the high-level screening of ILI data to be of immediate concern (as defined 8.3.2), that is, potentially a threat to pipeline integrity. The effect of an anomaly on the remaining strength of a pipeline depends on its physical dimensions and the strength and (in the case of a cracklike anomaly) the toughness of the material. When the remaining strength of an anomaly is lower than the potential stress in the pipe wall that could be achieved during current and future operations, then certain immediate actions are warranted. The comparison of remaining strength to pipe stress should consider internal design pressure, MOP, and potential surge pressures. When operators cannot take immediate action to repair these defects, they should consider lowering their operating pressures. The remaining strength calculations provide a basis for determining appropriate operating levels. When remaining strength cannot be calculated, then a pressure reduction may be based on previous operating history. Typically, a 20 % reduction from previous known operating pressure has been utilized. Models for predicting the effects of certain types of anomalies on the pressure-carrying capacity of pipe are available in various pipeline industry publications. Generically, these models are termed "Fitness-For-Service" models or "engineering critical assessment" models.

From the standpoint of corrosion-caused metal loss, the applicable ILI technologies provide axial length and depth-of-wall-thickness-penetration dimensions with sufficient accuracy that reasonable predictions of remaining pressure-carrying capacity can be made with confidence based on the data obtained from a given tool run. As a result metal loss anomalies can be graded by the vendor on the basis of one of the widely accepted metal loss failure criteria (e.g. ASME B31G, RSTRENG), and the list of graded anomalies will indicate to the pipeline operator the locations and severities of anomalies that need to be addressed to preserve the integrity of the pipeline.

The data obtained from crack tools may be of adequate quality to permit the grading of cracks as well; however, the ability to accurately depict the crack type anomaly is dependent on the technology as well as the type of feature (e.g. ERW seam crack versus SCC or circumferential field MFL versus ultrasonic). A number of methods exist for evaluating the remaining strength of a pressurized pipe containing an axially oriented crack based on its length and depth and the strength and toughness of the pipe material. Pipeline operators may obtain guidance on the evaluation of the effects of cracks from API 579-1/ASME FFS-1 or BSI BS 7910.

Pipeline operators should arrange to receive the final ILI report for an inspected segment within a timely period after completion of the tool run. For anomalies that appear to fall into the category of an "immediate concern" (defined below), operators should take action within five days. This action could include further data integration/evaluation, additional assessment, excavation, and repair. Alternatively, temporary mitigative activities such as pressure reduction should be considered until the anomaly can be addressed.

Whenever pressure reductions are implemented, regulatory statutes for reporting and timing should be followed (such as safety related condition reporting). A schedule for addressing anomalies judged not to be immediate concerns but which could affect pipeline integrity in the future should be established that will assure that mitigative action is taken in time to prevent a leak or a rupture of the pipe. Section 9 provides guidance for assessing the remaining life of anomalies that fall outside the category of immediate concern.

8.3.2 Strategy for Responding to Anomalies Identified by ILIs

Because of the complexity of raw ILI 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 ILI tool.

An operator should take action to address pipeline integrity concerns identified during the evaluation of ILI data. If a condition exists on the pipeline, in critical or noncritical areas, that presents an "immediate concern" (defined below), the operator should 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 ILI tool, the final results of the inspection should be provided to the operator within a reasonable timeline. 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 ILI vendor as soon as possible but within 30 days of completion of inspection.

8.3.3 Immediate Response Conditions (All Pipeline Segments)

Immediate response conditions describe anomalies or conditions that could potentially represent severe and immediate threats to pipeline integrity. They require prompt action by an operator regardless of whether they are found within a segment of pipeline that could potentially impact a critical area or not. Prompt action usually consists of excavation and repair or change in operating pressures to maintain safety margins.

1) Metal loss greater than 80 % of nominal wall regardless of dimensions.

2) For metal loss, a calculation of the remaining strength of the pipe shows the predicted burst pressure to be

— less than 1.1 times the maximum surge pressure generated at the location of the anomaly during a transient event

  or if maximum surge pressure is not available

— less than 1.1 times current established MOP at the location of the anomaly.

Suitable remaining strength calculation methods include but are not limited to ASME B31G.

3) Any dent (regardless of o'clock position) that contains indications of cracking.

4) Any dent (above the 4 and 8 o'clock position) that contains indications of stress risers (gouges, grooves, scratches), or corrosion unless an industry recognized engineering evaluation shows that it is not an immediate risk to the pipeline.

5) A dent located on the top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 6 % of the nominal pipe diameter unless an industry recognized engineering evaluation shows that it poses no risk to pipeline integrity.

6) An anomaly that in the judgment of the person designated by the operator to evaluate assessment results requires immediate action.

8.3.4 Other Anomalies (Critical Area Impacting Only)

8.3.4.1 General

The following sets of investigation and response criteria describe conditions that could, if left unaddressed over long time periods, represent eventual threats to pipeline integrity and when found in a pipeline segments that could impact critical areas, should be addressed in a timely manner. These criteria may also be used to manage the integrity of all pipeline segments (noncritical).

8.3.4.2 365-day Conditions

Applicable conditions that could represent eventual threats to pipeline integrity include:

1) A dent located on top of the pipeline (above the 4 and 8 o'clock positions) with a depth greater than 2 % of pipeline diameter [greater than 0.250 in. in depth for a pipeline diameter less than nominal pipe size (NPS) 12].

2) Any dent (below the 4 and 8 o'clock position) that contains indications of stress risers (e.g. gouges, grooves, scratches), or corrosion. Alternately, an industry-recognized engineering evaluation may be used to determine a response schedule.

3) A dent located on the bottom of the pipeline with a depth greater than 6 % of the pipeline's diameter and for which an engineering analysis of the dent demonstrates that critical strain levels in the dent have been exceeded unless another industry recognized engineering evaluation shows that it poses minimal risk to pipeline integrity.

4) A dent with a depth greater than 2 % of the pipeline's diameter (0.250 in. in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or longitudinal seam weld and for which an engineering/technical analysis of the dent demonstrates that critical strain levels in the dent have been exceeded or another industry recognized engineering evaluation shows that it poses minimal risk to pipeline integrity.

5) Preferential or selective seam corrosion of or along a seam weld unless an industry recognized engineering evaluation shows that the area poses minimal risk to pipeline integrity.

6) A gouge or groove greater than 12.5 % of nominal wall.

7) Metal loss greater than 50 % of nominal wall that is located at a crossing of another pipeline.

8) A potential crack indication that when excavated is determined to be a crack.

8.3.4.3 Scheduled Conditions

When determining the schedule for conditions containing corrosion, the applicable corrosion rate, operating pressure of the pipeline and the remaining wall thickness of the pipeline should be considered. When determining the schedule for conditions that include dents or potential cracks, the likelihood of SCC, the operating pressure of the pipeline, and the estimated number of pressure cycles should be considered. Investigations should be scheduled to be completed before anomalies are predicted to elevate to a more serious criterion (metal loss growing to more than 80 % of wall thickness, for example). If the schedule is longer than a subsequent reassessment, then the reassessment data should be used to adjust the schedule accordingly. It should be noted that a schedule could be shorter than 365 days.

1) An area of general corrosion with a predicted metal loss greater than 50 % of nominal wall.

2) Predicted metal loss greater than 50 % of nominal wall that is in an area of widespread circumferential corrosion or is in an area that could affect a girth weld unless an industry recognized engineering evaluation shows that they pose no risk to pipeline integrity.

3) For metal loss, a calculation of the remaining strength of the pipe shows the predicted burst pressure to be

— less than 1.25 times (but greater than 1.1 times) established MOP at the location of the anomaly

  or

— less than 1.25 times (but greater than 1.1 times) the maximum surge pressure at the location of the anomaly and the maximum abnormal pressure generated at the anomaly during a transient event.

Suitable remaining strength calculation methods include, but are not limited to, ASME B31G. Investigation should be scheduled before the anomaly becomes an immediate response condition.

8.3.4.4 Monitored Conditions

An operator does not have to schedule the following conditions for remediation but should record and monitor the conditions during subsequent integrity assessments for any change that may require attention.

1) Any manufacturing or construction condition that an industry recognized engineering evaluation or technical analysis shows to be stable and for which operating conditions have not significantly changed since the last successful pressure test that met the requirements listed in 49 *CFR* 195 Subpart E.

2) Any condition identified by an integrity assessment or information analysis that could impair the integrity of the pipeline.

8.4 Hydrostatic Pressure Testing

8.4.1 General

Hydrostatic testing is a widely used method of establishing or revalidating the integrity of a pipeline. It is required almost universally to validate the serviceability of a newly constructed pipeline, and it can be used to revalidate the integrity of an existing pipeline after it has been in service for a period of time. Its value as an integrity assessment technique is embodied in the probability that the increasing of test pressure beyond the MSSOP will cause defects that are critical at the test pressure to fail thereby eliminating the possibility that the defects could fail at the MSSOP. The higher the test-pressure-to-operating-pressure ratio, the more effective the test is as a demonstration of pipeline integrity. API 1110 provides additional guidance for performing pressure tests.

Hydrostatic testing is suitable for assessing anomalies associated with time dependent and stable threats (see Annex A for more information on threats). Specific threats need to be matched with the integrity assessment options.

For example, hydrostatic testing is not generally a good method for assessing corrosion-caused metal loss. ILI tools have proven to be more effective for identifying small corrosion pits. Short, deep pits that would be detectable by ILI may survive a hydrostatic test but leak soon thereafter. Moreover, the ILI results show where corrosion is occurring and record the locations and dimensions of corroded areas that, while not in danger of imminent failure, may become a problem if corrosion continues. Where it is an appropriate assessment method, however, a test either eliminates defects that have failure pressures less than the test pressure or it shows that any surviving defects have failure pressures at or above the test pressure (except for the possibility of a pressure reversal as explained below). The validation provided by a test is highest at the time of the test, but the margin of safety embodied in the test-pressure-to-operating-pressure ratio will be degraded with the passage of time for time-dependent defects that are increasing in severity (i.e. their failure pressures are declining) with the passage of time. Therefore, as is the case with integrity assessment by means of ILI, the process should be repeated periodically to assure continuing pipeline integrity. Guidelines for estimating the time interval between hydrostatic retests are presented in Section 9.

Hydrostatic testing has some technical limitations. First, the only anomalies identified by a hydrostatic test are those that fail during the test. Anomalies having failure pressures above the test pressure will not be discovered. This means that short, deep anomalies (that have inherently high failure pressures) could go undetected. Moreover, the operator gains no knowledge of the numbers and locations of anomalies that have survived the test. Therefore, in establishing the time for the next integrity assessment by testing, one should assume that the failure pressure of the most severe remaining anomaly is no higher than the test pressure, and that the anomaly could be located anywhere within the segment. Unless a large number of defects fail during the test, the pipeline operator learns little or nothing about the locations of potential anomalies and problem spots where phenomena such as corrosion, SCC, or pressure-cycle-induced fatigue may be taking place.

The successive cycles of test pressure may cause other anomalies to grow such that successive failures can occur at pressure levels below that of a prior pressurization (see pressure reversals in 8.4.5). While this phenomenon tends to prolong the testing process, adding to the cost, the impact of potential pressure reversals on pipeline integrity at the MSSOP is usually negligible. Lastly, hydrostatic testing of a pipeline that has been in service is complicated by the need to interrupt liquid transportation service and by the difficulties in acquiring water for testing and in disposing of the water once it has become contaminated by contact with a petroleum product or crude oil.

8.4.2 Minimum Test-pressure-to-operating-pressure Ratio

The test-pressure-to-operating-pressure ratio for integrity assessment purposes should be greater than or equal to 1.25 times MOP at each point along the pipeline.

8.4.3 Minimum Hold Time

Holding the test pressure at a constant level for a period of time is an appropriate method to detect leaks. Beyond the regulatory requirements, the length of hold time employed to look for leaks should be based on the volume of water in the test section: the larger the volume, the longer holding at constant pressure is required to detect a leak of a given size. It should be noted that the value of hold time is solely that of establishing that the test segment is free of leaks. It does not add to the value of the test with respect to the margin of safely. Defects that are on the verge of failure at the test pressure may continue to grow during the hold period. If a growing defect fails, it is eliminated and the hold period should be restarted. If no failure occurs during the hold period, but one or more defects grow without failing, the hold time has potentially made the defects worse. Since there is no way to determine the status of defects that survive the hold period, the test pressure is the sole measure of the effectiveness of the test with respect to the margin of safety for operating the pipeline at its MOP.

8.4.4 "Spike" Testing

The value of a hydrostatic test in terms of integrity assessment is embodied in the test-pressure-to-operating pressure ratio. The value of hydrostatic testing can be enhanced by spike testing. This test is a common assessment method for ERW and FW pipe, cracklike anomalies, and other time-dependent threats. For further explanation of the uses of spike tests, see API 1110.

The higher the ratio, the more effective the test is as a demonstration of pipeline integrity. In spite of the possible upper limits on test pressure that arise from the potential to yield some pipe and from the likelihood that numerous test failures may occur, the benefit of optimizing the test-pressure-to-operating-pressure ratio should be kept in mind. The higher the ratio, the smaller the risk will be of any surviving defects, and the longer it will take for the smaller anomalies to grow to failure at the MOP after the test has been completed. The magnitude of the benefit is made clear in Annex D where setting reassessment intervals is discussed.

The concept of a “spike” test has evolved as a means of enhancing a hydrostatic test. As an example, a test to 1.25 times the MOP held for four to eight hours is required to meet certain codes and regulations. A spike test conducted at a higher ratio of test pressure to operating pressure (e.g. 1.30, 1.40, or 1.50 times the MOP) would be more effective than a test at 1.25 times MOP. The spike test target pressure, if attained, is generally held longer than five minutes but less than one hour. A spike test is not intended to be a leak test, and generally no attempt is made to look for leaks. The hold-time portion of the test to look for leaks can be carried out after the spike test by lowering the test pressure to the minimum required value of 1.25 times MOP.

A spike test is usually followed by a longer test at a pressure level such as 1.25 times the MOP in order to demonstrate with a high degree of certainty that no leak exists. As an example, whereas a test of 1.25 times the MOP held for four or eight hours would tend to meet the minimum requirements of certain codes and regulations, a spike test conducted at a higher ratio of test pressure to operating pressure would provide more confidence in the serviceability of the pipeline at its MOP, and it would also assure a longer interval until the next integrity assessment is needed. Caution should be taken to not exceed 1.5 times the rated pressure of any valves/fittings included in the hydrotested segment.

One caveat with respect to conducting a spike test is that the test should not be terminated with a test failure. This may require lowering the target pressure level of the spike test to avoid another failure. Terminating a test with a failure greatly increases the chance that one or more surviving defects will have a failure pressure less than the final level of test pressure achieved (see pressure reversals).

8.4.5 Pressure Reversals

The term “pressure reversal” is commonly used to describe the following situation which may occur repeatedly within a single hydrostatic test section. As test failures begin to occur, it is possible, that successive failures will occur at a pressure below a prior test failure. This phenomenon, commonly called a “pressure reversal” arises from the tendency for a defect to grow by slow ductile tearing as the applied pressure approaches its failure pressure. If this growth is terminated just before the defect fails because another defect in the test section fails, it is possible that the failure pressure of the just-surviving defect will now be less than the pressure it has just survived.

Pressure reversals are common in hydrostatic tests of pipeline segments that contain families of defects having similar failure pressures. Generally, their impact on pipeline integrity at the MOP is negligible for two reasons. First, the potential size of a pressure reversal is inversely proportional to its likelihood. Secondly, in most cases where pressure reversals have been observed, the probability of a defect being present that would fail at the MOP because of a pressure reversal is extremely small.

8.4.6 Essential Test Data

8.4.6.1 General

The essential data that should be recorded during a hydrostatic test to assess pipeline integrity include the following:

— operator name;

— name of person responsible for making the test;

— name of the test company used, if any;

- date and time of test;
- minimum test pressure
- test medium (e.g. water, nitrogen);
- description of the facility tested (e.g. location, beginning and endpoints, name of segment);
- description of the test apparatus, including location and temperature recording devices and location and elevation of all pressure recording devices;
- pipeline attributes (e.g. length of test section, diameter, wall thickness, grade);
- the layout and high and low elevations of test sections, including an pipeline elevation profile, if available;
- the spike test pressure levels attained;
- the deadweight gage readings and its location and elevation;
- instrument calibration records;
- the pressure-volume relationship;
- the hold time pressure charts;
- the temperature charts for the pipe and/or test medium;
- ambient temperature readings and description of weather at time of test;
- a detailed listing of all test failures;
- an explanation of any pressure discontinuities, including test failures, that appear on the pressure recording charts.

8.4.6.2 Test Results Analysis

The information in Table 2 is an example of the essential data that the operator needs to evaluate the effectiveness of the hydrostatic test, and it provides part of the information that will be needed to determine the reassessment interval. Note that four pressure reversals were observed, and that the sizes of the reversals are determined on the basis of a common elevation reference point, in this case, the location of the deadweight gage.

If pressure reversals are observed, the sizes of the reversals are determined on the basis of a common elevation reference point. The site failure pressures are important from the standpoint of the cause of failure, and they can be meaningfully compared to assess whether or not a pressure reversal has occurred, but only if site elevation differences are taken into account. Test Break 1-3 occurred as a 5-psig pressure reversal. Test Break 1-4 occurred as a 15-psi pressure reversal referenced to the highest previous pressure. If the pipeline operator wishes to develop the statistical distribution of pressure reversals, the pressure reversals should be considered separately by cause. For example, if all four of the pressure reversals in Table 2 were caused by ERW seam defects, they would constitute one common class of reversals that could be grouped together for analysis. If the reversals in Test Section 1 were caused by ERW seam defects, but those in Test Section 2 were caused by SCC, the two classes of reversals would have to be grouped and analyzed separately.

Test failures should be investigated to determine their causes. The causes of failures will indicate the types of threats that are affecting the segment and their significance. The information on causes should be fed back into the risk assessment model to see if the segment needs to be reprioritized.

Table 2—Sample Test Failure Information

Test Section and Test Break Number	Pressure at Failure Recorded at Deadweight psig	Pressure Reversal Size psig	Location of Test Break, Mile Post	Elevation of Test Break Location ft	Pressure at Failure at Site of Test Break psig
TS 1: MP 140.1 to MP 155.3	DW elev. 1000 ft; Low elev. 900 ft; High elev. 1145 ft		DW loc. MP 140.1		
1-1	1250		143.7	950	1272
1-2	1260		143.9	955	1279
1-3	1255	5	142.0	1010	1251
1-4	1245	15	150.4	903	1287
Section 1 final	1300	Range: 1237 psig to 1343 psig			
TS 2: MP 155.3 to MP 171.5	DW elev. 1100 ft; Low elev. 1100 ft; High elev. 1280 ft		DW loc. MP 165.9		
2-1	1200		169.1	1150	1178
2-2	1270		155.5	1245	1207
2-3	1260	10	160.1	1234	1201
2-4	1250	20	169.3	1155	1226
2-5	1280		161.3	1200	1237
Section 2 final	1300	Range: 1222 psig to 1300 psig			

8.5 Other Assessment Methods

Technologies other than ILI or hydrostatic testing that could be used to assess pipeline integrity include “direct assessment” (applicable to external corrosion, internal corrosion, SCC, and possibly to mechanical damage—delayed failure) and guided wave ultrasonic technology (GWUT—applicable to external and internal corrosion). Visual inspection or other traditional nondestructive examination (NDE) methods [ultrasonic testing (UT), magnetic particle testing (MPT), liquid-penetrant testing (PT), etc.] can be used on excavated or aboveground piping. These methods offer means of assessing for the time-dependent threats (excluding assessment to control a pressure-cycle-induced-fatigue threat) in pipeline segments that are nonpiggable (meaning that ILI is not possible) and/or cannot be taken out of service to accommodate a hydrostatic test. Understanding the use of other assessment methods is important. The application of one or more of these technologies could suffice for assessing the integrity where applicable threats are limited. Each direct assessment methodology is designed to assess a specific threat. There are limitations when applying a direct assessment methodology to threats for which the method is not applicable. It is, however, possible to use multiple direct assessment methods on a single segment where those methods each address the appropriate threat. Moreover, the direct assessment technologies can be usefully applied in conjunction with hydrostatic testing or ILI, particularly in conjunction with hydrostatic testing where little if any knowledge is gathered regarding the nature of the threat. For example, the application of SCCDA could help an operator decide whether or not an assessment for SCC is necessary.

8.6 Seam Integrity Assessment

The integrity assessment processes described above in 8.3, 8.4, and 8.5 should be applicable to and sufficient for a line pipe material with a longitudinal seam made by means of double submerged arc welding (DSAW), helical seam double submerged arc welding (HSAW), or high-frequency welded electric resistance welding (HF-ERW) manufactured after about 1980. For more information on manufacturers of ERW and other types of pipe, see “History of Line Pipe Manufacturing in North America.” Seam integrity for such materials are usually not a more significant concern than overall pipeline integrity. Pipeline operators should be aware, however, that the seam characteristics of some types of older line pipe materials, particularly, furnace LW pipe and low-frequency welded electric resistance welding (LF-ERW) or FW pipe and “susceptible” HF-ERW (see next two paragraphs) may require a special assessment of seam integrity. The issues of concern with these materials are the inherently low fracture toughness of the seams and the higher likelihood that the seams will contain defects because of the nature of the hot-rolled skelp from which they were made, the fact that nondestructive seam inspections at the time were of limited capabilities, and because the hoop stress levels employed in the manufacturers’ hydrostatic tests frequently were less than 90 % of SMYS.

As mentioned above, some HF-ERW pipe materials may be susceptible to the same seam integrity threats that affect LF-ERW and FW pipe. Until sometime in the early 1980s, most HF-ERW pipe was made from the same type of skelp as LF-ERW and FW pipe, that is, skelp hot-rolled from open-hearth, ingot-cast steels with sulfur contents typically in the range of 0.015 % to 0.030 % by weight. These materials were often characterized by high inclusion contents that could lead to the formation of “hook” cracks adjacent to the bondline of the ERW seam. Hook cracks are one of the primary initiators of pressure-cycle-induced fatigue (discussed below). The threat of pressure-cycle-induced fatigue in HF-ERW pipe may exist if any one of the three following conditions has occurred:

1) pipeline has experienced failure due to pressure-cycling-induced fatigue,

2) hydrostatic test records indicate numerous seam splits,

3) pressure cycle spectrum is known to have caused fatigue failures in other types of pipe subjected to similar circumstances.

Therefore, these types of HF-ERW materials should be considered possibly susceptible to pressure-cycle-induced fatigue. As such they should be treated as potentially having the same seam integrity assessment needs as LF-ERW and FW pipe materials.

As steel manufacturers in the early 1980s changed over to basic oxygen steel making (which is capable of reducing sulfur contents to levels below 0.01 % by weight) and continuous casting, the quality of the skelp used to make ERW pipe greatly improved. Alternatively, some manufacturers used sulfide shape control to prevent the formation of elongated manganese sulfide inclusions that contribute to the formation of hook cracks. These types of improvements along with improved seam inspection by the manufacturers greatly reduced the potential for hook cracks ending up in finished line pipe. Thus HF-ERW pipe made after the early 1980s generally will not have the same seam integrity issues as HF-ERW pipe made prior to that time. HF-ERW materials that generally are not susceptible to the problems associated with hook cracks would be characterized by low sulfur contents (<0.01 % by weight) and/or the absence of elongated sulfide inclusions as viewed on a metallographic section. When available, a review of the vintage and manufacturing history of HF-ERW materials may help determine the potential for the existence of hook cracks. Factors such as being manufactured prior to 1980, skelp being rolled from an open-hearth furnace steel, sulfur content being in excess of 0.01 % by weight, low toughness being exhibited in Charpy impact tests in the vicinity of the ERW bondline, or elongated sulfide inclusions appearing in a metallographic section would tend to indicate potential susceptibility to hook cracks. If the existence of hook cracks is confirmed and the operational pressure cycles are considered to be relatively aggressive, the operator should consider the particular HF-ERW material as “susceptible” and implement a program of seam integrity assessment for that pipe.

Pressure-cycle-induced fatigue crack growth of seam-related manufacturing anomalies is one concern with a LF-ERW material, a direct current welded electric resistance welding (DC-ERW) material, a FW material, or a susceptible HF-ERW material. Susceptibility to selective seam corrosion is another. While selective seam corrosion has been known to affect HF-ERW materials, the improved toughness of the bondline region associated with these materials means that they will tolerate much more seam metal loss without failing than the older types of materials where the bondline regions typically exhibit very poor toughness.

To determine whether or not a special seam integrity assessment is needed the pipeline operator should review the following attributes of all pipeline segments as part of the operator’s IMP.

— diameter;

— wall thickness;

— grade;

— seam type (furnace LW, ERW, FW, etc.);

— MOP (useful to know whether or not pipeline actually operates at the MOP);

— representative pressure cycles (e.g. 1 year of data taken at regular intervals such as 15 minutes, 30 minutes, 1 hour);

— manufacturer and year of manufacture if known (helpful in separating LF-ERW from HF-ERW);

— sulfur content of the material in percent by weight where possible to extract;

— metallographic section across seam if available (helpful in separating LF-ERW from HF-ERW and susceptible HF-ERW from nonsusceptible HF-ERW);

— causes of seam failures in service, if any;

— year and pressure level of last hydrostatic test;

— causes of seam-related test breaks if known;

— coating type;

— coating condition if known;

— year cathodic protection installed;

— relevant information as to the adequacy of the cathodic protection;

— seam toughness.

Coating type, coating condition, the time cathodic protection was installed, and the adequacy of cathodic protection are relevant in deciding whether or not selective seam corrosion could be an issue.

If a segment comprised of furnace LW pipe has never sustained a seam-related failure and it has been tested to at least 1.25 times MOP, the need for assessment is based on whether or not the MOP exceeds 30 % of SMYS. Assessment is not needed if the MOP does not exceed 30 % of SMYS. Assessment is also not needed if the MOP does exceed 30 % of SMYS but does not exceed 72 % of the manufacturer's hydrostatic test pressure. If none of these conditions is satisfied, the operator should perform a baseline seam integrity assessment to assure that no pipe body or seam manufacturing anomalies could cause a failure at the MOP. Periodic seam integrity assessment is probably not necessary for segments comprised of furnace LW pipe. However, there is insufficient knowledge concerning the possible modes of time-dependent deterioration of the furnace LW materials. While no known instances of failure have occurred from either selective seam corrosion or pressure-cycle-induced fatigue, in-service failures of furnace LW pipe materials have occurred after such materials have been pressure tested to levels in excess of their MOP. Some of these, perhaps all of them, may be attributable to accidental overpressurization. The operator of a LW pipeline that is operated at a pressure level that exceeds 72 % of the manufacturer's hydrostatic test pressure should monitor the condition and service history of the pipeline, and consider periodically assessing its integrity if the operating history suggests that in-service seam-related failures have taken place after a hydrostatic test to at least 1.25 times the MOP. At this time there is no known technology for determining how often such an assessment would be needed.

If the material falls into one of the categories of either LF-ERW pipe, DC-ERW pipe, FW pipe, or susceptible HF-ERW pipe, periodic reassessment may be needed at an interval that should be determined by a pressure-cycle analysis using a representative operating pressure spectrum and/or by an assessment of susceptibility to selective seam corrosion.

With regard to segments comprised of LF-ERW pipe, DC-ERW pipe, FW pipe and susceptible HF-ERW pipe it is assumed that all such pipelines have been subjected to a previous hydrostatic test to a level of at least 1.25 times MOP. If not, a baseline seam integrity assessment should be carried out. For those pipeline segments that have been subjected to a previous test to 1.25 times MOP (believed to be almost all pipelines comprised of these materials) the operator should consider the following. All such pipelines should be subjected to seam integrity assessment, but the frequency of such assessments should be based on pressure-cycle-fatigue analysis and an assessment of exposure to selective seam corrosion. A pressure-cycle-fatigue analysis and/or an assessment of the selective seam corrosion rate should be conducted and used to schedule periodic seam integrity assessments.

Periodic seam integrity assessment is required for any segment if the segment has had either an in-service or a hydrostatic test failure either from selective seam corrosion or from pressure-cycle-induced fatigue crack growth of a seam-related defect. Guidelines for determining the appropriate reassessment interval for both pressure-cycle-induced fatigue and selective seam corrosion are provided in Annex D.

If no failure from selective seam corrosion has occurred, the operator should carry out additional analysis or investigation. If the segment is bare or poorly coated and is inadequately cathodically protected, susceptibility to selective seam corrosion should not be ruled out without additional supporting data. If deemed susceptible, a seam integrity assessment is needed. Whether or not periodic assessment is needed then depends on the outcome of the seam integrity assessment. If test leaks or test breaks occur because of selective seam corrosion anomalies or if selective seam corrosion anomalies are found by ILI, periodic seam assessment is needed. Selective seam corrosion appears to occur irrespective of the operating stress level of the pipeline; therefore, even low-stress pipelines comprised of materials with susceptible seams should be investigated with respect to exposure to selective seam corrosion.

8.7 Stress Corrosion Cracking (SCC) Assessment

8.7.1 General

SCC is a crack-formation and growth phenomenon that requires the presence of a significant tensile stress, a susceptible material, and an electrochemical environment conducive to the phenomenon. Line pipe materials increase in susceptibility to SCC as stress levels increase and has been reported predominantly in pipe operating at or above 60 % of SMYS. NACE SP0204, *Stress Corrosion Cracking Direct Assessment Methodology* and OPS-TTO8, *Stress Corrosion Cracking Study* use 60 % of SMYS as one of the screening criteria. SCC has been found in pipelines associated with various soil-groundwater environments and with various types of external coatings. It is commonly believed that SCC has not occurred in pipelines coated with fusion-bonded epoxy coatings. Note that a pipeline coated at the factory with fusion-bonded epoxy where the field joints are coated with something other than fusion-bonded epoxy, while not susceptible in the factory-coated regions, may be susceptible at the field joints. Pipelines coated with single-layer polyethylene tape coatings have been found to be particularly susceptible to SCC. SCC has also been associated with residual stress due to deformation of the pipe (i.e. dents and pipe bends).

Pipeline operators should determine whether or not a segment of pipe may be susceptible to SCC particularly if the pipeline is known to be subjected to a significant level of hoop stress. A segment should be considered susceptible if it has sustained an in-service or hydrostatic test failure where SCC is identified as the cause. A segment should also be deemed susceptible to SCC if evidence of arrays of cracks are discovered as a result of running an ILI crack-detection tool and verified during pipe surface examinations. For assistance in determining whether or not a segment is susceptible to SCC, a pipeline operator is advised to consult such documents as OPS-TTO8, NACE SP0204, the Canadian Energy Pipeline Association's (CEPA) *SCC Recommended Practices*, and other standards ASME STP-PT-011, *Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas.* Although the different approaches for the detection and assessment of SCC leverage data integration to varying degrees, it is particularly important in regards to SCCDA.

In-the-ditch inspection for SCC cracks requires a clean surface and the use of an appropriate NDE method (e.g. magnetic particle inspection). Where blast media is used in surface preparation, care should be taken to not peen the cracks shut prior to inspection.

8.7.2 SCC Characterization

Since it has been observed that SCC can be superficial (the occurrence of shallow, nonpropagating cracks), the designation of "noteworthy" SCC should be used to clearly communicate the threshold for moving from a nominal monitoring phase into an active assessment/mitigation phase regarding the SCC threat on a particular pipeline asset. "Noteworthy" as defined in ASME STP-PT-011, *Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas,* with the inclusion of a pure depth criteria represents an enhancement of the term "significant" that was originally defined by CEPA in regards to SCC and then adopted in the NACE SP0204. The importance of the pure depth criteria is that it encompasses the potential for short deep cracks associated with high pH SCC. Both ASME STP-PT-011 and CEPA's *SCC Recommended Practices* provide a further delineation of the crack severity into a ranking, with the ASME criteria providing more clarity through its unequivocal reference to failure pressure.

It is important to understand that the effective management of SCC will not be solely achieved through strict adherence to a standard. Rather, the operator managing the presence of noteworthy SCC needs to develop a program in consideration of the specifics of the pipeline and the limitations of the assessment techniques and technologies as applied. The effective management of noteworthy SCC typically requires periodic assessment via hydrostatic testing or ILI using an crack-detection tool. Reassessment intervals can be calculated by the method applied to anomalies with linear crack growth rates discussed in Annex D.

8.7.3 ILI Considerations

ILI technologies are available that detect and evaluate SCC within reasonable bounds. However, limitations inherent in the ILI technology and data interpretation lead to some challenges in the detection and characterization of SCC. For information on ILI technologies for assessing SCC, refer to OPS-TTO8, *Stress Corrosion Cracking Study.*

8.8 Repair Methods

Anomalies exposed for direct examination that on the basis of engineering critical assessments are found to be injurious to pipeline integrity should be repaired by an acceptable repair method. Acceptable repair methods for a wide variety of defects are described in ASME B31.4-2009, Paragraph 451.6. Alternatively, the pieces of pipe containing injurious defects may be cut out and replaced with sound previously hydrostatically tested pipe. If pipe replacement is the chosen repair method, the replacement pipe should meet the design criteria of the pipeline and should have been tested prior to commissioning to a level of at least 1.25 times the MOP, and the tie-in welds should be radiographed. As a temporary mitigative measure or to protect personnel conducting a repair, the operator may choose to reduce the operating pressure of the pipeline. When a pressure reduction is employed to mitigate the effects of an anomaly, the time limit before a permanent repair should be made should be calculated in accord with the method shown in Annex D. Acceptable repair methods include but are not necessarily limited to:

— pipe replacement,

— full-encirclement split steel sleeves,

— composite wrap repairs,

— mechanical clamps,

— deposited weld metal.

The applicability of each of these to the various types of anomalies is shown in Table 3. Note that pipe replacement is also an acceptable permanent solution. Also, for relatively shallow defects (less than 12.5 % of the actual wall thickness)

Table 3—Acceptable Repair Methods

Type of Anomaly	Repair Methods				
	Type A Steel Sleeve (Note 1)	Type B Steel Sleeve (Note 2)	Composite Wrap Repair (Note 3)	Mechanical Clamp (Note 4)	Deposited Weld Metal (Note 5)
External corrosion, depth ≤ 80 % of wall	Yes	Yes	Yes	Yes	Yes
External corrosion, depth > 80 % of wall	No	Yes	No	Yes	No
Internal corrosion, depth ≤ 80 % of wall	No	Yes	No	Yes	No
Internal corrosion, depth > 80 % of wall	No	Yes	No	Yes	No
Selective seam corrosion, LF-ERW or DC-ERW or FW	No	Yes	No	Yes	No
Crack	No	Yes	No	Yes	No
Seam-related defect, LF-ERW or DC-ERW or FW	No	Yes	No	Yes	No
Any leaking defect (Note 6)	No	Yes	No	Yes	No
Girth weld defect	No	Yes	No	Yes	Yes (Note 7)
Dent with gouge or other stress concentrator	Yes with filler	Yes	Yes with filler	Yes	No
Plain dent	Yes with filler	Yes	Yes with filler	Yes	No

NOTE 1 Type A steel sleeves are comprised of two half-sleeves joined by means of an axial weld on both sides. The ends of the sleeve are not welded to the pipe, and hence, a Type A sleeve may not be used to repair a leak. These sleeves function as reinforcement to a defective pipe, and they do not need to carry much of the hoop stress to be effective. It is essential to have the sleeve in intimate contact with the pipe at the area of the defect to prevent it from bulging outward and perhaps failing. Any gap that exists at that location should be filled with a hardenable filler such as epoxy or polyester material.

NOTE 2 Type B steel sleeves are comprised of two half-sleeves joined by an axial weld on both sides. The ends are fillet welded to the pipe so as to make the sleeve capable of containing the pressure in the event that the defect leaks. These sleeves should be designed to carry the full MOP of the pipeline. The side seams should be full-penetration V-butt welds.

NOTE 3 Composite wrap repairs come in a variety of forms and are comprised of a variety of materials. All are patented devices offered by vendors who may perform the installations or provide training for the operator's personnel to install the wraps. Basically, they consist of a fiber-reinforced matrix. The known types of fibers used are carbon fibers and glass fibers. The matrix materials are usually either a polyester material or an epoxy material. One style of wrap consists of a preformed composite. Layers of the composite are successively wrapped around the pipe as they are coated with an adhesive to create a solid composite sleeve upon curing. Another style of wrap consists of laying up the composite in a "wet" matrix so that the final wrap becomes a solid composite upon curing. Composite wrap repairs reinforce a defective pipe in much the same manner as a Type A steel sleeve. Therefore, using a hardenable filler to achieve continuity at the defect is necessary. Composite wrap repairs cannot be used to repair leaking defects. Some composite wrap materials may be not be compatible with all environments (such as contaminated soil). Operators should carefully follow the manufacturer's instructions during installation.

NOTE 4 Mechanical clamps consist of a two half-circumference steel forgings that are placed around a defective segment of pipe and bolted together via axial flanges on both sides. The clamp halves are equipped with elastomeric seals along the sides and at both ends, which upon tightening of the bolts, seal the internal annular space between the pipe and the clamp. The clamp is capable of carrying the full MOP of the pipeline. The compatibility of this seal material should be checked against the product within the pipeline. Before installation, seal materials should be inspected as some of them have limited shelf lives.

NOTE 5 Deposited weld metal repairs involve depositing weld metal over a defect to replace missing metal. The technique is applicable only to metal loss defects or areas where any other type of defect have been removed by grinding to create an open pitlike area for deposition of weld metal. Associated with the technique is the inherent risk of burning through the remaining wall thickness. Therefore, a minimum wall thickness of at least 0.125 in. (3 mm) should be present if this type of repair is contemplated for an in-service pipeline.

NOTE 6 Leaking defects should be stopped before attempting a repair by use of a Type B sleeve.

NOTE 7 The welding procedure specification should define minimum remaining wall thickness in the area to be repaired and maximum level of internal pressure during repair. A low-hydrogen welding process should be used.

removal by grinding, followed by nondestructive examination to assure the absence of cracks is an acceptable repair. Grinding and inspection to assure the absence of cracks is acceptable for defects deeper than 12.5 % of the actual wall thickness but no deeper than 40 % of the actual wall thickness, if the length of the ground-out area does not exceed the allowable length based on the maximum depth of grinding determined by ASME B31G (2009 or later).

9 Reassessment Frequencies

9.1 General

Pipeline integrity assessment and remediation as described in Section 8 establishes the integrity of a pipeline segment at a given point in time. Some of the threats to pipeline integrity are time dependent as noted previously. Reassessment of the integrity a pipeline segment subject to a time-dependent anomaly growth mechanism should be carried out at appropriate intervals to minimize the risk of a pipeline failure caused by an anomaly that was too small or was under the reporting size criteria detected in the last assessment growing to a size that would fail at maximum calculated surge pressure or 1.1 times MOP. The appropriate interval for reassessment in the case of a time-dependent anomaly growth mechanism depends on the failure pressures of the anomalies established by the most recent integrity assessment, 1.1 times MOP, or the maximum calculated surge pressure of the pipeline, and the rates of growth of the anomalies. Section 9 and Annex D provide guidance for pipeline operators in establishing representative growth rates for various time-dependent anomaly growth mechanisms and for calculating reassessment times for these mechanisms.

9.2 Anomaly Growth Rates

9.2.1 General

If possible, the pipeline operator should establish the actual effective anomaly growth rates for every time-dependent anomaly growth mechanism that affects any segment that is to be considered for reassessment. Some available techniques for determining growth rates are described below. Alternatively, if the operator cannot establish the actual effective anomaly growth rates, default rates may be available from other standards as explained below.

9.2.2 Anomaly Growth Rates for External Corrosion, Internal Corrosion, and SCC

It is customary to assume that anomalies created by external corrosion, internal corrosion, and SCC grow deeper linearly with time even though in reality these processes are probably intermittent. In other words, if the pit or crack depth is d_1 measured at time t_1 and its depth increases to d_2 at a later time t_2, it is customarily assumed that the growth rate of the corrosion is $(d_2 - d_1)/(t_2 - t_1)$ at that pit or crack. An operator therefore may establish the actual effective rate of external corrosion, internal corrosion, or SCC at the location of any given point where the particular phenomenon has occurred by comparing the depths of a pit or crack as seen in two successive ILI runs after measurement errors are taken into account. Comparing a large number of pits or cracks in this manner may indicate a range of anomaly growth rates wherein the worst-case rate may be established from the distribution of rates with an appropriate degree of confidence. If only one ILI run is available or if only pit or crack depth measurements made at specific locations are available, the 80-confidence level worst-case anomaly growth rate can be established from the family of pit depths or crack depths determined by the tool or by means of physical measurements taking into account measurement errors by a Monte Carlo simulation using an appropriate distribution of corrosion or SCC starting times. If the Monte Carlo technique is applied in the case where actual pit depths or crack depths are determined at a few excavations instead of on the basis of an ILI tool run covering the whole segment, the pit or crack growth rate determined thereby should be doubled.

Actual external corrosion rates at specific locations along a segment also may be determined by means of buried coupons or linear polarization resistance measurements. These measurements should be taken at sufficient locations to represent the corrosion conditions along the segment.

If the pipeline operator has no way to determine the actual effective rate of external corrosion, a credible default value may be selected using the criteria stated in ASME B31.8S-2010, Appendix B, Table B-1. Those criteria are shown in Table 4.

Table 4—Corrosion Rates Related to Soil

Resistivity (from ASME B31.8S-2010)	
Corrosion Rate mils/year	**Soil Resistivity** ohm-cm
3	>15,000 and no active corrosion
6	1,000 to 15,000 and/or active corrosion
12	<1,000 (worst case)

If the operator has not determined the actual effective rate, has no information concerning soil resistivity, and has reason to suspect that unusually aggressive corrosion mechanisms are present, such as stray currents or microbially induced corrosion (MIC), a default rate of 16 mils/year should be assumed (see NACE SP0502).

Actual internal corrosion rates at specific locations along a segment may be determined by means of coupons or electrical resistance change measurements taken through hot tap fittings. These measurements should be taken at locations where internal corrosion is most likely to occur along the segment (i.e. places where water and solids are likely to accumulate).

As in the case of external or internal corrosion, the rate of selective seam corrosion (external or internal) is customarily assumed to be constant (i.e. varies linearly with time). However, the rate of corrosion at the bondline of an ERW or FW seam will be higher than that of the immediately adjacent base metal if selective seam corrosion is occurring. The ratio of the corrosion rate in the bondline to that in the base metal is referred to as the “grooving” ratio, and grooving ratios as high as 4-to-1 have been observed.

If the pipeline operator has no way to determine the actual effective rate of selective seam corrosion, a default rate of could be based on the worst-case known rates of external and internal corrosion for the segment multiplied by the grooving ratio. If the grooving ratio is unknown, the pipe body corrosion rate should be multiplied by 4 to establish the rate for selective seam corrosion reflecting the highest grooving ratio that has been commonly seen in ERW line pipe materials that are susceptible to selective seam corrosion.

If the pipeline operator has no way to determine the actual effective rate of SCC crack growth, a default rate of 24 mils/year (worst case) should be assumed (see National Energy Board, *Public Inquiry Concerning Stress Corrosion Cracking on Canadian Oil and Gas Pipelines*). For additional information on SCC, see the following resources:

— “Methodology for Ranking SCC Susceptibility of Pipeline Segments Based on the Pressure Cycle History,”

— “Method for Establishing Hydrostatic Re-Test Intervals for Pipelines with Stress-Corrosion Cracking,”

— “Analytical Approach to Determine Hydrotest Intervals.”

9.2.3 Crack Growth Rates for Fatigue

Fatigue crack growth in a buried steel pipeline has been observed to follow a “Paris Law” relationship wherein the log of the rate of fatigue crack growth varies linearly with the log of the change in applied stress intensity factor associated with a given stress (i.e. pressure) cycle. Mathematically, the Paris Law relationship is:

$$\frac{da}{dN} = C(\Delta K)^n \tag{1}$$

where

da/dN is the incremental crack growth per cycle (inches per cycle in U.S. customary units);

C and n are constants that depend on the material and the environment;

ΔK is the change in stress intensity factor per cycle (psi-root-inch in U.S. customary units);

ΔK is usually expressed in a form such as the following:

$$\Delta K = C_1 \Delta S \sqrt{\frac{\pi a}{Q}} \tag{2}$$

where

C_1 is a constant

ΔS is the change in hoop stress (psi in U.S. customary units);

a is the current crack depth (inch in U.S. customary units);

Q is a function of the depth/length ratio of the crack.

Because ΔK is a function of both the change in hoop stress and the current crack depth, the rate of fatigue crack growth in not constant; it increases with time. The effective rate of fatigue crack growth depends on the constants C and n. These may be estimated from the status of actual fatigue cracks in a pipeline if the progressive steps of crack growth can be measured. More often than not, they cannot be determined from actual fatigue cracks in a pipeline, so the operator may have to rely on rates determined by special laboratory tests or on default rates. One set of C and n values often used as a default rate is given in API 579-1/ASME FFS-1. The values frequently used based on that document are: C = 8.6E-19 (for ΔK in psi-root-inch units) and n = 3. There are ways to determine the crack growth rates in some cases if a fatigue failure has already occurred. Some have had success counting striations on the fracture surface using an SEM. In other cases the rate has been fit to the actual known circumstances. The point is that in most cases this is not feasible.

9.3 Reassessment Intervals for Anomalies with Linear Growth Rates

Generically, establishing a reassessment interval to deal with a time-dependent threat to pipeline integrity requires calculating the failure pressure of the worst-case anomaly remaining in the segment after an initial assessment and determining the time it will take for the anomaly to reach a size that will cause failure at the MOP. Calculating failure pressures requires the use of a failure-pressure-versus-anomaly-size model as discussed in Annex D. The time for the failure pressure of a growing anomaly to decay from the benchmark value established by the last assessment to the MOP depends on the rate of growth. Since it is not prudent to allow this entire calculated time period to expire before carrying out a reassessment, a safety factor is embodied in the calculation.

The pipeline operator should establish the lengths and depths of the anomalies that remain after an integrity assessment and the amount of growth that would cause their failure pressures to decay to 1.1 × 72 % of SMYS as described above. The operator should also establish the rate of growth appropriate to the time-dependent growth mechanism as described in 9.2.2 and 9.2.3. For anomalies that are believed to grow at linear rates with time (external and internal corrosion, selective seam corrosion, and SCC), the operator may then use Figure 5 to establish a reassessment interval, to calculate a reduced MOP to schedule mitigation or reassessment, or to schedule remediation of individual anomalies as their failure pressure approaches 1.1 times MOP.

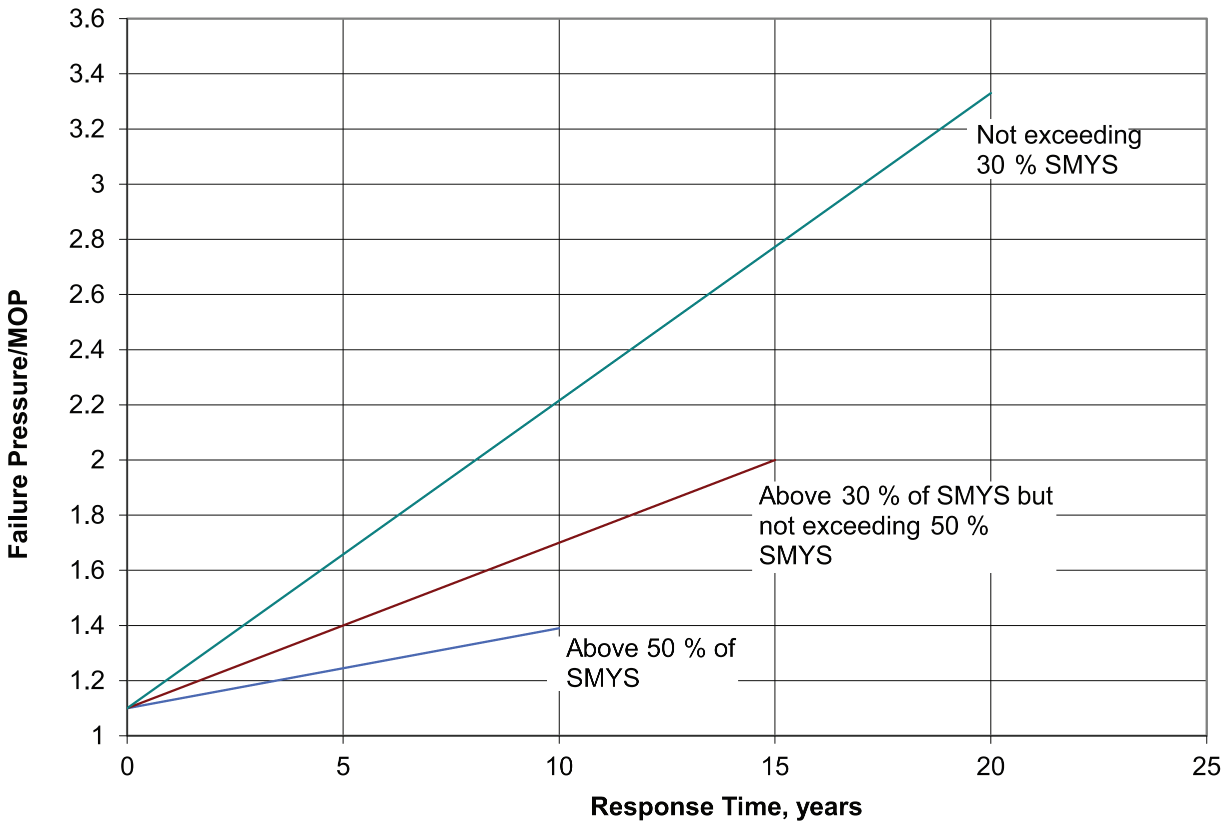


Figure 5—Timing for Scheduled Responses

To use Figure 5 correctly, the operator should consider the nominal wall thickness of the pipe, the MOP, and the established corrosion or crack-growth rate. For example, consider the case for dealing with the effect of external corrosion on the 20-in. OD, 0.250-in., X52 pipeline that has a MOP of 72 % of SMYS represented in Figure D.2. Assume that it was assessed by ILI and that the operator repaired all anomalies having failure pressures below 100 % of SMYS. From Figure D.2, it can be ascertained that 50 mils of growth for a 14-in.-long anomaly is about the least amount of growth required to erase the margin of safety established by the integrity assessment, that is, to cause the ratio of 100 % of SMYS to 72 % of SMYS (1.39) to decline to a ratio of 1.1 × 72 % of SMYS. If the operator determines that the corrosion rate is 5 mils/year, reassessment should be carried out within 10 years. This situation is represented by the line labeled "Above 50 % of SMYS" in Figure 5. The line slopes from a Y axis failure pressure/MOP ratio of 1.39 at a time of 10 years on the X-axis (remaining safe life) to a failure-pressure-to-MOP ratio of 1.1 at a time of zero years (meaning that time has run out). An anomaly that had a rupture pressure exceeding 100 % of SMYS that is growing at a rate of 5 mils/year can be placed farther to the right of 10 years on the time axis by extrapolation of the line to the appropriate failure-pressure-to-MOP ratio for the anomaly, and then it can be remediated within the indicated time. Additionally, an anomaly indicated by ILI to have a failure-pressure-to-MOP ratio of 1.55 (end of the dashed line extension) has a remaining safe life of 15 years. Conversely, if the operator had left unremediated, an anomaly with a failure-pressure-to-MOP ratio less than 1.39, the time to address the anomaly would be less than 10 years (e.g. 5 years for an anomaly with a failure-pressure-to-MOP ratio of 1.25). It is very important to note that this example applies only to a pipe with wall thickness of 0.250-in. with a MOP of 72 % of SMYS corroding at a rate not exceeding 5 mils/year. For other conditions, the operator should adjust Figure 5 in an appropriate manner as outlined below.

The effect of a MOP other than 72 % of SMYS can be seen in Figure 5. Suppose that the 20-in. OD, 0.25-in. wall, X52 pipeline that was corroding at a rate of 5 mils/year had a MOP of 50 % of SMYS. The "Above 30 % of SMYS but not exceeding 50 % SMYS" line on Figure 5 indicates that if reassessment results in repair or removal of all anomalies with failure pressures of less than 100 % of SMYS, then the remaining safe life is 15 years. That is because a minimum failure-pressure-to-MOP ratio of 2 has been established. If the MOP of the pipeline were 30 % of SMYS, by the same reasoning (a minimum failure-pressure-to-MOP ratio of 3.3), Figure 5 indicates a remaining safe life of 20 years. These principles also would apply to an operator using a pressure reduction to delay remediation or reassessment. Users are cautioned, however, that these gains in time are absolutely tied to the minimum failure-pressure-to-MOP ratio being validated by the current integrity assessment. For example, if the current assessment consisted of a hydrostatic test of to a level of 1.5 times MOP for a pipeline with a MOP of 50 % of SMYS, the remaining safe life assured would be only seven years based on the point where the “Above 30 % of SMYS but not exceeding 50 % SMYS” slope intersects the failure-pressure-to-MOP ratio of 1.5.

The effects of wall thickness and anomaly growth rate on the remaining safe life are illustrated in Figure 6.

Figure 6 is based on a pipe wall thickness of 0.312-in. and a MOP of 72 % of SMYS. The more steeply sloping line represents a 0.312-in.-wall pipe with an anomaly growth rate of 7 mils/year. Note that the remaining life following an assessment to 100 % or SMYS (a failure-pressure-to-MOP ratio of 1.39) is 10 years. Recall that the 10-year remaining life for the 0.25-in. wall pipe corresponded to a corrosion rate of only 5 mils/year. The difference arises from the facts that the thinner pipe will be penetrated more deeply in relation to its wall thickness in a fixed amount of time than the thicker pipe and that for a fixed value of remaining life, the ratio of growth rates has to be the inverse of the ratio of the thicknesses. Now consider the effect of a lower growth rate on the 0.312-in. wall pipe (see the line with the least slope in Figure 6). If the growth rate is cut in half from 7 mils/year to 3.5 mils/year, the remaining safe life is doubled.

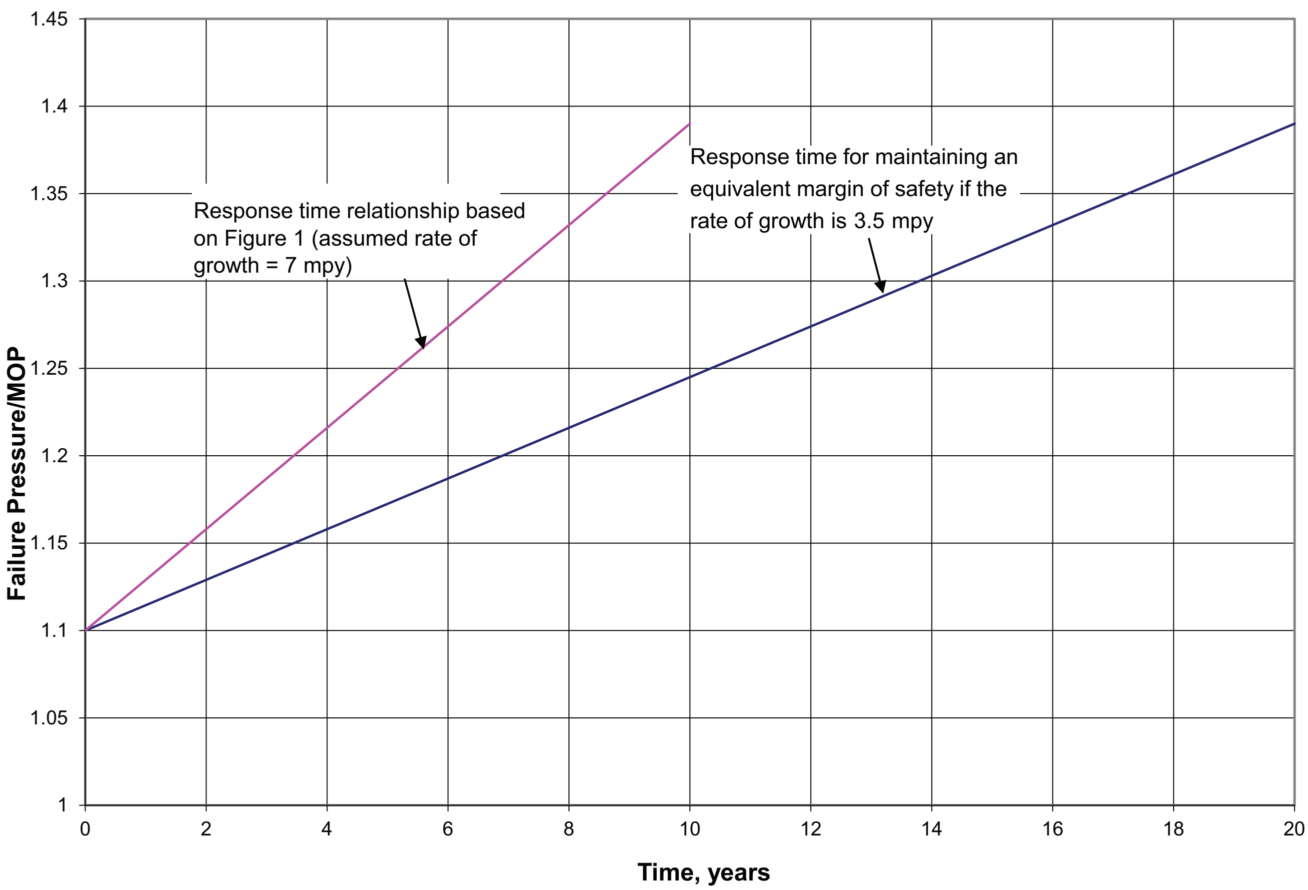


Figure 6—Effects of Wall Thickness and Defect Growth Rate

The examples described herein indicate that a pipeline operator should establish a Figure 5 for the specific circumstances of wall thickness, anomaly growth rate, MOP, and minimum failure-pressure-to-MOP ratio achieved by the current assessment in order to determine either when reassessment is needed or when it is necessary to remediate a particular anomaly. The process can be applied to corrosion-caused metal loss, SCC, and selective seam corrosion (i.e. to any time-dependent anomaly growth mechanism where it is safe to assume a constant anomaly growth rate). For each particular type of threat other than corrosion-caused metal loss in the body of the pipe, however, the user should account for the effect of material toughness on the sizes of defects that will fail at particular benchmark pressure levels.

9.4 Reassessment Times for Cracks That Grow by Pressure-cycle-induced Fatigue

To calculate times for reassessment for cracks that grow by fatigue, the pipeline operator should determine the appropriate C and n values to represent the maximum rate of fatigue crack growth in the segment and the pressure-cycle spectrum for a representative period for the location of the anomaly (usually a full year's worth of data is required). Cycle counting by the "rain-flow" method [see ASTM E1049-85, *Standard Practices for Cycle Counting in Fatigue Analysis* (reapproved in 1997)] is strongly recommended. If the last assessment was by means of a hydrostatic test, the operator should analyze a family of anomalies with different length/depth combinations each having the same failure pressure as the hydrostatic test pressure. This may be done on the basis of a model such as that represented in Figure D.3 taking the toughness of the material into account and using the length corresponding to the point of intersection of each d/t curve and the horizontal line representing the test pressure. The operator should assume that the family of anomalies is located at a point along the pipeline where it will experience the maximum pressure range (usually but not always the discharge of a pump station). If the analysis is based on an anomaly located by ILI, the operator may use the dimensions determined by ILI (considering the possibility of tool error), the toughness of the material, and the pressure cycle spectrum representative of the location of the anomaly. The operator should then apply the cycles to representative anomalies using an appropriate fatigue-crack growth model to ascertain the time it takes for each analyzed anomaly to grow from the size that it was at the time of the last assessment to the size that will cause a failure at the MOP. The reassessment interval should be one-half to one-quarter of the shortest calculated time to failure or less. When the safety factor for reassessment is being considered, the accuracy of known measurements, the risk of the pipeline segment and the accuracy of cycle counting should be considered.

10 Preventive and Mitigative Measures to Assure Pipeline Integrity

10.1 General

The preceding sections, Section 8 and Section 9, are focused primarily on integrity assessment and reacting to what is found through integrity assessment to address the time-dependent degradation threats such as corrosion, SCC and pressure-cycle-induced fatigue growth of pipe manufacturing flaws. In addition to conducting integrity assessments, a pipeline operator should implement preventive and mitigative measures that would tend to reduce the probability of a release and/or the consequences of a release from these time-dependent threats and from random (time-independent) threats such as third-party damage, equipment failure, and incorrect operations. Section 10 provides guidance for establishing and implementing preventive and mitigative measures to reduce the probabilities of releases and the consequences of releases from all threats.

The process of establishing and implementing preventive and mitigative measures begins with data gathering, data integration, and informational analysis as outlined in Section 6. Data integration and the analysis of the information developed through data gathering often reveal aspects of an operator's operations and maintenance that allow the operator to address the threats to pipeline integrity and reduce the consequences of potential releases. Most importantly, the incident history associated with certain components or circumstances should be considered. One or more incidents associated with any component or circumstance may indicate the need for enhanced preventive and mitigative measures associated with the particular component or circumstance. Some examples are shown in Table 5 and Table 6.

Table 5—Examples of Preventive Measures to Address Pipeline Integrity Threats

Threat	Problems Identified through Data Gathering and Integration	Preventive Measures
Weather/outside force	River crossing inspections identify exposed pipe due to river scouring.	Install protective mats in some cases or replace crossings with directional drills.
Internal corrosion	Internal MFL anomalies discovered at low spots in the pipeline.	Inject inhibitor. Run cleaning pigs more frequently.
Third-party damage	Near hits from landowners not making one-calls.	Install line-of-sight markers, trim rights-of-way more frequently, enhance contacts with landowners, or establish agreements not to cultivate.
Equipment failure	Seeps or stains in facilities at fittings or flanges.	Increase frequency of inspections. Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. Develop flange torque procedures.
Mechanical damage with delayed failure	Alignment of MFL anomalies with geometric anomalies reveals locations of previous damage to pipelines.	Increase frequency of aerial and foot patrols in areas of frequent new construction.
External corrosion	MFL anomalies and/or low cathodic protection readings.	Increase cathodic protection. Conduct more frequent close-interval P/S potential surveys.
Incorrect operations	Surges caused by poorly coordinated start-ups and unexpected shutdowns from power failures.	Conduct advanced hydraulic studies to optimize start-up procedures and train operators to use the new procedures. Install improved electrical gear at remote stations to minimize power outages.

Table 6—Examples of Mitigative Measures to Address Consequences

Consequences	Mitigative Measures
Contamination of drinking water aquifer.	Install hydrocarbon detection cable next to pipeline across the aquifer recharge area. Conduct spill drills aimed at rapid containment.
Ignition of vapor cloud in populated area.	Educate the public as to the danger of a vapor cloud. Provide emergency phone number to residents. Increased frequency of ILI. Improve emergency response criteria.
A release results in large drain-down.	Install EFRDs. Increase frequency of ILI. Improve emergency response criteria.
Small leak over time accumulates into large release.	Improve leak detection; increased frequency of ILI; enhanced patrol technology.

In addition to their application to specific problems identified by data analysis and integration, preventive and mitigative measures are needed to address all threats to pipeline integrity, including those that can be assessed as described in Section 8 and Section 9. Threats that cannot be addressed by integrity assessment methods include:

— manufacturing anomalies (hard heat-affected zones in ERW pipe);

— equipment failure;

— mechanical damage (causing an immediate failure);

— incorrect operations;

— weather and outside force (floods, landslides, subsidence, earthquakes, etc.).

The threat of mechanical damage causing an immediate failure and the threat of failure from weather and outside force are threats that potentially affect all pipelines. The threats of hard spots and hard heat-affected zones affect pipelines constructed with certain older, easily recognized materials that are susceptible to these phenomena. The measures for preventing and mitigating these are addressed in Section 10. In addition, this section presents minimum requirements for preventing corrosion, and it presents guidance for limiting consequences of pipeline releases by means of leak detection programs, flow restriction devices, and emergency response planning. Lastly, this section discusses the use of reducing operating pressure as a means to assure pipeline integrity. The preventive and mitigative measures for the threats of equipment failure and incorrect operations can be defined based on data gathering as shown in Table 5. Prevention of equipment failure is a subject to be addressed in a pipeline operator's operating and maintenance procedures. Prevention of incorrect operations should be covered in pipeline operator's operating procedures and operator training practices.

10.2 Prevention of Third-party Damage

10.2.1 General

To protect a pipeline system from immediate failures caused by mechanical damage, a pipeline operator should establish a program to detect and prevent unauthorized encroachments on the rights-of-way of the pipeline system. A damage prevention program should contain the following elements:

— maintaining adequate, up-to-date maps of the system;

— participating in a one-call system;

— providing for timely temporary marking of any portion of the operator's system that falls within the location scope of a one-call "ticket";

— establishing written guidelines for excavators authorized to work on the right-of-way stating what procedures an excavator should follow;

— providing a full-time observer while excavation is in progress on, or in proximity to the pipeline;

— establishing and continuing a public awareness program with land occupants, excavators, and contractors;

— maintaining adequate permanent pipeline-identifying markers along the rights-of-way and trimming and mowing the rights-of-way, where permissible, so that they remain identifiable and visible from the air;

— conducting periodic aerial and/or ground-based surveillance of all rights-of-way;

— installing continuous markers or physical barriers where appropriate on new or reinstalled segments or providing for deeper burial where appropriate;

— documenting all detected hits or near misses associated with either authorized or unauthorized encroachments on rights-of-way and investigating the causes for the hits or near misses;

— minimizing impacts to critical locations and/or designated high consequence areas.

See API 1166 for additional guidance on excavation monitoring and observation.

Implementation of an effective damage prevention program requires adequate resources and adequately trained personnel to execute it. Therefore, a pipeline operator should establish a team of personnel that is responsible for the damage prevention program and should provide the training necessary to assure that the personnel have adequate knowledge and skills to understand the elements of damage prevention in order to be able to execute the program effectively. At a minimum the damage prevention personnel should:

— be familiar with the pipeline system so that one-call "tickets" will be screened in a timely manner;

— be able to communicate easily with the appropriate one-call centers;

— be trained in locating underground facilities;

— be able to communicate with excavators, land occupants, emergency response personnel, and the public;

— be trained to monitor excavation and are familiar with the pipelines to which they are assigned;

— be familiar with pipeline surveillance techniques and have the opportunity to communicate with patrol pilots.

10.2.2 Mapping

A pipeline operator should create and maintain an up-to-date map of each pipeline facility. The maps of appropriate parts of the system should be provided to all one-call centers whose coverage includes those pipeline segments. Alternatively, the operator should indicate to all one-call centers covering regions containing segments of the operator's pipelines, the "grid squares" through which those segments pass (see 10.2.3). Preferably, electronic maps should be provided which show each of the operator's pipelines within a corridor of suitable width (e.g. 500 ft on either side of the centerline of the pipeline).

10.2.3 One-call Systems

Many states within the United States and many countries require operators of underground utilities to participate in a "one-call" system. The United States has established 811 as a nationwide one-call number. The purpose of the one-call system is to accept calls from potential excavators and to relay the location, scope, and time of the excavation to each utility having a facility located within a particular square of the "grid" covered by the one-call system (a typical grid square might be 1000 ft by 1000 ft). The information provided by the excavator is recorded on a document commonly referred to as a "ticket." Copies of the ticket are sent to each of the participating utilities to notify them of the location, scope, and time of the excavation. Each notified utility is then responsible for locating and marking their facilities located within the square that could be affected by the excavation. A pipeline operator should participate in a one-call system in every area in which the operator has facilities. The operator should either indicate which of the system's grids contain segments of the operator's pipelines and/or supply the one-call center with up-to-date maps of the pipeline segments.

10.2.4 Locating and Marking

Upon receipt of a ticket from a one-call center, a pipeline operator should attempt to determine whether or not the excavation could affect one of the operator's pipelines. If the operator is certain that the excavation will not encroach upon any of the operator's facilities, the ticket should be "cleared," that is, the operator should notify the one-call center that none of the operator's facilities will be impacted or make contact with the excavator directly if the one-call center does not have positive response capability. If, however, the excavation will be on or close to the operator's right-of-way, the operator should promptly locate the pipeline that could be affected and mark its location with temporary markings. The markings should indicate the location of the centerline and size of the pipeline or the sides of the pipeline (or pipelines if it is a multiple-pipeline right-of-way). The operator should renew the markings if they become displaced by excavation or if they become degraded with the passage of time until all excavation activity has ceased.

10.2.5 Communication with an Excavator and Monitoring an Excavation

The pipeline operator, besides locating and temporarily marking the pipeline, should establish a communication link with the excavator that may involve the following:

— exchange of names of contacts and phone numbers;

— issuance of a written procedure for the excavator to follow that includes a distance-to-the-pipeline limit within which nonmechanical excavating techniques should be used, a description of how any exposed pipe should be supported, and a procedure for back-filling that will avoid damaging the coating on the pipeline or any cathodic protection attachments;

— agreement on a start time and the fact that the operator's observer should be present when excavation is approaching within a specified distance of the pipeline.

Pipeline operators may obtain detailed guidance on monitoring and observing excavations in API 1166.

10.2.6 Public Awareness

Because not every potential excavator may be aware of the dangers of excavating near a hazardous liquid pipeline, a pipeline operator should establish a public awareness program. Pipeline operators may obtain detailed guidance on establishing and maintaining a public awareness program in API 1162.

10.2.7 Right-of-way Maintenance and Surveillance

As a defense against unauthorized encroachments, a pipeline operator should clear the rights-of-way of underbrush, tall weeds, trees, and canopy (where permissible). Keeping the rights-of-way clear in this manner facilitates aerial surveillance, alerts land occupants and others to presence of a pipeline corridor and increases the likelihood that anyone happening onto a right-of-way will see one or more permanent markers indicating the presence of an underground pipeline.

A pipeline operator should regularly conduct surveillance of each right-of-way, either by aerial patrol or other means such as ground patrol. When using aerial patrols, operators should consider the use of a separate observer in addition to the pilot in order to improve the effectiveness of this type of right-of-way surveillance.

Alternatively, a pipeline operator may decide to patrol certain rights-of-way on foot or by means of a vehicle.

10.2.8 Permanent Markers, Warning Techniques, and Physical Barriers

A pipeline operator should install permanent markers to alert anyone approaching a pipeline right-of-way that a pipeline is present. For guidance on the appropriate design of pipeline markers including where to put them and the types of information that should be provided on the markers, the operator should consult API 1109.

A pipeline operator may consider installing physical barriers such as concrete slabs above the pipeline to protect it. Alternatively, the operator may elect to bury a warning tape or plastic mesh above the pipeline to alert an excavator to the presence of a buried pipeline. These measures, if desired, can usually only be taken in conjunction with the construction of a new pipeline or the relocation of an existing pipeline. A pipeline operator may also consider lowering an existing pipeline by exposing and reburying it at a deeper depth. This may be necessary where a new road or railroad is being built over an existing pipeline. Another option is performing a depth of cover survey and proactively lowering shallow pipe in actively tilled land or areas where significant construction activity is occurring, planned or expected.

10.2.9 Documenting Hits and Near Misses

In order to determine which damage prevention techniques are the most cost effective, it is helpful to study and evaluate past mechanical damage hits and near misses. By understanding how these hits or near misses occurred, pipeline operators will be able to focus resources on the preventive techniques that are the most effective. In North America, the Common Ground Alliance has establish a formal, but voluntary, Damage Incident Reporting Tool (DIRT). An operator of an underground facility who wishes to participate in this effort is asked to document each hit or near miss in conjunction with any excavation that takes place on, above, or immediately adjacent to the facility whether authorized or unauthorized. Analyses of these data have helped to identify when and how preventive measures either work as intended or fail to do their job. As this effort continues, it is reasonable to expect that pipeline operators will learn which preventive measures are the most effective.

10.3 Preventing Releases Associated with Hard Spots and Hard Heat-affected Zones in Line Pipe

Pipeline operators have dealt successfully with round or oval hard spots in the body of the pipe by locating them with ILI magnetic tools and eliminating them or shielding them from cathodic protection. Unfortunately, to date no ILI technique has emerged that is capable of locating the narrow hard zones adjacent to some ERW bondlines. Pipeline operators experiencing the latter phenomenon generally have had to resort to barring the transport of sour crude or to monitoring cathodic protection levels and limiting them to levels that are adequate to prevent corrosion but not so high as to generate excessive amounts of hydrogen at coating holidays.

10.4 Preventing or Mitigating Releases Associated with Weather and Outside Force

A pipeline operator should attempt to prevent or mitigate the damage from weather events such as extreme cold, high winds, and flooding and from geophysical events such as earthquakes, landslides, land erosion, or subsidence that could cause releases. Preventive or mitigative activities that an operator should consider are:

— inspecting drain valves and pipe extensions before cold weather arrives to eliminate water that will freeze and could cause breakage;

— shutting down and, if feasible, purging pipeline segments that could be damaged by impending hurricanes or floods;

— providing for movement of the pipeline to occur without damaging the pipeline at seismic fault crossings, seismic fault crossings, unstable slopes, or areas of subsidence;

— training patrol pilots to spot areas of developing soil instability, landslides, and subsidence;

— conducting patrols as soon as feasible after the passage of severe weather, flooding, or an earthquake;

— monitoring river crossings for exposed pipe in crossings or at riverbanks;

— routinely gather updated GIS data regarding fault zones, land use, etc.

10.5 Control of Corrosion

10.5.1 External Corrosion

All new pipelines should be protected from external corrosion by the installation of a protective external coating and an adequate cathodic protection system. NACE SP0169 provides minimum criteria for applying cathodic protection to mitigate external corrosion of a buried steel pipeline. Cathodic protection should be applied to an existing pipeline as well whether it is coated or bare. Pipeline operators should also follow NACE SP0169 with regard to the minimum level of protection that should be maintained on an existing pipeline. Cathodic protection levels should be monitored at least once every 12 months. The levels of protection should be determined by making pipe-to-soil potential measurements at test leads typically located at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

At areas where the potentials fall below the levels indicated by NACE SP0169, the operator should investigate the cause of the low potentials and mitigate them. Mitigation should consist of bringing the cathodic protection levels into compliance with the levels specified in NACE SP0169 either by making sufficient repairs to the coating and/or by increasing the current outputs of existing anodes or adding anodes to increase the current output necessary to achieve the recommended levels. A pipeline operator may also find it useful to employ one or more of the ECDA techniques described in 8.5 to enhance the mitigation of external corrosion of a given pipeline segment.

Induced AC corrosion has become better understood and should be controlled. For information on mitigating induced AC corrosion, see NACE 35110 and also NACE SP0177.

10.5.2 Internal Corrosion

If the fluid being transported in a pipeline has the potential to corrode the internal surface of the pipeline, the operator should determine the nature of the corrosion that could occur and should take adequate steps to mitigate it. The most common form of internal corrosion arises in conjunction with the holdup of water and/or the deposition of sediment. These phenomena are a function not only of the fluid characteristics but also of the flow velocity and the elevation profile. The operator can monitor critical locations by installing coupons or resistance-change devices or by measuring wall thickness to detect loss of metal. Mitigative steps include:

— the injection of a suitable inhibitor or biocide,

— frequent cleaning with cleaning pigs to remove sediment and water,

— maintaining a minimum flow velocity to minimize water and sediment entrainment,

— flushing dead-legs or valve bodies.

A pipeline operator may also find it useful to employ one or more of the internal corrosion direct assessment (ICDA) techniques described in 8.5 to enhance the mitigation of internal corrosion of a given pipeline segment. See also NACE SP0208 and NACE SP0106.

10.6 Detecting and Minimizing the Consequences of Unintended Releases

10.6.1 General

An IMP should contain protocols for detecting leaks and for limiting the consequences in the event of an unintended release. Elements of the plan should describe the means and procedures for:

— minimizing the time required for detection of a release,

— minimizing the time required to locate a release,

— minimizing the volume that can be released,

— minimizing emergency response time,

— protecting the public and limiting adverse effects on the environment.

10.6.2 Reducing the Time to Detect and Locate Unintentional Releases

A pipeline operator should select, install, and maintain a leak detection system or systems appropriate for the length and size of the pipeline, the type of products within the pipeline, and the spill scenarios for critical locations developed in Section 5 of this RP. The abilities to detect a leak of a certain minimum size and to locate where such a leak has occurred depend on the type of leak detection system or systems employed. The leak detection methods and their characteristics are summarized in Table 7. Brief descriptions of leak detection methods are presented below.

A pipeline operator may find it advantageous to employ a combination of these methods. For example the computational methods could be augmented by a volume balance approach and/or tracer chemicals or a stand-up test could be used on occasion as a check on the real-time methods. In any case all real-time leak detection systems should be tied to the SCADA system, and the operating personnel should be well-versed as the nature, characteristics, and operation of each leak detection system.

Table 7—Leak Detection Methods

Method	Locates Leak	Availability	Beneficial Feature	Biggest Limitation
Periodic auditory, visual, and olfactory inspections	Yes	Periodic	Simplicity	Delayed recognition of leak between intervals
Volume balance	No	Intermittent based on comparison time	Simplicity	Transients tend to cause false alarms
Dynamic flow modeling	Yes if analysis is done	Continuous even when transients are present	Best method to detect small leak rapidly	Complexity and cost
Tracer chemical	Yes	Can be either continuous or one time	Accurately locates small leaks	Must add something to the product and requires air sampling
Release detection cable	Yes	Continuous	Accurately locates small leaks	Next to impossible to retrofit to an existing pipeline
Shut-in leak detection	No	Periodic	Simplicity	Requires shutting off flow and accurate pressure monitoring
Pressure point analysis	Yes, if multiple points used	At the sampling rate except during transient operation	Simplicity	Not suitable for large pipelines or compressible fluids
Acoustic leak detection	Yes	Continuous		

10.6.3 Isolation and Control of a Release

Once a release has been confirmed the pipeline should be shut down. An exception to this would be leaving a pump station in operation if it is pulling product away from the release site. Shutting down the system and/or pumping product away from the release limits the subsequent volume of the release to the gravity drain-down volume (or vaporization of a HVL). The pipeline operator should locate and isolate the release as rapidly as possible to further limit the quantity of the release by minimizing gravity drain-down (or the size of the vapor cloud in the event of the release of a HVL).

Manually closing block valves may aid in limiting the gravity drain-down volume. Operators should consider installing block valves or check valves in appropriate locations to minimize spills. EFRDs such as remotely actuated, automatic valves, or check valves can be employed to further limit the gravity drain-down volume. Automatic valves should be employed only in situations where normally expected transients will not cause them to close when there is no leak.

It should be noted that adding additional valves to a pipeline right-of-way may increase the risk of certain threats. The potential increase in risk should be considered in a manner consistent with considering other risk factors. When determining whether to install additional remote or check valves, an overall risk reduction would be needed to justify such installations.

10.6.4 Emergency Response

A very important means to limit the consequences of a release is for the operator to provide a timely and sufficient response to a leak. Note that the need for an emergency response may not arise as the result of the operator's leak-detection system. Sometimes releases are discovered by the operator's personnel or a third party. Even when a release has occurred, the consequences of a release can be significantly reduced if the operator is adequately prepared to deploy personnel and equipment who can install or erect physical barriers to limit the spread of released product and to recover as much of the spilled product as possible. The operator's emergency response plan should provide for:

— establishing lines of responsibility for an emergency response to an unintended release;

— training for all personnel responsible for mitigation of an unintended release;

— communication with law enforcement and firefighting agencies who can limit access to the site and to protect the public;

— isolation of the leak to limit the volume released;

— limiting the spread of the released product by deploying booms on water or by erecting soil berms on land;

— recovery of as much released product as possible;

— temporary accommodation of members of the public displaced by the release;

— providing potable water if drinking water supplies are at risk.

On a longer term basis the operator should also provide for:

— mitigation of contaminated soil or water,

— restoration of the site.

Response drills should be carried out periodically to train response personnel, to test response equipment, and to improve procedures if possible. It is a good practice for operators to evaluate their response after the exercise to identify opportunities for improved performance. Outside agencies such as law-enforcement and firefighting agencies should be informed of and included in response drills. Pipeline operators in the United States are bound by 33 *CFR* Chapter 40, Oil Pollution (otherwise known as OPA 90) with regard to unintended release that could cause substantial harm to the waters of the United States.

10.7 Reducing Pressure

A reduction in operating pressure can be used to reduce the risk associated with threats to pipeline integrity that are hoop stress related (i.e. corrosion-caused metal loss, SCC, mechanical damage, or the growth of an anomaly through pressure-cycle-induced fatigue). A pressure reduction can be either permanent or temporary. If operators are unable to meet repair or reassessment deadlines, they should implement a temporary pressure reduction. An operator wishing to employ a pressure reduction can assess the value of a given amount of pressure reduction in the same manner as the test-pressure-to-operating-pressure ratio of a hydrostatic test by consulting Annex D.

11 Integrity Management of Pump Stations and Facility Piping

11.1 General Considerations

Because the piping and operation of facilities are distinctly different from that of mainline pipe, the threats to piping at facilities such as pump stations, terminals, and loading facilities are characterized and grouped in a different manner than they are for mainline pipe. Experience suggests that facilities piping incidents typically involve small leaks. Large-volume releases in facilities piping are rare. The attributes of facilities piping that distinguish it from mainline piping and need to be considered in the management of its integrity are:

— relatively low operating stresses,

— multiple types and sizes of piping and tubing,

— smaller sizes of pipe often joined by nonwelded fittings,

— branches of the system that are utilized infrequently leading to low or intermittent flow,

— much of the system installed aboveground on supports,

— aboveground piping sometimes covered with insulation,

— piping configurations that result in “trap space” where water may accumulate,

— located within a facility where access is controlled by the operator.

The hazardous liquids industry’s Pipeline Performance Tracking System (PPTS) has made a study of facilities piping and has issued PPTS Advisory 2009-5 that identifies the primary threats to facilities piping as:

— improperly installed fittings in small-bore tubing and piping (≤ 2-in. NPS);

— vibration of small-bore tubing and piping;

— internal corrosion from trapped water and/or sludge particularly with crude oil—types of piping most susceptible are drain lines, relief lines, and “dead-legs” that experience low or intermittent flow of product;

— freezing of trapped water.

Other threats to facilities include:

— external corrosion at supports or hangers,

— external corrosion at soil/air interfaces,

— external corrosion under insulation (CUI),

— Internal erosion and corrosion/erosion,

— environmental cracking associated with the transport of fuel grade ethanol,

— flanged or other connections.

These threats and their mitigation are discussed in this section. This section does not cover threats that arise from equipment failure or operating errors. The latter should be addressed through operating procedures, equipment maintenance and inspection, and operator qualification. Similarly, pipeline breakout storage tanks are outside the scope of this document. Inspection and maintenance or pipeline breakout storage tanks are covered by API 653.

Section 11 is organized as shown in Table 8.

11.2 Tubing and Small-bore Piping

Tubing and small-bore piping (generally considered to be piping of ≤ 2-in. NPS) have many uses within a facility including instrumentation lines and control lines. Often these lines are assembled with fittings of various types rather that with electric arc girth welding as is the case with mainline pipe. The previously mentioned PPTS advisory found that improperly installed fittings were one of the most frequent causes of leaks in tubing and small-bore piping. Pipeline operators should establish written standards for the assembly of piping and tubing with fittings. Fitting

Table 8—Organization of Topics Covered in Section 11

Main Topic	Subtopic	Subject Matter
11.2 Tubing and Small-bore Piping		Importance of proper installation, mitigation of vibration and stress, use of electrical instrumentation in place of small tubing.
11.3 Mitigating Internal and External Corrosion	11.3.2 Dead-legs, Drain Lines, and Relief Lines	Periodic flushing to remove water and sludge, periodic UT measurements of wall thickness, GWUT for inspection of buried segments, remove unnecessary dead-legs.
	11.3.3 Soil-to-air Interface	Visual inspection, removing soil and coating if necessary, carefully replacing coating and seals.
	11.3.4 Contact Corrosion	Visual inspection possibly supplemented by UT or GWUT, use of dielectric materials to separate pipe from support structures or hangers.
	11.3.5 Corrosion under Insulation (CUI)	Preventing water ingress, checking for missing or damaged insulation, using “plugs” for inspection sites.
	11.3.6 Erosion and Corrosion/ Erosion	Inspecting wall thickness at locations of high flow and/or direction changes.
11.4 Preventing Freezing of Trapped Water		Inspecting areas where water may become trapped and draining any water before freezing weather occurs.
11.5 Preventing Ethanol-related Cracking		Inspection for systems that have demonstrated susceptibility, reference documents for detailed prevention and mitigation.
11.6 Visual Inspections and NDE		Setting up systematic inspections, reference documents for details of facility inspection procedures, lists of some of the major items that should be inspected.
11.7 Incident History		Reviewing records to recognize the relevant threats and to focus mitigation where needed.

manufacturers’ assembly instructions should be carefully followed, and individuals employed for the purpose of assembling piping and tubing with fittings should be adequately trained for that purpose.

Other important causes of releases from tubing and small-bore piping included vibration and damage by outside force. These problems tend to arise from inadequate design and/or protection of piping and tubing systems. Piping spans should be supported and protected such that the effects of mechanical vibrations and exposure to outside forces will be minimized. Long unsupported spans of tubing or piping should be avoided. Using tubing or piping to support concentrated loads should be avoided. Tubing and small-bore piping should be protected from vehicles that may be moving around a facility.

Pipeline operators should take steps to minimize the risk of tubing and small-bore piping failures by replacing instrumentation lines with electrical signal devices where possible. For example, pressure readings can be conveyed electrically from pressure transducers rather than through tubing connecting the pressurized fluid to a mechanical pressure gage. Operators should also maintain adequate and up-to-date piping and instrumentation P&ID diagrams. Visual inspections of the tubing and piping should be carried out at regular intervals to assure that all critical components and locations a visually inspected.

11.3 Mitigating Internal and External Corrosion

11.3.1 General

Because facility piping generally cannot be inspected by ILI or subjected to periodic hydrostatic testing, inspections of facility piping and tubing depends on periodic visual inspection and the use of ultrasonic and/or radiographic wall thickness measurements. For additional information, see API 570 and API 2611. Pipeline operators should perform visual and wall thickness measurements where corrosion rates are known to be higher than average. Each operator should establish periodic inspection programs for the following specific types and areas of deterioration:

— internal corrosion in dead-legs, drain lines, and relief lines;

— external corrosion at supports and hangers;

— external corrosion at soil-to-air interfaces;

— external CUI;

— internal erosion and corrosion/erosion.

These situations are explained in more detail below. In all cases periodic inspections in conjunction with wall thickness measurements are suggested as means to monitor these situations. The frequency of inspection can be based on a corrosion rate established from the measured wall thickness loss. In the absence of established corrosion rates, other methods may be used to determine corrosion rates (e.g. a Monte Carlo simulation with distributions of pit depths and corrosion starting times). Models for calculating remaining strength of corroded pipe such as Modified B31G or RSTRENG can be used to predict SOPs or corroded tubing and piping within facilities. However, operators should be cautious about using these models alone with piping that is operated at low levels of hoop stress (i.e. less than 50 % of SMYS) because the effect of contact stresses or secondary stresses could cause the failure stress to be less than that predicted by such models. In such cases the operator should consider carrying out a more sophisticated analysis, for example, by using finite element modeling.

11.3.2 Dead-legs, Drain Lines, and Relief Lines

Dead-legs are segments of pipe connected at one end to active piping that experiences constant or frequent flow but are closed at one end so that they experience no flow. They may exist for a variety of reasons such as stubs installed for planned future expansions or locations where some type of equipment has been removed. Drain lines are used to drain product from the system when drain-down is required. Relief lines connect pressure relief valves to tanks or flare stacks. The common characteristic of these lines is that the flow of product is either intermittent or nonexistent. As a result, water and or sludge may accumulate in these lines possibly resulting in internal corrosion. The problem is most pronounced with crude oil, but water/condensation is also a cause of internal corrosion in refined product systems. Such systems may be subject to MIC as well. The wall thickness should be monitored periodically at locations where water may be expected to accumulate (i.e. at the stagnant end of a dead-leg and at the point of its connection to an active line, and low points and blocked ends to drain lines and relief lines. Wall thickness measures on aboveground piping can be made by an appropriate nondestructive examination (NDE) method such ultrasonic or radiographic thickness determination. Buried segments may be inspected by GWUT. Where wall thickness losses portend the occurrence of leakage, the particular piping should be repaired or replaced.

Consideration should be given to removing dead-legs that serve no further process purpose. Where possible, dead-legs, drain lines, and relief lines should be flushed out/displaced on a regular basis. The addition of biocides and corrosion inhibitors to the flushing fluid can slow the rate of deterioration.

11.3.3 Soil-to-air Interface

Inspection at grade should include checking for coating damage, bare pipe, and pit depth measurements. If significant corrosion is noted, thickness measurements and excavation may be required to assess whether the corrosion is sufficient to impair the integrity of the piping. Consideration should be given to excavating 300 mm (12 in.) deep to assess the potential for hidden damage. Significantly impaired piping should be repaired or replaced. Thickness readings at soil/air interfaces may expose the metal and accelerate corrosion if coatings and wrappings are not properly restored. If the buried piping has satisfactory cathodic protection, excavation is required only if there is evidence of coating or wrapping damage. At concrete-to-air and asphalt-to-air interfaces for buried piping without cathodic protection, the interface should be inspected for evidence that the caulking or seal at the interface has deteriorated and allowed moisture ingress. If such a condition exists on piping systems over 10 years old, it may be necessary to inspect for corrosion beneath the surface before resealing the joint.

11.3.4 Contact Corrosion

Contact corrosion, particularly more aggressive in humid climates and/or coastal locations, needs to be monitored. Typical areas for more aggressive corrosion are between the pipe support and contact area of the pipe, and welds/ joints along the pipe. Corrosion cells may arise from moisture/dew collection and/or dissimilar metals (i.e. weld material has different composition than the pipe base metal).

Where visual inspection at supports of hangers suggests the presence of corrosion products, the piping and support should be separated to permit detailed inspection with equipment to determine the remaining wall thickness. Whenever possible, the use of NDE, such as UT or GWUT, should be considered in addition to visual inspection. Care should be taken to avoid overstressing the piping by temporarily supporting the pipe adequately if the pipe is to be lifted or the support is to be removed. Piping that has sustained significant wall loss such that either internal pressure or support stresses could cause leakage should be repaired or replaced.

To prevent further corrosion, operators should consider recoating or installation of dielectric material between the pipe and support. Operators could also design out or minimize the crevice. If no corrosion exists, operators should consider applying epoxy or other sealant material to the pipe support interface.

11.3.5 Corrosion Under Insulation (CUI)

External inspection of insulated piping systems should include a review of the integrity of the insulation system for conditions that could lead to CUI and for signs of ongoing CUI. Sources of moisture may include rain, water leaks, condensation, and firewater deluge systems. The most common forms of CUI are localized corrosion of carbon steel.

The extent of a CUI inspection program may vary depending on the local climate. Warmer marine locations may require a very active program, whereas cooler, drier, mid-continent locations may not need as extensive a program.

Certain areas and types of piping systems are potentially more susceptible to CUI, including the following:

— areas exposed to frequent rains;

— areas exposed to steam vents;

— areas exposed to firewater deluge systems;

— areas subject to spills, ingress of moisture, or acid vapors (i.e. from neighboring businesses);

— carbon steel piping systems, including those insulated for personnel protection, operating between 4 °C and 120 °C. CUI is particularly aggressive where operating temperatures cause frequent or continuous condensation and reevaporation of atmospheric moisture;

— attachments that protrude from insulated piping and operate at a different temperature than the operating temperature of the active line;

— vibrating piping systems that have a tendency to inflict damage to insulation jacketing providing a path for water ingress;

— steam traced piping systems that may experience tracing leaks, especially at tubing fittings beneath the insulation;

— piping systems with deteriorated coatings and/or wrappings.

Piping systems may have specific locations within them that are more susceptible to CUI, including the following.

- All penetrations or breaches in the insulation jacketing systems, such as:
  - dead-legs (vents, drains, and other similar items),
  - pipe hangers and other supports,
  - valves and fittings (irregular insulation surfaces),
  - bolted-on pipe shoes,
  - steam tracer tubing penetrations.
- Termination of insulation at flanges and other piping components.
- Damaged or missing insulation jacketing.
- Insulation jacketing seams located on the top of horizontal piping or improperly lapped or sealed insulation jacketing.
- Termination of insulation in a vertical pipe.
- Caulking that has hardened, has separated, or is missing.
- Bulges or staining of the insulation or jacketing system or missing bands. (Bulges may indicate corrosion product buildup.)
- Low points in piping systems that have a known breach in the insulation system, including low points in long unsupported piping runs.

Locations where insulation plugs have been removed to permit piping thickness measurements on insulated piping should receive particular attention. These plugs should be promptly replaced and sealed. Several types of removable plugs are commercially available that permit inspection and identification of inspection points for future reference.

11.3.6 Erosion and Corrosion/Erosion

Erosion can be defined as the removal of surface material by the action of numerous individual impacts of solid or liquid particles, or cavitation. It can be characterized by grooves, rounded holes, waves, and valleys in a directional pattern. Erosion is prone to occur in areas of turbulent flow, such as at changes of direction in a piping system or downstream of control valves, where vaporization may take place. Erosion damage is usually increased in streams with large quantities of solid particles and high velocities. A combination of corrosion and erosion (corrosion/erosion) results in significantly greater metal loss than can be expected from corrosion or erosion alone. This type of corrosion occurs at high velocity and high turbulence areas. Examples of places to potentially inspect include:

- downstream of orifices;
- downstream of pump discharges;
- at any point of flow direction change, such as the outside radius of elbows.

Areas suspected to have localized corrosion/erosion should be inspected using appropriate NDE methods that will yield thickness data over a wide area, such as UT, GWUT, ultrasonic scanning, radiographic profile, eddy current, or external MFL. The effect of wall thickness loss on piping integrity should be determined using industry approved methods such as Modified B31G or RSTRENG, and piping that exhibits inadequate remaining strength should be repaired or replaced.

11.4 Preventing Freezing of Trapped Water

At subfreezing temperatures, water and aqueous solutions in piping systems may freeze and cause failure because of the expansion of these materials. After freezing weather, it is important to check for freeze damage to exposed piping components before the system thaws. If rupture has occurred, leakage may be temporarily prevented by the frozen fluid. Low points, drain nipples with valves or caps, and dead-legs of piping systems containing water should be carefully examined. If possible, low points and drain lines should be purged of water each year before the start of freezing weather.

11.5 Preventing Ethanol-related Cracking

Where specific segments or piping circuits have a demonstrated susceptibility to environmental cracking, the operator should schedule supplemental inspections. Such inspections can take the form of nondestructive examination (NDE), for example, PT or wet fluorescent magnetic-particle testing (WFMT). Where feasible, suspect spools may be removed from the piping system and split open for internal surface examination.

Environmental cracking is not common in pipeline facilities. For consideration of fuel ethanol transport, see API 939-D.

Another document for consideration is API 939-E.

11.6 Visual Inspections and NDE

While more thorough guidance is available in documents such as API 570, API 2611, and API 2610, operators should conduct periodic visual and NDE inspections to assure that all important elements of a facility are inspected. Elements to be considered for inspection at recurring intervals should include the following.

- Valves and flanges:
  - establish torque procedure for making up a joint,
  - look for signs of leakage such as stains,
  - examine studs and nuts for looseness and/or corrosion,
  - make sure threads extend through and beyond nuts,
  - establish an alignment procedure for making up a flange connection,
  - establish a procedure for monitoring buried flange connections.
- Threaded, compression, or flared fittings:
  - check for signs of leakage, misalignment, corrosion, or mechanical damage;
  - assure that the schedule (wall thickness) of threaded nipples provides for an allowance to threats that may be encountered (e.g. corrosion, vibration).
- Vibration:
  - observable oscillation,
  - excessive overhung weight,
  - inadequate support,
  - loose supports causing metal wear.

- Dead-legs:
  - eliminate or isolate/drain identified dead-legs, if possible;
  - establish a periodic flushing procedure if possible;
  - develop a method to assess the integrity of the dead-leg (e.g. UT wall thickness measurements).
- Drain lines and relief lines:
  - measure wall thickness at low spots,
  - purge water from low spots each year before start of freezing weather,
  - where feasible, flush with product containing inhibitor and/or biocide.
- Supports:
  - missing shoes,
  - hanger distortion or breakage,
  - brace distortion/breakage,
  - loose brackets,
  - metal wear or corrosion at support contact.
- Coating:
  - general coating or paint deteriorated,
  - soil-to-air interface coating missing or deteriorated.
- Insulation:
  - damage/penetrations,
  - missing jacketing/insulation,
  - end seal deteriorated,
  - bulging,
  - banding broken or missing.
- Casings:
  - both ends of the casing extending beyond the ground line, if practical;
  - verify that the pipe and casing are not metallically shorted.

In addition to these scheduled external inspections by inspection personnel, other personnel who frequent the piping system area should be on the lookout for and report deterioration, changes to the piping system, or other irregularities.

11.7 Incident History

The pipeline operator should conduct a thorough review of the incident history of the facility and of facilities with similar designs and characteristics. Operators should also consider industry incident history such as the PPTS Operator Advisory 2009-5. The focus of mitigative actions to prevent releases at facilities should be on the threats that are known to have caused releases in the past. In addition, any near misses or incidents that required repairs to facilities and reconstruction of certain components should be studied.

12 Program Evaluation

12.1 General

Reviews need to be performed on a periodic basis to evaluate the effectiveness of a pipeline operator's IMP. The intent of this section is to provide operators with a methodology that can be used to evaluate the effectiveness of their pipeline and facility integrity management. An integrity management program evaluation should help an operator answer the following questions:

1) Were all integrity management program objectives accomplished?

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

The operator should 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 self-reviews is necessary to evaluate the overall effectiveness of a pipeline integrity management program. Operators may consider communicating the benefits and accomplishments of their IMPs and activities to various stakeholders including regulators and the public.

12.2 Performance Measures

12.2.1 Performance Measures by Integrity Threat

From the standpoint of threats to pipeline integrity, three types of performance measures should be considered: process measures (also called activity measures), operational measures, and integrity measures. Each of these types of measures can be made through comparisons between leading (proactive or goal-oriented) activities or benchmarks and lagging (reactive or outcomes-oriented) indicators. Operators are encouraged to select as many measures as make sense for their system. As will become apparent, the period of measuring may vary because it may take years rather than weeks or months to achieve a meaningful measurement of the effectiveness of some integrity assessment, mitigation, and preventive measures. Examples of performance measurements from the standpoint of threats to pipeline integrity are presented in Table 9, and the examples are discussed in some detail to assist a pipeline operator in designing an adequate program of performance measurements.

The performance measures are presented by integrity threat in Table 9. All threats applicable to an operator's system should be included. For the hypothetical example represented in Table 9, the operator was concerned with 6 of the 13 threats listed in Section 6 and Section 8. For simplicity, only one or two performance measures are included in this example, but an operator may identify many performance measures for each threat.

Consider first, measures of the performance of the integrity management process. For the threat of external corrosion, the hypothetical operator's IMP called for inspecting (and remediating anomalies) on the 20 highest risk segments within Year 1 of the program (a leading indicator of the integrity management process). In Year 1, the 19 highest risk segments were inspected and the anomalies remediated (a lagging indicator of the integrity management process). One measure of success of the external corrosion integrity management process is that 95 % (the 19 highest risk segments out of 20) were inspected and the anomalies remediated in 1 year. A second measure of success of the process comes from the facts that the operator planned to inspect (and remediate) all remaining

Table 9—Examples of Performance Measurement by Threat

Threat	Measure Number	Process Measures		Operational Measures		Integrity Measures	
		Leading	Lagging	Leading	Lagging	Leading	Lagging
External corrosion	1	Planned to inspect 20 highest risk segments in Year 1	Actually inspected 19 highest risk segments	Installed 10 new rectifiers in Year 1	Potentials on the five highest risk segments brought into compliance with NACE criteria	Goal of reducing leaks to zero by the end of Year 5	Reduced leaks by 88 %
	2	Planned to inspect the remaining segments by the end of Year 5	All segments inspected by the end of Year 5	Installed rectifiers as needed in Year 2 through Year 5 to bring all segments into compliance	Potentials on 95 % of mileage brought into compliance with NACE criteria		
Internal corrosion	1	Planned to inspect one problematic segment	Inspected segment and repaired all anomalies over 50 % of wall	Injected inhibitor and ran cleaning pigs monthly	Spot checks of hold up locations after five years showed no more wall loss	Reduce leaks to zero by the end of Year 5	One leak in Year 1, zero leaks thereafter through Year 5
Stress corrosion cracking (SCC)	1	Planned to hydrostatically test two segments every 10 years	Hydrostatically tested two segments in Year 1	Recoated 20 miles of pipe where old coating was mostly disbonded	Spot checks after 10 years showed no areas of disbonding	Goal of zero releases from SCC before the next test	No releases from SCC have occurred through Year 5
Mechanical damage (immediate failure)	1	Contact every land occupant once in three years	Personal contact was made with 95 % of land occupants	Land occupants informed of risks and obligations	More than 50 times in 5 years occupants called to warn operator	Goal of reducing hits and near misses by 50 % in five years	Hits and near misses reduced by 75% in five years
	2	Hire additional personnel for ground patrolling	Four technicians added to ground patrol staff	Enhanced ground patrols to once a week in critical areas	20 % more activities with no one-call spotted per year		
Incorrect operations	1	Provide training on new leak-detection software and conduct five alarm drills for control room operators	All operators received training and attended all five drills	Installed dynamic flow modeling software	New software detected three releases of less than 5 bbls in less than one hour	Goal of no releases of more than 5 bbls going undetected for more than one hour	No release in two years of more than 5 bbls went undetected for more than one hour
Fatigue crack growth of seam defects	1	Conduct hydrostatic retest of 10 segments once every 10 years	Hydrostatic retests of five segments completed within first two years	Install variable speed pumps at stations in fatigue affected segments at outset of program	Reduced frequency and magnitude of pressure cycles	Goal of no releases from fatigue enlarged seam defects	No release from a seam-related defect in the last five years

segments within the first 5 years of the program and that all remaining segments were inspected (and remediated) within that time frame.

Next, consider the measures of the performance of the operational integrity management activities. For the threat of external corrosion the operator's integrity management goals for operational changes were

1) to install 10 new rectifiers in the first year of the program and

2) to install as many rectifiers as needed in Year 2 through Year 5 to bring cathodic protection potentials into compliance with the criteria in NACE SP0169.

As it turned out the operator was able to achieve satisfactory cathodic protection on the five highest risk segments within Year 1, and on 95 % of the system within the first five years.

Lastly, consider the measures of the improvement in integrity achieved as a result of the integrity assessment, remediation, and mitigation activities. As before, the threat of external corrosion is used as an example. Note that whereas there were two performance measures for the process and the operational changes, there is only one for integrity improvement. The operator had set a goal of reducing external corrosion leaks to zero by the end of Year 5 of the program. The goal of zero leaks was not reached but an 88 % reduction in leaks per mile per year was achieved.

As can be seen in Table 9, a similar review and evaluation matrix exists for the other five threats. The actual matrix of performance measurements used by any given operator may or may not look something like Table 9. In all likelihood it will contain many more performance measurements and goals than seen here, because many aspects of integrity management should be assessed.

12.2.2 Performance Measures by Integrity Assessment Process Steps

Measuring the performance of the integrity plan should also be done in terms of the effectiveness of the elements of the program, namely, the subjects of each section of this document as illustrated in Table 10.

As seen in Table 10, each of the elements of an IMP is considered in terms of its effectiveness. For example, if any deficiency in the element resulted in an adverse impact to integrity or could have resulted in an adverse impact, a corrective action should be defined so that the performance of the element improves with the next integrity assessment.

12.3 Performance Tracking and Trending

Evaluating performance relative to actions taken, calculations made, and goals set for improvement as done in Table 9 and Table 10 are, in a sense, relative measures. A pipeline operator should also evaluate its IMP in more absolute terms such as:

— Will the goals, if achieved, enhance pipeline safety and integrity significantly (i.e. will the benefits outweigh the costs)?

— Are the results on par with those of other operators?

— Will regulatory expectations, if applicable, be met?

To meet these conditions, the operator should conduct periodic evaluations of their own performance in comparison with industry-wide data sources. For example, a U.S. operator should periodically review its performance in comparison with the database of reportable incidents maintained by the U.S. Department of Transportation. Other countries maintain similar incident databases as well. U.S. operators may also take advantage of two voluntary performance tracking programs. One of these was mentioned previously. It is the DIRT database of excavation hits and near misses maintained by the Common Ground Alliance. The other is a general incident reporting database

Table 10—Performance Measures by Process Step

Process Element	Section of This RP Where Covered	Process Measures	Integrity Impact	Corrective Action (if any)
Critical location selection	6	Did any release spread farther than predicted?	One spill spread beyond limits defined by the model.	Reassess and improve the model for defining critical locations.
		Was any release larger than predicted?	Two spills were larger than predicted.	
Data gathering	7	Were the data sufficient for assessing the threats?	No specific impact but some suspect data had to be used.	Acquire specific data that will improve the assessment of threats.
Risk assessment	8	Were the prioritized segments ranked appropriately based on the integrity assessment findings?	The condition of certain segments was either better or worse than suggested by their ranking.	Modify model as appropriate or chose alternative model for next assessment.
Integrity assessment	9	Were the chosen assessment methods effective?	Crack tool failed to indicate anomaly that led to a release.	Choose alternative methods or tools for next assessment.
Reassessment frequencies	10	Are the reassessment intervals appropriate?	A release occurred before the calculated safe period had expired.	Examine the assumptions about pressure histories, grow rates, and initial flaw sizes and reevaluate the model used for predicting remaining life.
Preventative and mitigative measures	11	Are the preventative and mitigative measures sufficient?	Five hits occurred in three years because of land occupants digging without making a one-call.	Repeat personal contacts with land occupants and increase patrolling frequencies for the affected segments.
			Corrosion leaks occurred in one segment in spite of adequate potentials at test leads.	Conduct ECDA on segment, increase potentials if appropriate and repair coating.
Facilities assessment	12	Were the facilities assessments satisfactory?	Leaks at seals still unacceptably frequent.	Inspect seals more frequently and shorten replacement interval.

maintained by API that is referred to as the PPTS. By participating in and examining such databases, a pipeline operator will be able to compare its integrity management effectiveness against the levels of effectiveness of other operators' programs. The pipeline operator should then make improvements in its program if the need is indicated by the comparisons.

12.4 Self-reviews

Self-reviews of integrity management programs should be performed to establish and maintain the quality and effectiveness of the programs. These reviews should be performed periodically by the operator's own personnel, and external reviews by an independent outside organization should occur when deemed necessary (e.g. the self-reviews are finding significant deficiencies in the IMP, the occurrence of a significant incident points to weaknesses in the plan). In some jurisdictions, inspections by regulatory authorities will be mandated. Reviews should address the following issues.

— Are activities being performed as outlined in the operator's program documentation?

— Is someone assigned responsibility for each subject area?

— Are appropriate resources available to those who need them?

— Are the people who do the work trained in the subject area?

— Are qualified or certified people used where required by code or regulation?

— Are activities being performed using an appropriate integrity management program as outlined in this document?

— 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 the operator?

— Are the criteria for assessing and remediating anomalies adequate?

— Are the criteria for establishing reassessment frequencies adequate?

— Are the criteria for preventive and mitigative measures adequate?

— Are the criteria for the assessment of nonpipeline facilities adequate?

— Is there a process for internal and outside auditing?

— Is there a process for review and updating of the program in response to changes in the pipeline attributes, changes in operating conditions, changes in technology, and changes in code or regulatory requirements?

12.5 Performance Improvement

The results of the performance evaluation should be used to modify the integrity management program as part of a continuous improvement process. Recommendations for changes and/or improvements should be based on analysis of the performance measures and the audits. All recommendations for changes and/or improvements should be documented, and the recommendations should be implemented in the next cycle of integrity assessment.

13 Management of Change

Formal management of change procedures should be developed to identify and consider the impact of changes in pipeline attributes, pipeline operations, technology, and code or regulatory requirements on an operator’s IMP. Management of change should address operational, technical, physical, procedural, and organizational changes to the operator's pipeline system. A management of change process should include the following:

— description of the change;

— reason for the change;

— effective date for change to occur;

— authority approving the change;

— analysis of implications of the change;

— acquisition of required work permits for any necessary construction or operational changes;

— listing of roles, responsibilities, and accountabilities for management-of-change stakeholders;

— modification of appropriate elements of the IMP;

— documentation of change and rationale;

— communication of change to affected parties;

— implementation of the change;

— workflow process for assuring that management-of-change stakeholder concerns are addressed.

Examples of how an operator might organize a “management of change” plan are provided in Table 11.

Table 11—Examples of Management of Change

Description	Reason	Effective Date	Implications	Authority	Work Permits	Modifications to IMP	Documentation	Communication	Implementation
Raising MOP of Line 1.	To increase capacity.	Two years from current date.	New pumping units to be installed at Stations 1 and 2. Need to retest to 1.25 times new MOP.	Authorized by Board of Directors and approved by FERC.	Construction permits to install new pumps and associated control equipment. Work and environmental permits for retest.	Reevaluate remaining life of unrepaired anomalies. Calculate effect of retest to see if it holds the margin of safety until the next ILI.	Managers of pipeline and facility integrity will prepare full reports of all construction and retesting and modify the IMP as required.	Managers of pipeline and facility integrity will prepare memos to staff and operating personnel and inform PHMSA and state regulators.	Upon completing of construction and retesting the MOP will be raised to the new level.
Appointment of new company president.	Retirement of current president.	Six months from current date.	Organizational changes will follow.	Authorized by Board of Directors.	none	Manager of pipeline integrity will change, not expected to impact IMP.	New organization chart will follow.	New organization chart will serve as documentation.	Schedule for IMP will be unaffected.
New crack tool to be used to assess Line 1.	Improved sensitivity.	Next scheduled ILI.	Staff responsible for ILI will attend orientation on new tool.	Authorized by Manager of Pipeline Integrity.	none	Change text were necessary to indicate use of new tool is mandated.	Person responsible for ILI section of IMP will make the necessary changes to the text.	Manager of Pipeline Integrity to send memo to all staff involved in IMP implementation.	New tool to be used for next assessment of Line 1.
Begin program of personal contacts with land occupants.	Need to reduce encroachments with no one-call.	Beginning three months from current date.	Selected staff will be trained to interact with land occupants, informing them of the risks and trying to secure their cooperation.	Authorized by Manager of Pipeline Integrity.	none	IMP public awareness section will be modified to indicate the land occupant contact program.	Manager of pipeline integrity will see that the appropriate sections of IMP are changed and document training of the relevant staff.	Manager of Pipeline Integrity to send memo to all staff involved in IMP implementation.	Contacts will begin in three months and a full cycle of contacts is expected to be completed in two years. Cycle will be repeated every two years.

Annex A
(normative)

Threats to Pipeline Integrity

A.1 General

As stated in Section 4 and Section 8, experience has indicated that the following are potential threats to the integrity of a hazardous liquid pipeline.

The threats for hazardous liquid pipelines that operators should address can be characterized as follows:

1) external corrosion;

2) internal corrosion;

3) selective seam corrosion (external or internal);

4) SCC;

5) manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots);

6) construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure);

7) equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous);

8) mechanical damage (causing an immediate failure or from vandalism);

9) mechanical damage (previously damaged pipe causing a delayed failure or vandalism);

10) incorrect operations;

11) weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement);

12) the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue).

Threats 1), 2), 3), 4), and 12) are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. Threats 5), 6), and 9) are considered possibly time-dependent threats because of the potential for their enlargement by pressure-cycle-induced fatigue. For the latter threats, the pipeline operator will be called upon to judge the need for continuing assessments or monitoring. Threats 7), 8), 10), and 11) are considered time-independent because they involve random events for which the time of occurrence is usually not predictable. Management of the latter class of threats involves employing preventive and mitigative measures.

It is recognized that not all 12 may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 12 threats are discussed in detail in Annex A of this RP.

Annex A presents definitions and descriptions that are intended to assist a pipeline operator with the identification of threats to pipeline integrity.

A.2 Corrosion

Corrosion is defined as the deterioration of a material, usually a metal, by an electrochemical reaction with its environment. The rate in which a metal will deteriorate (corrode) is primarily governed by the environment in which it resides and by the nature and aggressiveness of measures that have been put in place to mitigate the reaction. Although there are several different forms of corrosion each share some common elements:

- 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 reaction. The elimination of one of the four common elements is the basis for a corrosion control program. The most common methods of corrosion control are selecting a material with inherent resistance to corrosion in a particular environment, applying protective paints and coatings to exposed surfaces, inducing corrosion inhibiting chemicals, and applying cathodic protection.

A.3 External Corrosion

When a pipeline is placed in the ground, the pipeline itself is the metallic path and the soil is the electrolyte. Areas of the pipe surface that come into contact with the electrolyte because of faults in any protective coating will tend to be either anodic to the environment (meaning metal will be dissolved) or cathodic to the environment (meaning the metal will be protected). External corrosion may be controlled 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.

One form of external corrosion, galvanic or electrolytic corrosion, may occur simply because the amount of cathodic protection is inadequate. A pipeline operator should periodically monitor the pipe-to-soil potential levels along the pipeline. This should be done at least once a year utilizing permanent test leads installed at intervals (usually every mile or so) along the pipeline. Occasionally, a pipeline operator should consider doing a “close-interval” pipe-to-soil potential survey. Such a survey involves acquiring potential measurements every few feet along the pipeline. The close-interval survey is much more likely to disclose local areas of inadequate cathodic protection than the test lead monitoring. Suggested levels of pipe-to-soil potential required for adequate protection are given in NACE SP0169. Galvanic corrosion can also occur when dissimilar metals are imbedded in an electrolyte such as moist soil. Thus corrosion may occur preferentially at a weld in a piece of buried pipe because the microstructure and chemical content of the weld metal differs sufficiently from those of the base metal.

Corrosion may occur even when pipe-to-soil potential measurements suggest adequate protection. Examples are cases where disbonded coating, rocky areas, or road-crossing casings shield the pipe from the protective current. Pipeline operators should be aware that such areas could exist along a pipeline and consider possibly enhanced inspections or mitigative measures.

Stray current corrosion is corrosion (usually pitting) caused by the influence of outside sources of electrical currents that cause electrons to flow off of exposed pipe surfaces. Stray current corrosion can be caused by either direct current (DC) or alternating current (AC). Pipeline operators should be aware that DC corrosion can be caused by interference with another cathodic protection system, from mining operations, from electric railways, or from ground return or unbalanced phases of DC power transmission systems. AC corrosion can arise when a pipeline runs parallel to a high-voltage AC transmission system and AC is induced into the pipeline. In many cases, AC corrosion may be most severe where the pipeline right-of-way becomes parallel to or diverges from the AC transmission right-of-way.

Another external corrosion threat to pipeline integrity arises from MIC. Acidic compounds produced by certain types of bacterial may attack an exposed pipeline surface. The bacteria are often capable of forming a film that shields the pipe from cathodic protection. Pipeline operators should be aware of this phenomenon and take appropriate steps to mitigate its effects. The real extent of external corrosion usually depends on how big an area of coating is damaged or missing and on the ability of cathodic protection to reach the surface of the pipe at an area of coating disbondment. Typically, the metal loss that results is not uniform but instead appears as isolated pits or arrays of pits of various sizes and shapes. The effect of the metal loss on the pressure carrying capacity depends on the amount of material remaining along the axis of the pipe. When the pitting is randomly oriented, the integrity of the pipe becomes seriously impaired if and only if one or more pits becomes deep enough to penetrate the wall thickness (resulting in a leak) or a sufficient number of pits overlap along a sufficient length of the pipe to cause the remaining ligament to fail (often resulting in a rupture). Less typically, the metal loss may occur in a concentrated manner predominantly in the longitudinal direction of the pipe. One such case is selective seam corrosion that is discussed separately below. Another is narrow axial external corrosion (NAEC) often found at double submerged arc welded seams coated with polyethylene tape. The “tenting” of the tape over the crown of the weld 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 groovelike defect is more likely to rupture than typical pitting corrosion.

A.4 Internal Corrosion

Internal corrosion has, mechanically speaking, the same deleterious effect on the pipe as external corrosion, but its causes are different. Refined petroleum products and crude oil can contain water, bacteria, chemical contaminants, and debris that can create a corrosive environment on the internal surface of the pipe. Like external corrosion, localized pitting and arrays of pits are the typical forms of 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 and/or 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. It is also helpful to maintain the highest feasible flow rates to avoid pooling of water in low spots or at the beginnings of steep upslopes.

Pipeline operators should be aware of and take mitigative measures to minimize low flow conditions that allow water to stagnate. Dead-leg piping, for example, is a place where water and/or sludge could accumulate and cause corrosive conditions. If dead-leg piping is necessary, it should be checked regularly to see that wall thickness loss is not occurring. Microbially induced internal corrosion can occur if water containing certain kinds of bacteria is introduced into a pipeline. In such cases, treatment of the fluid with a biocide may be necessary.

Internal corrosion and hydrogen blisters that form at laminations in the pipe material can threaten pipeline integrity if the product being shipped is sour crude oil. If water is present as well as hydrogen sulfide and/or carbon dioxide, an acid reaction can occur that causes internal pitting of the pipe. Moreover, atomic hydrogen generated by the acid reaction can easily diffuse into the pipe steel. If the atomic hydrogen passes clear through the wall thickness, it dissipates harmlessly, but if it encounters a lamination in the pipe wall, hydrogen gas (H_2) is formed. The hydrogen gas can continue to form as long as atomic hydrogen is being generated at the ID surface of the pipe. The pressure of the hydrogen gas will tend to separate the lamination forming a blister. Along the longitudinal edges of a blister, cracks may form and propagate to the ID surface of the pipe. Since most laminations are located mid-wall, once the crack penetrates to the ID surface, the outer half of the wall thickness becomes the effective thickness. At that point a failure of the pipeline may occur. Operators of sour crude oil pipelines should be aware of this potential threat and take mitigative action. Inhibitors can be used to prevent the acid reaction from occurring. Ultrasonic metal loss ILI tools can find laminations and blisters so that they can be repaired.

A.5 Selective ERW Seam Corrosion (External or Internal)

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

The effect is the creation of a groovelike anomaly that is usually centered on the bondline of the seam. Both LF-ERW and HF-ERW can be affected by the phenomenon, though the occurrence is more critical in LF-ERW or FW pipe because of the relatively low toughness of the bondline region typically associated with the LF-ERW and A.O. Smith flash-welding processes.

A.6 Stress Corrosion Cracking (SCC)

SCC is a form of environmentally assisted cracking, wherein small cracks form and often continue to lengthen and deepen over a period of time. Typically, multiple small individual cracks form adjacent to one another in an array. If the cracks continue to grow, they frequently overlap and/or coalesce such that they become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack large enough to cause the pipeline to leak or rupture. Three conditions must be present for SCC to occur: a susceptible material, a conducive environment, and a tensile stress.

1) *Material*—All commonly used line pipe steels are susceptible, though susceptibility may vary considerably from one material to another.

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, and pipelines that are operated at stress levels above 60 % of SMYS appear to be the most susceptible. There is thought to be a lower-bound threshold stress level below which SCC will not occur, but the threshold has not been firmly established and is likely to be situation dependent. SCC has been identified in one case in a pipeline being operated at hoop stress level of 47 % of SMYS. 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 form's on the crack surface, reexposing 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 and near-neutral pH 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 groundwater. Cracks are generally trans-granular, wide, and more corroded than those found in high pH SCC. Generally, tape coated systems are susceptible to this type of environment. At the time this document was prepared, no one appears to have ever encountered SCC on a pipeline with a properly applied fusion-bonded epoxy coating. The absence of SCC in conjunction with such a coating is thought to be attributable to the facts that the pipe surface has to be shot-blasted before the application of such a coating system and that the compressive residual stress induced at the surface by the shot-blasting raises the threshold stress for SCC above the level that the pipe will experience in service.

A.7 Other Forms of Environmental Cracking

Pipelines that transport sour crude oil that also contains water may be susceptible to other forms of cracking including sulfide stress cracking (SSC), hydrogen-induced cracking (HIC), or stress-oriented hydrogen-induced cracking (SOHIC).

Sulfide stress cracking is a form of hydrogen embrittlement that can affect a line pipe steel exposed to hydrogen sulfide and water while the material is subjected to tensile stress. A cathodic reaction in the presence of hydrogen sulfide and water can allow atomic hydrogen to diffuse into the steel. Normally, this will not affect the base metal of a line pipe steel, but if weldments on the pipe have created heat-affected zones with hardnesses of Rockwell C 22 or more, hydrogen cracking of the microstructure may occur. The phenomenon can be mitigated by preheating the material before welding or by postweld heat treatment to eliminate zones of high hardness. Treatment of sour crude oil to eliminate free water and/or the use of an inhibitor to prevent the cathodic reaction may be an effective way to prevent the occurrence of SSC.

HIC and SOHIC are also threats associated with the transportation of sour crude oil containing water and are forms of SSC. The main characteristic of HIC is that diffusing atomic hydrogen tends to recombine into molecular hydrogen at manganese sulfide inclusions in the steel. The inclusions tend to “blister,” and hydrogen cracks will then propagate through the wall thickness from one inclusion to another in stepwise fashion. SOHIC has a similar appearance and is caused by the same cathodic generation of atomic hydrogen, but the presence of manganese sulfide inclusions is not necessary for SOHIC to occur. The stepwise cracking instead begins at planes of weakness parallel to the surfaces of the plate. Hence, SOHIC may occur in steels that have been purposely manufactured with low sulfur to prevent the formation of manganese sulfide inclusions. Unlike SSC, both HIC and SOHIC can occur in the normal line pipe material; high hardness is not necessary. Prevention of HIC and SOHIC requires either removal of water or the introduction of an inhibitor that prevents the cathodic reaction between water and hydrogen sulfide.

More information about the phenomena of SSC, HIC, and SOHIC may be obtained from the following:

— NACE MR0175/ISO 15156;

— Pargeter, R. J., “Susceptibility to SOHIC for Linepipe and Pressure Vessel Steels—Review of Current Knowledge,” *CORROSION 2007*, Paper 07115, NACE International, Nashville, Tennessee, March 11–15, 2007.

A.8 Manufacturing Defects (Defective Pipe Seams Including Hard Heat-affected Zones and Defective Pipe Including Pipe Body Hard Spots)

Pipe materials made with welded longitudinal or helical seams may contain defects within the seam weld or the heat-affected zones. Pipe seams made with filler metal such as DSAW pipe or HSAW may contain weld cracks, lack-of-fusion, toe cracks, mismatched edges, misformed edges, or offset inside and outside weld beads. Pipe seams made without filler metal such as ERW or FW seams may contain cracks, lack-of-fusion, and mismatched plate edges. Cracks, pits, scabs, slivers, and laminations in the body of the pipe may arise from the manufacture of pipe skelp and/or the manufacture of line pipe. These include longitudinal or helical seam anomalies which are usually cracklike. Definitions and descriptions of these types of anomalies appear in API 5T1. The user should refer to that document for the standard definitions of these anomalies and imperfections. If any such anomalies are not found by means of the manufacturer’s hydrostatic test and/or nondestructive examinations and they are not eliminated by the initial preservice hydrostatic test of the pipeline, they will remain as anomalies in the pipeline. Frequently, such anomalies are revealed by ILI or hydrostatic retests. Having survived an initial preservice hydrostatic test to a level of at least 1.25 times MOP, these types of anomalies will be noninjurious to pipeline integrity unless they are subject to enlargement by pressure-cycle induced fatigue (see pressure-cycle-induced fatigue).

A.9 Manufacturing Defects (Hard Spots or Hard Heat-affected Zones)

Hard spots are regions of the pipe material that possess hardness levels (and ultimate tensile strength levels) significantly higher than the ranges of hardness that characterize the normal parent pipe material. Hard spots may exist as local round or oval areas in the body of the material or in a narrow zone immediately adjacent to the seam bondlines of some older-vintage ERW materials. Both types of hard zones arise from excessive cooling rates applied to the zones as they were cooled from temperatures above 777.8 °C (1432 °F) during the manufacturing process. The round or oval hard spots in the pipe body were most likely to be found occasionally in older Grade X52 materials made in the late 1940s or early 1950s. The hard zones adjacent to ERW seams were most likely to be found occasionally in materials of Grade X46 and Grade X52 manufactured prior to 1960.

The hazard associated with hard zones or hard spots is that if their hardness levels exceed 350 Hv10 (33 to 35 Rockwell C), they are prone to hydrogen stress cracking in the presence of atomic hydrogen (that is, hydrogen ions in solution, not hydrogen gas, H_2). Sources of atomic hydrogen arise internally if sour crude is transported and externally from cathodic protection with sour crude being the more aggressive of the two environments. Service failures have been known to occur as a result of exposure of hard spots or hard zones to either of these environments.

Neither hard spots in the body of the pipe nor hard heat-affected zones adjacent to the bondline can be satisfactorily addressed by hydrostatic testing. Prior to the formation of any cracking in these materials, no defect exists that would cause them to fail in a hydrostatic test. If and when they begin to crack after sufficient exposure to atomic hydrogen, the cracking can lead to rapid or even immediate failure. Therefore, there is no way to apply hydrostatic testing in a timely manner.

A.10 Construction and Fabrication Defects (Including Defective Girth Welds, Defective Fabrication Welds, Wrinkle Bends and Buckles, and Stripped Threads/Broken Pipe/ Coupling Failure)

Construction defects include girth weld defects, rock dents, installation damage, flaws in fabricated fittings or branch connections, bending mandrel marks, ripples, buckles, and wrinkle bends. Aside from acetylene girth welds, an obsolete joining technique employed in some very old pipelines, electric arc girth welds seldom cause pipeline to fail. Usually when it is found that a girth weld has failed it is because the pipeline has been subjected to some extreme longitudinal load such as that from a landslide or washout. Therefore, girth welds (except for acetylene girth welds) are usually not a significant threat to pipeline integrity. As part of its IMP, a pipeline operator that operates a pipeline fabricated by means of acetylene girth welds should establish a program of monitoring soil stability and riverbank erosion for signs of movement or change that might add stress to such welds. Such an operator should be prepared to mitigate any situations where it appears that the acetylene welds might be experiencing added stress.

Although the use of an intentional wrinkle bend (a buckle allowed to form intentionally during cold field bending) is prohibited by safety codes such as ASME B31.4, some may exist in older pipelines designed prior to the existence of consensus safety codes. These will show up during ILI runs. Removal of wrinkle bends is recommended, but if they cannot be removed, the operator should periodically check the stability of the soil in their vicinity since movement of the pipeline at a wrinkle bend is one cause of them failing.

Ripples and bending mandrel marks are considered noninjurious to pipeline integrity. A criterion for acceptable ripple height is contained in ASME B31.4. Buckles are anything that falls outside the limits on ripple height, and any such buckle should be repaired.

Flaws in fabricated fittings are usually not something that can be reliably detected in an integrity assessment. Therefore, a pipeline operator should have a quality control program that assures the satisfactory fabrication and inspection of fabricated fittings.

Rock dents and installation damage are discussed in A.13.

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.

An arc burn results from momentary contact between a welding electrode and a pipe or fitting that leaves little or no weld metal, but may cause local pitting and almost always results in a small area of damaged microstructure at the point of contact. Because of their small size, arc burns are generally not a threat to pipeline integrity. If arc burns are discovered on a pipeline as the result on an integrity assessment, they need not be repaired. However, they are usually a sign of poor workmanship and should not be tolerated on any new construction.

A.11 Equipment Failure

Pumps, valve, seals, O-rings, meters, pressure switches, temperature gauges, prover loops, scraper traps, strainers, truck loading racks, etc. are types of equipment found mostly at terminals and pump stations. These components are subject to occasional malfunction and/ or failure, and they may in certain cases cause an unintended release. A pipeline operator's facility IMP should address the periodic inspection and routine maintenance of such equipment with the intent of preventing equipment failures. Attention should be paid to known mean times to failure for commonly used components, and a timely replacement of parts or units should also be part of the facility's IMP.

A.12 Mechanical Damage (Causing an Immediate Failure)

This threat arises from excavation, drilling, boring, farming, or other soil moving or removal activities where the mechanical equipment being used comes in contact with a buried pipeline causing it to leak or rupture. Other failures have also been known to occur in conjunction with someone imposing a heavy load on the soil over a pipeline. Immediate failures have occurred as the result of vandalism as well. Preventive measures such as one-call systems, locating and marking for a potential excavation, monitoring of any excavation on or near a pipeline, public awareness campaigns, and aerial or ground surveillance are intended to prevent such occurrences. When an excavator makes a one-call and the pipeline operator responds appropriately, the risk of such an incident is small. However, firm lines of communication between the excavator and the pipeline operator and continued diligence on the part of both is essential to minimize the chances of an incident or near miss. A more perplexing problem arises in conjunction with land occupants and others who initiate excavations without making a one-call and without notifying the operator of the pipeline. A pipeline operator should consider the value of occasional communications with land occupants and other potential excavators to educate them of the risks associated with excavating around a pipeline and encourage them to make a one-call before excavating even on their own land. In addition, a pipeline operator should conduct regular aerial and/or ground patrols of their rights-of-way except in remote or inaccessible areas.

A.13 Mechanical Damage (Causing a Delayed Failure)

This threat arises from excavation, drilling, boring, farming, or other soil moving or removal activities where the mechanical equipment being used comes in contact with a buried pipeline leaving a dent or dent and gouge that are not severe enough to cause it to leak or rupture immediately. Dents arising from lowering a pipeline onto a rock or from pushing a rock onto the pipe during backfilling also fall into this category. If the anomalies created in this manner are not discovered or if they go unreported, they may become more severe with the passage of time such that eventually they cause a leak or a rupture. Factors that may cause them to become more severe with the passage of time include, external corrosion, SCC, further creep of the defect or settlement of the pipeline, and pressure-cycle-induced fatigue. A hydrostatic test does not guarantee that such a threat will be neutralized unless the anomaly causes a leak or a rupture during the test. ILI metal loss tools and geometry tools, especially if used in combination, are the best means to locate and mitigate any such anomalies. A pipeline operator's IMP should address using ILI for that purpose, and it should contain criteria for deciding if and when a discovered anomaly should be excavated and examined.

A.14 Incorrect Operations

The threats to integrity from incorrect operations include but are not necessarily limited to accidental overpressurization; failure to design properly for or limit surges; improper closing or opening of valves; overfilling tanks; exercising inadequate or improper corrosion control measures; and improperly maintaining, repairing, or calibrating piping, fittings, or equipment. A pipeline operator should create and maintain an operating and maintenance manual and make sure that all operating and maintenance personnel are well-versed in its contents and properly trained and equipped to comply with its requirements. Pipeline operators should consult documents such as API 1168 and ASME B31Q, *Standard for Pipeline Operator Qualification* with regard to proper training for pipeline operators.

A.15 Weather and Outside Force (Cold Weather, Lightning, Heavy Rains or Floods, and Earth Movement)

Cold weather, lightning, floods, landslides, subsidence, earthquake, etc. are known causes of pipeline failures. Since these are random, often unpredictable events, an operator should establish a preventive and mitigative program to minimize the risk of a pipeline failure from such phenomena. Appropriate actions might consist of:

— inspecting drain valves and pipe extensions before cold weather arrives to eliminate water that will freeze and could cause breakage;

— removing trees where tree roots could impinge on the pipeline;

— shutting down and, if feasible, purging pipeline segments that could be damaged by impending hurricanes or floods;

— providing for movement of the pipeline to occur without damaging the pipeline at seismic fault crossings, unstable slopes, or areas of subsidence;

— training patrol pilots to spot areas of developing soil instability, landslides, and subsidence;

— conducting aerial patrols as soon as feasible after the passage of severe weather, flooding, or an earthquake;

— monitoring river crossings for exposed pipe in the crossing or at riverbanks.

For guidance on pipelines in floodplains, see API 1133.

The growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue.

Any longitudinally oriented anomaly of sufficient size has the potential to become enlarged by pressure-cycle-induced fatigue. Repeated cycles of stress are known to cause defects above a certain threshold size to grow, and if the growth continues long enough the defect can cause structural failure. The types of pipeline anomalies that are considered potentially susceptible to growth by pressure-cycle-induced fatigue include longitudinally oriented manufacturing defects, stress corrosion cracks, gouges, gouges in dents, and stress risers associated with poorly fabricated repairs. The degree of this threat is strongly dependent on the initial size of the defect, the aggressiveness of the pressure cycles in terms of stress range and frequency, and the effective crack-growth rate. Details are provided in Section 8 and Section 9 on how an operator might evaluate the degree of threat presented by pressure-cycle-induced fatigue.

A.16 Transit Fatigue

Transit fatigue is damage that arises from transportation of line pipe by rail car, truck, or marine vessel. The most common problem caused by transit fatigue is the formation of a longitudinal crack at the toe of a longitudinal DSAW seam from improper loading on a rail car. Fatigue cracks of this type may be small enough to survive the initial preservice hydrostatic test of a pipeline, but they can become large enough to cause an in-service failure of a pipeline through pressure-cycle-induced fatigue. An operator ordering new pipe can minimize the risk of receiving pipe with transit fatigue damage by requiring manufacturers or stockpilers of line pipe to observe API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe* when loading pipe onto rail cars or API Recommended Practice 5LW, *Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessels* when loading pipe onto a marine vessel. If pipe has been shipped under conditions where transit fatigue can develop, the threat has to be addressed as any other initially noninjurious anomaly that can become injurious as the result of pressure-cycle-induced fatigue. Though transit fatigue cracks could potentially be detected prior to the installation of the pipe into a pipeline, there is no practical way to screen each and every piece on a large construction job. Certainly, no such inspections have been performed routinely in the past. So, if a transit fatigue crack survives the preservice hydrostatic test, it can only be addressed in the manner that any anomaly subject to pressure-cycle-induced fatigue should be addressed. Industry has had success finding these defects with ultrasonic ILI technology.

Annex B
(informative)

In-line Inspection Technologies

B.1 Metal Loss Tools

ILI tools are available for locating and sizing internal and external corrosion-caused metal loss. The generic technologies preferred for this purpose are:

— high-resolution axial field MFL tools,

— circumferential field MFL (also known as transverse flux MFL) tools,

— ultrasonic compression wave tools.

Axial Field MFL Tools—This type of tool establishes a direct magnetic field circuit using the pipe wall as a conductor. The magnetic field is oriented parallel to the axis of the pipe. Metal loss within the pipe causes flux to leak outside or inside the pipe wall, and arrays of sensors are used to detect the flux leakage. Tools with coil-type sensors rely on movement of the tool through the flux leakage field to induce a detectable voltage in the coil. Tools with Hall-element sensors can detect the absolute flux field even when the tool is not moving. Some tools employ one or the other of these types of sensors and some employ both types of sensors. In any case, the physical dimensions of the metal loss are inferred from size and shape of the flux disturbance. The axial orientation of the flux field makes the tool particularly sensitive to the circumferential width and depth of an anomaly but less sensitive to its axial length. The length is usually inferred from the location of the beginning and end of the flux disturbance. In areas of multiple metal loss anomalies, the accuracy of the sizing may vary from vendor to vendor depending on the criterion a particular vendor uses for “clustering” the anomalies.

The magnetic phenomena are independent of the type of fluid in the pipe as the magnetism is induced by direct contact between steel brushes and the pipe wall. The tools are fairly insensitive to velocity over the range of typical liquid pipeline flow velocities; however, the tools with coil-type sensors must be moving at some minimum velocity to work. Axial field tools almost always include a mechanism to detect when the metal loss is internal and when it is external. An evolving variant of this type of tool uses bi- or tri-directional hall elements which measure magnetic flux levels in two or more directions. It is believed that the use of this technology will improve quantitative measurement of clusters of pits and complex corrosion profiles.

Axial field MFL tools have poor capability to sense the presence of axially oriented cracklike anomalies, and are not particularly good at characterizing “narrow axial external corrosion,” a particular type of external corrosion described in Annex A that is associated with the “tenting” of tape-type coating over the crown of a submerged arc seam weld. Such tools cannot be relied upon to detect selective seam corrosion either. When used in conjunction with adequate verification digs to evaluated sensitivity, however, these tools have been found to be highly reliable for detecting and characterizing the severity of wide corrosion-caused metal loss (i.e. remaining strength of the pipe) and other volumetric anomalies but generally have decreased sensitivity to mechanical damage gouges due to the cold working of the metal beneath the gouge, which affects the magnetic field. They are probably the most frequently used type of ILI tool.

Circumferential Field MFL Tools—These tools employ a direct magnetic field to detect flux leakage at metal loss anomalies in much the same manner as the axial field MFL tools. The main difference is that the field is oriented circumferentially instead of axially. This makes the technology more sensitive to the axial length and less to the circumferential width of the anomaly. Depths of anomalies are also detectable by this method. The circumferential orientation of the flux makes it possible to detect narrow axial external corrosion, selective seam corrosion, and some types of cracklike anomalies that arise from pipe manufacturing (e.g. ERW seam anomalies). The user of this type of tool may be able to better characterize the axial lengths of corrosion-caused metal loss (particularly for narrow axial external corrosion) for the purpose of calculating the effect of an anomaly on remaining strength. Generally, these tools are capable at identifying the orientation of the long seam, even in ERW pipe. Calculating the remaining strength at a bondline anomaly such as selective seam corrosion by means of standard remaining strength equations for metal loss (i.e. RSTRENG, ASME B31G) is not recommended. If accurate values of depth and length are known, then a remaining strength for a selective seam corrosion anomaly ostensibly could be calculated from an operator-selected crack equation. However, this requires information specific to the piece of pipe involved as the bondline toughness values are likely to vary significantly from joint to joint.

Ultrasonic Compression Wave Tools—Ultrasonic compression wave tools are equipped with arrays of individual ultrasonic transducers that transmit and receive acoustic energy through the transported fluid in the pipeline. This is an important point because the tools may work better in some fluids than others. They do not work at all in natural gas, and their performance may be degraded in some lighter hydrocarbons. Two reflections of the signal from each transducer are transmitted back to the transducer: one from the ID surface of the pipe and one from the OD surface. The difference in arrival times is calculated from the wave speed and constitutes a direct measure of the wall thickness at a point. If the arrival time of the first reflection is longer than the arrival time for the standoff distance from the normal ID pipe surface, the corrosion is assumed to be internal. If the arrival time of the first reflection is the same as the time for the standoff distance and the arrival time of the second reflection is shorter than the arrival time from the normal OD surface, the corrosion is assumed to be external. While these tools can be quite accurate and can give thickness along the length of an anomaly, they have some limitations. Wax or debris or an irregular surface can prevent a recapture of the return wave resulting in no useful information. High tool velocity within the pipeline can degrade the signal. At bends the tool sensor standoff distance can change, resulting in misinterpretation of the signal. At dents with certain curvature, the reflection can be lost resulting in an area of no inspection. If the pipe is significantly laminated, the signal can be almost entirely reflected by the lamination resulting in unreliable inspection for external metal loss behind the lamination. Nevertheless, these tools have been found to give highly reliable detection and characterization of corrosion-caused metal loss, and they have been widely used.

B.2 Crack Tools

ILI tools are available for locating and sizing cracks and cracklike anomalies. The generic technologies available for this purpose are:

— ulltrasonic angle beam tools,

— electromagnetic acoustic transducer (EMAT) tools,

— circumferential field MFL (also known as transverse flux MFL) tools.

Ultrasonic Angle Beam Tool—Ultrasonic angle beam tools are equipped with arrays of sensors that introduce acoustic energy into the pipe wall at an angle to the ID surface. The beam (i.e. wave) is transmitted to the pipe wall through the fluid in the same manner as with the ultrasonic compression wave tool for metal loss, so the same limitations on fluid type and cleanliness apply. When used for detecting axial cracks, the beam is aimed in the circumferential direction. In sound pipe, the beam will propagate around the circumference reflecting off the OD and ID surfaces repeated, eventually being dissipated. If the beam encounters a crack, it will be reflected off the surface of any crack back to the transducer. Reflections to several transducers and the "times of flight" are used to interpret the location and size of the crack and whether it is externally connected, internally connected, or embedded. Sizing of cracks in terms of length and depth is possible, but accuracy of the depth measurement tends to vary over a wide range. These tools have been found to reliably locate very tight cracks, including fatigue cracks and stress corrosion cracks. The limitations on sizing accuracy mean that ranking by severity should include a wide margin of error. Also, the probability of detecting cracks is significantly degraded if the tool velocity exceeds its recommended upper limit. Also, the presence of lamination can limit detection and sizing of indications (see comments on *Ultrasonic Compression Wave Tools*).

EMAT Tools—EMAT tools utilize a magnetic exciter to excite elastic waves in the pipe wall thickness. The waves propagate around the circumference with the pipe metal serving as a wave guide. Reflections that occur when the waves encounter a crack induce electric currents in the magnetic exciter that can be interpreted to give the location and size of the crack. The main advantage of this technology is that no contact between the pipe wall and magnetic exciter is necessary nor is there any need to transmit elastic waves through the fluid in the pipeline. At the time of preparation of this document, the technology is being used in actual pipelines, but no information on the success of the technology has been made public.

Circumferential Field MFL Tool—These are the same tools described above for the detection of metal loss anomalies. As noted above this technology has been shown to be capable of locating selective seam corrosion, and some types of cracklike anomalies that arise from pipe manufacturing (e.g. ERW seam anomalies). However, these tools cannot reliably detect very tight cracks such as fatigue or stress corrosion cracks, and the sizing information provided in conjunction with selective seam corrosion or cracklike anomalies is probably insufficient to use for calculating remaining strength.

B.3 Geometry Tools

ILI tools are available for locating and sizing dents, ovalities, and buckles. The generic technologies available for this purpose are:

— caliper tools,

— high-resolution geometry tools.

Caliper Tools—Caliper tools employ mechanical arms that contact the inner wall of a pipeline at discrete locations. As the tool moves along the pipeline, the arms deflect in response to physical irregularities in the circular shape of the pipe. The recorded deflections reveal the circumferential deviations from circularity and the manner in which they vary along the axis of the pipe. Using this type of tool, a pipeline operator can locate and characterize dents, ovality, and buckles in a pipeline segment. The level of accuracy depends on the number of mechanical arms employed and the number of data channels recorded. At a minimum caliper tools can indicate the maximum height of the geometric anomaly and its overall length. Generally, however, caliper tools are not sufficiently sensitive to determine curvature of the pipe wall in the vicinity of a geometric anomaly.

High-resolution Geometry Tools—These tools provide measurements of the position of the centerline and ID surface of the pipe with a higher degree of accuracy than most caliper tools. The physical locations of the pipe wall may be sensed by electromagnetic or acoustic signals, and in some tools both position sensors and mechanical arms are used. The accuracy of the data usually is sufficient to indicate the curvature of the pipe wall in the vicinity of a geometric anomaly. Thus, a pipeline operator using a high-resolution geometry tool may be able to estimate metal strains as well as to determine the height and length of the anomaly. In such cases the "sharpness" of the anomaly which bears on its potential effect on pipeline integrity can be determined without excavating.

B.4 Pipeline Profile and Alignment Tools

Inertial guidance tools are available for detecting changes in profile and changes in alignment as well as anomaly locations. This type of information is useful for locating areas of possible landslide or settlement that could threaten the integrity of the pipeline. Note that having a baseline profile and alignment is necessary to determine from a subsequent inspection whether or not a change has occurred.

B.5 Combination Tools

ILI vendors are increasingly offering ILI tools with multiple inspection technologies on a single tool chassis. Not only do these tools offer reduced inspection costs, they offer data that are fully integrated between the technologies on-board. This capability is particularly helpful in identifying certain threats, such as mechanical damage anomalies (gouge and dent combinations created by mechanical excavating equipment that require multiple inspection technologies to properly identify and characterize). Some vendors offer a modular approach to tool design that allows operators the flexibility to pick which inspection technologies they want on-board. Sometimes the combination of these features in one tool results in the vendor being able to give a more accurate depiction of the combination anomaly such as a dent containing metal loss.

B.6 Additional ILI Technologies

Below are some additional ILI technologies that may address various needs:

— spiral (helical) MFL for assessment of seams and metal loss;

— residual MFL for assessment of hard spots, dents, or pipe property changes

Annex C
(informative)

Repair Strategies

C.1 General

Inspections conducted per the operator's IMP will result in anomalies that should be evaluated. A number of these anomalies will require repair and this annex provides guidance to develop repair strategies. The information provided in this annex 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 PRCI *Pipeline Repair Manual R2260-01R* (Catalog L52047) should be consulted.

Table 3 (see Section 8) 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 B31.4-2009, Paragraph 451.6, "Pipeline Integrity Assessments and Repairs," describes thresholds for repair of specific defects.

Title 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 analyses 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 in a manner that complies with applicable safety codes and regulations.

C.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 pipe should have the capability to carry the MOP of the pipeline safely, and it should have been tested prior to commissioning to a four-hour-long pressure test to 1.25 times MOP while being visually monitored for leakage.

C.3 Recoat and Backfill

After an external anomaly has been evaluated and determined to not require a repair, the anomaly may be recoated and backfilled. After the pipe has been recoated and backfilled, the anomaly will be once again be 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 recurrence or an increase in severity of the anomaly.

C.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 welding the side seams via a full penetration butt weld, by fillet-welding an overlapping strap across the joint, 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. The resulting sleeve cannot contain pressure and can only be used on nonleaking defects. To be effective, the Type A sleeve should 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.

1) Advantages:

   a) no welding to the carrier pipe is required;

   b) longitudinal welds can be made with cellulose rods, if necessary.

2) Disadvantages:

   a) the repair is not recommended for circumferentially oriented defects;

   b) 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. In any case, it should be designed to safely carry the MOP of the pipeline. This type of sleeve can be used to repair leaks and strengthen circumferentially oriented defects. Sometimes Type B sleeves used to repair nonleaking defects are pressurized by hot tapping through the sleeve and the pipe to relieve hoop stress from the defective area. The Type B sleeve should be fabricated using full penetration welds for the side seam. Only Type A sleeves that have butt welded longitudinal side seams and that are designed to safely carry the MOP of the pipeline may be made into Type B sleeves by fillet-welding the ends to the pipe.

1) Advantages:

   a) it can be used on most every type of anomaly, including leaking defects;

   b) it can be used for circumferentially oriented anomalies;

   c) the repair is easily detected by a metal loss ILI tool;

   d) annular space between the sleeve and the carrier pipe is protected from corrosion.

2) Disadvantages:

   a) 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;

   b) the quality of welding needed and the heat sink conditions associated with the end fillet welds require that only skilled welders who are qualified to use low-hydrogen processes be used to fabricate a Type B 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 may be 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 after the leak has been stopped. 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. When used to repair leaking taps, pumpkin sleeves and attachments should only be used as a last resort. Used in this manner, they typically are considered temporary.

C.5 Split Sleeve Reinforcement Clamps (or Bolt-on Clamps)

Split sleeve reinforcement clamps 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 backup 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 care should be taken when welding bolt-on clamps, especially due to wall thickness mismatch. In addition, packing materials should not be overheated, yet fusion to the heavy wall must be obtained.

1) Advantages:

   a) clamps are cost effective,

   b) no welding to the carrier pipe is required,

   c) clamps can be used to repair leaking defects.

2) Disadvantages

   a) the short length prevents use on larger anomalies although custom sleeves can be fabricated in longer lengths,

   b) typically used on straight sections of pipe but custom applications for elbows and fittings are available.

C.6 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 and their inability to carry significant hoop stress. 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 are comprised of lightweight metal bands with single draw bolts to lighten them onto a pipeline. They also include a threaded fitting located 180° from the draw bolt that is used to force a neoprene cone into the leaking pit.

C.7 Composite Reinforcement Sleeve

Composite reinforcement sleeves are used to reinforce a defect-weakened area of pipe as an alternative to a Type A split steel sleeve for nonleaking defects. They are designed to repair blunt corrosion defects and are available in a variety of technologies. An operator should investigate each technology to ensure that reliable engineering tests and analysis show the repair can permanently restore the serviceability of the pipe.

1) Advantages:

   a) no welding is involved,

   b) the material does not corrode,

   c) can repair bends and long radius elbows.

2) Disadvantages:

   a) the installed sleeve has less reinforcing ability than a steel sleeve of comparable thickness. This limits its use to repair of blunt defects and dents;

   b) as with a Type A steel sleeve, the composite sleeve cannot be used to repair a leaking defect or one that may develop a leak;

   c) the repair cannot be seen by an ILI tool without the installation of a marker, such as a steel band;

   d) there is no nondestructive method to determine if the wrap has been properly installed and is properly supporting the anomaly.

C.8 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 nonleaking, 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.

Other Composite Repairs—Other wet layup wraps can be used to repair elbows, tees, or other fittings.

Caution—When using this repair, operators should verify compatibility of wet layup material with product being transported.

Annex D
(normative)

Calculating Reassessment Intervals

D.1 Reassessment Intervals for Corrosion-caused Metal Loss

The principle involved in calculating reassessment intervals for anomalies with linear growth rates is illustrated in Figure D.1.

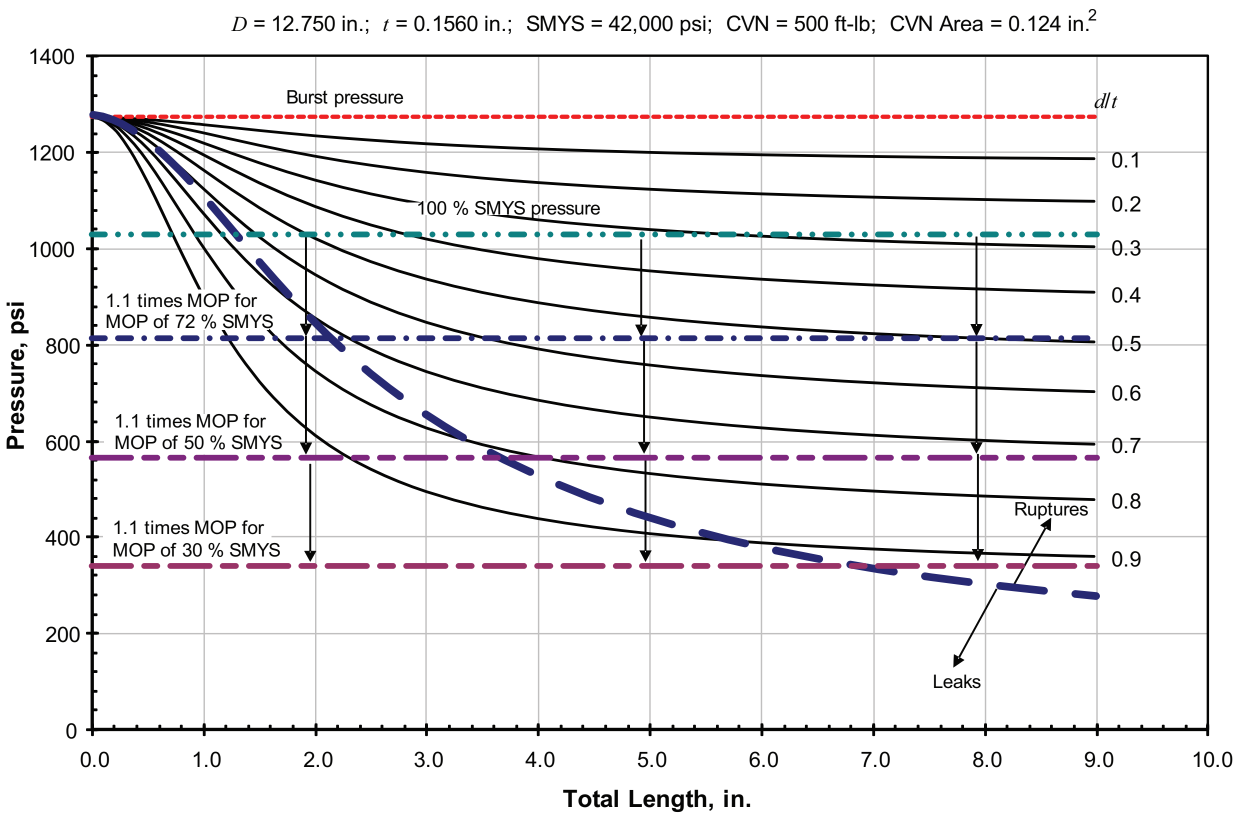


Figure D.1—Reassessment Intervals Based on a Specific Failure-pressure-vs-anomaly-size Model

Figure D.1 is based on a specific failure-pressure-versus-anomaly-size model, but generically, the procedure would be similar for any validated model. In this example, it is assumed that an initial integrity assessment has established a minimum failure pressure corresponding to 100 % of SMYS for the worst case (i.e. lowest-failure pressure anomaly) that could possibly remain in the pipeline segment. This level can be established either by completing a hydrostatic test of the segment to a minimum hoop stress level of 100 % of SMYS or by remediating all anomalies that were shown by ILI to be of a size that would cause failure at a hoop stress level less than 100 % of SMYS. For the 12.75-in. OD, 0.156-in. wall X42 pipe (SMYS = 42,000 psi) considered in this example, the 100 % of SMYS level cuts across the specific maximum depth-to-thickness curves at specific lengths (e.g. a length of 2 in. for a *d*/*t* ratio of 0.5, a length of 6 in. for a *d*/*t* ratio of 0.3, etc.). Growth of an anomaly in depth has a much greater deleterious effect on failure pressure than growth in length, so much so that growth in length can be safely ignored. Therefore, each length of anomaly that is considered is considered on the basis of its growth through the wall thickness (i.e. an increase in *d*/*t* with the passage of time). A pipeline operator should plan on remediating a potentially growing anomaly or preventing it from failing in service by performing a reassessment of the integrity of the segment by the time the anomaly has grown to a depth that will cause a failure at 1.1 times the MOP of the segment. When planning the reassessment, the amount of time it could take to excavate an area should be considered such that the anomaly can be remediated before a timeline is exceeded. If the MOP of the segment corresponds to 72 % of SMYS, the limiting d/t ratio for each anomaly corresponds to the point where the vertical arrow for each length of anomaly intersects the horizontal line at 1.1 × 72 % of SMYS.

According to Figure D.1, a 2-in.-long anomaly could survive a test to 100 % of SMYS if it has a d/t not exceeding 0.5. If the anomaly grows to a d/t of 0.72, it will fail at a pressure level of 1.1 × 72 % of SMYS. Similarly, a 5-in.-long anomaly could survive a test to 100 % of SMYS if it has a d/t not exceeding 0.31, but it will fail at a pressure level of 1.1 × 72 % of SMYS if it grows to a d/t of 0.53. The change in d/t required for the decay from 100 % to 1.1 × 72 % varies over a narrow range irrespective of the length of the anomaly, so the assumption that length is not very important when it comes to calculating a retest interval is a good one. However, the operator should focus on the lowest amount of growth required, in this case, a change of 20 % of the wall thickness. Note that decay to a lower pressure level requires more growth of an anomaly, and that means that lowering the operating pressure is one option for prolonging the time between assessments.

Armed with information that a change in d/t ratio of 0.2 will lower the failure pressures of the worst-case anomalies in the example pipe material by a critical amount that should not be exceeded, the pipeline operator then calculates the maximum time allowed before remediation of the anomaly dividing the corresponding wall thickness change by the rate of anomaly growth for any mechanism expected to have a constant growth rate (i.e. corrosion or SCC, but not fatigue). For the 0.156-in. wall pipe of the example, 20 % of the wall thickness is 0.031 in. or 31 mils. If the anomaly growth rate does not exceed 3.1 mils/year, the operator would have 10 years to either remediate the worst-case anomaly (and others as their 1.1 × 72 %-of-SMYS failure pressure level is approached) or conduct a reassessment of the integrity of the segment.

D.2 Reassessment Times for Corrosion-caused Metal Loss and SCC

In one respect, calculating a reassessment interval for a segment affected by external or internal corrosion-caused metal loss is similar to calculating a reassessment interval for a segment affected by SCC. Both phenomena are usually assumed to have constant growth rates. The major difference between calculating reassessment intervals for corrosion-caused anomalies and calculating reassessment intervals for SCC arises because the corrosion-caused anomalies are blunt anomalies and SCC anomalies are comprised of sharp cracks. Failures of blunt defects tend to be controlled solely by the size of the defect and the strength of the material. In contrast, failures of sharp cracks tend to be controlled by the size of the defect, the strength of the material, and the toughness of the material (i.e. its resistance to tearing in the presence of a sharp crack). Sharp cracks in materials of less-than-optimum toughness tend to fail at stress levels below that at which the same-size blunt defect would fail. The significance of this difference in behavior can be seen by comparing Figure D.2, Figure D.3, and Figure D.4.

Figure D.2 gives failure-pressure-versus-anomaly-size relationships for anomalies in a 20-in. OD, 0.250-in.-wall, X52 (SMYS = 52,000 psi) material. The toughness of the material is characterized by a Charpy V-notch upper shelf energy of 500 ft-lb. This level is fictitious since it exceeds the maximum level that is technologically possible. A material with this level of energy is so tough that all defects fail when the stress level in their remaining ligaments reach the flow stress of the material. That is also how blunt anomalies behave, so Figure D.2 can be used to represent corrosion-caused metal loss anomalies.

Figure D.2 is the basis for the example used in Section 9 with Figure 5. In that example a 14-in.-long anomaly was considered. The upper end of the vertical arrow in Figure D.2 represents the maximum depth-to-thickness ratio that would allow the 14-in.-long defect to survive the integrity assessment hydrostatic test to 100 % of SMYS, namely, d/t = 0.20. Since the nominal wall thickness is 0.250 in., d_{initial} is 0.050-in. The lower end of the arrow (representing growth to the depth that causes the failure pressure of the anomaly to decline to 1.1 × 72 % of SMYS) is located at a depth-to-thickness ratio of 0.40. The d_{final} is 0.100 in. Thus growth of 0.050-in. (50 mils) lowers that failure pressure of the anomaly from an initial value of 100 % of SMYS to a final value of 1.1 × 72 % of SMYS.

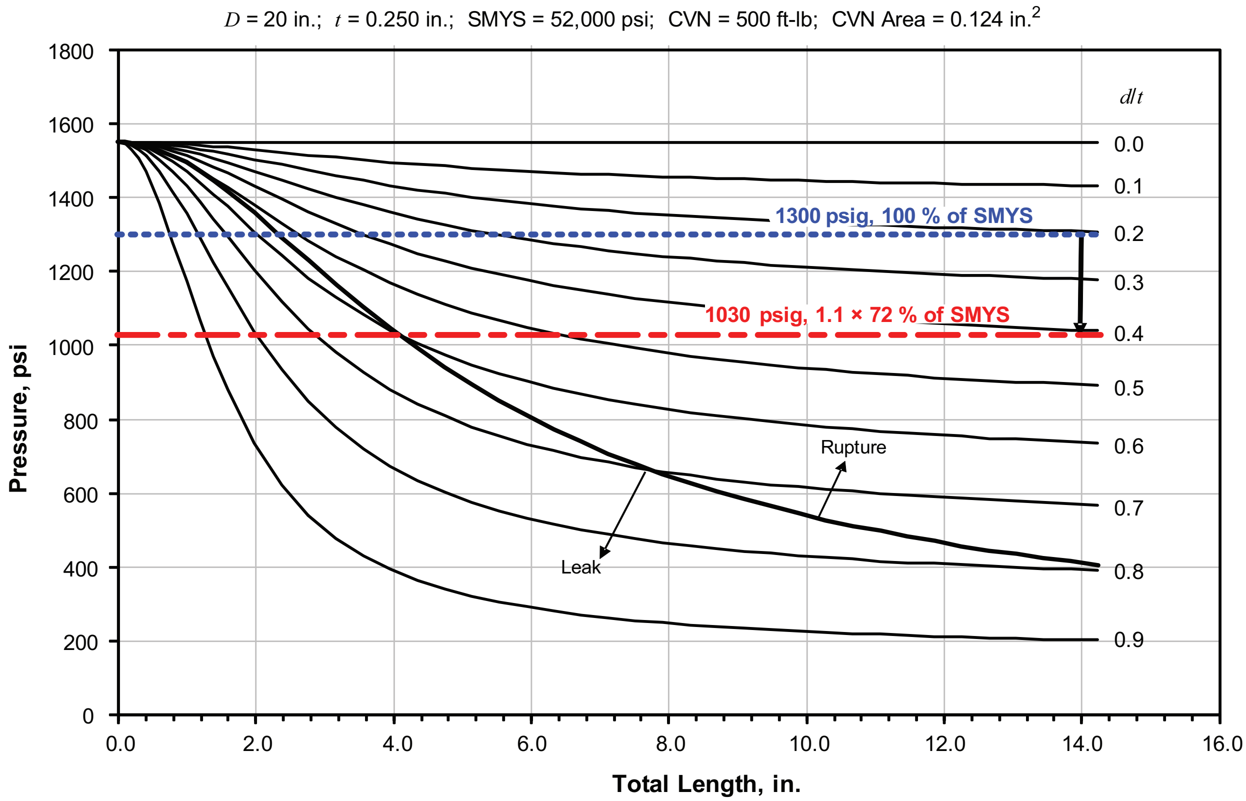


Figure D.2—Remaining Life of a Blunt Anomaly or a Cracklike Anomaly in a Material of Optimum Toughness

Figure D.3 also gives failure-pressure-versus-anomaly-size relationships for anomalies in a 20-in. OD, 0.250-in. wall, X52 (SMYS = 52,000 psi) material, but the toughness in this case is less than optimum. The toughness of the material is characterized by a Charpy V-notch upper shelf energy of 25 ft-lb. A material with this level of energy is typical of older vintage (pre-1970) line pipe materials. It may be expected that sharp defects will fail at a stress level in their remaining ligament that is somewhat less than the flow stress of the material. For example, the 14-in.-long defect that survived the 100 % of SMYS test with optimum toughness as shown in Figure D.2 had a depth-to-thickness ratio of 0.20. As shown in Figure D.3, the 14-in.-long defect would have a depth-to-thickness ratio of 0.14 if the toughness corresponds to 25 ft lb of Charpy energy. Figure D.3 can be used to represent SCC in the base metal of a line pipe material, but the actual Charpy energy of the material being considered should be used to generate the curves.

Figure D.4 also gives failure-pressure-versus-anomaly-size relationships for anomalies in a 20-in. OD, 0.250-in. wall, X52 (SMYS = 52,000 psi) material, but in this case the toughness is much less than optimum. The toughness of the material is characterized by a Charpy V-notch upper shelf energy of 5 ft-lb. This level of energy could be representative of the effective Charpy energy in the bondline region of a LF-ERW or a FW material. It may be expected that sharp defects will fail at stress levels in their remaining ligaments that are significantly less than the flow stress of the material. Figure D.4 can be used to represent cracks or selective seam corrosion in the bondline of a low-frequency welded or FW material, but the actual Charpy energy of the material being considered should be used to generate the curves.

Using these three figures, one can compare the amount of growth in depth required for the failure pressure of a 14-in.-long anomaly to decay from 1300 psig (100 % of SMYS) to 1030 psig (1.1 × 72 % of SMYS). For the blunt flaw or optimum toughness case (Figure D.2) the depth of the defect changes from 20 % of the wall thickness to 40 % of the wall thickness. This corresponds to a change of depth of 50 mils. For the SCC in a material with a Charpy shelf energy of 25 ft-lb the depth changes from 14 % of the wall thickness to 31 % of the wall thickness. This also corresponds to a change in depth of 42.5 mils. Note that the depth of the anomaly in the latter case is

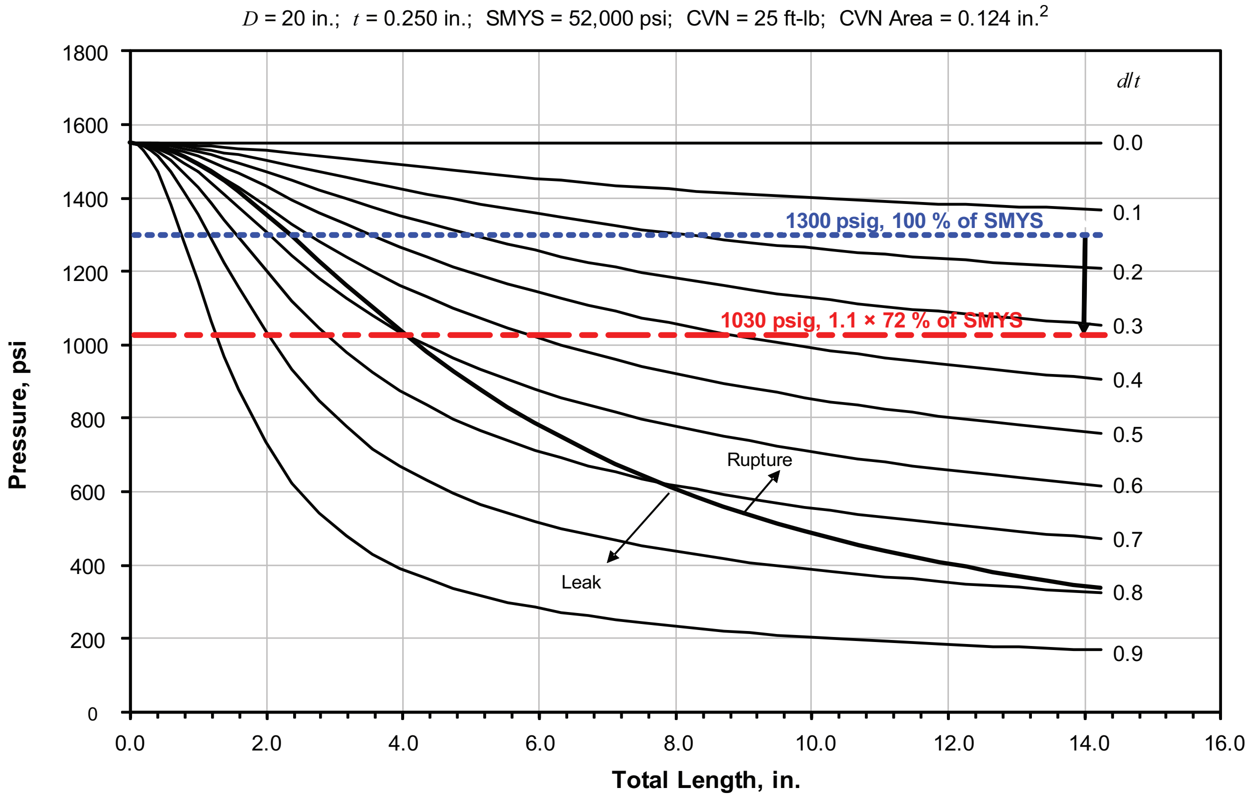


Figure D.3—Remaining Life of a Cracklike Anomaly in a Material of Less-than-optimum Toughness

less at each benchmark pressure level than in the case of the blunt anomaly. Lastly, for a 14-in.-long anomaly such as selective seam corrosion located in the low-toughness bondline material, the depth changes from 11 % of the wall thickness to 26 % of the wall thickness. This corresponds to a change in depth of 37.5 mils, and the depth of the 14-in.-long anomaly at each benchmark pressure level is considerably less than those of the anomalies in either of the other two materials.

D.3 Benchmark Cycles for Assessing Fatigue Crack Growth

For a pipeline operator to determine whether or not a particular segment needs a seam integrity assessment from the standpoint of anomalies that may be growing as the result of pressure-cycle-induced fatigue, the following procedure may be used. The objective is to compare the actual cycles experienced by the segment to a set of benchmark cycles that have been developed based on actual pipeline experience that indicate the degree of aggressiveness of the cycles in terms of the likelihood that fatigue crack growth will occur. The benchmark cycles are shown in Table D.1. Note that the benchmark cycles were developed from pipelines comprised of X52.

The actual cycles experienced for a representative year should be obtained from the operating data for the segment. A sampling rate of less than 15 minutes is recommended to capture all pressure fluctuations of 25 psig or more. Cycles of less than 25 psig may be ignored because they appear to have a negligible effect on fatigue crack growth. Cycles are counted by paring maximums and minimums in a systematic way. Although a number of schemes for counting cycles exist, "rain-flow" counting has been found to be one of the most conservative and therefore it is appropriate for fatigue crack growth in pipelines [see ASTM E1049-85, *Standard Practices for Cycle Counting in Fatigue Analysis* (reapproved 1997)].

Once the pressure cycles are counted they can be compared to the benchmark cycles in Table D.1. However, in most cases they have to be adjusted to make a legitimate comparison. Adjustments to convert the actual cycles to

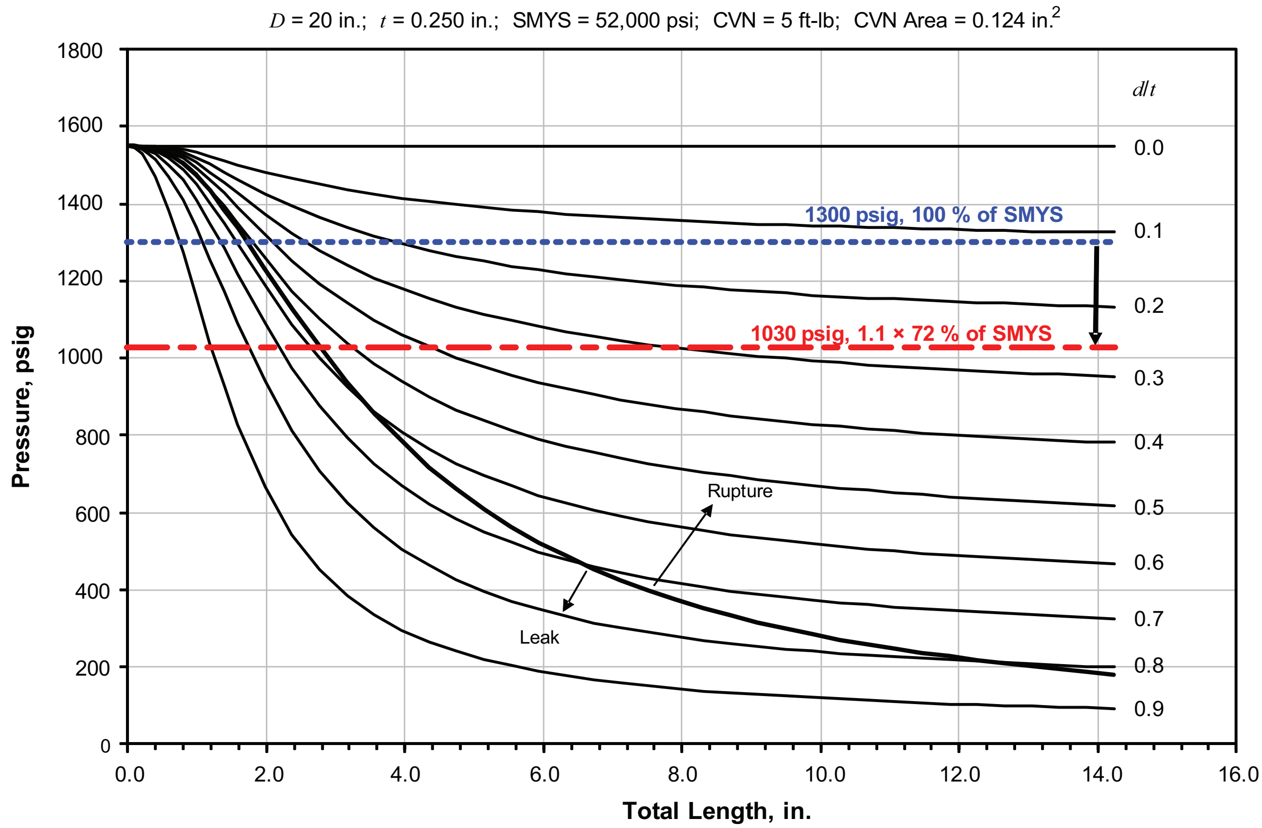


Figure D.4—Remaining Life of a Cracklike Anomaly or Selective Seam Corrosion in a Material of Much Less-than-optimum Toughness

Table D.1—Benchmark Cycles to Determine Cycle Aggressiveness

Cycle Size, % SMYS **(X52 Pipe)**	**Cycle Size,** psi **(X52 Pipe)**	**Very Aggressive**	**Aggressive**	**Moderate**	**Light**
Over 65 to 72	33,801 to 37,440	20	4	1	0
Over 55 to 65	28,601 to 33,800	40	82	0	0
Over 45 to 55	23,401 to 28,600	100	25	10	0
Over 35 to 45	18,201 to 23,400	500	125	50	25
Over 25 to 35	13,001 to 18,200	1000	250	100	50
25 or less	13,000 or less	2000	500	200	100
	TOTAL	3660	912	363	175

benchmark-equivalent cycles can be done by means of techniques such as Miner's rule using an applied-stress-versus-cycles-to-failure relationship such as the one given for carbon steel in the ASME *Boiler and Pressure Vessel Code*, Section VIII, Division 2, Appendix 5 (Figure 5-110.1). However, it should be remembered that the ASME "fatigue" curve applies to specimens containing no anomaly. Therefore, comparing time to failure using a fatigue crack growth model would be expected to produce time to failure for the actual cycles for any surviving anomalies. This would provide a more reliable assessment of cycle severity, and it establishes for the user the worst-case anomalies that remain after the last integrity assessment.

The process of comparing cycle aggressiveness using a fatigue-crack-growth model is illustrated by the following examples. Consider a pipeline comprised of 20-in. OD, 0.250-in. wall, X52 pipe with a Charpy shelf energy of 100 ft-lb. Assume that the pipeline experiences one pressure cycle from zero to the MOP of 936 psig (72 % of SMYS) and back to zero every 16 days and that the last integrity assessment consisted of a hydrostatic test of the pipeline to a minimum pressure of 1300 psig (100 % of SMYS). It is possible to compare this spectrum with the four benchmark spectrums using Miner's rule and the ASME fatigue curve mentioned above, but it is better to use a fatigue crack growth model if one is available. Using a typical fatigue crack growth model and the default C and n values listed in 9.2.3, one can show that the shortest calculated time to failure arises from an anomaly that is initially 80 % through the wall and 1.16 in. long. The calculated time is 16.6 years, so applying a factor of safety of two, the pipeline operator might decide to reassess the pipeline in 8.8 years anyway even if the cycles do not turn out to be aggressive or very aggressive. One reason that the operator might not reassess the pipeline in that amount of time could be that there is sound evidence that no 80 % through-the-wall anomaly exists. The same analysis shows, for example, that a 40 % through-the-wall anomaly has a remaining life of 30.2 years. Another reason could be that the default crack growth rate is too conservative for the particular environment of the pipeline segment.

To evaluate the degree of cycle aggressiveness one has to run the fatigue-crack-growth model for the same pipeline four times using the very aggressive, aggressive, moderate, and light cycles of Table D.1. The same C and n values should be used throughout that were used for the calculation using the actual operating spectrum. The model shows that the minimum remaining lives in these cases are also associated with an 80 %-through, 1.16-in. long anomaly. The times to failure are:

— 0.9 year for very aggressive cycles,

— 3.7 years for aggressive cycles,

— 9.6 years for moderate cycles,

— 23.3 years for light cycles.

Thus the operator can conclude that one cycle from zero to the MOP and back to zero every 16 days constitutes light to moderate cycle aggressiveness. This does not mean that the pipeline would never experience a fatigue failure, but experience has shown that pipelines that do exhibit fatigue failures tend to have aggressive to very aggressive cycles.

Some additional points about cycle severity worth noting are as follows.

— If the cyclic spectrum changed from one full-MOP cycle every 16 days to one full-MOP cycle every 4 days, the minimum calculated time to failure would change by a factor of 4 to 4.4 years. This would put the pipeline in the aggressive category.

— If the pipeline experiences one full-MOP cycle every 16 days, but it was tested to only 90 % of SMYS instead of 100 % of SMYS the minimum calculated time to failure is 3.9 years. Thus the pipeline would be placed in the aggressive category. This illustrates why it is good to test a pipeline to as high a pressure as possible, or if ILI is the means of assessment, anomalies having predicted failure pressures below 100 % of SMYS should be remediated.

— If the pipeline was comprised of a pipe material of the same geometry and Charpy energy, was tested to 100 % of SMYS, is operated at 72 % of SMYS, and is operated with one full-MOP cycle every 16 days, but is comprised of X60 pipe instead of X52, the minimum calculated time to failure is 13.2 years (compared to 16.6 years for X52). The 100 % of SMYS pressure for X60 is 1500 psig and the 72 % of SMYS pressure is 1080 psig. Therefore, a full-MOP cycle is zero to 1080 psig (43,200 psi hoop stress) and back to zero for the X60 pipeline in contrast to the full-MOP cycle for X52 (37,440-psig hoop stress). The larger stress cycle produces a shorter fatigue life even though both pipelines were subjected to the same test-pressure-to-operating-pressure ratio.

Annex E
(informative)

Other Technologies

E.1 Direct Assessment

Direct assessment is four-step process:

1) preassessment is carried out for a segment based on the attributes of the segment and its operating history;

2) indirect measurements are made to detect possible locations where anomalies may exist;

3) direct examinations (excavations and examinations of the pipeline) at selected locations (based on the indirect measurements) are made to assess the nature of anomalies, if any; and

4) postexamination is carried out to evaluate remaining life and to evaluate the direct assessment process itself.

In the case of ECDA, the preassessment identifies whether or not ECDA is feasible for a given segment. ECDA cannot be used for underwater pipelines. The electrical measurements typically used for ECDA do not work inside casings; however, GWUT can be used as an indirect inspection method for pipes inside steel casings as part of the ECDA. Other factors such as extremely poor coating or excessively deep burial may defeat the use of ECDA. The indirect assessment entails utilizing at least two types of aboveground electrical measurements such as close-interval pipe-to-soil potential surveys, DC voltage gradient surveys, or current attenuation surveys to locate coating faults and cathodic protection current anomalies that may indicate that external corrosion has occurred, may be occurring, or could occur in the future. Because mechanical damage inherently is associated with coating damage, it is likely that locations of mechanical damage will be identified by the electrical surveys. Locations for direct examinations are selected based on the findings of the electrical surveys, and usually, some random locations not indicated by the surveys are examined as well to check the validity of the surveys. Repairs are made to any coating anomalies, the anomalies are assessed in terms of their effect on remaining strength and repaired if necessary, and data are gathered on coating condition and soil properties that could affect corrosion. Repairs are made to any pipe defects which would impair pipeline integrity based on criteria such as B31G, Modified B31G, or RSTRENG. The postexamination step involves calculating remaining life, setting reassessment intervals, and determining whether or not ECDA has been shown to work for the segment. A pipeline operator who elects to use ECDA for integrity assessment should carry out the assessment in accord with NACE SP0502-2002.

In the case of ICDA, the preassessment involves examining pipeline attributes and historical data; gathering, terrain (elevation profile) and flow rate data; and consideration of factors such as product type, water content, inhibitor or biocide programs, and cleaning pig frequency to be able to identify locations where internal corrosion might be expected to occur. Note that the flow rate should be great enough to entrain water and solids into the fluid stream; the presence of turbulent flow alone does not necessarily guarantee sufficient velocity. The use of ICDA is not recommended if these data cannot be acquired, if the likely rate of corrosion cannot be inferred, if a continuous water phase is present, or if direct examination of the likely locations of corrosion is not feasible. Indirect examination involves identifying the likely locations for internal corrosion to have occurred. This is done by considering where liquid water and/or solid waste or sediment could accumulate as the result of elevation profile and flow rate. Models are available for determining such locations. Locations for direct examinations are selected based on the findings of the evaluations of likely locations for internal corrosion to have occurred, and usually, some random locations not indicated by the evaluations are examined as well to check the validity of the evaluations. Nondestructive thickness measurements are made at the selected locations to determine whether or not wall thickness degradation has taken place. Repairs are made to any pipe defects which would impair pipeline integrity based on criteria such as B31G, Modified B31G, or RSTRENG. The postexamination step involves estimating remaining life, setting reassessment intervals, and determining whether or not ICDA has been shown to work for the segment. A pipeline operator who elects to use ICDA for integrity assessment should carry out the assessment in accordance with NACE SP0208.

In the case of stress corrosion cracking direct assessment (SCCDA), the preassessment involves reviewing historical data for a given segment that would suggest whether or not the segment might be susceptible to SCC. The factors that control susceptibility to “high-pH” SCC for a liquid pipeline are operating stress level (60 % of SMYS is threshold above which susceptibility is assumed likely), an operating temperature above 100 °F, the years the system has operated in the susceptible range, and the coating type is other than fusion-bonded epoxy. The factors that control susceptibility to “near-neutral-pH” SCC are the same except that susceptibility may exist irrespective of the operating temperature. When determining the susceptibility of a pipeline segment for near-neutral-pH SCC, it is important to consider the presence of dents with high residual strain as potentially susceptible sites. The indirect assessment entails acquiring data such as pipe-to-soil potential measurements from close-interval surveys and DC voltage gradient surveys to indicate where coating disbondment may have occurred and information on terrain, soil type and drainage as these factors are known to influence susceptibility. Locations for direct examinations are selected based on the findings of the electrical, soil type, terrain, and drainage surveys. Soil models exist that may assist the operator in identifying locations of likely susceptibility. Usually, some random locations not indicated by the surveys are examined as well to check the validity of the surveys and any soil model that may be employed. The direct examinations involve examining the coating, terrain, soil, and drainage conditions and examining the pipe surface by means of magnetic particle inspection to ascertain whether or not SCC exists and, if so, which type of cracking (high-pH or near-neutral-pH) is taking place. Repairs are made to any pipe defects which would impair pipeline integrity based on an engineering fracture mechanics assessment criterion. The postexamination step involves setting reassessment intervals, and determining whether or not the SCCDA survey and analysis process has been shown to work for the segment. A pipeline operator who elects to use SCCDA for integrity assessment should carry out the assessment in accord with NACE SP0204.

GWUT involves inducting ultrasound waves into a pipe segment through a concentric collar (the pipe does not have to be out of service). Waves propagate axially using the pipe wall thickness as a wave guide. Wall thickness anomalies cause reflections that are interpretable in terms of thickness loss. The distance capability for this to work is limited. It is on the order of 100 ft to 200 ft, depending on energy absorption characteristics of the pipe-coating-soil interface, so it is not practical to inspect long segments of pipe by this method. However, the technique has proven useful for short segments where neither access to the pipe nor pigging is feasible. Examples are pipe inside a casing, risers at platforms, and short delivery lines. The technique can locate areas of metal loss caused by either external or internal corrosion.

E.2 Visual Inspection

Visual inspection of an aboveground pipeline is useful for identifying areas of external corrosion or mechanical damage. Visual inspection of pipe exposed by excavation is useful for identifying areas of sagging or missing coating. All anomalies identified at an excavation site should be visually inspected and photographed in addition to whatever physical measurement or nondestruction inspections are used.

Annex F
(informative)

Leak Detection Methods

The well-known leak detection systems are as follows.

Periodic Auditory, Visual, and Olfactory Inspections—Operators use a variety of periodic inspections to detect leaks. These may include aerial patrols, surface patrols, station walk-throughs, etc., and personnel are looking for dead vegetation, stained areas, pooled or free-flowing product, vapor or vapor clouds, ground frost, hissing sounds, and/or odors.

Volume Balance—One of the oldest techniques involves comparing the mass of fluid put into the pipeline with the mass of fluid coming out at the other end. The comparison should be made over a period of time such as one hour or longer to eliminate the effects of transients (i.e. its application is based on the assumption that the flow is steady state. The method does not locate the leak. Errors in measurement, metering, or temperature can limit success.

Dynamic Flow Modeling—Dynamic flow modeling involves simulating the operating conditions of the pipeline through hydraulic calculations based on flow rate, temperature, pipeline profile, and fluid properties. The calculated conditions are then compared to real time data acquired from various measurement points along the pipeline. Deviations are evaluated against alarm set points. The alarm set points should be selected to find the smallest leak that is distinguishable from background noise so as to minimize false alarms. The size of leak that can be found will be certain percentage of the volume of fluid in the system. The software models for this purpose are normally integrated into the SCADA system of the pipeline. Leak location information is not provided automatically, but analysis of transients can be used to locate a leak. A pipeline operator may find it useful to consult API 1149 and API 1130 in conjunction with employing a dynamic flow model leak detection system.

Tracer Chemical—This approach to leak detection requires mixing a small amount 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 soil. After the chemical is injected into the pipeline, 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. Presence of the chemical in the sample can only occur through leakage from the pipeline. This method can be used periodically or continuously to examine for leakage. Since the locations of the samples are known, it is possible to locate the leak within the limits of distances between sample points. One limitation of this method is that you need to restart a line with a suspected leak in order for tracer chemicals to work.

Release Detection Cable—Leak-detection-sensing cables can be installed in the pipeline trench over, under, or along-side the pipeline. Typically, the cable is installed within a continuous perforated plastic tube. The presence of a hydrocarbon creates a circuit between to sensing wires within the cable, sending a signal of the leak and the location to the pipeline control center. This kind of system most likely can only be installed as the pipeline is being constructed. It would seem that retrofitting an existing pipeline would be prohibitively expensive. One limitation of detection cables is that they can be defeated by previously existing contamination.

Shut-in Leak Detection—Shut-in leak detection, also known as a “stand-up test” consists of shutting off flow in a pipeline and closing the valves to hold the pressure constant. The pressure will remain constant except for changes due to temperature variations unless a leak exists. The rate of pressure decay in the event of a leak is indicative of the size of the leak. It should be noted that leakage through valves, if it occurs, will confound the ability to judge whether or not a leak exists. Also, no information on the location of the leak is provided by this type of test.

Pressure Point Analysis Leak Detection Software—This software examines pressure data acquired at high sampling rates from discreet locations and it calculates mass balance in real time. Pattern recognition algorithms are used to distinguish leak events from normal operations. Since the locations of the pressure point samples are known, it is possible to locate the leak within the limits of distances between sample points.

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Dent Assessment Methodologies

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