Facilities Integrity Management

API RECOMMENDED PRACTICE 2611

Second Edition, XXXX, 202x

1 Scope

1.1 General

This recommended practice (RP) covers the integrity management of facilities. This RP provides guidance on:

- High Consequence Area Impact Determinations
- Data Integration
- Threat Identification
- Risk Assessment
- Inspection and Re-Inspection
- Preventive and Mitigative (P&M) Measures
- Performance Measures

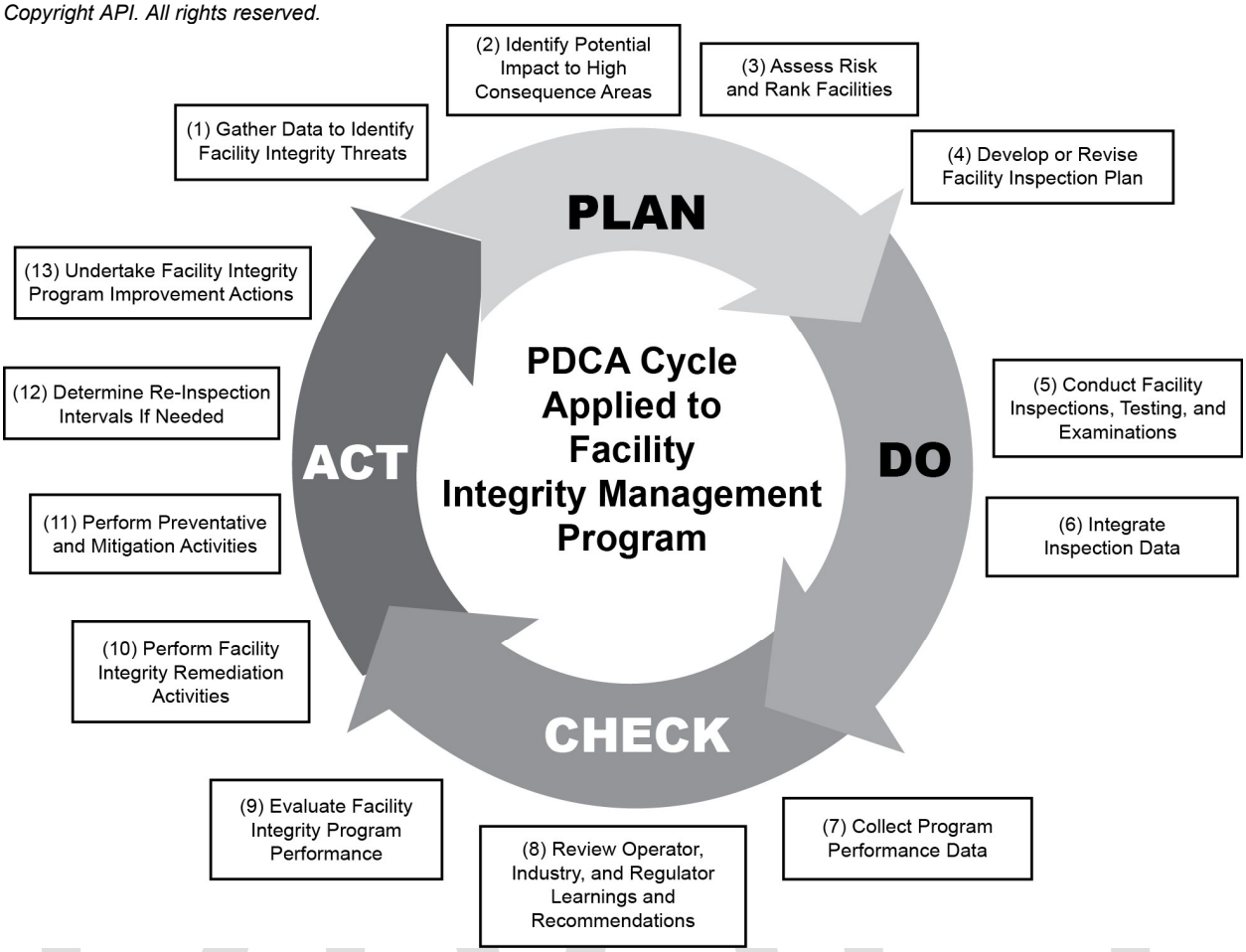
Facilities include terminal and pipeline station piping systems within terminal and pipeline facility boundaries, which includes off-plot piping. Off-plot piping includes, but is not limited to: piping between facilities, piping that comes from or goes to a refinery, or other type facility, or piping that may cross a road, ditch or other property outside the confines of a terminal facility.

Piping for transportation of hazardous liquids, such as, but not limited to, crude oil, highly volatile liquids (HVLs), gasoline, diesel, biofuels, lubricating oils, jet fuel and aviation fuel are covered by the scope of this document.

The scope includes both high- and low-pressure pipeline facilities, but does not include refinery piping, sanitary waste piping, cast iron piping, nonmetallic gravity flow piping systems or tanks. For guidance on tanks, refer to API 653 or API 2510. However, tanks are considered and reviewed as part of the high consequence area analysis and risk assessment.

Additional guidance is available in documents such as API 570 and API 2610.

Figure 1 – Plan-Do-Check-Act Cycle for Facility Integrity



1.2 Integrity Management of Facilities

1.2.1 General Considerations

A facility integrity management program is a documented set of policies, processes, and procedures to manage facility risk. Integrity management is more complex for facilities than for mainline pipe due to the nature and complexity of facility assets and operations in contrast to typical mainline or “right of way” pipeline. Attributes of facilities piping that distinguish it from mainline piping are:

— relatively low operating stresses as compared to mainline pipe, except downstream of pump discharge or at booster stations,

— multiple types and sizes of piping and tubing, both above and below ground, which may be insulated, and/or on pipe supports

— smaller sizes of pipe often joined by non-welded fittings,

— piping used infrequently leading to low or intermittent flow, and/or piping configurations that result in dead legs where water may accumulate

— difficult to inspect and unpiggable piping,

— located where access is controlled by the operator, and often protected with secondary containment.

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 Publication 340, *Liquid Release Prevention and Detection Measures for Aboveground Storage Facilities*

API 570, *Piping Inspection Code: Inspection, Repair, Alteration, and Rerating of In-service Piping Systems*

API Recommended Practice 571, *Damage Mechanisms Affecting Fixed Equipment in the Refining Industry*

API Recommended Practice 574, *Inspection of Piping System Components*

API Recommended Practice 577, *Welding Inspection and Metallurgy*

API Standard 579-1, *Fitness-For-Service*

API Publication 2201, *Procedures for Welding or Hot Tapping on Equipment Containing Flammables*

ASME B31.3, *Process Piping*

ASME B31.4, *Pipeline Transportation Systems for Liquid Hydrocarbons and other Liquids*

ASTM G57, *Method for Field Measurement of Soil Resistivity: Using the Wenner Four-electrode Method*

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

3 Terms, Acronyms, and Definitions

3.1 Definitions

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

3.1.1
alteration
Physical change, approved by a piping engineer, having design implications in any component that may affect the pressure containing capability or flexibility of a piping system beyond the scope of its original design.

NOTE The following are not considered alterations: comparable or duplicate replacements and the addition of small-bore attachments that do not require reinforcement or additional support.

3.1.2
applicable code
Requirement(s), requirement section(s), or other recognized and generally accepted engineering Standard or practice to which the piping system was built, or which is deemed by the Operator or the piping engineer to be most appropriate for the situation.

3.1.3
authorized inspection agency
Defined as any of the following.

a) An organization representing an insurance company that is licensed or registered to write insurance for piping systems.

b) An Operator of piping systems that has designated a certified company or person to function as the authorized inspector.

c) An independent organization employed by or under contract to the Operator of piping systems that are used only by the Operator.

d) An independent organization licensed or recognized by the jurisdiction in which the piping system is used and employed by or under contract to the Operator.

3.1.4
corrosion under insulation
Generalized corrosion that developed on the outer surface of unprotected piping beneath fully encompassing insulation when moisture is apparent.

3.1.5
deadlegs
Internal areas of a piping system that are isolated by valves or location having no flow for more than three consecutive months.

3.1.6
defect
Flaw or other discontinuity noted during inspection of a type or magnitude exceeding the acceptable criteria.

3.1.7
environmental cracking
The intergranular or transgranular cracking of a material due to the combined action of tensile stress and a specific environment.

3.1.8
examiner
Person trained and qualified to provide quality functions of a component manufacturer, fabricator, or erector.

3.1.9
guided wave ultrasonic testing
Nondestructive examination technique that utilizes ultrasonic waves that travel down the length of pipe, screening areas that are otherwise difficult to access.

3.1.10
High Consequence Area
HCA
Those locations where a facility release might have a significant adverse effect on a population area, an ecological area, a public drinking water source, or a commercially navigable waterway, or area as determined by the operator.

NOTE For operators within the US, this includes the definition codified in pipelines safety regulations found in 49 CFR 195.450.

3.1.11
indication
Response or evidence resulting from the application of a nondestructive evaluation technique.

3.1.12
in-service
Piping systems that have been placed in operation, as opposed to new construction prior to being placed in operation.

3.1.13
inspector
authorized piping inspector
Employee of an authorized inspection agency who is qualified by experience, training, and accredited testing to perform the functions specified in this document.

NOTE Whenever the term inspector is used in this document, it refers to an authorized piping inspector. A nondestructive (NDE) examiner is not required to be an authorized piping inspector.

3.1.14
jurisdiction
Legally constituted government administration that may adopt rules relating to terminal piping systems.

3.1.15
liquid-dye penetrant testing
Nondestructive test used to evaluate a variety of non-porous materials (metals, plastics, or ceramics) by revealing surface discontinuities using a dye and powder system to visually identify surface cracks.

3.1.16
magnetic-particle testing
Nondestructive test that is used to detect surface and subsurface flaws in ferrous materials.

3.1.17
mils per year
Standard corrosion rate measurement.

NOTE One mil = 0.001 in.

3.1.18
pipe wall retirement thickness
The pipe wall thickness at which the pipe should be declared out of service and replaced.

NOTE Determination of the pipe wall retirement thickness is based on the value (*t*) in ASME B31.3 Para. 304.1.2, in which (*t*) = pressure design thickness.

3.1.19
nondestructive examination
NDE
Any recognized test procedure that does not compromise the integrity of the object being examined/tested.

3.1.20
on-stream
Piping containing any amount of process fluid.

3.1.21
operator
Authority of a terminal piping systems who exercises control over the operation, engineering, inspection, repair, alteration, testing, and rerating of that piping system.

3.1.22
pipe
Pressure-tight cylinder used to convey a fluid or to transmit a fluid pressure.

NOTE Materials designated “tube” or “tubing” in specifications are treated as pipe when intended for pressure service.

3.1.23
piping circuit
Section of piping that has all points exposed to an environment of similar corrosivity and that is of similar design and construction material.

NOTE Complex process units or piping systems are usually divided into piping circuits to manage the necessary inspections, calculations, and record keeping. When establishing the boundary of a particular piping circuit, the inspector may also size it to provide a practical package for record keeping and performing field inspection.

3.1.24
piping engineer
Person or organization qualified by the Operator as to their knowledge, capability and experience in the engineering disciplines associated with evaluating mechanical and material characteristics affecting the integrity and reliability of terminal piping components and systems.

3.1.25
piping system
Assembly of interconnected piping components that is subject to the same set or sets of design

conditions and is used to convey, distribute, mix, separate, discharge, meter, control, or snub fluid flows.

NOTE Piping system also includes pipe-supporting elements but does not include support structures, such as structural frames and foundations.

3.1.26
radiographic examination
Non-destructive test that uses an x-radiation source to provide a film image of defects in welds and structures, typically not employed in small bore piping found in terminals because of the need to work on both sides of the object being x-rayed.

3.1.27
repair
Work necessary to restore a piping system to a condition suitable for safe operation at design conditions.

NOTE 1 If any of the restorative changes result in a change of design temperature or pressure, the requirements for rerating also shall be satisfied.

NOTE 2 Any welding, cutting, or grinding operation on a pressure-containing piping component not specifically considered an alteration is considered a repair.

3.1.28
repair organization
Any of the following.

a) Operator of terminal piping systems who repairs or alters its own equipment in accordance with applicable standards or codes.

b) Contractor whose qualifications are acceptable to the Operator of terminal piping systems and who makes repairs or alterations in accordance with applicable standards or codes.

c) Entity authorized by, acceptable to, or otherwise not prohibited by the jurisdiction and that makes repairs in accordance with applicable standards or codes.

3.1.29
rerating
Change in either the design temperature or the maximum allowable working pressure of a piping system that may consist of an increase, a decrease, or a combination of both.

NOTE Derating below original design conditions is a means to provide increased corrosion allowance.

3.1.30
small-bore piping
Piping that is less than or equal to NPS 2.

3.1.31
soil-to-air interface
Area in which external corrosion may occur on partially buried pipe

NOTE The zone of the corrosion may vary depending on factors such as moisture, oxygen content of the soil, and operating temperature; the zone generally is considered to be from 12 in. (305 mm) below to 6 in. (152 mm) above the soil surface, including pipe running parallel with the soil surface that contacts the soil.

3.1.32
spool
Prefabricated section of piping with ends that are plain-end for field cutting, prepared for welding or flanged.

3.1.33
temperature and pressure in a piping system
The following definitions refer to only positive pressure (not a vacuum) and positive temperatures (ambient or higher, but not cryogenic). The temperature and pressure specifications are always directly linked together in a process piping system.

3.1.34
design pressure
Pressure of a piping system which shall be not less than the pressure at the most severe condition of coincident internal or external pressure and temperature (minimum or maximum) expected during service.

3.1.35
design temperature
Temperature of a piping system at which, under the coincident pressure, the greatest thickness or highest component rating is required.

3.1.36
temporary repairs
Short term repairs made to piping systems in order to restore sufficient integrity to continue safe operation until permanent repairs can be scheduled and accomplished within a time period acceptable to the inspector or piping engineer.

3.1.37
terminal
distribution terminal
Facility designed for the receipt, storage and distribution of refined hydrocarbon products (typically motor gasolines, diesel, heating oils, and/or aviation fuels) that usually receives product by pipeline or marine vessel and distributes product by tank truck and/or pipeline.

3.1.38
test circuit
Segment or extent of a piping system included in a single leak test.

3.1.39
test point
Area defined by a circle having a diameter not greater than 2 in. (51 mm) for a pipeline diameter not exceeding 10 in. (254 mm) or not greater than 3 in. (76 mm) for larger pipelines.

NOTE Thickness readings may be averaged within this area. A test point shall be within a thickness measurement location.

3.1.40
thickness measurement locations
Designated areas on piping systems where periodic inspections and thickness measurements are conducted.

3.1.41
trap space
Any pipe configuration that allows for a water phase to stagnate in low points in a piping section.

3.1.42
ultrasonic examination
Non-destructive test that uses acoustic energy (2 MHz to 10 MHz) to detect anomalies in pipe material and welds by creating a detection signature.

NOTE The material mass and any anomalies are represented as an electronic signature on a video screen and/or graph.

3.1.43
visual inspection
Examination of an object with the naked eye, or with the assistance of a mirror or through magnification.

3.1.44
wet fluorescent magnetic particle testing
Specific type of magnetic particle (nondestructive) test that uses a carrier liquid (oil or water) to rapidly form the magnetic particle pattern.

3.2 Terms and Acronyms

For the purposes of this document, the following abbreviations and acronyms apply.

AC alternating current

ACVG alternating current voltage gradient

API American Petroleum Institute

ASME American Society of Mechanical Engineers

ASTM American Society of Testing and Materials CFR Code of Federal Regulations

CIS close interval survey

CUI corrosion under insulation

DCVG direct current voltage gradient

EMAT electromagnetic acoustical transducer

GWUT guided wave ultrasonic testing

HAZ heat affected zone

ILI in-line inspection

LNG liquefied natural gas

LRUT long range ultrasonic testing

NACE National Associate of Corrosion Engineers

NDE nondestructive examination

NPS nominal pipe size

PCM pipeline current mapper

PCW process contact water

PT [liquid] penetrant testing

ROW right-of-way

S/A soil-to-air [interface]

SCC stress corrosion cracking

TML thickness measurement location

USCG United States Coast Guard

USDOT United States Department of Transportation

WFMT wet fluorescent magnetic-particle testing

4 High Consequence Areas (HCA)

4.1 General

As part of the process of data gathering and integration of information into a facility integrity management program, an operator may develop a process to determine if, in the event of a failure, facility piping or associated assets and operations could affect an HCA.

In determining if a facility could affect an HCA, the boundary of each HCA should be defined in a way that delineates the physical area that has increased sensitivity to a release of product. Considerations should be given to the nature of individual HCA areas, and how that could influence the extent of a sensitive area (e.g. habitat range of a species or ecological community, whether a drinking water resource is surface or well-based). Furthermore, allowance should be made for any possible inaccuracies (e.g. spatial) of the

locations of the boundaries.

In determining if facility assets could affect HCAs, operators may consider:

a) Taking a holistic view of facility assets involved in transportation of products that could contribute to a release that impacts an HCA.

b) Employing §195.450 HCA locations or HCAs identified by the facility operator

c) Secondary or connected asset(s) and how these could contribute to or compound a failure

d) Locations where a pipeline entering or leaving a facility could affect an HCA

e) Identifying locations where facility assets are in or directly intersect HCAs

f) Identifying locations where, in the event of a failure, HCAs could be indirectly impacted. In determining indirect impacts, a facility operator may consider:

   i. Potential release scenarios and tank volumes

   ii. Product types and characteristics (e.g. refined products, crude oil, and highly volatile liquids [HVLs])

   iii. Operating conditions (e.g. operating pressures, temperature, and flow rate)

   iv. Area topography

   v. Soil porosity and permeability

   vi. Water pathways (e.g. rivers, streams and aquifers)

   vii. Local features (e.g. ditches, storm sewers, outfalls, and other means of conveyance)

   viii. Potential for air dispersion of toxic and flammable constituents

   ix. Presence and effectiveness of containment barriers such as dikes and berms

   x. Leak detection capabilities

   xi. Isolation capabilities

   xii. Spill and emergency response capabilities

Variables that may be monitored include:

- Changes to facility boundaries
- Changes to facility piping characteristics
- Changes to operations
- Capacity changes
    - Product changes (excludes batches)
- Changes in leak detection capabilities
- Changes in shutdown and segment isolation time
- Operational changes (e.g. MOP)
- Changes or updates to the NPMS or other relevant data sources employed
- Changes to local factors:
    - Identification of potential transport features (e.g. ditches, storm sewers, and other means of conveyance)

- Changes to containment barriers, such as dikes and berms
- Updated topography or waterway data

5 Data Integration

5.1 Gathering, Reviewing, and Integrating Data

Data integration is the process whereby analysis of available pertinent integrity and risk information about a facility is performed. Data integration activities help identify facility locations requiring further attention in the form of repairs and/or further investigation for proactive risk reduction.

5.2 Data Gathering

The types of data that are useful for integrity management of facilities include but are not limited to:

— Scope of facility integrity management program;

— Type of facility (pump station, metering, storage, mainline valve, etc.) and its location;

— Products type, throughput, and storage capacity

— Geographic Information Systems (GIS) files, drawings such as Piping and Instrumentation Diagrams (P&IDs) and Process Flow Diagrams (PFDs);

— List of equipment and piping, including location, age, material of construction, and construction documents (e.g. MTRs, NDT reports, pressure test records);

— Operating conditions including design limits, product corrosivity (including impurities), and operating history;

— Inspection and maintenance history including monitoring locations, repair history, maintenance and inspection records, pressure test records;

— Failure history (incidents and near misses in facility and adjacent piping).

5.2.1 Data Review

The data review process is an integral part of an effective data integration. The pipeline operator could conduct a thorough review of the incident history of the facility and of facilities with similar designs and characteristics. Reviews of the pertinent data are evaluated for the potential impacts to integrity and/or risk to each Facility. For example, deadlegs containing corrosive internal environments if left untreated/unmitigated may lead to loss of containment as a function of time. In this example an operator could utilize a strainer maintenance program or facility inspection program to identify internal corrosion and apply the learnings to the entire facility if deemed appropriate. It is important that the operator conduct thorough facility data reviews to obtain a complete and informative risk/integrity view of each facility.

5.2.2 Data Integration

Data integration is the process of combining multiple pieces of information to gain a better understanding of overall facility integrity. Data may be integrated with knowledge about pipe diameter, age, grade, location (above or below ground), facility cathodic protection effectiveness, evidence of corrosion from visual inspections, operating temperatures, thermal or product temperatures, low-flow locations, and product corrosivity to indicate where corrosion threats may be more severe. Data from routine equipment inspections can also be integrated with operational knowledge to determine where threats may be more severe from vibration, wear, improper installation, and mechanical damage.

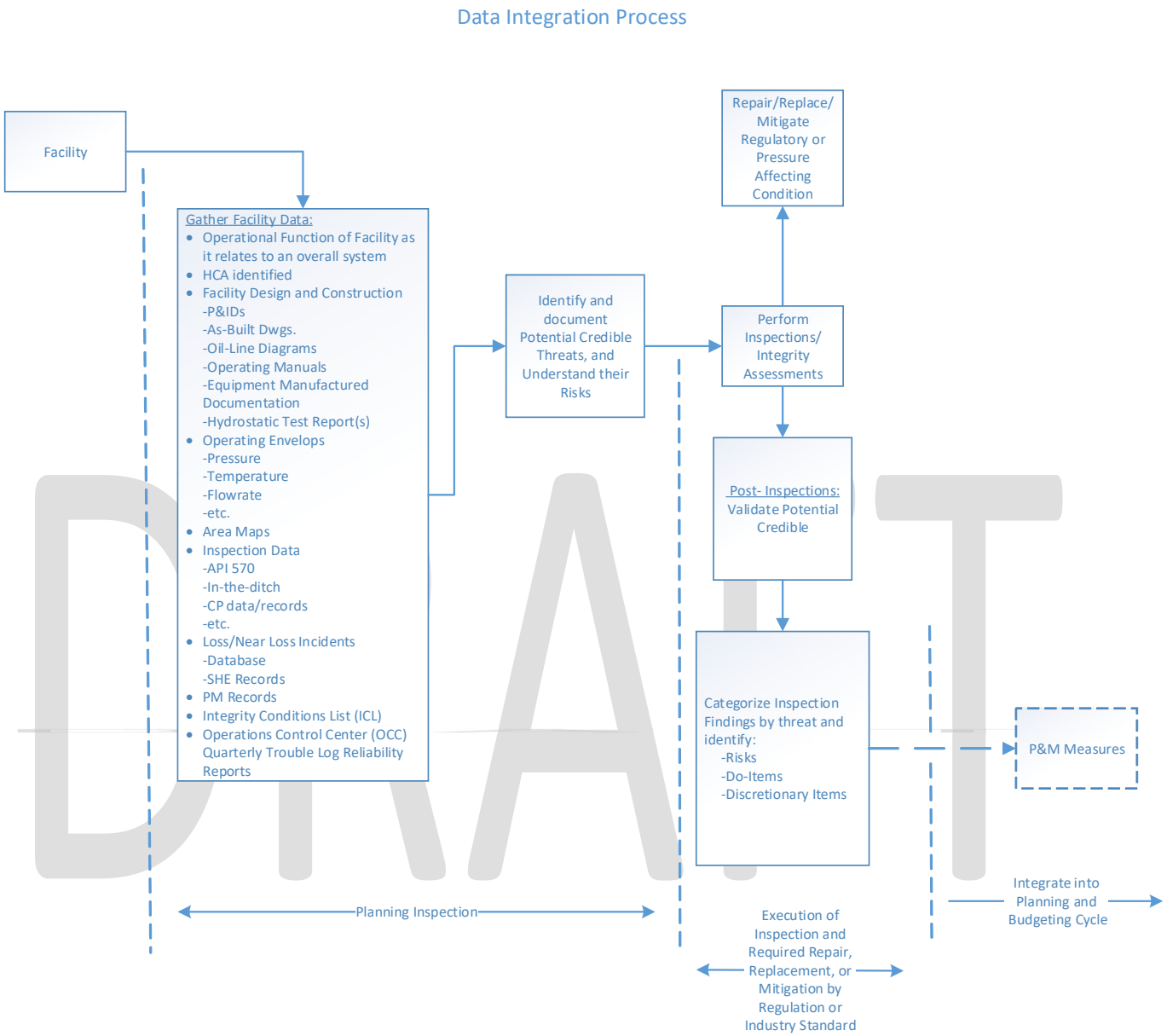


Figure 2 – Data Integration Process

6 Threat Identification

6.1 Threat Identification at Facilities

Recognizing that not all threats may exist at each facility, an operator may choose to utilize different methodologies such as, but not limited to,

- Threat screening process incorporating local operational knowledge
- Visual Inspection (e.g. walk-arounds)
- Incident Investigations
- Maintenance/Operational/Construction/Material records

Potential credible threats may be identified, captured, and verified/confirmed through various inspections (e.g., NDT Inspections, site walk-arounds, routine rotating equipment inspections, etc.) as appropriate for the facility that is being assessed. See Table 1 – Facility Integrity Threats for further information.

Threats/hazards are categorized and evaluated for sites as follows:

6.1.1 Time Dependent Threats

- Internal Corrosion
- External Corrosion
- Environmental Stress Corrosion Cracking
- Original Manufacturing/Fatigue
- Equipment Malfunction

6.1.2 Time Independent Threats

- Mechanical or Third Party Damage
- Environmental and Outside Force
- Incorrect Operation
- Original Construction

6.2 Time Dependent Threats

6.2.1 Corrosion (External and Internal)

Facility piping generally cannot be inspected by ILI. Inspections of facility piping and tubing depends on periodic visual inspection and other methods of indirect or direct assessment, such as the use of ultrasonic and radiographic wall thickness measurements. For additional information, see Section 8.1 on facility inspection. Pipeline operators should perform visual and/or wall thickness measurements more frequently where corrosion rates are known to be higher than average. Each operator should establish periodic inspection for the following specific types and areas of deterioration:

— external corrosion at supports and hangers;

— external corrosion at soil-to-air interfaces;

— external corrosion under insulation;

— external corrosion from interference;

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

— internal erosion and corrosion/erosion.

Periodic inspections in conjunction with wall thickness measurements are suggested as ways to monitor these situations. The frequency of inspection can be based on a corrosion rate established from the measured wall thickness loss. In the absence of established corrosion rates, other methods may be used to determine corrosion rates (e.g. a Monte Carlo simulation with distributions of pit depths and corrosion starting times). Models for calculating remaining strength of corroded pipe such as Modified B31G, RSTRENG, or API 579 can be used to predict safe operating pressures on corroded tubing and piping within facilities. Operators should be cautious about using these models alone with piping that is operated at low levels of hoop stress (i.e. less than 50 % of SMYS) because the effect of contact stresses or secondary stresses could cause the failure stress to be less than that predicted by such models. In such cases the operator should consider carrying out a more sophisticated analysis, for example, by using finite element modeling.

Areas suspected to have localized corrosion/erosion should be inspected using appropriate NDE methods that will yield wall thickness data over a wide area, such as UT, GWUT, ultrasonic scanning, radiographic profile, eddy current, or external MFL. The effect of wall thickness loss on facility integrity

should be determined using industry approved methods such as Modified B31G, RSTRENG, or API 579, and piping that exhibits inadequate remaining strength should be repaired, reinforced, or replaced.

Operators should specifically consider the potential for interference at facilities because of the close proximity to electrical systems that may not be isolated. For equipment that might be affected by interference, operators should ground and bond equipment, use sacrificial anodes, or try to eliminate sources of interference, where possible.

6.2.2 Erosion and Corrosion/Erosion

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

6.2.3 Environmental Stress Corrosion Cracking

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

API Bulletin 939-E, “Identification, Repair, And Mitigation Of Cracking Of Steel Equipment In Fuel Ethanol Service,” provides guidelines for identification, mitigation and prevention of ethanol SCC.

6.2.4 Original Manufacturing/Fatigue

Manufacturing defects at facilities can include equipment body defects, piping or components not meeting engineering specifications, and seam weld defects. Quality control during procurement can prevent manufacturing defects from entering service. Inspection protocols and procedures can identify equipment and piping manufacturing defects in service.

6.2.5 Equipment Malfunction

The periodic inspection and routine maintenance of equipment with the intent of preventing equipment failures should be considered. Attention should be paid to known mean times to failure for commonly used components, and a timely replacement of parts or units.

Pipeline operators should take steps to minimize the risk of tubing and small-bore piping failures by replacing instrumentation lines with electrical signal devices where possible. For example, pressure readings can be conveyed electrically from pressure transducers rather than through tubing connecting the pressurized fluid to a mechanical pressure gage.

Operators should also maintain up-to-date P&IDs. Configuration of the tubing should be designed to eliminate long runs, reduce or prevent vibration, and allow for periodic inspection. Visual inspections of the tubing and piping should be carried out at regular intervals to ensure that they are properly installed and inspected per manufacturer’s recommendations.

6.3 Time Independent Threats

6.3.1 Third Party/Mechanical Damage

Facility locations susceptible to damage from vehicular impact should be protected by fencing, concrete bollards, or other physical barriers. First, second-, and third-party impacts on above-ground and below-ground facility piping and equipment are also possible. Similar methods applied to pipelines can also be applied to pipeline facilities such as surveillance, observers during construction activities, and guidelines for contractors.

6.3.2 Environmental and Outside Force

Equipment at facilities can be susceptible to damage from weather events such as tornadoes, hurricanes, floods, lightning, and extreme temperatures and as such, operators should implement spill prevention and control measures to reduce potential consequences of a release from weather events. In addition, where

inspections or patrols indicate ground movement could increase the stress on piping and equipment, operators should consider increasing monitoring or performing additional inspections.

6.3.3 Incorrect Operations

Incorrect operations can involve process upsets due to slug flow, cavitation, changes in fluid dynamics, upstream or downstream process changes, overpressures, and tank overfills. When appropriate, an operator should use root cause analysis to uncover underlying drivers that can lead to operator error incidents.

Operators can maximize learning opportunities by communicating lessons learned from incident investigations and periodic reviews of operations and maintenance practices and procedures. For unusual operations and one-time events, operators should consider developing detailed work plans and conducting a job safety analysis (JSA) or process hazard analysis (PHA) to reduce the risk of error during unfamiliar situations. Operator qualification (OQ) programs help to reduce human error through training and qualification on specific tasks under normal and abnormal conditions.

6.3.4 Original Construction

Construction defects at facilities can include fabrication weld defects, dents, or gouges that occur during construction activities, and improper installation of equipment, piping, flanges, and fittings. These threats can be prevented or mitigated using approved procedures, inspection protocols, and robust quality assurance and control programs during construction activities.

Table 1—Facility Integrity Threats

Threat	Example Mechanism	Example Methods of Identification
External Corrosion	Soil-to-Air Interface	Visual inspection, removing soil and coating if necessary, or other technologies
	Contact Corrosion (Metal to metal contact)	Visual inspection, UT, GWUT, and other technologies
	Corrosion under insulation	Visual inspection, eddy current, GWUT, or other technologies
	Stray Current Interference (below ground)	CP records, interference testing, failure history, corrosion morphology, other metallic structures
Internal Corrosion	Dead legs, Drain Lines, and Relief Lines	Operational knowledge, drawings, excavation inspections, acoustic pipe locate, electromagnetic, GPR, or radio detection,
	Product Corrosivity	MIC/bacteria testing, corrosion coupons, water sample analysis, corrosion morphology
Erosion and Erosion/Corrosion	High flow and/or direction changes, presence of particulates, chemistry	UT, radiograph/x-ray, modeling, product quality, and other technologies
Environmental Cracking	Internal – Ethanol, high stress, hydrogen embrittlement due to H2S composition, hydrogen induced cracking, sulfide stress corrosion cracking	Phased array, historical failure history, product quality testing, ILI (if applicable), and other technologies
	External	Soil conditions, pH, high CP potentials, coating condition, coating type, external stresses, temperature, cyclic stresses, vibration, historical failure history, hoop stress, excavation inspections, Mag particle (MPI), Dye penetrant, ILI (if applicable), and other technologies
Manufacturing Defects	Hook cracks, lack of fusion, misalignment of seam weld, laminations, inclusions, hard spots, toe cracks	Age of pipe, manufacturing process, manufacturer history, failure history, quality assurance and quality control process, operational history (duty cycle), material records, industry advisory bulletins, inspection methodologies, hydrotest records, and other technologies
Construction and Fabrication Damage (Includes HDD, Maintenance and Repair Installations)	Weld defects, misalignment, improper handling, arc burns, deformations, residual and/or pull stresses, welding process, coating holidays, metallurgy, hydrogen induced cracking	Welding procedures, quality assurance and quality control process, inspection methodologies, industry advisory bulletins, material records, hydrotest records, and other technologies
Equipment Failures	Valves, seals, closures, hydraulic/instrumentation lines, O-rings, gaskets, threaded joints, thermal relief, improper installation, strainers, meters, fabricated skids, material incompatibility	Visual inspections, vibration sensors/monitoring, documentation, operational procedures and policies, failure history, telemetry, product quality, fire eyes, equipment runtime, industry advisory bulletins, and other technologies

Mechanical Damage (First Party, Second Party, Third Party)	Dents, gouges, ovalities, punctures, coating damage, fitting damage, vandalism	Secondary or connected assets, disturbed soil, excavations, line locate, controlled supervision, acoustic detection technologies, camera surveillance, patrolling, visual inspection, gas detection monitoring, and other technologies
Incorrect Operations	Valve misalignments, maintenance tasks, overpressure, product quality, tank/sump tank overfill	Operating history, abnormal operating conditions, procedures, quality management, training, Toolbox discussions, setpoint review, human factors, relief design, automation, redundancy review, HAZOP
Weather and Outside Forces	Lightning, flooding tornadoes, high winds, hurricanes, snow load, land movement, blasting, earthquakes, subsidence, soil swelling, frost heave, freezing, fire	Visual inspection, national weather and geological services, strain gauges, piezometers, line marker movement, survey, inclinometers, rain gauges, LIDAR, photogrammetry, seismograph, and other technologies, product quality (water composition)

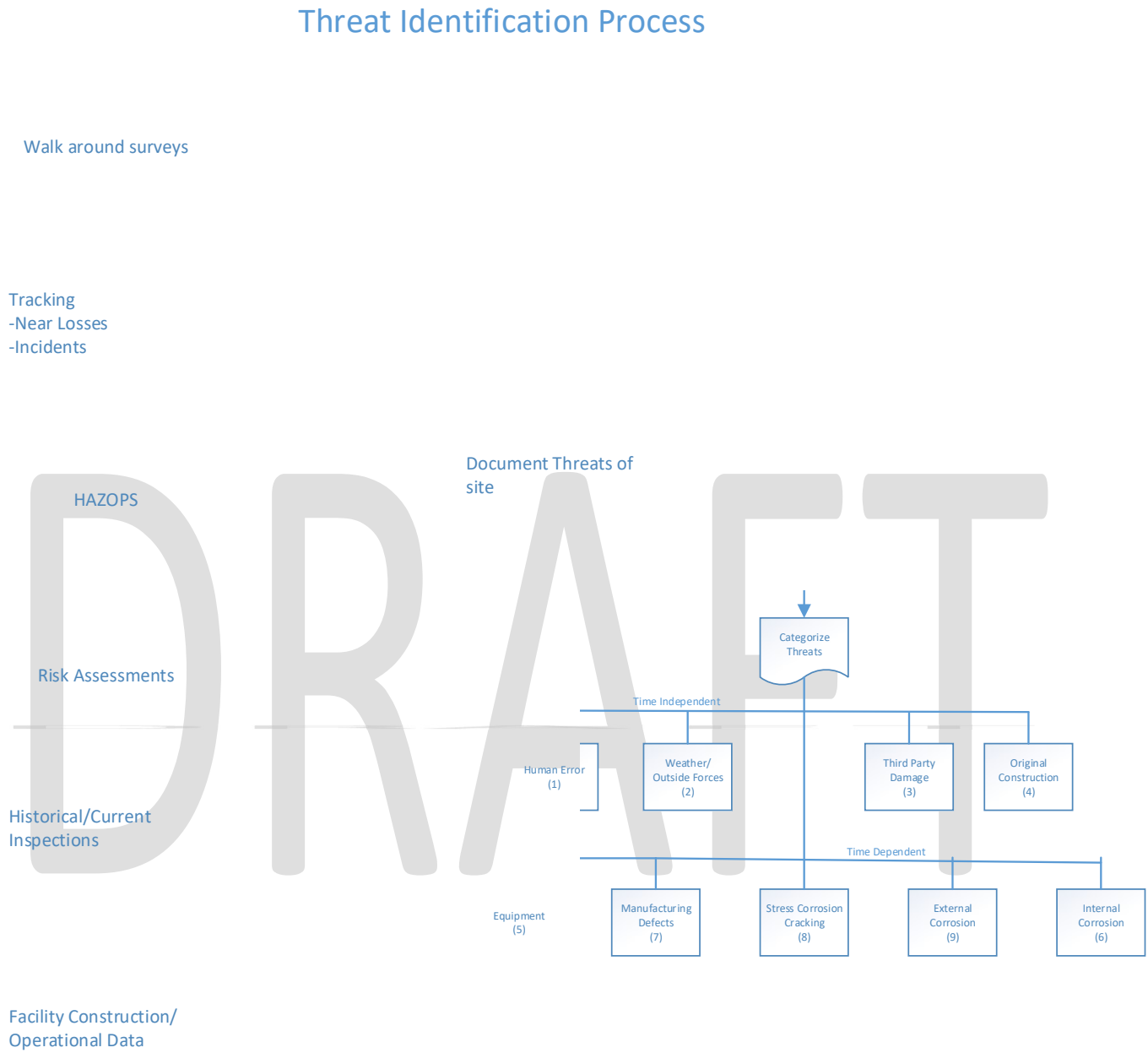


Figure 3 – Threat Identification Process

6.4 Identifying Threats

There are several techniques that may be used to identify threats at a particular facility including but not limited to Subject Matter Expert (SME) expertise, Company History based identification, Scenario Based Risk Assessment (SBRA), checklists, Hazard Identification (HAZID), Hazard and Operability Study (HAZOP), What-If Analysis, reliability centered maintenance (RCM), and Failure Modes, Effects, and Criticality Analysis (FMECA), etc.. Some examples of where an operator may seek and find evidence of threats at their facilities are:

- external corrosion at supports or hangers, at soil-to-air interfaces, corrosion under insulation (CUI), CP interference;

- internal corrosion from trapped water or sludge particularly with crude oil-types of piping most susceptible are drain lines, relief lines, low points, intermittently used facility lines, stub lines, and "dead legs" that experience low or intermittent flow of product; The table below provides a basis for establishing deadlegs:

Table 2—Deadleg Guidance

Branch Position (O'clock Orientation) on Operating Line [b]	Length of Deadleg [c]	Deadleg
 (12:00)	Any	NO
 (9:00 and 3:00)	≤ 3" Diameter of branch	NO [d]
 (9:00 and 3:00)	> 3" Diameter of branch	YES
 (6:00)	Any	YES

[a] This table provides a basis for establishing deadlegs. It is the responsibility of the owner/operator to identify *specific* deadlegs.

[b] Black section denotes location of potential deadleg based on a horizontal position of the operating line.

[c] Length to be measured from outside diameter of carrier pipe to end of deadleg branch.

[d] Branch is a deadleg if trap space present.

— internal erosion and corrosion/erosion;

— environmental cracking associated with the transport of fuel grade ethanol and SCC;

— manufacturing defects including seam and equipment body defects;

— construction and fabrication defects including installation girth weld failures;

— equipment failure including pump seal, packing, gasket, and o-ring failures, control or relief equipment failures, external fitting leaks; improper support of piping spans, flanged or other connection leaks;

— mechanical damage and vandalism causing an immediate or delayed failure;

— incorrect operations including overpressure from transients or thermal effects, tank and sump overfills, incorrect valve positions, improperly installed equipment or fittings in small bore tubing and pipeline (<2 in. nominal pipe size), operator errors;

— weather and outside force defects including freezing of trapped water, potentially from hydrostatic testing in fittings or small diameter piping, ground movement, and settlement.

7 Risk Assessment

7.1 Introduction

Risk is the product of the likelihood or frequency and consequence of an adverse event occurring. Risk assessments can be completed using industry-recognized assessment methods including Relative or Indexing Assessment, Quantitative Assessment, and SME or Qualitative Assessment. Each method has its own strengths and limitations. When selecting the risk assessment method to be employed, consideration should be given to the risk assessment goals and availability and granularity of available data.

Elements of a risk assessment can be used at any stage of the Plan-Do-Check-Act cycle. Elements can be used in the "Plan" phase with a Risk Based Inspection (RBI) program, through the "Do" phase to measure the amount of residual risk, in the "Check" phase as assurance that activities completed meet tolerable risk criteria, or during the "Act" phase to help define new risk tolerability.

7.2 Using Risk

The purpose of performing a facility risk assessment is to guide operators in selecting and prioritizing risk reduction activities. Risk assessment results can be used to:

- Identify relevant threats to facility integrity
- Identify consequences related to environmental or health and safety and other receptors
- Risk rank facilities, segments, groups of assets, or individual assets for additional preventative or mitigative measures
- Assess suitability of current maintenance activities
- Determine inspection and re-inspection intervals
- Periodically determine tolerable risk based on operator risk profile
- Measure the change in risk based on implementation of preventative and mitigative measures
- Justify continued operation or assess liability of continued operation

7.3 Risk Assessment Scenarios and Asset Listings

A key aspect of facilities risk assessment is defining the asset(s) being assessed, as well as the threats being evaluated. Asset listings can range from simple to complex and are determined by the operator's unique operations. One approach for an asset listing is to determine the asset type based on its operation and functionality within a facility. This allows an operator to group assets operating under similar service. An example of asset types within a facility that operators can assess include:

- Aboveground station piping
- Belowground station piping
- High pressure piping
- Low pressure piping
- Manifolds
- Transfer lines
- Relief lines
- Tank lines
- Trap piping
- Laterals
- Low flow/deadlegs/bypasses
- Valves
- Pig traps
- Storage tanks (even though tanks are explicitly excluded from this document, they may be included in the overall facility risk analysis)

More information on data collection for asset types can be found in Section 5 – Data Integration.

7.4 Threat and Scenario Analysis

A threat or scenario analysis should be completed as part of a risk assessment program. Determining which threats are applicable to each asset type helps define the appropriate damage factors to consider within a risk management program.

More information on Threat Analysis can be found in Section 0 of this document

7.4.1 Likelihood of Failure

Likelihood of Failure (LoF) is the possibility of an adverse event occurring. LoF can be defined, measured, or determined objectively or subjectively, qualitatively, or quantitatively, and described using general terms or mathematically. To determine LoF, a threat analysis, possibly including plausible failure scenarios should be completed. LoF can be calculated using Relative or Indexing Assessment, Quantitative Assessment, or Qualitative Assessment. Each threat or scenario should be evaluated individually and can be aggregated to determine the overall facility risk.

7.4.2 Consequence of Failure

Consequence of Failure (CoF) is the measure of direct and/or indirect impact that an adverse event could have on the public, employees, property, the environment, or organizational objectives. Release data, such as API Pipeline Strategic Data Tracking System (PSDTS) suggests that facilities incidents typically involve small volume releases that are contained on site. Large-volume releases (greater than 50 barrels) in facilities are less frequent.

Some examples of direct impacts can include:

- Health and safety of the public and/or organization personnel
- Environmental impacts
- Cleanup costs
- Potential business disruption

Some examples of indirect impacts can include:

- Long term remediation of the facility
- Reputational impact

CoF can be estimated using Relative or Indexing Assessment, Quantitative Assessment, or Qualitative Assessment. Each threat or scenario should be evaluated individually and can be aggregated to determine the overall facility risk.

7.4.3 Available Methodologies

There are several different available methodologies for performing risk assessment within a facility. The method chosen should be one which aligns to the final needs of the risk assessment, what data is available, and what level of expertise is available. Discussed in this document is relative or indexing assessment, quantitative assessment, probabilistic assessment, and qualitative assessment. Algorithms and models are available in various industry documents and recommended practices and can also be developed internally with the aid of a risk and reliability expert.

7.4.3.1 Relative or Indexing Assessment

Relative or Indexing assessments may use numerical values or subject matter expert input to create a semi-quantitative analysis of risk. This flexible nature allows for operators to use a wide variety of data and inputs to assess risk, minimizing the need for data in specific formats. Relative or Indexing Assessments also allow operators to rank and prioritize asset types by risk across facilities or to aggregate total risk scores to rank and prioritize overall facilities though results can be influenced by the amount and nature of qualitative SME input employed by the model.

7.4.3.2 Quantitative Assessment

Quantitative assessments use quantitative inputs such as historic failure records to estimate the likelihood of undesirable events. Events considered in the assessment may be treated as a single even such as in the historical rate of a specific release or may be evaluated by ranking the likelihood and relationship of a series of events happening such as that used in an event tree approach. The assessment routine is a numerical analysis which can use adjustment factors to represent actual design, operation, and maintenance conditions of the asset comparative to the base data set. A quantitative model must output quantitative metrics of risk such as probability or frequency.

7.4.3.3 Probabilistic Assessment

A subset of quantitative assessments are probabilistic assessments. These assessments can incorporate a range of scenarios such as change over time and effects of maintenance and repair strategies. The assessment models typically comprise a limit state function that incorporates an engineering assessment model, with input data entered as distributions. The key difference with a probabilistic approach is the quantification of uncertainty, removing the need for conservatism usually associated with the risk models. Results are expressed either as the probability of exceeding the limit state, or a range of possible values.

7.4.3.4 Qualitative Assessment

Qualitative assessments are the simplest form of risk assessment. Qualitative assessments are generally completed by a team with specific knowledge of the threats, the threat barriers, and the consequences of a failure.

Operators can complete an qualitative assessment using a standard risk matrix and decisions can be made by that team for an asset or asset grouping on the threat or scenario risk within a facility.

Qualitative assessments can be quickly and easily completed by operators without the need to employ a risk expert. Though the disadvantage of this assessment type is that a large group SMEs which is necessary to maintain the assessments as new inspection data becomes available. Additionally, they can be influenced by opinions of different team members as each individual assessment is completed thereby varying the risk results through the process and skewing the relative ranking.

7.4.4 Simple Risk Results Matrix

Risk can be depicted on a risk matrix which is individual to each operator. A sample risk matrix is shown in Figure 4, *Sample Risk Matrix*.

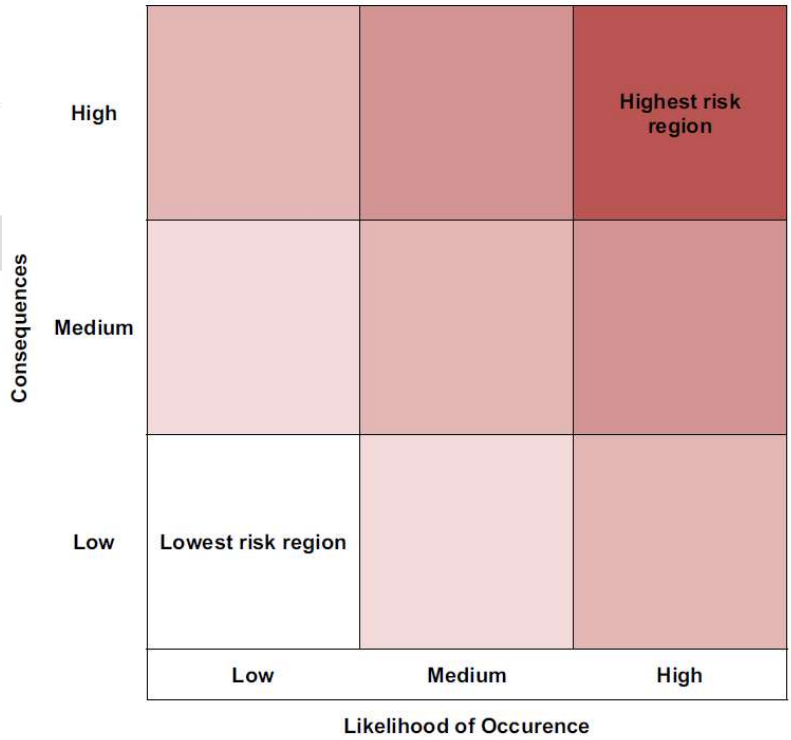


Figure 4—Sample Risk Matrix

7.5 Risk Based Decision Making

Operators can use risk results to guide decision making within the facility and within their organization. Operators can implement P&MMs to reduce risk across the organization or use analytical tools outlined in this section to achieve specific goals.

7.5.1 As Low as Reasonably Practicable (ALARP)

As Low As Reasonably Practicable (ALARP) is the principle of managing the region of risk between broadly acceptable and intolerable. Figure 2, *ALARP Regions,* shows the ALARP "Carrot". Using this figure an operator may balance the time, cost, and difficulty of implementing preventative measures against the risk of the scenario being addressed. When the implementation of risk reduction becomes grossly disproportionate to the threat being managed, ALARP is said to be achieved.

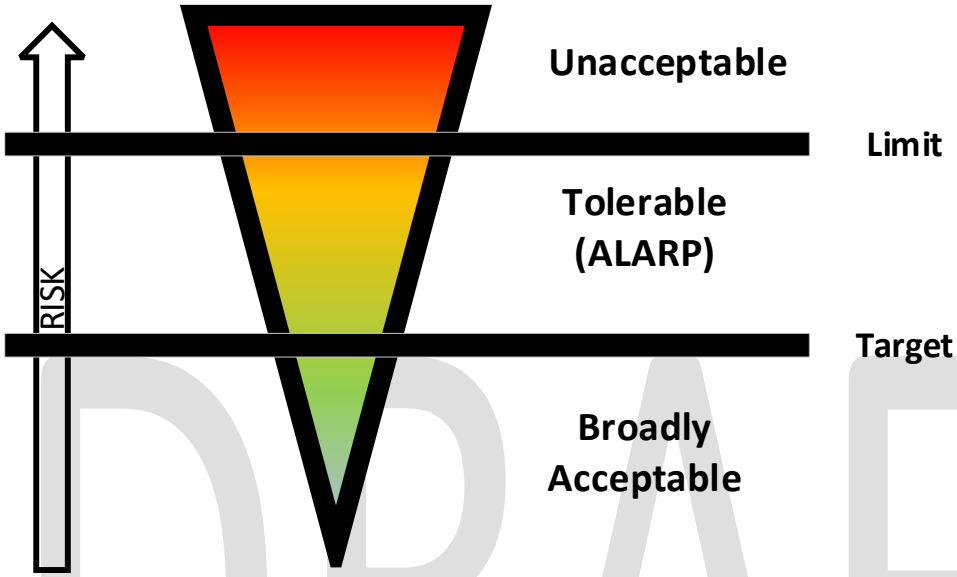


Figure 5—ALARP Regions

ALARP assessments can be completed as a qualitative exercise, or through a formal cost benefit analysis. Based on each scenario, the gross disproportion factor used can and will change throughout the assessment depending where on the "Carrot" the risk is. When completing an ALARP assessment, considerations should be given to factors including, but not limited to, societal risk, off-site environmental risk, business risk, and occupational health and safety.

7.5.2 Major Accident Hazard Investigations (MAH)

Major Accident and Hazard (MAH) investigations are investigations into the "what-if" scenarios of low-likelihood, high impact events at a facility. MAH investigations move beyond a typical integrity program and evaluate not only the likelihood and direct consequences of a specific MAH scenario occurring, but also take into consideration, among other things, natural disasters, operator habits, and proximity to the general public.

The basis of an MAH can include the bowtie analysis which is used to evaluate the plausible MAH scenarios, their consequences, and the preventative and mitigative measures in place. A sample bowtie is presented as Figure 3, *Bowtie Analysis*. P&MMs form the barriers of protection from an incident becoming catastrophic. P&MMs are closer examined in Section 9.

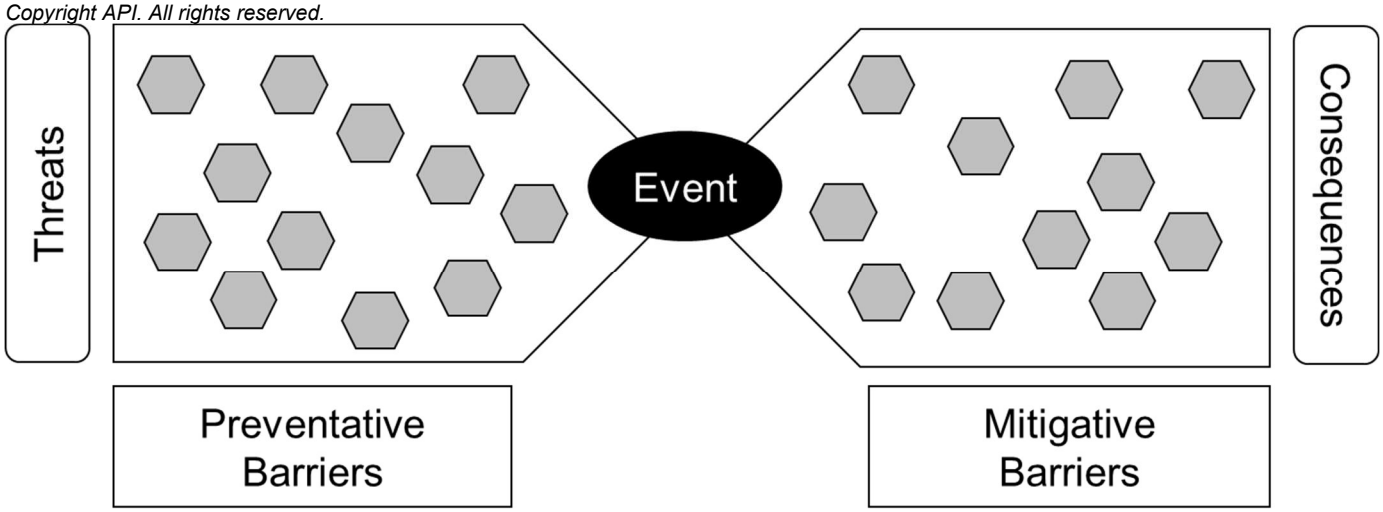


Figure 6—Bowtie Analysis

By evaluating the results of an MAH, an operator can better understand the gaps in the overall facility integrity program beyond the direct assessment of piping systems.

7.5.3 Risk and Integrity Results Review

Risk and integrity reviews of a facility play a critical role in the overall integrity of a system. Reviews need to be targeted towards the risk of the adverse scenario that is being evaluated and will help give a general view of the risk at a facility. One example of a risk review that can be performed is a Major Accident and Hazard Investigation (see Section 7.5.2).

8 Inspection and Re-Inspection

8.1 Facility Integrity Inspection

The following section provides guidance on performing periodic inspections and reinspections on facility piping. Due to unique characteristics of facility piping, a range of inspection techniques and technology may be used. Operators may use their risk results, inspection results, or SME input to determine if a facility needs to be assessed.

Each operator should develop and implement their own approach for facility inspection. The initial step for facility integrity inspection is for operators to identify and document the threats that may be present as well as potential threats so that the operator can effectively manage the integrity of piping or systems within a facility. This is discussed in Section 0 Threat Identification. As inspection technologies improve with time, operators are encouraged to evaluate and adjust their inspection program. Appropriate measures should be taken upon discovery of threat severity, consistent with established practices as well as any regulatory requirements.

Periodic inspections may include visual inspection, NDE, etc. to ensure that applicable piping and appurtenances are inspected. The following above and below ground assets may be considered for inspection:

- Pipe
  - Cased pipe
  - Insulated pipe
  - Dead legs
  - Relief lines and drain lines
  - Supports
- Appurtenances

- Valves and flanges
- Pumps/compressors
- Meters
- Tubing and fittings
- Strainers

8.1.1 Visual Inspection/Surveillance

External visual/surveillance inspections are performed to assess for abnormal physical conditions of a facility such as missing or degraded insulation, deteriorated coating, misalignments, evidence of corrosion, excessive vibration, and leakage.

Operators can determine the inspection/surveillance frequency based on the facilities characteristics, historical data (leaks, construction and maintenance records, etc.) etc. In addition to scheduled inspections/surveillance, observed deterioration changes should be reported to appropriate personnel.

8.1.1.1 Visual Inspection

Typically, the inspection is performed by a qualified inspector (operator or 3rd party), and a formalized report is provided that describes the various individual facilities and descriptions of their physical condition. Photographs may be included. Any corrective actions/repairs should be done in accordance with the operator's policies and/or procedures. Annex A of this document provides a list of items that can be considered during an inspection.

8.1.1.2 Surveillance

Surveillance typically consists of a visual inspection using a predefined list of equipment or tasks to capture the physical condition of the facility. Items on the list may include observations of pipe supports, air-to-soil interface coating condition, vibration, leaks, misalignment, paint condition, and tank appurtenances (unless included in API 653 inspections).

8.1.2 Indirect Inspection Techniques

The following provides guidance on indirect inspection technologies that may be used.

8.1.2.1 Guided Wave Ultrasonic (GWUT)

The GWUT method may be used to inspect a length of pipe for metal loss and other anomalies. This method is most useful where the pipe is difficult to directly access such as at road crossings, tank dike penetrations, transitioning from above ground to below, penetrating walls or structures, at pipe supports, and long sections of above ground piping.

The methodology sends a full circumference ultrasonic (UT) wave through the pipe in the axial direction to detect changes in cross sectional areas of piping (internally or externally). While quantitative measurements of area are provided, this method is considered as a screening method since the length and depth dimensions of metal loss anomalies are not provided in sufficient detail to perform accurate integrity inspections.

Other places where GWUT may be used are on above ground locations where full inspection coverage is desired. Screening by GWUT is first applied and then may be followed up by more specific inspection tools such as radiography, automated ultrasonic testing (AUT), laser scanners, or electromagnetic acoustic transducers (EMAT) to quantify the feature(s) called out by GWUT.

There are four references that provide guidance on use of GWUT technologies:

1) ASME *Boiler and Pressure Vessel Code (BPVC)* Section V, Article 19, *Guided Wave Examination Method for Piping*

2) BS 9690-1&2, *Non-destructive testing-Guided wave testing*

3) ASTM E2775, *Standard Practice for Guided Wave Testing of Above Ground Steep Pipework*

Using Piezoelectric Effect Transduction

4) PRCI Catalog No PR-306-123740-R01, *Comparative Analysis of Pipeline Inspection Technologies Using Guided Waves and Ranges of Applicability*

5) Appendix F Part 192 Criteria for Conducting Integrity Assessments Using Guided Wave

8.1.2.2 Indirect Inspections (ACVG/DCVG/CIS/Current Attenuation Survey)

Many of the direct assessment processes used for line pipe can also be applied to facilities. The focus of an ECDA, ICDA, or SCCDA is to identify more probable locations of external corrosion, internal corrosion, or SCC. The direct assessment process can be applied for multiple facility integrity threats by integrating knowledge of the physical characteristics and operating history of a pipeline with the results of diagnostic and direct measurements performed on the pipeline or equipment. A detailed description of the direct assessment process is available in Table 8.

8.1.3 Direct Inspection Techniques

Several direct inspection techniques exist to quantify features that can affect the integrity condition of the piping components in a facility. Each technique has advantages and disadvantages that the operator must consider while planning an inspection. Multiple inspection techniques may be required to accurately assess the integrity condition of facility piping. The integrity inspection plan should be assessed prior to commencing the job at each site. An operator is encouraged to analyze and define the potential integrity threats that may be encountered so that the inspection instruments selected are appropriate to assess the facility. Techniques on how to perform such tasks are described in API 570, API RP 571, API RP 574, and API RP 577. These techniques or a risk management program may be used form an operator's inspection program. If applicable, recommended practices such as, API RP 580, API RP 581, and ASME PCC-3 may guide an operator through RBI techniques. A complete inspection equipment list can be reviewed from ASME *BPVC* Section V, Table A-110 Imperfection vs Type of NDE Method. Examples of inspection techniques that may be used, but are not limited to, are provided in Table 8, with hydrostatic testing included at the end for comparison. Table 8 provides basic advantages and limitations to different inspection techniques; however, an in-depth analysis of the inspection technique may need to be done before implementation.

8.1.4 Repair Methods

Facility operators should identify the features that require repair as well as determine the extent and timing of a response in accordance with their own procedures and policies. Acceptable repair methods for a wide variety of defects are described in industry standards and documents such as API 570, ASME B31.4, the *PRCI Repair Manual*, API RP 1176, Section 9.5 in API 1160, and CSA Z662. Fitness for service methods to determine response timing may include RSTRENG, Modified B31G, or methods described in API 579.

8.2 Re-Inspection Intervals

Re-inspection intervals may be determined from a variety of different methods. Operators may use their risk results, inspection results, or SME input to determine if a facility needs to be inspected. This information can then be used to establish an inspection interval if needed.

Other useful references for determining growth rates and re-inspection intervals include API RP 1176, API 580, API 581, and API 570.

Table 3—Inspection Methods Applicable to Facilities

Technique	Typical Applications	Identified Threats*	Advantages	Limitations

UT—thickness gauging	Measures wall thickness. Attenuation and velocity changes in acoustic wave assist in evaluation of materials properties, in-service damage, and corrosion.	— Internal Corrosion, External Corrosion	— Direct measurement — Quick — Can be combine d with a scanner to produce and image (AUT)	— Requires a liquid couplant — Surface must be smooth — Limited coverage proportional to the size of the probe
UT—flaw detection (shear wave, angle beam, time-of-flight diffraction (TOFD))	Quantifies and qualifies anomalies such as cracks, crack- like, non-fusion, slag, and corrosion.	— Internal Corrosion, External Corrosion	— Direct measurement — Quantifies flaw size	— Requires a highly trained inspector — A slow process that can be costly — Laminations can hide features or cause a false positive call.
Guided Wave Ultrasonic (GWUT)	An NDE technique used as a screening tool to detect corrosion. Long range inspection can be achieved from a single location as ultrasonic guided waves travel along the pipe and report differences in thickness and may detect coating deviances.	— Internal Corrosion, External Corrosion, Manufacturing Defects	— Provides a screening of piping — Allows inspection for difficult to access locations	— Indirect measureme nt, screening tool — Limited range of inspection due to elbows, bends, fittings, coating type or deviances, diameter, etc.
ACVG/DCVG/CIS/C urrent Attenuation Survey	Methods used to evaluate the coating condition of buried pipelines.	— External Corrosion	— No digging required to perform the procedure — Relatively low cost	— Time consuming — Difficulty in congested locations — Detection capability differences in pipe orientation — Difficulty in holiday sizing

Eddy Current	Detection of near surface cracks, stress corrosion cracking	— Environmental Cracking	— Detect cracks not detectable by radiography — Lower cost than radiography — No couplant or probe contact required	— Shallow depth, only will detect cracks close to the surface — Sensitive to changes in geometry
Radiography	Detection of cracks, voids, inclusions, thickness changes, lack of fusion, incomplete penetration, and corrosion. Typically used for small bore piping, fittings, and corrosion under insulation (CUI).	— Internal Corrosion, Manufacturing Defects, Construction and Fabrication Damage, External Corrosion	— Direct image of flaw (size and location) — Permanent record — Simple interpretation — Applicable to many materials	— Radiation hazard — Orientation of flaw affects detection — Difficult to apply on complex parts — Defect volume (planar vs volumetric) — Thickness and pipe diameter limitations — Piping must be completely purged of liquids on pipes larger than 4 inches
Direct Magnetic Particle Inspection (MPI) or Liquid Dye Penetrant Inspection	Finds narrow surface breaking discontinuities, cracks, or porosity.	— Manufacturing Defects, Construction and Fabrication Damage	— Relatively inexpensive — Fast and simple to use	— Only finds surface breaking features — Depth not provided — Requires good illumination and a clean surface

Direct Electro-Magnetic Acoustic Transducer (EMAT)	Locates and qualitatively assesses wall loss, corrosion under supports, air-to-soil interfaces, mill related features, cracks, and coating disbondment	— External Corrosion, Environmental Cracking, Manufacturing Defects	— Fast screening tool — No liquid couplant needed	— Requires a highly trained inspector — Wall thickness must be less than $^{3}/_{4}$ in. — Flaw detection sensitivity usually lower than conventional UT
Laser Scanning	Maps metal loss areas as well as dents with and without metal loss., and external corrosion.	— External Corrosion	— Quick scanning — Image quality within a ±50-micron accuracy — The system via software can perform fitness for purpose calculations	— Only for surface and volumetric type features
In Line Inspection (ILI) Using Tethered Tools and Robotic Crawlers	Useful when standard free swimming, conventional tools are impractical due to piping constraints (e.g. multiple diameters, tight or complex bends or miters, fittings, valve restrictions, low flow or no flow conditions, no launcher or receiver facilities)	— External Corrosion, Internal Corrosion, Erosion and Erosion/Corrosion, Environmental Cracking, Manufacturing Defects, Construction and Fabrication Damage, Mechanical Damage, Weather and Outside Force Damage	— More thorough inspection of pipe integrity. — Uses convention al ILI technologie s such as MFL, Eddy Current, Ultrasonic, Electromag netic Acoustic Transmitter , and Geometry	— The technology selected can have limitations that are inherent to any other manual methodology (e.g. crack like features with no volume may be missed using MFL technology or external metal in close proximity will not be detected by UT technology).

In-Line Inspection (ILI) Tools	Conventional MFL, UT, EMAT useful for long lengths of facility piping, such as tank lines. Detection of external and internal corrosion, and mechanical deformation.	— External Corrosion, Internal Corrosion, Erosion and Erosion/Corrosion, Environmental Cracking, Manufacturing Defects, Construction and Fabrication Damage, Mechanical Damage, Weather and Outside Force Damage	— More coverage and data of facility piping — More thorough inspection of pipe integrity	— Impractical for some facility piping (e.g. smaller diameter pipe (<3”), multiple diameters, tight or complex bends or miters, fittings, valve restrictions, low flow or no flow conditions, no — launcher or receiver facilities) — Tool availability
Hydrostatic Testing	Used to establish MOP or that the piping system is not leaking. This method can also be used to remove any features that will not be able to withstand pressures above a certain value of MOP (e.g. MOP ≥ 1.25 or 1.39).	— External Corrosion, Internal corrosion, Incorrect Operations, Environmental Cracking, Manufacturing Defects, Construction and Fabrication Damage, Equipment Damage, Weather and Outside Force Damage	— Simple to use, reliable, and proven — Complete coverage (Proves up all fittings and valves)	— Can be difficult to administer at an existing facility with multiple manifold connections or lack thereof — Does not provide detailed integrity conditions for the piping system — Pass/fail test at a specific moment in time — Impact to customers due to line out of service — Increased costs (disposal of water, line purge) — Potential for brittle fracture — Potential for integrity issues (water/moisture in pipe causing internal corrosion, frozen water in deadlegs causing cracking)

Large Standoff Magnetometry (LSM)	Measures stress concentrators ambient magnetic field to potentially predict corroded areas on a pipe.	— Internal corrosion — External corrosion — Deformation	— Non-invasive – no digging required during screening — Large lengths of facility piping can be screened in a short amount of time	— Screening tool only — Difficult to complete in crowded piping corridors — Identifies but does not measure absolute severity of anomalies — Requires locating and depth of cover survey prior to completion — Rate of false positives and false negatives can be high

*Identified threats in this table may be inspected via these inspection techniques, however there are limitations and circumstances where identified threats may not apply to the given technique.

9 Preventive and Mitigative Measures

9.1 Preventive Measures

Risk assessment often reveals aspects about operations and maintenance that allow an operator to address facility integrity threats and reduce the consequences of potential releases. The incident history associated with certain assets or circumstances should be considered.

One or more incidents associated with any asset or circumstance may indicate the need for enhanced preventive and mitigative measures. Some examples of prevention of each facility threat are shown in Table 4 and for mitigating consequences in Table 5.

Table 4— Examples of Preventive Measures to Address Facility Integrity Threats

Threat	Possible Items Identified through Data Gathering and Integration	Examples of Preventive Measures to Reduce Probability of Incident
External corrosion	— Low cathodic protection readings — Anomalies detected with NDE methods — Wall loss at a piping support — Anomalies identified with visual inspection — Known coating issues — Environmental factors (i.e. coastal, rocky conditions) — Corrosion under insulation (CUI)	— Optimize cathodic protection and/or Interference testing (consider DCVG, ACVG). — Conduct more frequent inspections (NDE, atmospheric, ILI, etc.). — Recoat or upgrade coating. — Pressure reductions where applicable (i.e. pump discharge). — Evaluate design of pipe supports. — Remove insulation (permanently or for inspection).
Internal corrosion	— Internal anomalies discovered at dead legs, drain lines, relief lines, low flow or low spots. — Known presence of Microbial Induced Corrosion (MIC) — Potential for under-deposit corrosion or paraffin — Corrosivity of product	— Inject inhibitor and/or biocide. — Conduct periodic flushing. — Drain and blind dead legs. — Purge with nitrogen. — Physically remove dead legs. — Complete chemical cleaning. — Conduct more frequent inspections. — Monitor corrosion rate with coupons or probes. — Sample and analyze water collected from drains or low points. — Consider internally coating pipe (for new construction). — Consider heavier wall pipe or fittings. — Monitor corrosion growth (i.e. UT sensors, permanent guided wave collars as a screening tool, increased inspection rate). — Periodic replacement of small components
Internal erosion and erosion corrosion	— Wall thickness measurement using UT discovered thinning at a 90 degree bend.	— Install filters to remove particulates. — Minimize locations with abrupt velocity changes. — Increase frequency of inspections at locations more susceptible to erosion. — Reduce flow velocity.

Environmental Stress Corrosion Cracking	— Crack anomalies detected with NDE/ILI methods	— Internal: Inject inhibitors and oxygen scavengers. — External: Sleeve, Recoat, Remove by grinding — Reduce residual tensile stresses. — New construction: Heat treat welds or replace with internally coated pipe. — Consider if piping can be made piggable for ILI technology.
Original Manufacturing/ Fatigue	— Quality control identified an out of specification component. — Anomalies detected with NDE/ILI methods	— Improve procurement practices to meet specifications. — Monitor quality control during installation. — Identify similar components at other locations. — Inspect piping and components for defects.
Equipment Malfunction	— Seeps or stains at fittings, flanges, pump seals, or valve packing. — Known vibration issues/alarms. — Trending equipment data and performance — Deviations from maintenance programs. — Risk of spray from high energy piping.	— Increase frequency of visual inspections. — Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. — Develop flange torque procedures. — Install equipment vibration monitoring. — Install cover.
Third Party/ Mechanical damage	— Vehicular impacts. — First or second party damage.	— Establish exclusion zones where large vehicles are not permitted without additional surveillance. — Consider bollards or jersey barriers. — Utilize hydro/air vac in place of excavators.
Environmental / Outside Force	— Water freezing in tubing or valves causing equipment to malfunction or fail. — Facilities located in low-lying areas or areas prone to flooding. — Facilities located in areas prone to geohazard or seismic activities. — Facility damage due to adverse weather conditions (i.e. lightning, hurricane, tornado, etc.)	— Increase inspection frequency for equipment prone to water accumulation and exposed to cold temperatures. — Develop winterization plans. — Develop flood control plans. — Elevate equipment. — Install high water alarms. — Develop emergency plan. — Develop business continuity plan where manned facility is required.
Incorrect Operations	— Improper replacement of tubing or small piping. — Gaskets replaced without considering torque limits. — Sump overfill due to valve misalignment — Inadequate maintenance activities of engineering controls — Inadequate calibration of engineering controls — Overpressure event	— Consider engineering controls to eliminate future incorrect operations. — Establish procedures (tubing, torque, etc.) — Conduct training. — Install high sump/run time alarms. — Maintain existing controls. Complete hydraulic or surge analysis. — Consider sump leak monitoring

Original Construction	— Wrong welding rods/procedure used. — Vibration issues — Threaded connections	— Ensure quality control during installation. — Install additional support to minimize vibration. — Minimize amount of threaded connections or periodic inspection/replacement — Install heavier wall pipe or fittings where known vibration

9.2 Mitigation of Consequences at Facilities

Multiple methods are used to mitigate consequences at facilities. Storage tanks are constructed inside berms or dikes to prevent releases from impacting surrounding areas. Facility specific leak detection can be used to minimize the amount of product that can be released during an unintended release. Sumps and drains contain and direct spills to safe locations. Mitigation can also include the use of higher toughness materials for pipe and vessels, improved methods for recovery and clean-up, and limiting the presence of personnel in hazardous areas.

Consequences of failures at facilities may include the following:

- Ignition of a vapor cloud in an occupied area.
- A fire that causes loss of a facility.
- A release that results in a large drain down.
- A small leak that over time accumulates into a large release.

Examples of potential mitigative measures can be seen in the table below.

Table 5—Examples of Mitigative Measures to Address Consequences at Facilities

Examples of Mitigative Measures to Limit the Consequence of an Event
Educate employees and nearby public as to the danger of a vapor cloud. — Provide emergency phone number to residents. — Improve emergency response criteria.
Increase frequency of inspections.
Install isolation valves as needed. .
Install containment berms or dikes.
Install or improve leak detection systems. — Consider localized leak detection (i.e. hydrocarbon sensing) — Work to control false alarms/false positives
Upgrade fire detection and prevention measures.
Improve remote monitoring of the facility.
Enhance emergency response criteria.
Install permanent guided wave collars or UT monitoring.
Consider additional monitoring techniques: — Cameras — Frequent walk-arounds — Station awareness programs — Drones
Have emergency response procedures in place (drills, working with local responders, equipment, etc.) and train personnel as appropriate.
Install component specific leak detection (pump seal, tank mixer, HI level sump).

Limit use of prohibited items (electronic devices that are intrinsically safe limited to certain areas, etc.)
Manage water or drainage to off-sight locations (ponds, rivers, etc.
Perform Major Accident Hazard (MAH) Analysis to evaluate high consequence event

9.3 Leak Detection

In addition to visual inspection, other options of leak detection are available within facility boundaries. When selecting a leak detection technology and establishing programmatic drivers, an operator should consider various factors such as company objectives, environmental impact, leak history, and any other factor that will frame the basis for an appropriate system choice. An understanding of the technology's capabilities and limitations should be gained in determining which system will perform best against the company's objectives.

Each leak detection system should be evaluated on items such as:

- Sensitivity
- Accuracy
- Calibration frequency
- Reliability
- Robustness
- Maintenance requirements
- Other system limitations.

An operator's response to potential releases should be based on these parameters. Common leak detection approaches are discussed below.

9.3.1 Tracer Gas

This methodology uses specifically tuned detection equipment that is sensitive to trace amounts of an inert chemical not otherwise found at the facility which is added to the product at low concentration levels. Tracer gas detection is accomplished by sampling vapors with probes placed throughout the facility or by using handheld units during facility walkthroughs. Since the probes are dispersed along facilities, detection of a leak at a specific probe(s) can also help pinpoint its location. This method can be used during normal operation and does not require service interruption while the test is being performed. A variety of tracer gas inoculations can also be used to differentiate which component might be leaking.

9.3.2 Cameras

Various types of specialized video cameras can be used at facilities to monitor operations and identify leaks but generally require humans to view and interpret the video images. Specific gases such as hydrogen, methane, carbon monoxide, and carbon dioxide can be detected by optical gas imaging (OGI) cameras where a leaking gas plume appears in real time as a smoke-like cloud from the leaking components. In addition, escaping hot gases and local cooling caused by expansion of gases from high-pressure systems can be detected by infra-red (IR) cameras. Factors that could affect the recorded IR image include temperature difference between vapor and background, and distance between the camera and plume source. A protocol for consistent and qualitative OGI surveys has been developed in the Netherlands (Standard NTA 8399).

9.3.3 Acoustic Techniques

As a pressurized system leaks, acoustic energy is emitted that can be detected by sensors in the vicinity of the leak. Acoustic leak detection systems typically use piezoelectric sensors. Sensor tuning and digital signal processing are needed to detect low amplitude leak signals in the presence of more dominant facility noise. This method is not intended to determine leak size but rather is used as a qualitative technique (e.g. a leak is occurring). The system can be susceptible to interferences from mechanical

noise (grinding, welding, impact wrenches, compressors, pumps etc.) or electrical noise, and these phenomena could affect the sensor's sensitivity. See ASTM E1211/E1211M-12, *Standard Practice for Leak Detection and Location Using Surface-Mounted Acoustic Emission Sensors*.

9.3.4 Liquid Hydrocarbon Monitors

Fiber optic cable systems detect leaks by monitoring for changes in light transmission properties in the presence of hydrocarbons that contact the cable. Cables must be strategically placed near valves, flanges, pipes and other components with the potential to leak. Another method involves hydrocarbon vapor monitoring sensors at sumps, catch basins, and underground monitoring wells. These two methods directly detect liquid hydrocarbon leaks without the need for tracer gases, temperature changes, or acoustic emissions.

API RP 1130 and API RP 1175 detail leak detection programs and methods.

10 Program Evaluation

10.1 General

Operators should periodically measure and evaluate the effectiveness of their Facility Integrity Management Programs. The review should include both measures of integrity performance, as well as measures of the program itself. The intent of this section is to provide operators with a methodology that can be used to evaluate the effectiveness of their pipeline and facility integrity management. An integrity management program evaluation should help an operator answer the following questions:

a) Were integrity management program objectives accomplished?

b) Was facility integrity and safety effectively improved through the integrity management program?

The operator should collect performance information and periodically evaluate the effectiveness of its integrity assessment methods and its preventive and mitigative risk control activities including repair. The operator should also evaluate the effectiveness of its management systems and processes in supporting integrity management decisions. A combination of performance metrics and system self-reviews are necessary to evaluate the overall effectiveness of an integrity management program. Operators may consider communicating the benefits and accomplishments of their programs and activities to various stakeholders including regulators and the public.

10.2 Performance Measures

There are multiple categories of the measures necessary to demonstrate the effectiveness of an integrity management program. The integrity of the facility, operations and maintenance activities performed, as well as program management activities all contribute to the safety performance of a facility. Each of these types of measures can be made through comparisons between leading (proactive or goal-oriented) activities or benchmarks and lagging (reactive or outcomes-oriented) indicators. Operators are encouraged to select as many measures as needed for their system. The period of measuring may vary to achieve a meaningful measurement of the effectiveness of some integrity inspections, mitigation, and preventive measures. Some examples of performance measures include incidents, volume released, number of abnormal operations, number of repairs, pump runtime and reliability, etc.

10.2.1 Integrity Performance Measures

Facility integrity performance measures examine the state of the asset itself. Integrity measures can include issues surrounding pipe corrosion, cracking or dents in the piping. While not the most frequent cause of pipeline incidents, these integrity issues may result in larger releases per incident.

10.2.2 Operation and Maintenance Performance Measures

Operations and maintenance measures can track issues associated with incorrect operations and equipment failure. Although operations and maintenance issues generally result in smaller releases per incident, they are a leading cause of pipeline incidents and should be measured as a category of safety performance. Specific examples of incorrect operation might include storage tank overfills or valves left in the wrong position.

Equipment failure measures may track pump failures, defective relief valves or loose fittings. Operators should also consider measuring excavation damage. These described measures of incident causes are lagging indicators. Thus, operators should also consider leading indicators of operations and maintenance effectiveness, such as providing training on new leak-detection software or conducting fire alarm drills for control room operators.

10.2.3 Program Management Performance Measures

In addition to measures of integrity and measures reflecting operation and maintenance of the pipeline and facilities, operators should also measure the management of their integrity program. Elements of an IMP accomplish the threat management goals of the program through both direct integrity-related activities, as well as supporting activities to improve the quality of the program itself.

Table 6—Performance Measures by Process Step

Program ID	Program Element	Potential Measures
1	Identification of Threats to Facility Integrity	Are threats identified for particular facilities accurate? Are they appropriate for facility being assessed? Are they up-to-date?
2	Identification of Potential Impacts to HCAs	Are populated and environmentally sensitive locations accurately identified? Does information reflect recently changed or expanded critical locations?
3	Risk Assessment	Do risk assessments appropriately reflect threat and consequence data? Are the facilities ranked appropriately based on the integrity inspection findings?
4	Inspection	Do inspection techniques or technologies reflect identified threats?
6	Data Collection	Is data from inspections, testing and examination collected (above and/or below ground)
7	Program Performance Data	Are program performance metrics developed and data collected?
8	Facility Remediation Activities	Do remediation activities reflect facility inspection results? Do remediation activities reflect identified threats and assessed risks?
9	Preventive and Mitigative Activities	Do P&MM recommendations effectively prevent and mitigate threats?

10.2.4 Meaningful Measures and Incidents Impacting the Public or Environment

While it is important to measure a broad range of integrity activities and performance results, some measures are considered more meaningful because they reflect incidents with an impact to the public or environment. An example is the meaningful measures developed in the United States jointly by regulators, liquid pipeline operators and pipeline safety advocates. These measures, defined below, track liquid pipeline incidents impacting human health or the environment.

a) Regardless of incident location, incidents resulting in:

— death;

— serious personal injury;

— fire;

— explosion;

— wildlife impacts;

— water contamination;

— soil contamination;

— public or non-operator private property damage.

For incidents not totally contained on operator-controlled property:

— unintentional release volume greater than or equal to 5 gallons in an HCA;

— unintentional release volume greater than or equal to 5 barrels outside an HCA;

— surface water contamination;

— soil contamination.

In addition to total incidents, also measured are incidents with causes expected to be found by integrity inspection and incidents with causes dependent on operations and maintenance. Operators should consider including in their internal performance measures these or similar types of meaningful measures based on public, environmental or sensitive location, and volume factors.

10.3 Performance Tracking and Trending

Evaluating performance relative to actions taken, calculations made, and goals set for improvement are relative measures. A pipeline operator should also evaluate its facility integrity management program in more holistic terms such as:

— Will the goals significantly enhance facility safety and integrity?

— Are the results consistent with those of other operators?

— Will any applicable regulatory expectations be met?

To meet these conditions, the operator should conduct periodic evaluations of their own performance in comparison with industry-wide data sources. For example, a U.S. operator can review its performance in comparison with the database of reportable incidents maintained by the U.S. Department of Transportation. Other countries maintain similar incident databases as well.

10.4 Self-Reviews

Self-reviews of integrity management programs should be performed to establish and maintain the quality and effectiveness of the programs. These reviews should be performed periodically by the operator's own personnel, and external reviews by an independent outside organization may be beneficial if deemed necessary. In some jurisdictions, inspections by regulatory authorities may be mandated.

Reviews should address the following questions:

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

— Is someone assigned responsibility for each subject area?

— Are appropriate resources available to those who need them?

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

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

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

— Are all required activities documented by the operator?

— Are action items followed-up?

— Is there a formal review of the rationale used for developing the risk criteria used by the operator?

— Are the criteria for assessing and remediating anomalies adequate?

— Are the criteria for establishing reassessment frequencies adequate?

— Are the criteria for preventive and mitigative measures adequate?

— Are the criteria for the assessment of facilities adequate?

— Are there processes for internal and outside auditing?

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

— Are incidents being reduced?

— Are procedures being updated based on new knowledge (major events, new regulations, new advisories, new research)?

— Is knowledge being shared throughout the organization?

— Is knowledge being shared throughout the industry?

10.5 Performance Improvement

The results of the performance evaluation should be used to modify the facility integrity management program as part of a continuous improvement process. Recommendations for changes and improvements should be based on analysis of the performance measures and the audits. All recommendations for changes and improvements should be documented, communicated as needed (senior management, industry lessons learned, etc.) and implemented in the next cycle of integrity assessment.

Annex A
(informative)
Example Visual/Surveillance Inspection Form for Facilities

Inspection Check List

Customer_____Date _____

Location_____Drawing _____

Line number/Description_____Material _____

A= Acceptable, FEN= Further Evaluation Needed, NA= Not Applicable, NI= Not Inspected

Item Number

1 Leaks

2 Misalignments

3 Vibration

4 Supports

5 Corrosion

6 Insulation/Coating

7 Flange and Pipe Information

8 Piping Start and Stop Locations

9 Injection or Mixing Locations

10 Dead Leg Piping

11 Pressure and Temperature

12 PSV External Inspection Checklist

a) Equipment Integrity/Serviceability

i) Leakage at Flange

ii) Evidence of mechanical Damage

iii) Bolting Corroded

iv) Isolation valves open and car-sealed

v) Bleeder valves closed and capped

vi) Service tag attached

b) Vent piping

i) Closed system

ii) Vent piping properly supported

iii) Weep hole open and clear

c) Insulation Condition

i) Blanket or sheathing in place

ii) Evidence of damage to sheating

iii) Bands/wires secure

iv) Leakage onto insulation

d) Paint Condition

i) Fair to Good

ii) Blisters

iii) Peeling

iv) Other

e) Service tag information

Figure A.1—Example of a Visual/Surveillance Inspection Form for Facilities