

# Managing System Integrity for Hazardous Liquid Pipelines

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## Introduction

The goal of any pipeline operator is to operate the pipeline so that there are no adverse effects on the public, employees, the environment, or customers. The goal is an error-free, spill-free, and incident-free operation of the pipeline.

An integrity management program provides a way 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 method for examining and comparing the spectrum of risks and risk reduction activities available,
- provide a structured, easily-communicated way 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 to achieve a number of goals, including reducing both the number and consequences of incidents. Section 4 describes the components of an integrity management program. 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 may include engineers, operating personnel, and technicians or specialists with specific experience or expertise (such as corrosion, in-line inspection, and right-of-way patrolling). Users of this RP should be familiar with applicable pipeline safety regulations (e.g. 49 CFR 195). This RP is also designed to serve as a roadmap to relevant consensus standards, recommended practices, guidance documents, technical reports, advisory bulletins, and safety regulations that can help operators manage integrity for hazardous liquid pipelines.

## Guiding Principles

The development of this RP was based on certain guiding principles. These principles are reflected in multiple sections and are provided to give the reader the opportunity to view pipeline integrity from a broader 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 several consensus standards, including ASME B31.4, as well as 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

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 ensure 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.

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 applicable 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. 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 an iterative process. The operator continuously gathers new and refreshed information about the pipeline system through operating, maintenance, and testing 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. The following applies to operators:

- 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.
- Operators should 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 remediate or eliminate injurious defects.
- 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 RP is largely targeted to onshore pipelines 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 Bulletin 5T1, *Imperfection and Defect Terminology*

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

API Recommended Practice 1110, *Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide*

API Standard 1163, *In-line Inspection Systems Qualification*

API Recommended Practice 1166, *Excavation Monitoring and Observation for Damage Prevention*

API Recommended Practice 1173, *Pipeline Safety Management Systems*

API Recommended Practice 1176, *Assessment and Management of Cracking in Pipelines*

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

ASME B31.4, *Liquid and Slurry Piping Transportation Systems*

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

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

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

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

NACE SP0502, *Pipeline External Corrosion Direct Assessment Methodology*

### 3 Terms, Definitions, Acronyms, and Abbreviations

#### 3.1 Terms and Definitions

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

##### 3.1.1

##### **abandoned pipeline**

Pipeline has been shut down, physically isolated from other in-service lines, connections to all sources of hazardous liquid or gas/natural or other gas are isolated (capped or blinded), system purged of combustibles, sealed, and permanently removed from service. Some or all of the pipeline may have been physically removed.

NOTE See also decommissioned pipeline and idle pipeline.

##### 3.1.2

##### **actionable anomaly**

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

##### 3.1.3

##### **active pipeline**

A pipeline or pipeline segment being used to transport hazardous liquids in accordance with the provisions of the applicable code.

NOTE See also in-service pipeline.

##### 3.1.4

##### **anomaly**

An unexamined deviation from the normal sound pipe material, coatings, or welds.

NOTE 1 See also flaw, defect, and imperfection.

NOTE 2 Also, an indication generated by nondestructive inspection; see NACE 35100.

##### 3.1.5

##### **cathodic protection**

Technique by which metallic pipe is protected against external corrosion.

##### 3.1.6

##### **check valve**

A valve that permits fluid to flow freely in only one direction and contains a mechanism to automatically prevent flow in the other direction.

##### 3.1.7

##### **critical location**

Locations such as populated areas, commercially navigable waterways, drinking water resources, ecologically sensitive areas, and others as designated by the operator.

NOTE 1 See also high consequence area.

NOTE 2 Operators in the United States shall comply with 49 CFR 195 requirements for high consequence areas.

**3.1.8****decommissioned pipeline**

Pipeline has been shut down, physically isolated from other in-service lines, connections to all sources of hazardous liquid or gas/natural or other gas are sealed (capped or blinded), system purged of combustibles, sealed, and removed from service. Decommissioned pipelines are generally not intended to be returned to service.

NOTE See also idle pipeline and abandoned pipeline.

**3.1.9****defect**

Imperfection of a type or magnitude exceeding acceptable criteria.

NOTE See also anomaly, flaw, and imperfection.

**3.1.10****design pressure**

Pressure defined by the yield strength, wall thickness, nominal outside diameter, and appropriate joint and design factors.

**3.1.11****direct assessment****DA**

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.

NOTE See also external corrosion direct assessment, internal corrosion direct assessment, and stress corrosion cracking direct assessment.

**3.1.12****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.

**3.1.13****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.

**3.1.14****emergency flow restriction device****EFRD**

A valve that restricts fluid flow to only one flow direction or can be closed from a location remote from where the valve is installed.

NOTE See check valve or remote control valve.

**3.1.15****environmentally assisted cracking****EAC**

Corrosive attack of the pipe metal caused by exposure to specific environments either internal or external to the pipe and resulting in any of several forms of metal cracking. EAC includes, but is not limited to, hydrogen-induced cracking

(HIC), stress-oriented hydrogen-induced cracking (SOHIC), sulfide-stress cracking (SSC), or stress corrosion cracking (SCC).

#### 3.1.16

##### **estimated rupture pressure**

##### **ERP**

Failure pressure, estimated using an appropriate fitness for service calculation without a factor of safety.

#### 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 above-ground measurements and following up with excavations to examine the pipe where appropriate; see NACE SP0502.

#### 3.1.18

##### **failure pressure ratio**

##### **FPR**

Ratio of the ERP to the maximum pressure expected during service, i.e. the ratio of the calculated failure pressure of an anomaly to the maximum operating pressure (MOP) at the location of the anomaly, i.e.  $FPR = ERP/MOP$ .

#### 3.1.19

##### **Fatigue (cited in API RP 1176)**

Process of forming or enlarging a defect or flaw due to cycles of stress.

#### 3.1.20

##### **flaw**

An imperfection that is smaller than the maximum allowable size.

NOTE See also anomaly, defect, and imperfection.

#### 3.1.21

##### **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 depending on site specific conditions such as bends, coating type, weld spacing or other factors.

#### 3.1.22

##### **heat-affected zone**

##### **HAZ**

The portion of the base metal that was not melted during brazing, cutting, or welding, but whose microstructure and properties were affected by the heat of these processes.

#### 3.1.23

##### **hard spot**

Area in the pipe with a hardness level considerably higher than that of the surrounding metal, usually due to localized quenching or alloy segregation.

**3.1.24****high consequence area  
HCA**

Those locations where a pipeline release might have a significant adverse effect on an unusually sensitive area, a high population area, another populated area, or a commercially navigable waterway.

NOTE 1 This definition is specific to the federal regulations in the United States, see 49 CFR 195.

NOTE 2 An unusually sensitive area is a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

**3.1.25****high pressure test**

A test undertaken at pressures potentially greater than necessary for qualifying a pipeline for service under regulations in order to address or assess for an identified or targeted pipeline threat.

NOTE Similar to a “spike” test, an alternative when spike testing may not be advised or warranted.

**3.1.26****highly volatile liquid**

A hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 40 psia (276 kPa) at 100 °F (37.8 °C).

**3.1.27****hydrogen-induced cracking  
stepwise cracking  
HIC**

Cracking that may occur in line pipe steels containing manganese sulfide inclusions exposed to atomic hydrogen generated at the surface of the pipe externally by a cathodic reaction or internally by a corrosion reaction of sour products and water.

**3.1.28****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.

**3.1.29****hydrostatic test**

Means of assessing the integrity of a new or existing pipeline that involves filling the pipeline with water and pressurizing to a level significantly in excess of the MOP for an appropriate duration to confirm no leaks are present and to demonstrate that the pipeline is fit for service at the MOP.

NOTE See API RP 1110.

**3.1.30****idle pipeline**

Pipeline has been shut down, physically isolated from all sources of hazardous liquid or gas/natural or other gas (capped or blinded), system purged of combustibles or maintain a blanket of natural gas at pressure and removed from service. An idled line may be returned to active service. Certain inspection and maintenance activities may be suspended.

**3.1.31****imperfection**

A flaw or other discontinuity noted during inspection that passes acceptance criteria during an engineering and inspection analysis.

NOTE See also anomaly, defect, and flaw.

### **3.1.32**

#### **indication**

A discovery from nondestructive testing (NDT), inspection technique, or signal from an ILI system.

### **3.1.33**

#### **in-line inspection**

##### **ILI**

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

NOTE 1 This is also called intelligent or smart pigging.

NOTE 2 This includes free swimming, tethered, and self-propelled inspection tools.

### **3.1.34**

#### **in-service pipeline**

##### **active pipeline**

A pipeline or pipeline segment that currently transports hazardous liquids.

### **3.1.35**

#### **integrity assessment**

Method for determining the pipe's condition.

NOTE Methods can include ILI, pressure testing, direct assessment, or other technologies that can demonstrate the integrity of the pipe.

### **3.1.36**

#### **internal corrosion direct assessment**

##### **ICDA**

Integrity assessment process conducted for the purpose of locating and remediating anomalies arising from internal corrosion of a pipeline.

NOTE See NACE SP0208 (LP-ICDA standard for liquid petroleum), NACE SP0206 (DG-ICDA standard for dry gas), and NACE SP0110 (WG-ICDA standard for wet gas).

### **3.1.37**

#### **maximum operating pressure**

##### **MOP**

Maximum pressure at which a liquid pipeline system may be operated in accordance with the provisions of the applicable code.

### **3.1.38**

#### **mill test pressure**

The test pressure applied in the pipe mill as part of the original pipe manufacturing process.

### **3.1.39**

#### **mitigation**

##### **mitigative action**

Taking appropriate action based on an assessment of risk factors to reduce the overall level of pipeline integrity risk by reducing the amount of risk from a probability or consequence standpoint.

### **3.1.40**

#### **operator**

Entity that operates pipeline facilities.

**3.1.41****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.

**3.1.42****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).

**3.1.43****remediation**

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

**3.1.44****remote control valve**

Any valve that is operated from a location remote from where the valve is installed.

NOTE A remote control valve is usually operated by the supervisory control and data acquisition (SCADA) system.

**3.1.45****risk**

Measure of loss in terms of both the incident likelihood of occurrence and the magnitude of the consequences.

**3.1.46****risk assessment**

Systematic, analytical process in which potential hazards from facility operation are identified and the likelihood and consequences of potential adverse events are determined.

**3.1.47****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.

**3.1.48****selective seam weld corrosion****SSWC**

Form of external or internal corrosion attack that occurs preferentially along the weld bond line of ERW or FW line pipe that often has the appearance of a wedge-shaped groove when conditions exist that cause the bond line region or the ERW or FW seam to corrode at a faster rate than the surrounding base metal.

**3.1.49****spike hydrostatic test**

Short-duration hydrostatic test wherein the pressure level is higher than the strength test, 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.

NOTE Similar to high pressure testing.

**3.1.50****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 and does not exceed the MOP of the pipe.

**NOTE** A pipeline company may conduct this test after a pipeline is constructed but prior to beginning shipment of product delivery.

**3.1.51****stress corrosion cracking direct assessment****SCCDA**

Direct assessment conducted for the purpose of locating and remediating anomalies arising from stress corrosion cracking (SCC) of a pipeline or evaluating whether SCC is a threat on a particular pipeline.

**NOTE** See NACE SP0204.

**3.1.52****stress riser**

a scrape, gouge, groove, notch, or metal loss unrelated to corrosion.

**3.1.53****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.

**3.1.54****transit fatigue**

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                               |
| AFD    | axial flaw detection                              |
| ASME   | American Society of Mechanical Engineers          |
| ASNT   | American Society for Nondestructive Testing       |
| AUT    | automated ultrasonic testing                      |
| CEPA   | Canadian Energy Pipeline Association              |
| CFR    | Code of Federal Regulations                       |
| CMFL   | circumferential magnetic flux leakage             |
| CP     | cathodic protection                               |
| 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                      |
| EAC    | environmentally assisted cracking                 |
| ECDA   | external corrosion direct assessment              |
| EFRD   | emergency flow restriction device                 |

|        |                                                   |
|--------|---------------------------------------------------|
| EMAT   | electromagnetic acoustic transducer               |
| ERP    | estimated rupture pressure                        |
| ERW    | electric resistance welding                       |
| FMECA  | Failure Modes, Effects, and Criticality Analysis  |
| FPR    | failure pressure ratio                            |
| FW     | flash welded                                      |
| GIS    | geographic information system                     |
| GPS    | global positioning system                         |
| GW     | girth weld                                        |
| GWUT   | guided wave ultrasonic testing                    |
| HAZ    | heat affected zone adjacent to a weld             |
| HAZID  | Hazard Identification                             |
| HAZOP  | Hazard and Operability Study                      |
| HCA    | high consequence area                             |
| HF-ERW | high-frequency welded electric resistance welding |
| HIC    | hydrogen-induced cracking                         |
| HSAW   | helical seam double submerged arc welding         |
| HVAC   | high voltage alternating current                  |
| HVDC   | high voltage direct current                       |
| HVL    | highly volatile liquid                            |
| ICDA   | internal corrosion direct assessment              |
| ID     | inner diameter                                    |
| ILI    | in-line inspection                                |
| IMP    | integrity management plan                         |
| JSA    | job safety analysis                               |
| LF-ERW | low-frequency welded electric resistance welding  |
| LPR    | linear polarization resistance                    |
| LW     | lap welded                                        |
| MFL    | magnetic flux leakage                             |
| MIC    | microbially induced corrosion                     |
| MOC    | management of change                              |
| MOP    | maximum operating pressure                        |
| MPI    | magnetic particle inspection                      |
| MPT    | magnetic particle testing                         |
| MTR    | mill test report                                  |
| NAEC   | narrow axial external corrosion                   |
| NDE    | nondestructive examination                        |
| NDT    | nondestructive testing                            |
| NPS    | nominal pipe size                                 |
| NTSB   | National Transportation Safety Board              |

|       |                                                                            |
|-------|----------------------------------------------------------------------------|
| OD    | outer diameter                                                             |
| OQ    | operator qualification                                                     |
| PDCA  | Plan-Do-Check-Act (a systematic approach to pipeline integrity management) |
| PFD   | process flow diagram                                                       |
| PHA   | process hazard analysis                                                    |
| PHMSA | Pipeline and Hazardous Materials Safety Administration                     |
| P&ID  | piping and instrumentation diagram                                         |
| POD   | probability of detection                                                   |
| POE   | probability of exceedance                                                  |
| POI   | probability of identification                                              |
| PPTS  | Pipeline Performance Tracking System                                       |
| PT    | liquid-penetrant testing                                                   |
| RCA   | root cause analysis                                                        |
| RCM   | Reliability Centered Maintenance                                           |
| ROW   | right-of-way                                                               |
| SCADA | supervisory control and data acquisition                                   |
| SCC   | stress corrosion cracking                                                  |
| SCCDA | stress corrosion cracking direct assessment                                |
| SME   | subject matter expert                                                      |
| SMS   | safety management system                                                   |
| SMYS  | specified minimum yield strength                                           |
| SOHIC | stress-oriented hydrogen-induced cracking                                  |
| SOP   | safe operating pressure                                                    |
| SSC   | sulfide-stress cracking                                                    |
| SSWC  | selective seam weld corrosion                                              |
| TOFD  | time of flight diffraction                                                 |
| USCD  | ultrasonic crack detection                                                 |
| UT    | ultrasonic testing                                                         |
| WFMT  | wet fluorescent magnetic particle testing                                  |

## 4 Integrity Management Program

### 4.1 Program Considerations

#### 4.1.1 Integrity Management Program Components

A pipeline integrity management program is a documented set of policies, processes, and procedures to manage pipeline risk. The program should begin with threat identification and then facilitate appropriate and timely actions on the part of a pipeline operator to ensure that a pipeline system is continually operated in a manner that manages risk to the public, employees, the environment, and customers. In addition to traditional integrity management activities related to assessment, inspection, and maintenance of the pipeline system, a comprehensive pipeline integrity management program should also include activities that assess and improve the performance of the program itself. The program elements that should be included in an integrity management program are depicted in Figure 1 and discussed in detail in Section 4.2.

To address pipeline risk changing over time, a pipeline operator must continue to assess its pipelines at specified intervals and periodically evaluate the integrity of its pipelines. A pipeline operator ensures these periodic reassessments are effective through a continuous cycle of monitoring pipeline condition, identifying and assessing risks, and taking action to reduce the most significant risks. 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.

#### 4.1.2 Continuous Integrity Management Improvement with a Pipeline Safety Management System

Figure 1 illustrates one example of the continuous cycle of a pipeline integrity management program. Figure 1 also reflects the way this continuous cycle aligns with the Plan-Do-Check-Act (PDCA) cycle of a pipeline safety management system (pipeline SMS). Discussed in greater detail in API RP 1173, Pipeline Safety Management Systems, a pipeline SMS provides a mechanism for enhanced risk assessment and continuous pipeline safety performance improvement. While API RP 1173 is a flexible and scalable framework, its core principles of learning from experience, continuous improvement, and awareness and management of many linked activities will improve the effectiveness of a pipeline integrity management program. To emphasize these benefits, the elements of an integrity management program discussed in Section 4.2 are organized by their occurrence in the PDCA cycle of a pipeline SMS. Programs may evolve and mature over time. The PDCA elements depicted in Figure 1 also apply to facility integrity management programs which are discussed in Section 12.

In addition to organizing integrity management program activities in a continuous PDCA improvement loop, application of individual elements of API RP 1173 will enhance the effectiveness of integrity management program activities. Examples include the following:

- Supporting integrity management resource needs and commercial trade-offs
  - Leadership and Management Commitment (API RP 1173, Section 5)
- Influencing pipeline integrity risk assessment
  - Stakeholder Engagement (API RP 1173, Section 6)
  - Risk Management (API RP 1173, Section 7)
  - Operational Controls (API RP 1173, Section 8)
  - Management of Change (API RP 1173, Section 8.3)
- Benefiting pipeline integrity assessment and program evaluation activities
  - Incident Investigation, Evaluation and Lessons Learned (API RP 1173, Section 9)
  - Safety Assurance (API RP 1173, Section 10)
  - Management Review and Continuous Improvement (API RP 1173, Section 11)

A further concept for operators to consider is applying the PDCA cycle to individual integrity management activities. Just as the activities of the integrity management program may be arrayed around the PDCA cycle as illustrated in Figure 1, each of those activities may have their own PDCA cycle of tasks. For example, the activity of Conduct Pipeline Inspections, Testing, and Examinations is positioned in Figure 1 in the “Do” stage of the cycle. Conducting pipeline inspections also involves planning the inspections, performing the inspections, tasks to verify the inspections, and potential improvement tasks for the next round of inspections. Organizing individual tasks formally by PDCA stage is up to the operator, but the model may prove useful for some operators.

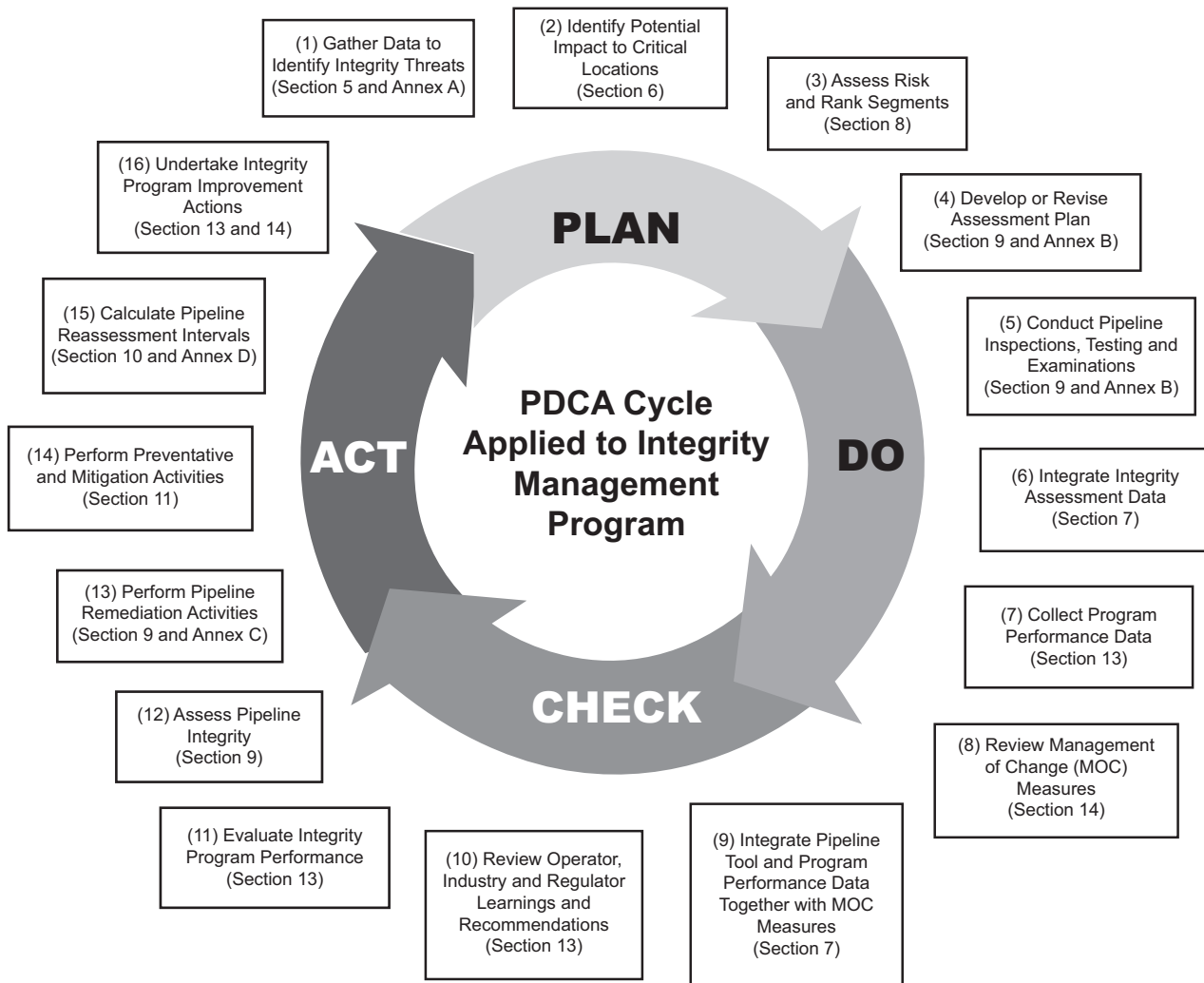


**Figure 1—PDCA Cycle Applied to an Integrity Management Program**

## 4.2 Elements of Integrity Management

Integrity management program elements accomplish the threat management goals of the program through both direct pipeline integrity-related activities as well as supporting activities to improve the quality of the program itself. In pipeline SMS terms, a successful integrity management program includes integrity management “Plan and Do” assessment, inspection and maintenance activities, “Check and Act” performance measuring, evaluation, and improvement activities.

### 4.2.1 “Plan” Integrity Management Elements

(1) Gather Data to Identify Integrity Threats—To understand the potential threats to the integrity of a pipeline segment an operator should gather, review, and integrate the relevant and available 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. 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 re-evaluation of risk prior to the next integrity assessment. Section 5 provides an overview of hazardous liquid pipeline threats and Annex A provides a detailed description of each threat. Section 7 provides a summary of the data sources, common data elements that are typically used in risk analyses, and approaches to data review and integration.

(2) Identify Potential Pipeline Impacts to Critical Locations—This program element involves the identification of pipeline segments that may affect critical locations in the event of a release. Identification of critical locations involves evaluating populated, environmentally sensitive, and navigable water area information, integrating this information with pipeline mapping data, and determining at which locations a release may 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 and updated on a regular basis. Guidance for making these determinations is provided in Section 6 of this RP.

(3) Assess Risk and Rank Segments—Data assembled from the previous steps are used to conduct a risk assessment of the pipeline system. 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) and operation (e.g. a change in flow or the hydraulic pressure profile). Changes in population, changes altering segments that can affect critical locations, the results of previous integrity assessments, and the impacts of repairs and mitigative measures should also be taken into account in these risk reassessments. The goal should be to ensure that the analytical process reflects the latest understanding of pipe condition. Section 8 provides guidance for developing and implementing a risk assessment approach.

(4) Develop or Revise 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 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 9 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.

#### 4.2.2 “Do” Integrity Management Elements

(5) Conduct Pipeline Inspections, Testing, and Examinations—The pipeline operator should implement the in-line inspection (ILI), hydrostatic pressure testing, or direct assessment described in the pipeline integrity assessment plan. The specific type of inspection, testing, or examination undertaken will reflect the most appropriate method for addressing the threat and risks identified in the integrity assessment plan. Section 9 provides guidance for conducting integrity assessments and Annex B provides a description of available internal inspection techniques.

(6) Integrate Integrity Assessment Data—The pipeline operator should collect data on the integrity of its pipeline, including data generated by integrity inspections, testing, and examination. The pipeline operator should gather data in a timely manner, including results and reports generated by inspection vendors. The pipeline operator should pay particular attention to regulatory or other recommended timeframes within which to obtain results from inspection vendors.

In addition to data on its pipelines, the operator should also collect data on its inspection, testing, and examination methods. The pipeline operator will use this inspection tool and method data to analyze the effectiveness of its inspection tools and integrity program. Data on in-line inspections should be collected to compare to integrity excavations and non-destructive examination results to assess the effectiveness of each inspection tool or examination method. Section 7 provides a summary of the data sources, common data elements, and approaches to data review and integration.

(7) Collect Program Performance Data—The pipeline operator should collect program performance metrics that indicate the effectiveness of its integrity management program. The operator should collect measures of the quality of

its threat assessment, critical location selection, risk assessment, assessment planning, inspection, integrity assessment, remediation activities, preventive and mitigative activities, reassessment intervals, and program improvement. Section 13 provides guidance for developing performance measures to evaluate program effectiveness and for conducting audits of integrity management programs.

#### 4.2.3 “Check” Integrity Management Elements

(8) Review Management of Change (MOC) Measures—Pipeline systems and the environments 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 documented and evaluated. Furthermore, after these changes have been made, they should be incorporated, as appropriate, into future risk assessments to be sure the risk assessment process addresses the system as it is currently configured, operated, and maintained. Section 14 discusses the important aspects of MOC as it relates to integrity management.

(9) Integrate Pipeline, Tool, and Program Performance Data Together with MOC Information—The pipeline operator should integrate data from pipeline inspections, testing and examination, data on inspection tool performance, and MOC information. Each of these data sources analyzed individually may produce an incomplete picture of the integrity of a specific pipeline segment. Data integration will allow the operator to understand the cumulative impact of each threat factor reflected by multiple data sources when evaluating pipeline integrity.

Operators should ensure that policies, processes, procedures, and records are in place to provide integrity management program managers with the multiple streams and sources of data and information they need to review and integrate. Depending upon the specific organizational or authority structure of an operator, sources of data or information needed for pipeline integrity management may be generated or stored outside the purview of integrity managers. Established policies, processes, and procedures will ensure necessary data and information is generated and delivered into the integrity management program in alignment with the program’s PDCA cycle. Section 7 provides guidance on data maintenance and management of change.

(10) Review Operator, Industry, and Regulator Learnings, and Recommendations—An operator should also gather, review, and integrate applicable industry trends, regulatory notices, and other operators’ experiences where applicable. Pipeline safety information and lessons learned shared by pipeline operators through industry groups and forums may relate to a specific risk or threat faced by a pipeline operator. Recommendations or reports issued by investigators after incidents, as well as advisory bulletins issued by regulators, may also contain information beneficial to pipeline integrity. Many of the products produced for the Management Review and Continuous Improvement element of a pipeline SMS, discussed in Chapter 11 of API RP 1173, will benefit pipeline integrity management including results of risk management review, results and recommendations of incident investigations, evaluations and lessons learned, results of internal and external audits, and evaluations and stakeholder feedback. Section 13 discusses performance tracking and trending to facilitate continuous improvement efforts.

(11) Evaluate Integrity Program Performance—Reviews need to be performed on a periodic basis to evaluate the effectiveness of a pipeline operator’s integrity management program. The operator should review program performance metrics 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. Section 13.4 describes integrity management program issues recommended for review and evaluation. Results of this evaluation may also feed into a Management Review conducted as part of an operator’s pipeline SMS.

(12) Assess Pipeline Integrity—The pipeline operator should assess the integrity of its pipeline segments based on an evaluation and consideration of the results of its integrated data. As discussed above, pipeline inspection results, data on inspection tool performance, and MOC information are all necessary to develop a comprehensive assessment of a pipeline’s integrity. Pipeline operators should also incorporate into integrity assessments any applicable operator

industry, or regulator lessons, recommendations, or advisories. For pipeline segments that may 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 9.2 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.

#### 4.2.4 “Act” Integrity Management Elements

(13) Perform Pipeline Remediation Activities—The pipeline operator should implement appropriate remediation activities based on its pipeline integrity assessment(s). Specific remediation activities should address the threats to the pipeline segment and the risk represented by those threats. Section 9.2 describes strategies for responding to anomalies identified by pipeline inspection, testing, or examination, including conditions requiring immediate or scheduled response.

(14) Perform Pipeline Preventive and Mitigative Activities—A pipeline operator should establish and implement a process to evaluate the need for additional measures to reduce pipeline risk. 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 right-of-ways, and conducting periodic aerial or ground surveillance of the right-of-ways.
- 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.

Additional preventive and mitigative measures are described in Section 11.

(15) Calculate Pipeline Reassessment Intervals—The pipeline operator should conduct integrity reassessments 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 10 provides guidelines for scheduling reassessments. Examples of how one might go about calculating reassessment intervals are presented in Annex D.

(16) Undertake Integrity Program Improvement—The operator should use the results of the program performance evaluation to modify the integrity management program as part of a continuous improvement process. Recommendations for changes or improvements, or both, should be based on analysis of the performance measures and the audits. All recommendations for changes or improvements, or both, should be documented, and the recommendations should be implemented in the next cycle of integrity assessment. Section 13 provides guidance for developing performance measures to evaluate program effectiveness and Section 14 discusses the important aspects of MOC related to integrity management.

## 5 Threat Assessment

### 5.1 Threats

Integrity management begins with a systematic and comprehensive consideration of potential threats to the integrity of the pipeline or facility. The threats for hazardous liquid pipelines that operators should consider are as follows:

- a) external corrosion;

- b) internal corrosion;
- c) selective seam weld corrosion (SSWC), external or internal;
- d) environmentally assisted cracking (EAC) including stress corrosion cracking (SCC), hydrogen-induced cracking (HIC), stress-oriented hydrogen-induced cracking (SOHIC), and sulfide-stress cracking (SSC);
- e) manufacturing defects including defective pipe seams, hard heat-affected zones (HAZ), and defective pipe including pipe body hard spots;
- f) construction and fabrication defects including defective girth welds, defective fabrication welds, wrinkle bends, and stripped threads/broken pipe/coupling failures;
- g) equipment failure including gasket or o-ring failure, control or relief equipment failure, seal or pump packing failure, and miscellaneous;
- h) mechanical damage caused by accident, negligence or deliberate act of vandalism;
- i) incorrect operations; and
- j) weather and outside forces including cold weather, lightning, heavy rains or floods, or earth movements, or a combination thereof, which may cause wrinkles, buckles, cracked valve bodies, and girth weld cracks.

An operator shall review data for each pipeline segment or facility to determine which of these threats are credible and need to be addressed.

It is recognized that not all 10 threats may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 10 threats are discussed in detail in Annex A. Any of these threats may have a time-delayed or interactive component to them. While fatigue by itself is not a threat, it can facilitate crack initiation and growth from an extant defect.

Failure of dents through environmental cracking, and delayed failure of mechanical damage are considered interactive threats and are discussed in 5.2.

## 5.2 Threat Interaction

A review of industry failure databases has shown that threats can interact and combine to create a more severe situation than the individual threats alone. Identifying threats and their interactions is performed by overlaying, comparing, and integrating relevant data sets for the pipeline, including pipeline attributes, construction factors, operating parameters and history, integrity assessment history, maintenance and repair history, and incident data. The processes and considerations relevant to the integration of the data are discussed in Section 7. Additional information can be found in API Bulletin 1178.

Examples of specific threat interactions can be broadly categorized by the following:

- corrosion (external or internal) with manufacturing defects like defective pipe seams, EAC (typically SCC) or SSWC;
- mechanical damage that contains stress concentrators (gouges, grooves, arc burns, or cracks) or corroded areas;
- localized loading from weather and outside force events that would impact an anomaly's probability of failure;
- incorrect operations (e.g. valve closure leading to overpressure) affecting existing anomalies.



An additional reference is provided in the PHMSA Report Task III.B.2 Report DTPH56-14-H-00004, *Improving Models to Consider Complex Loadings, Operational Considerations, and Interactive Threats*. Inspection considerations for coincidental or interacting threats are provided in Annex B.8.

### 5.2.1 EAC and Manufacturing Defects Interacting with External or Internal Corrosion

The presence of external or internal corrosion in the same area as a cracking threat, either EAC (typically SCC), SSWC, or manufacturing defects (longitudinal seam weld anomalies) can create challenges for assessment methods. External or Internal corrosion can obscure the crack response for some ILI technologies and affect the depth measurement accuracy. Manufacturing defects interacting with external or internal corrosion can result in a narrow axially-oriented defect (more commonly known as SSWC) that is not easily detected or characterized with conventional metal loss ILI tools. The growth rate for SSWC, based on failure analysis experience, is typically two to four times the rate of growth in the base metal. This condition can lead to rapid development of a critically sized flaw in a defective seam bondline and has the potential to cause a rupture at low operating stress levels.

### 5.2.2 Mechanical Damage Interacting with External Corrosion or Cracking

Mechanical damage often damages the pipeline coating and creates a local stress in the pipeline which makes it more susceptible to external corrosion or EAC at the location of the damage. Threat interaction with external corrosion can occur where the indentation is sufficient to damage the coating and the cathodic protection is locally impaired. The increase in residual stress associated with the indentation or gouge can also be sufficient to initiate and grow cracks at this location.

Plain indentations less than six percent of the pipe diameter do not immediately reduce the strength of the pipe. Section 6.4.2 of API RP 1176 describes certain deformation geometries and susceptible environments that may potentially result in cracking and eventual failure (generally occurring as a leak) of an indentation. Factors that may lead to cracking include, but are not limited to, diameter to wall thickness ( $D/t$ ) ratio (with a ratio of 100 and higher being more prone to cracking), pressure cycle severity, indentation shape, and physical restraint of the indentation. Data evaluation and opportunistic excavations may enable an operator to identify where cracking in plain indentations may be a threat.

There is significant and ongoing research being done in this field, including by the Pipeline Research Council International, which was not available at the time of this writing.

### 5.2.3 Equipment, Construction and Fabrication Defects Interacting with Weather and Outside Force

Weather events, such as heavy rains and floods, can produce scouring of backfill, mudslides, floatation of a pipeline, and vortex shedding in water current. The resulting lateral forces can cause pipes to pull out of mechanical couplings, threaded pipe or fittings to break, and pipelines to fail at the girth weld. The bending moments associated with the weather and outside force loading events can contribute to the severity (i.e. the non-dormancy) of flaws in the girth welds. Given that these features are less sensitive to the internal pressure due to their circumferential orientation, they may fail from secondary loads where the hoop stress is well below the maximum allowable. Using ILI technology to detect girth weld anomalies as described in API RP 1176 and inertial mapping can help assess these interacting threats.

Cold weather can also produce threat interactions with equipment, specifically associated with water freezing inside a pipe or component. Water can expand within a component causing it to fail, flow restrictions or blockages can lead to a pressure excursion, or ice falling from a roof can break small diameter threaded connections.

### 5.2.4 Incorrect Operations Interacting with Other Threats

Incorrect operations can interact with the other nine threats through overpressure events causing failure of flaws that are not of a critical size during normal operation. Improperly installed equipment or misaligned valves can result in accelerated fatigue of welds, components, or the pipe body.

### 5.2.5 Time Dependent Interactions

Operational or environmental conditions can act on resident features in the pipeline to cause degradation over time. Examples include the threat of cracks forming and growing due to fatigue from pressure and temperature cycles or vortex-induced or mechanical vibrations. An additional example is the effects of hydrogen that can arise from cathodic protection (CP) systems or sour crude systems. The operator shall assess for the conditions that can lead to time dependent degradation. Section 10 provides guidance to determine appropriate reassessment intervals.

## 6 Identifying Critical Locations with Respect to the Consequences of a Release

### 6.1 General

Because the main goal of pipeline integrity management is to reduce 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. For operators in the United States, a critical location may be identified as a high consequence area (HCA) and therefore the requirements in 49 CFR 195.452 shall be followed. 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 service providers. Information about pipeline segments and facilities that may 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 use of leak detection systems;
- preventive and mitigative measures;
- development and implementation of spill response plans.

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

#### 6.2.1 General

As part of the process of data gathering and integration of information into a pipeline integrity management program (IMP), a pipeline operator should determine if there is a reasonable 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 consequence:

- a) the proximity of the pipe to identified critical locations;
- b) the nature and characteristics of the product or products transported (such as refined products, crude oil, and highly volatile liquids [HVLs]);
- c) the operating conditions of the pipeline (such as pressure, temperature, and flow rate);

- d) the topography of the land associated with the critical location and the pipeline segment;
- e) the hydraulic gradient of the pipeline;
- f) the diameter of the pipeline, the potential release volume (including drain out), and the distance between isolation points;
- g) the type and characteristics of the critical location crossed or in proximity to the segment;
- h) potential physical pathways between the pipeline and the critical location, including overland spread, water transport including drainage systems, or air dispersion in the case of an HVL;
- i) response capability (such as time to detect, confirm, and locate a release; time to respond; and nature of the response).

An outline of the process is shown in Figure 2.

### **6.2.2 Determining Critical Location Boundaries**

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 causing a fire or explosion. Allowance should be made for any possible inaccuracies of the locations of the boundaries.

### **6.2.3 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.

### **6.2.4 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 location. 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. Similarly, 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.

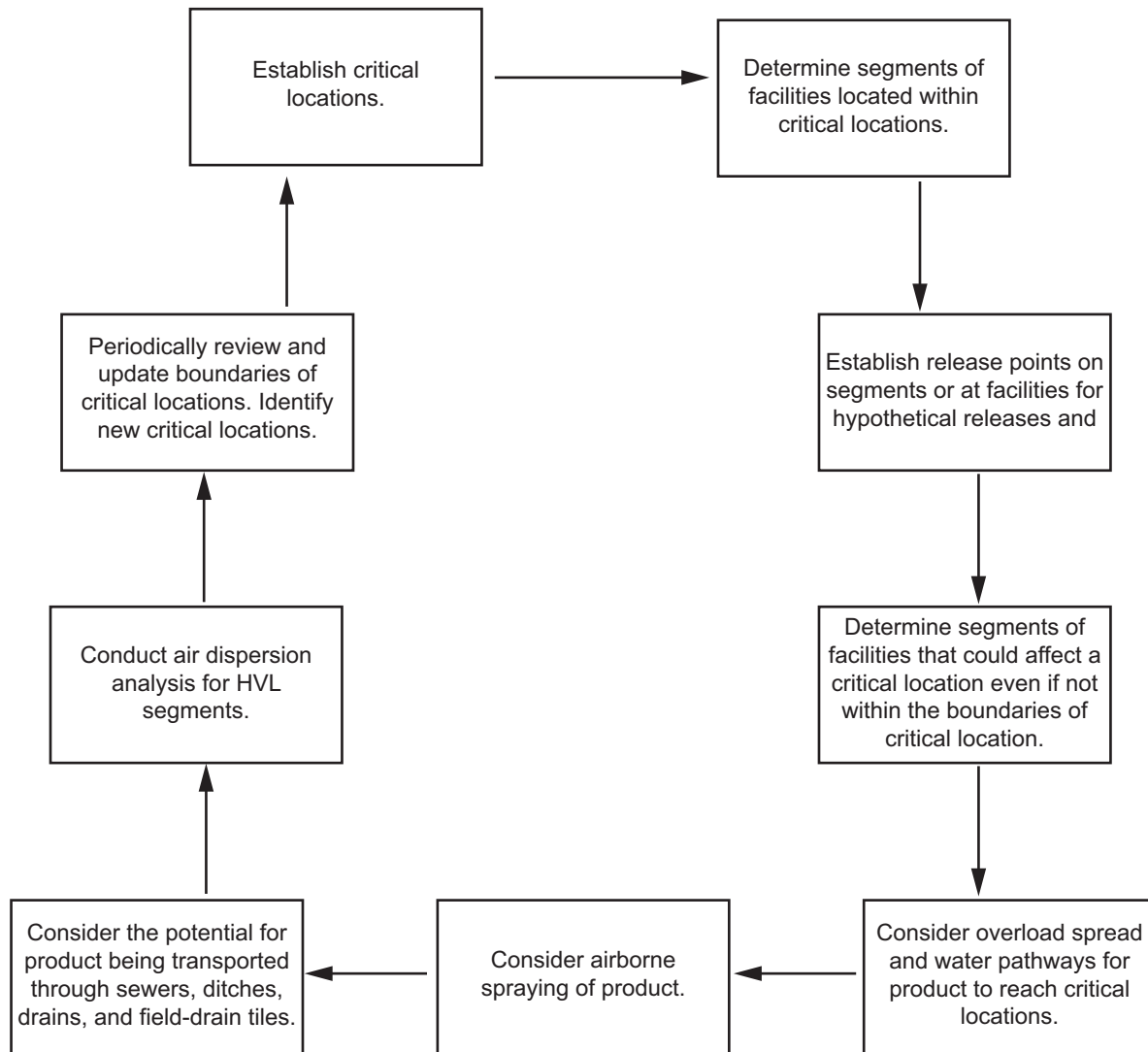


**Figure 2—Identifying Pipeline Segments or Facilities Located Within Critical Locations**

Factors for consideration in establishing release scenarios include the following:

- Release Volume—pipeline diameter, elevation profile, flow rate, time for detection, time to isolate, viscosity and vapor pressure of the product, and tank volume for tanks at facilities;
- Surface Transport—topography, terrain, extremes in ambient temperature, water pathways (surface and underground), ditches, sewers and drain tiles, porosity, and soil permeability;
- Aerial Dispersion—internal pressure and its effect on spraying product into the air, wind direction, analysis HVL (vapor cloud, effect that a vapor cloud fire, a pool fire, or a vapor cloud explosion would have on the critical location).

## 6.3 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.

## 7 Data Integration

### 7.1 General

This section provides an overview of considerations, processes, and data elements involved in data integration to identify and 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. These data may need to be gathered and organized differently for integrity management purposes.

Data integration generally refers to the process of utilizing two or more data sets to identify conditions of interest on the pipeline. API Bulletin 1178 provides detailed information on methodologies and considerations to integrating the underlying data used to support integrity management. Examples of data sets are provided in 7.3. 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 ILI data with other information such as coating condition, cathodic protection levels, or aerial surveillance records. In the first instance, an overlaying of data from a metal loss inspection with a geometry tool inspection may show that metal loss anomaly coincides with a geometric anomaly. The implication is that the anomaly is likely mechanical damage rather than corrosion-caused metal loss. In this case, the operator may elect to investigate the anomaly even though the metal loss or deformation anomaly alone would not warrant investigation. In the second instance, 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 may indicate mechanical damage from the pole auger.

### 7.2 Effective Data Integration

The structure and breadth of many pipeline companies may result in relevant data being produced and stored in different locations, by disparate owners, using potentially inconsistent formats. Policies and procedures within the SMS are one way to ensure that the necessary inputs are effectively aggregated and normalized. Operators should develop and implement procedures to:

- identify the types of data needed to support integrity management (discussed in 7.3),
- identify the location of the data within the organization,
- deliver identified information from the data owner to the group responsible for data integration and analysis,
- disseminate integrated data and the knowledge generated to the applicable stakeholders across the enterprise responsible for identifying and managing integrity threats.

Where the data are missing or lack sufficient quality, operators may need to account for the additional uncertainty. Section 5 of API Bulletin 1178 provides guidance on elements of data quality that are needed to ensure the data are

fit for purpose in supporting the intended process. 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 when possible. The use of default values should be delineated such that inferred versus actual values can readily be identified.

### 7.3 Types of Data to Integrate to Support Integrity Management

#### 7.3.1 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. The data elements listed below should be collected and integrated in support of an integrity management program. Where an operator determines that data is missing or incomplete, the operator should attempt to collect this data. If this data is not collectible, appropriate estimates should be used to replace it. The operator may consider implementing mitigative measures they deem necessary for the facility or pipe segment.

#### 7.3.2 Pipeline Attributes

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

- Pipe and system attributes—diameter, wall thickness, specified minimum yield strength (SMYS), manufacturer, dates of manufacture and construction, type of pipe (seamless, seam welded, and spiral), type of seam (low-frequency (LF) or direct current (DC) ERW, high-frequency (HF) ERW, flash welded (FW), single or double submerged arc welded), pipe coating, girth weld (GW) coating, operating pressures, and maximum design temperature;
- Appurtenances—valves (types and performance characteristics), flanges, fittings, dead legs, and instrumentation lines;
- Facilities—pump stations, booster stations, and terminals;
- Crossings—highway and road crossings (cased or uncased, and shorted where applicable), water crossings (river, creek, and lake), pipeline and other utility crossings, shared right-of-ways, and power lines (crossing and parallel);
- Corrosion mitigation and monitoring equipment
  - External corrosion—CP test stations, sacrificial anode installations, impressed current installations, and isolation equipment, AC and stray current mitigation
  - test stations, isolation equipment, voltage mitigation equipment, and monitoring equipment, Internal corrosion
  - inhibitor injection equipment, fluid sampling equipment, and monitoring equipment.

### 7.3.3 Construction Factors

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

- Construction—year, season, GW data including type, alignment and inspection, special protection (directional drills, concrete coating, barriers, and warning strips), pipeline weights installed during construction (types and locations);
- Coating installation method—over-the-ditch versus factory-applied coating of pipe and field coating of joints;
- Right-of-way—soil type (sand, silt, clay, and rock), soil resistivity, depth of burial, width of right-of-way, land use, and terrain.

### 7.3.4 Operating Parameters and History

Pipeline operating data elements can be found in the operator's Operation and Maintenance manuals, Standard Operating Procedures or Operator Training materials, or a combination thereof. 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:

- Operating Parameters—type(s) of liquids transported, bulk flow velocity, representative pressure histories, operating temperature range;
- Systems and Processes—SCADA and leak detection attributes, emergency response plans, public awareness program, one-call systems, excavation monitoring policy, qualifications and training programs, quality assurance practices, signage and markers requirements;
- Inspections—test lead surveys, river crossing inspections, valve inspections, cleaning pig frequency, inhibitor or biocide applications, aerial and ground patrol frequencies; and
- Reports—failure investigations, leak histories, incident reports, near-miss reports, soil and water sampling reports, corrosion coupons, and resistance measurements.

### 7.3.5 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;
- Documentation of severe weather events and outside force exposure including hydrotechnical scour, slope instability, and seismicity;
- Previous repair types and practices.

## 7.4 Data Maintenance (Management of Change)

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 by modifications to operating practices, changes in land use, or changes in 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.

## 7.5 Integration of Data to Validate MOP

An owner or operator of a pipeline should have traceable (i.e. clearly linked to original information about a pipeline segment or facility) records of the essential variables that support the determination of MOP. These attributes include the specified minimum yield strength (SMYS), wall thickness, diameter and hydrostatic test pressure. As an alternative to address gaps in historical documentation and records, the operator may resolve this information from one or more assessments, such as ILI, pressure testing, or in-situ examination.

Information from a transcribed document with its implied uncertainty, in many cases, should be verified with complementary or supporting documents (e.g. pressure charts or field logs), where available. Similarly, complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. An affidavit prepared and signed at the time of the assessment by a qualified individual familiar with the assessment would be acceptable, as verified complete, and complementary documentation.

Where an aggregation of records completely spans a pipe segment, linkage to an individual pipe joint within the segment is not necessary. For instance, if multiple hydrostatic test sections completely span a pipe segment and adequately support the MOP, delineating exactly where the transition point is between tests is not required if they are continuous.

# 8 Risk Assessment Implementation

## 8.1 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 10 threats listed in Section 5 and Annex A and the consequences (in terms of effects to critical locations as defined in Section 6) 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 3. By assessing risk as it varies throughout a pipeline system, a pipeline operator can identify and categorize locations according to risk. Prioritizing or ranking the calculated risks allows the operator to direct risk management personnel and 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 9) and preventive and mitigative action implementation (see Section 11). 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.

## 8.2 Developing a Risk Assessment Approach

Risk assessment has one or more of the following goals depending on the approach:

- to identify relevant threats to a given pipeline segment's integrity;
- to rank segments of a pipeline system in the order of greatest need for additional integrity assessment or mitigative action;
- to determine any segments where the risk level has exceeded the desired threshold
- to compare different prevention or mitigation options in terms of the risk reduction benefits and costs;
- to provide risk-based input to guide integrity decision making (e.g. repair criteria, reassessment intervals, etc.); and
- to facilitate reassessment and re-ranking once the preventive and mitigative actions have been completed.

A pipeline risk assessment process should address the following questions.

- 1) What kind of events or conditions might lead to a loss of system integrity?
- 2) How likely, in a relative or absolute sense, are these events or conditions to occur?
- 3) What are the nature and the severity of the consequences if these events or conditions occur?
- 4) What risks are associated with these events or conditions either in a relative sense or an absolute sense?

There are several approaches that can be taken to implement a risk process, each of which will provide answers to questions 1) through 4) above. 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 subject matter experts (SMEs) to design and implement risk processes is critical regardless of the approach taken. The following are generally accepted approaches:

- using SMEs;
- using a relative risk assessment;
- using a scenario-based model;
- using a 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 6), which of the 10 threats to pipeline integrity may be applicable to the system, and the types of data outlined in Section 7 (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 consider the boundaries of critical locations to 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.

|              |        |                          |        |                     |
|--------------|--------|--------------------------|--------|---------------------|
| Consequences | High   |                          |        | Highest risk region |
|              | Medium |                          |        |                     |
|              | Low    | Lowest risk region       |        |                     |
|              |        | Low                      | Medium | High                |
|              |        | Likelihood of Occurrence |        |                     |

**Figure 3—Simplified Depiction of Risk**

Using a 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. These models typically 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. Re-ranking 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 based on the re-ranking.

Using a Scenario-based Model—This approach involves considering events or sequences of events that lead to the risk of a release. A probability is assigned to 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 Tree analyses can be constructed for each of the 10 threats listed in Section 5 and Annex A that are 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 analysis 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.

**Using a 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. Integrity assessments can then be implemented on the segments for which the calculated risk (probability times consequence) 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 an ERP 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 should then choose a probability level and remediate anomalies having a higher probability; the inference is that this probabilistic approach would supersede prescriptive response criteria.

### 8.3 Characteristics of Risk Assessment Approaches

A pipeline operator needs to be aware of certain characteristics of risk assessment methods to use them appropriately. One is that they are data driven. As shown in Section 7, system data consisting of pipeline attributes, construction factors, operational factors, and integrity assessment histories should be available to assess the risk of each threat to pipeline integrity. The nature and extent of the critical locations should be well defined to determine the ways in which a pipeline release can affect a critical location as outlined in Section 6. The quality of the risk assessment is related to the quality of the data used and the expertise provided by the operator.

Probabilities of releases and consequences can be meaningfully combined to calculate risk for a specific location only if the data used in the calculation apply to that 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  $1 \times 10^{-6}$  might indicate that a segment could go X years before needing an integrity

assessment whereas a probability of failure of  $1 \times 10^{-3}$  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 regarding 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 ensures 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 for it to remain reliable. Data that should be gathered for future integration and considered in reassessing risk (that may necessitate modifications to the risk assessment approach) are discussed in detail in API Bulletin 1178. Some examples 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.

## 9 Integrity Assessment and Remediation

### 9.1 General

This section 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;
- various types of repair methods that can be used to restore the serviceability of pipe affected by defects.

The threats for hazardous liquid pipelines that operators should address are listed in 5.1 and explained in detail in Annex A.

The categorization of the threats as time-dependent, stable or time-independent (random events) is provided in the ASME B31.8S standard for gas transmission pipelines. Liquid pipeline operators should consider the physical and regulatory differences between gas and liquid pipelines since the potential for pressure-cycle-induced fatigue is much greater for liquid pipelines than it is for gas pipelines. An additional category, potentially time-dependent, can be helpful in categorizing some threats in liquid pipelines. Table 1 lists the categories for the threats listed in this RP. The internal corrosion, external corrosion, SSWC, and EAC threats are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. The manufacturing, construction and fabrication threats are considered possibly time-dependent threats because of the potential for their enlargement by fatigue. For the latter threats, the pipeline operator will be called upon to determine the need for additional assessments or monitoring. The equipment failure, incorrect operations, weather and outside force threats along with the immediate mechanical damage threat are considered time independent because they involve random events for which the time of occurrence is usually not predictable. Management of time independent threats involves employing preventive and mitigative measures.

**Table 1—Threat Categories**

| <b>Time Dependent Threat</b>                                       | <b>Potentially Time Dependent</b>                                                                                             | <b>Time Independent (Random Events)</b>                                                                                |
|--------------------------------------------------------------------|-------------------------------------------------------------------------------------------------------------------------------|------------------------------------------------------------------------------------------------------------------------|
| Requires Periodic Assessment and Monitoring                        | Requires Analysis of Need for Periodic Assessment or Monitoring                                                               | Occurrence Not Predictable                                                                                             |
| External Corrosion<br>Internal Corrosion<br>SSWC<br>EAC<br>Fatigue | Manufacturing Defects<br>Construction and Fabrication Defects<br>Mechanical Damage (that does not cause an immediate failure) | Equipment Failure<br>Mechanical Damage (causing immediate failure)<br>Incorrect Operations<br>Weather or Outside Force |

If no prior integrity assessment has been performed for a pipeline system, an initial integrity assessment plan should be developed based on identifying critical locations (Section 6), initial data gathering (Section 7), and risk assessment (Section 8). 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 6); 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 7); and by reassessing risk and reprioritizing segments for future integrity assessments. The relation of these activities to other integrity management functions and their placement in the PDCA cycle of activities is discussed in Section 4.

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 10 and guidance for calculating reassessment intervals is given in Annex D.

Regardless of the assessment or repair method selected, the operator should have applicable written procedures and adequate training regarding them. When outsourcing integrity assessment or remediation activities the operator should define responsibilities and accountability. API RP 1173 provides additional guidance on operational controls that can be used to establish and improve integrity assessments and remediation.

Table 2 shows applicable integrity assessment methods for each threat discussed in Section 5. This list is not meant to be all inclusive and does not preclude the use of ILI, hydrostatic testing, or different technology for use in certain threat assessments proven to be effective through experience.

## 9.2 In-line Inspection

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 3 and detailed descriptions of the various ILI

**Table 2—Integrity Assessment Methods**

| Threat                                                                  | ILI              | Hydrostatic Testing | Other                      |
|-------------------------------------------------------------------------|------------------|---------------------|----------------------------|
| External corrosion                                                      | a<br>(preferred) | a                   | ECDA<br>GWUT               |
| Internal corrosion                                                      | a<br>(preferred) | a                   | ICDA<br>GWUT               |
| SSWC (external or internal)                                             | a                | a                   | ECDA<br>ICDA               |
| <b>EAC</b>                                                              |                  |                     |                            |
| Axially oriented EAC                                                    | a                | a                   | SCCDA<br>NDE               |
| Axially oriented stress fatigue cracking and other cracks               | a                | a                   | NDE                        |
| Circumferential EAC                                                     | a                | b                   | SCCDA<br>NDE               |
| <b>Manufacturing defects</b>                                            |                  |                     |                            |
| Axially oriented crack-like seam defects (i.e. hook cracks, cold welds) | a                | a                   | NDE                        |
| Hard spots                                                              | a                | b                   | NDE                        |
| Laminations                                                             | a                | b                   | NDE                        |
| <b>Construction and fabrication defects</b>                             |                  |                     |                            |
| Defective girth weld                                                    | b                | b                   | NDE                        |
| Defective fabrication weld                                              | b                | b                   | NDE                        |
| Wrinkle bends                                                           | a                | a                   | NDE                        |
| Stripped threads, broke pipe, coupling failures                         | b                | b                   | Visual Exam                |
| Equipment failure                                                       | b                | b                   | Visual Exam<br>NDE         |
| <b>Mechanical damage</b>                                                |                  |                     |                            |
| Immediate failure                                                       | c                | c                   | Damage Prevention Programs |

**Table 2—Integrity Assessment Methods (Continued)**

| Threat                                                                                                                                                                                                                                                                                                    | ILI              | Hydrostatic Testing | Other                                             |
|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|------------------|---------------------|---------------------------------------------------|
| Delayed failure                                                                                                                                                                                                                                                                                           | a<br>(preferred) | a                   | Damage Prevention Programs<br>NDE                 |
| Illegal tapping (vandalism)                                                                                                                                                                                                                                                                               | a                | b                   | Visual Exam<br>ROW Patrol                         |
| Incorrect operations                                                                                                                                                                                                                                                                                      | c                | c                   | Operator Training and Qualification<br>Procedures |
| <b>Weather and outside force related defect</b>                                                                                                                                                                                                                                                           |                  |                     |                                                   |
| Vortex-induced vibration                                                                                                                                                                                                                                                                                  | b                | b                   | Monitoring                                        |
| Flooding                                                                                                                                                                                                                                                                                                  | b                | b                   | Monitoring<br>Visual Exam                         |
| Lightning                                                                                                                                                                                                                                                                                                 | a                | b                   | Leak Detection                                    |
| Ground movement (i.e. subsidence, earthquake, liquefaction, landslide)                                                                                                                                                                                                                                    | a                | b                   | Monitoring<br>LIDAR<br>ROW Patrol                 |
| High winds (i.e. hurricanes, tornadoes)                                                                                                                                                                                                                                                                   | b                | b                   | Monitoring<br>Visual Exam                         |
| <p><sup>a</sup> Represents commonly used industry practices.</p> <p><sup>b</sup> Represents assessment practices which generally are not recommended due to limited effectiveness although in certain circumstances operators may have found them effective.</p> <p><sup>c</sup> N/A = Non applicable</p> |                  |                     |                                                   |

technologies appear in Annex B. Neither the information in Table 3 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 interacting threats such as metal loss or cracking within a dent or cracking in combination with metal loss. ILI technology evolves rapidly such that tools may exist that are not covered in this RP. A pipeline operator is well advised to stay current with ILI vendors, technology center researchers, industry conferences, and other pipeline operators. Operators are encouraged to discuss improved inspection technologies with their vendors. Pipeline operators are encouraged to consult other industry standards on ILI including:

- NACE SP0102, *In-Line Inspection of Pipelines*;
- API Standard 1163, *In-line Inspection Systems Qualification*;
- API RP 1176, *Assessment and Management of Cracking in Pipelines*;
- ASNT ILI-PQ, *In-Line Inspection Personnel Qualification and Certification*;
- Pipeline Operators Forum, version 2016, *Specifications and requirements for intelligent pig inspection of pipelines*.

Table 3—In-line Inspection Tools and Capabilities

| Integrity Assessment<br>Detection/Sizing<br>Objective                                                                              | MFL Tools    |                                              |                               |                                 | Ultrasonic Tools (UT)                    |                                                     |                                 |         | Geometry Tools     |                     | Pipeline<br>Profile and<br>Alignment<br>Tools |
|------------------------------------------------------------------------------------------------------------------------------------|--------------|----------------------------------------------|-------------------------------|---------------------------------|------------------------------------------|-----------------------------------------------------|---------------------------------|---------|--------------------|---------------------|-----------------------------------------------|
|                                                                                                                                    | Axial<br>MFL | Circumferential<br>MFL (Transverse<br>Field) | Helical MFL<br>(Spiral Field) | Residual or<br>Low Field<br>MFL | Normal Beam<br>UT<br>(Wall<br>Thickness) | Angle Beam<br>Shear Wave<br>UT (Crack<br>Detection) | EMAT UT<br>(Crack<br>Detection) | Caliper | High<br>Resolution | Inertial<br>Mapping |                                               |
| Metal loss external or<br>internal                                                                                                 | S            | S                                            | S                             |                                 | S                                        | D                                                   | D                               |         | D<br>(internal)    |                     |                                               |
| SSWC external or internal                                                                                                          |              | S                                            | S                             |                                 |                                          | D                                                   | D                               |         |                    |                     |                                               |
| Axially oriented EAC                                                                                                               |              |                                              |                               |                                 |                                          | S                                                   | S                               |         |                    |                     |                                               |
| Axially oriented stress<br>fatigue cracking and other<br>cracks                                                                    |              |                                              |                               |                                 |                                          | S                                                   | S                               |         |                    |                     |                                               |
| Axially oriented crack-like<br>manufacturing defects (i.e.<br>hook cracks, cold welds)                                             | D            |                                              | D                             |                                 |                                          | S                                                   | S                               |         |                    |                     |                                               |
| Circumferential cracking                                                                                                           |              |                                              |                               |                                 |                                          | S <sup>b</sup>                                      | S <sup>b</sup>                  |         |                    |                     |                                               |
| Dents                                                                                                                              | D            | D                                            | D                             | D                               | D                                        | D                                                   | D                               | S       | S                  |                     |                                               |
| Gouge or groove                                                                                                                    | DM           | DM                                           | DM                            | D                               | DM                                       |                                                     |                                 |         |                    |                     |                                               |
| Wrinkles or buckles                                                                                                                | D            | D                                            | D                             | D                               | D                                        | D                                                   | D                               | D       | S                  |                     |                                               |
| Expanded pipe                                                                                                                      |              |                                              |                               |                                 |                                          |                                                     |                                 | D       | S                  |                     |                                               |
| Laminations                                                                                                                        | D            | D                                            | D                             |                                 | S                                        | D                                                   | D                               |         |                    |                     |                                               |
| Hard spots                                                                                                                         |              |                                              |                               | D                               |                                          |                                                     |                                 |         |                    |                     |                                               |
| Evidence of strain                                                                                                                 |              |                                              |                               | D                               |                                          |                                                     |                                 |         | S <sup>a</sup>     | S                   |                                               |
| Bends or curvatures                                                                                                                | D            | D                                            | D                             | D                               | D                                        | D                                                   | D                               | D       | S                  | S                   |                                               |
| S is detection and sizing capability as specified by vendor.                                                                       |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| D is detection capability with limited or no sizing capability as specified by vendor.                                             |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| DM is detection capability of metal loss portion of mechanical damage with limited or no sizing capability as specified by vendor. |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| NOTE 1 Refer to Table 1 of API RP 1176 for additional details on crack detection tools.                                            |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| NOTE 2 Inertial mapping tool information can be used to calculate safe operating pressure automatically.                           |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| Requires offline calculation.                                                                                                      |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |
| With special setup.                                                                                                                |              |                                              |                               |                                 |                                          |                                                     |                                 |         |                    |                     |                                               |

### 9.2.1 ILI Tool Workflow

In planning for ILIs, the process flow diagram shown in Figure 4 (from API 1163) can be used to outline the workflow associated with conducting an ILI.

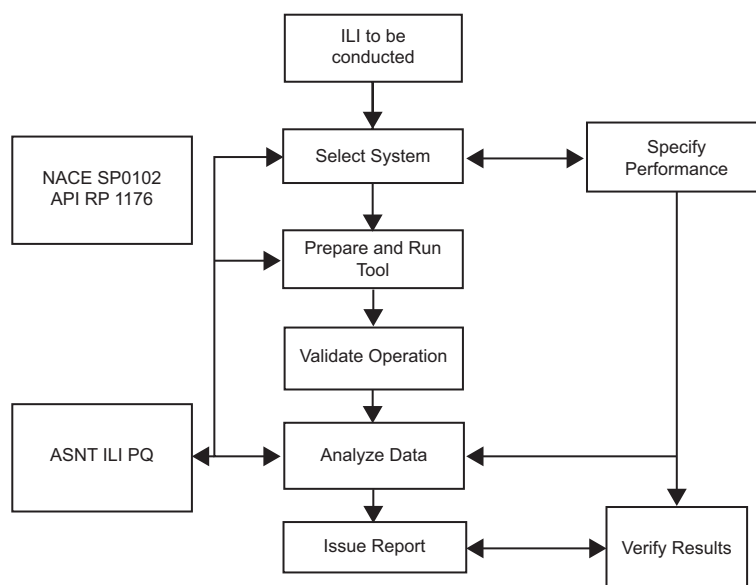


**Figure 4—ILI Process Flow Diagram**

A pipeline operator contemplating the use of ILI for integrity assessment should first determine whether the pipeline to be assessed can accommodate ILI tools. To accommodate ILI tools, the pipeline should be equipped 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. Diameter or ovality restrictions, short-radius fittings, and miter bends may 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. Many tools are sensitive to temperature extremes and fluctuations.

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; additionally, check valves may need to be lifted open and locked in place. 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. It may be necessary to run multiple tools or combinations of tools if there are multiple threats to be assessed. The pipeline operator should carry out the data analyses outlined in Section 7 and the risk assessment outlined in Section 8 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. Figure 5 outlines the terminology associated with the ILI analysis and deliverables.

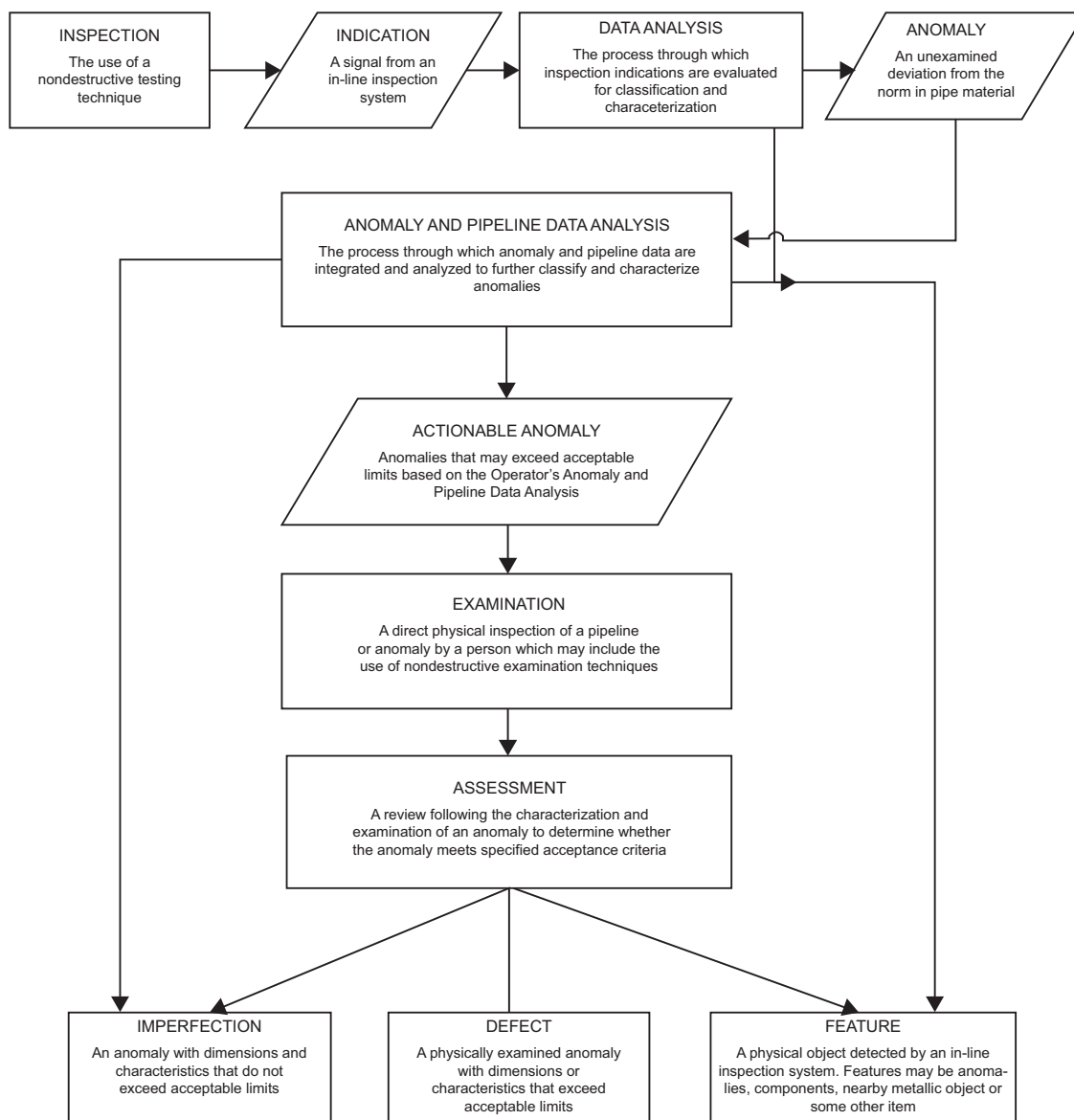


**Figure 5—Inspection Terminology**

First, although the tools typically measure distance traveled, the operator should work with the vendor to place above-ground marking equipment to “mark” the data as the tool passes particular locations. These markers, along with the known locations of other physical features, are needed to calibrate the distance measurements recorded for each anomaly to facilitate location of the feature if further examination is necessary. Some tools use inertial navigation or guidance systems to increase accuracy and ease of locating actionable anomalies. Inertial guidance tools (discussed in Annex B) combined with integrity assessment tools can obtain pipeline position information and assign calculated GPS coordinates. API Bulletin 1178 provides additional guidance and considerations regarding the use of GPS coordinates.

Second, there are several attributes of an ILI technology that will control whether and how features are reported. The ability of an ILI technology to detect an anomaly is based on the depth and magnitude threshold for the particular