In-Line Inspections of Pipelines

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Foreword

Since the transportation of hydrocarbons by pipeline began in the 1860s, the primary means of establishing pipeline integrity has been through the use of pressure testing. These tests have been most often performed upon completion of the construction of the pipeline. The completed pipeline segment has been pressurized to a level equal to or exceeding the anticipated maximum operating pressure (MOP). Government regulations have recently specified the test pressures, test media, and test durations that must be achieved for pipelines to be permitted to operate within their jurisdictions. However, until very recently, there have been no such requirements for pipelines to be periodically tested for integrity. Some pipeline operators have traditionally performed periodic integrity assessments in a variety of forms with varying degrees of success.

In the mid 1960s, pipeline operators began to use a form of instrumented inspection technology that has evolved into what is known today as in-line inspection (ILI). ILI is but one tool used in pipeline integrity assessment. The technology has now become so reliable that it holds a prominent place in many operators' integrity programs because when properly applied, ILI provides many economies and efficiencies in integrity assessment at a relatively small risk.

This standard practice outlines a process of related activities that a pipeline operator can use to plan, organize, and execute an ILI project. Guidelines pertaining to ILI data management and data analysis are included. A key companion guide to this standard is NACE International Publication 35100.[1]

This standard is intended for use by individuals and teams planning, implementing, and managing ILI projects and programs. These individuals include engineers, operations and maintenance personnel, technicians, specialists, construction personnel, and inspectors. Users of this standard must be familiar with all applicable pipeline safety regulations for the jurisdiction in which the pipeline operates. This includes all regulations requiring specific pipeline integrity assessment practices and programs.

This NACE standard was originally prepared by Task Group (TG) 212, "In-Line Nondestructive Inspection of Pipelines," in 2002 and was revised by TG 212 in 2010. This standard is issued by NACE International under the auspices of Specific Technology Group (STG) 35, "Pipelines, Tanks, and Well Casings."

In NACE standards, the terms *shall*, *must*, *should*, and *may* are used in accordance with the definitions of these terms in the *NACE Publications Style Manual*. The terms *shall* and *must* are used to state a requirement, and are considered mandatory. The term *should* is used to state something good and is recommended, but is not considered mandatory. The term *may* is used to state something considered optional.

NACE International
Standard Practice

In-Line Inspection of Pipelines

Contents

Section 1: General

1.1 This standard is applicable to carbon steel pipeline systems used to transport natural gas, hazardous liquids including those containing anhydrous ammonia, carbon dioxide, water including brine, liquefied petroleum gases (LPG), and other services that are not detrimental to the function and stability of ILI tools.

1.2 This standard is primarily applicable to free-swimming ILI tools, but is not applicable for tethered or remotely controlled inspection devices.

1.3 This standard provides recommendations to the pipeline operator based on successful, industry-proven practices in ILI.

1.4 This standard is specific to the inspection of line pipe installed along a right-of-way, but the general process and approach may be applied to other pipeline facilities such as hydrocarbon distribution and gathering systems, water injection systems, station piping, and isolated crossings of railroads, highways, or waterways.

1.5 ANSI(1)/ASNT(2) ILI-PQ[2] establishes minimum requirements for the qualification and certification of ILI personnel whose jobs require specific knowledge of the technical principles of ILI technologies, operations, regulatory requirements, and industry standards as applicable to pipeline systems.

1.6 API(3) 1163[3] provides requirements for qualification of ILI systems used in onshore and offshore gas and hazardous liquid pipelines. This includes, but is not limited to, tethered or free-flowing systems for detecting metal loss, cracks, mechanical damage, pipeline geometries, and pipeline location or mapping. This standard is an umbrella document covering all aspects of ILI systems, including procedures, personnel, equipment, and associated software. It is performance-based, but it does not define how to meet qualification requirements.

Section 2: Definitions

Aboveground Marker (AGM): A portable or permanently installed device placed on the surface above a pipeline that both detects and records the passage of an in-line inspection tool or transmits a signal that is detected and recorded by the tool.

Anomaly: An unexamined deviation from the norm in pipe material, coatings, or welds. See also *Imperfection* and *Defect.*

Appurtenance: A component that is attached to the pipeline: e.g., valve, tee, casing, instrument connection, etc.

Batch, Batching: Separated volume of liquid within a liquids pipeline or of liquid within a gas pipeline. Sealing (batching) pigs are typically used for separation.

Bellhole: An excavation to permit a survey, inspection, maintenance, repair, or replacement of pipe sections.

Bend: A physical configuration that changes pipeline direction. A bend can be classified according to the centerline radius of the bend as a ratio to the nominal pipe diameter. A 1½ D bend would have a centerline radius of 1½ times the nominal pipe diameter. A 3 D bend would have a centerline radius of three times the nominal pipe diameter.

(1) American National Standards Institute (ANSI), 11 W. 42nd St., New York, NY 10036.
(2) American Society for Nondestructive Testing (ASNT), P.O. Box 28518, 1711 Arlingate Lane, Columbus, OH 43228-0518.
(3) American Petroleum Institute, (API) 1220 L Street NW, Washington, DC 20005-4070.

Buckle: A condition in which the pipeline has undergone sufficient plastic deformation to cause permanent wrinkling or deformation of the pipe wall or the pipe's cross-section.

Calibration Dig: An exploratory excavation to compare findings of an in-line inspection system to actual conditions with the purpose of improving data analysis. See also *Verification Dig*.

Caliper Pig: A configuration pig designed to record conditions such as buckles, dents, wrinkles, ovality, bend radius and angle, and occasionally, indications of significant internal corrosion by sensing the shape of the internal surface of the pipe (also referred to as geometry pig).

Chainage: Cumulative pipeline distance usually measured on the surface from a specific point of origin.

Check Valve: Valve that prevents reverse flow. Can cause damage to ILI tools if not fully opened.

Cleaning Pig: A utility pig that uses cups, discs, scrapers, or brushes to remove dirt, rust, mill scale, corrosion products, and other debris from the pipeline. Cleaning pigs are utilized to increase the operating efficiency of a pipeline or to facilitate inspection of the pipeline.

Combination Tool: An instrumtented in-line inspection tool designed to perform both geometry (deformation) inspections as well as metal loss inspections with a single tool chassis.

Component: Any physical part of the pipeline, other than line pipe, including but not limited to valves, welds, tees, flanges, fittings, taps, branch connections, outlets, supports, and anchors.

Corrosion: The deterioration of a material, usually a metal, that results from a chemical or electrochemical reaction with its environment.

Crack, Cracking: A fracture type of discontinuity characterized by a sharp tip and high ratio of length to width to opening displacement.

Data Analysis: The evalution process through which indications are classified and characterized.

Defect: A physically examined anomaly with dimensions or characteristics that exceed acceptable limits. See also *Imperfection*.

Deformation: A change in shape, such as a bend, buckle, dent, ovality, ripple, wrinkle, or any other change that affects the roundness of the pipe's cross-section or straightness of the pipe.

Deformation Tool: An instrumented in-line inspection tool designed to record geometric conditions such as buckles, dents, wrinkles, ovality, and bend radius and angle. See *Caliper Pig* and *Geometry Tool*.

Dent: A local change in piping surface contour caused by an external force such as mechanical impact or rock impact.

Detect: To sense or obtain a measurable indication from a feature.

Electric Resistance Weld (ERW): A weld seam formed by resistance heating of the two edges of a pipe and then forcing them together.

Evaluation: A review, following the characterization and examination of an anomaly to determine whether the anomaly meets specified acceptance or rejection criteria.

Examination: A direct physical inspection of a pipeline or anomaly by a person, which may include the use of nondestructive examination (NDE) techniques.

Fatigue: The process of progressive localized permanent structural change occurring in a material subjected to fluctuating stresses less than the ultimate tensile strength of the material that may culminate in cracks or complete fracture after a sufficient number of fluctuations.

Feature: Any physical object detected by an in-line inspection system. Features may be anomalies, components, nearby metallic objects, welds, appurtenances, or some other item.

Gauging Pig: A utility pig mounted with a flexible metal plate or plates to gauge the internal diameter of the pipeline. Pipe bore restrictions less than the plate diameter or short radius bends will permanently deflect the plate material.

Geographical Information System (GIS): A computer system capable of assembling, storing, manipulating, and displaying geographically-referenced information.

Geometry Tool: An instrumented in-line inspection tool that records data about the geometric condition of the pipeline or pipe wall. Caliper tools and deformation tools are examples of geometry tools.

Girth Weld: A complete circumferential butt weld joining pipe or components.

Global Positioning System (GPS): The navigational system utilizing satellite technology to provide a user an exact position on the earth's surface.

Gouge: Elongated grooves or cavities usually caused by mechanical removal of metal.

Hydrostatic Test: A pressure test of a pipeline in which the pipeline is completely filled with water and pressurized to ensure it meets the design conditions and is free of leaks.

Imperfection: An anomaly with characteristics that do not exceed acceptable limits. See also *Defect*.

Indication: A signal from an in-line inspection system. An indication may be further classified or characterized as an anomaly, imperfection, or component.

Induction Coil: A type of sensor that measures the time rate of change in magnetic flux density. Induction coils do not require power to operate, but have a minimum inspection speed requirement.

In-Line Inspection (ILI): An inspection of a pipeline from the interior of the pipe using an in-line inspection tool. Also called *intelligent* or *smart pigging*.

In-Line Inspection Tool (ILI Tool): The device or vehicle that uses a nondestructive testing (NDT) technique to inspect the pipeline from the inside. Also known as *intelligent* or *smart pig*.

Interaction Rules: A spacing criterion among anomalies that establishes when closely spaced anomalies should be treated as a single, larger anomaly.

Kicker Line: Piping and valving that connects the pressurizing pipeline to the launcher or receiver.

Lamination: An internal metal separation creating layers generally parallel to the surface.

Launcher: A device used to insert an in-line inspection tool into a pressurized pipeline. It may be referred to as pig trap or scraper trap.

Liquefied Petroleum Gas (LPG): Petroleum gases (butane, propane, etc.) liquefied by refrigeration or pressure to facilitate storage or transport.

Magnetic Flux Leakage (MFL): A type of in-line inspection technology in which a magnetic field is induced in the pipe wall between two poles of a magnet. Anomalies affect the distribution of the magnetic flux in the wall. The magnetic flux leakage pattern is used to detect and characterize anomalies.

Magnetic Particle Inspection (MPI): A nondestructive examination (NDE) technique for locating surface flaws in steel using fine magnetic particles and magnetic fields.

Measurement Threshold: A dimension or dimensions above which an anomaly measurement can be made.

Metal Loss: Any pipe anomaly in which metal has been removed. Metal loss is usually the result of corrosion, but gouging, manufacturing defects, or mechanical damaging can also cause metal loss.

Nondestructive Examination (NDE): The evaluation of results from nondestructive testing methods or nondestructive testing techniques to detect, locate, measure, and evaluate anomalies.

Nondestructive Testing (NDT): A process that involves the inspection, testing, or evaluation of materials, components, and assemblies for materials' discontinuities, properties, and machine problems without further impairing or destroying the part's serviceability.

Nondestructive Testing Method (NDT Method): A particular method of NDT, such as radiography, ultrasonic, magnetic testing, liquid penetrant, visual, leak testing, eddy current, and acoustic emission.

Nondestructive Testing Technique (NDT Technique): A specific way of utilizing a particular NDT method that distinguishes it from other ways of applying the same NDT method. For example, magnetic testing is a NDT method, while magnetic flux leakage and magnetic particle inspection are NDT techniques. Similarly, ultrasonic is a NDT method, while contact shear-wave ultrasonic, and contact compression-wave ultrasonic are NDT techniques.

Operator: A person or organization that owns or operates pipeline facilities as an owner or as an agent for an owner.

Ovality: Out of roundness, i.e., egg shaped or broadly elliptical.

Pig: A generic term signifying any independent, self-contained or tethered device, tool, or vehicle that moves through the interior of the pipeline for inspecting, dimensioning, or cleaning. A pig may or may not be an in-line inspection tool.

Pig Signal: Usually a mechanical sensor on the pipe activated by the passage of a pig.

Pipeline: A continuous part of a pipe system used to transport a hazardous liquid or gas. Includes pipe, valves, and other appurtenances attached to the pipe.

Pipeline Coordinates: Location coordinates of the course that a pipeline follows as given in a standard geographic coordinate system.

Pipeline System: All portions of the physical facilities through which gas, oil, or product moves during transportation. This includes pipe, valves, and other appurtenances attached to the pipe, compressor units, pumping units, metering stations, regulator stations, delivery stations, tanks, holders, and other fabricated assemblies.

Pressure: Level of force per unit area exerted on the inside of a pipe or vessel.

Probability of Detection (POD): The probability of a feature being detected by an in-line inspection tool.

Pup Joint: A short piece of pipe, typically 3 m (10 ft) or less in length.

Receiver: A pipeline facility used for removing a pig from a pressurized pipeline. It may be referred to as trap*,* pig trap, or scraper trap.

RSTRENG:[4] A computer program designed to calculate the residual strength or failure pressure of corroded pipe.

RSTRENG 2: An enhanced version of RSTRENG as specified in the PRCI[(4)] project report PR-218-9205.[5]

Rupture: The instantaneous tearing or fracturing of pipe material causing large-scale product or water loss.

Seam Weld: The longitudinal or spiral weld in pipe, which is made in the pipe mill.

Sensors: Devices that receive a response to a stimulus, (e.g., an ultrasonic sensor detects ultrasound).

Shear Wave: Pertaining to pipe inspection, shear waves are generated in the pipe wall by transmitting ultrasonic pulses through a liquid medium. The same transducer is used for both sending and receiving ultrasound (so-called pulse echo technique). The angle of incidence is adjusted in such a way that a propagation angle of approximately 45° is obtained in the pipe wall. By using 45° shear waves, it is possible to detect radial-oriented, surface-breaking cracks at both sides of the pipe wall with high sensitivity, because the ultrasound pulse undergoes a strong angular reflection at the crack edge (so-called corner reflection).

Sizing Accuracy: The accuracy with which an anomaly dimension or characteristic is reported. Typically, accuracy is expressed by tolerance and a certainty. As an example, depth sizing accuracy for metal loss is commonly expressed as +/-10% of the wall thickness (the tolerance), 80% of the time (the certainty).

Slackline: The flow of product fails to completely fill the pipeline.

Smart Pig: See *In-Line Inspection Tool (ILI Tool).*

Strain: Increase in length of a material expressed on a unit length basis (e.g., millimeters per millimeter or inches per inch).

Survey: Measurements, inspections, or observations intended to discover and identify events or conditions that indicate a departure from normal operation of the pipeline.

Transducer: A device for converting energy from one form to another. For example, in ultrasonic testing, conversion of electrical pulses to acoustic waves, and vice versa.

Transmission Line: A pipeline, other than a gathering or distribution line, that transports gas from a gathering or storage facility to a distribution center or storage facility; operates at a hoop stress of 20% or more of the specified minimum yield strength of the pipe; or transports gas within a storage field.

Trap: A pipeline facility for launching or receiving tools and pigs. See *Launcher* and *Receiver*.

Ultrasonic Testing (UT): A type of inspection technology that uses ultrasound for inspecting pipe.

Verification Dig: An excavation made to verify the reported results of an in-line inspection. See *Calibration Dig*.

Wrinkle: A smooth and localized bulge visible on the outside wall of the pipe. The term wrinkle is sometimes restricted to bulges that are greater in height than one wall thickness. See *Buckle*.

Yield Strength: The stress at which a material exhibits a specified deviation from the proportionality of stress to strain. The deviation is expressed in terms of strain by either the offset method (usually at a strain of 0.2 percent) or the total-extension-under-load method (usually at a strain of 0.5 percent).

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(4) Pipeline Research Council International (PRCI), 1401 Wilson Blvd., Suite 1101, Arlington, VA 22209.

Section 3: Tool Selection[5]

3.1 Appropriateness of the Inspection Tool

3.1.1 Representatives from the pipeline operator and the ILI service vendor should analyze the goal and objectives of the inspection and match relevant facts known about the pipeline and expected anomalies with the capabilities and performance of an ILI tool. Table 1 provides an overview of types of anomalies and available tool categories, indicating their appropriateness for the objective of the inspection. A discussion of these items and their limitations is found in Paragraphs 3.1.1.1 through 3.1.1.6.

3.1.1.1 Accuracy and detection capabilities of the ILI method (i.e., probability of detection, classification, and sizing should match the expectations) should be evaluated (see Table 1).

3.1.1.2 Detection sensitivity: The minimum detectable anomaly size specified for the ILI tool must be smaller than the size of defect anticipated to be detected.

3.1.1.3 Classification capability: The ILI tool should be able to differentiate the targeted defect types from other types of anomalies.

3.1.1.4 The sizing accuracy should be sufficient to enable evaluation, or, when applicable, remaining strength determination.

3.1.1.5 The location accuracy should enable locating anomalies.

3.1.1.6 Requirements for defect assessment: Results of ILI must be adequate for the expected defect assessment algorithm.

3.2 Operational Issues

3.2.1 Pipeline operators shall provide a completed questionnaire that lists all relevant parameters and characteristics of the pipeline section to be inspected to the ILI vendor (see sample in Appendix A [Nonmandatory]). Operational issues that should be considered are discussed in Paragraphs 3.2.1.1, 3.2.1.2, and 3.2.1.3.

3.2.1.1 Mechanical characteristics of the pipe

3.2.1.1.1 Pipe characteristics such as steel grade, type of welds, length, internal diameter (ID), elevation profile, etc., are considered. Any restrictions, bends, known ovalities, valves, and unbarred tees through which the ILI tool may need to negotiate should be identified.

3.2.1.1.2 Launchers and receivers must be reviewed for suitability because ILI tools vary in complexity, geometry, and maneuverability.

3.2.1.1.3 Pipe cleanliness is reviewed as part of planning for an ILI run because this can influence tool wear, integrity of data collected, and other issues that may affect the success of a run.

3.2.1.1.4 Internal coating can interfere with inspection. Conversely, certain tools can damage internal coatings. Thus, this factor must be considered prior to ILI.

3.2.1.2 Characteristics of the fluid pumped

(5) For additional information, refer to API 1163.[3]

3.2.1.2.1 The type of fluid (gas or liquid) may affect the technology chosen (e.g., ultrasonic testing [UT] is not practical in gas pipelines without the use of a liquid couplant and some liquids, e.g., ethane, have unsuitable ultrasonic properties).

3.2.1.2.2 Aggressiveness of the fluid (e.g., hydrogen sulfide [H_2S]) can limit the tools' abilities to operate effectively.

3.2.1.2.3 Acceptable ranges of flow rate, pressure, and temperature must meet the vendor's specifications.

3.2.1.2.4 The speed of the product influences the speed of the ILI tool inspection. If speeds are outside the normal ranges, performance can be compromised.

3.2.1.2.5 Reduction of product flow, speed reduction capability of the ILI tool, or both should be considered for inspection of higher-velocity lines. Conversely, the availability of supplementary product or other liquid must be considered when speeds are too low.

3.2.1.2.6 Extreme (both hot and cold) temperature can also affect tool operation and must be considered.

3.2.1.2.7 The total time necessary for the inspection is dictated by inspection speed and may be limited by the total capacity of batteries and data storage capability of the tool.

3.2.1.3 Reliability of the ILI tool

The reliability of the ILI method should be evaluated based on analysis of the following factors:

3.2.1.3.1 Confidence level of the ILI tool, e.g., probability of detecting, classifying, and sizing the anomalies.

3.2.1.3.2 History of the ILI tool performance verified through excavation.

3.2.1.3.3 Operational success rate and failed surveys.

3.2.1.3.4 Ability of the tool to inspect the full length and full circumference of the pipe section.

3.2.1.3.5 Ability to indicate the presence of multiple-cause anomalies (anomalies other than those for which it is primarily designed (e.g., the detection of dents by a metal-loss tool).

Section 4: Pipeline ILI Compatibility Assessment

4.1 If analysis indicates that the ILI tool is not suited for the pipe section in question, the tool selection process should be revisited to address the specific operational limitation(s) encountered.

4.2 A typical prerun questionnaire used to compile information, to be given to the ILI vendor and which facilitates operator record keeping, is included in Appendix A (Nonmandatory). Table 1 is a more detailed discussion of items.

Table 1: Types of ILI Tools and Inspection Purposes[6]

Anomaly	Imperfection/ Defect/Feature	Metal Loss Tools			Crack Detection Tools		Deformation Tools
		Magnetic Flux Leakage (MFL)		Ultrasonic Compression Wave(M)	Ultrasonic Shear Wave(M)	Transverse MFL	
		Standard Resolution (SR)	High Resolution (HR)				
Metal Loss							
	External Corrosion	Detection,(A) Sizing(B) No ID/outer diameter (OD) discrimination	Detection,(A) Sizing(B)	Detection,(A) Sizing(B)	Detection,(A) Sizing(B)	Detection,(A) Sizing(B)	No Detection
	Internal Corrosion						
	Gouging						
Crack-Like Anomalies							
	Narrow Axial External Corrosion	Detection(A)	Detection(A)	Detection,(A) Sizing(B)	Detection,(A) Sizing(B)	Detection,(A) Sizing(B)	No Detection
	Stress Corrosion Cracking	No Detection	No Detection	No Detection	Detection,(A) Sizing(B)	Limited Detection,(A)(C) Sizing(B)	No Detection
	Fatigue Cracks	No Detection	No Detection	No Detection	Detection,(A) Sizing(B)	Limited Detection,(A)(C) Sizing(B)	No Detection
	Long Seam Cracks, etc. (toe cracks, hook cracks, incomplete fusion, preferential seam corrosion)	No Detection	No Detection	No Detection	Detection,(A) Sizing(B)	Detection,(A)(C) Sizing(B)	No Detection
	Circumferential Cracks	No Detection	Detection,(C) Sizing(B)	No Detection	Detection,(A) Sizing(B)(D)	No Detection	No Detection
	Hydrogen-Induced Cracking (HIC)	No Detection	No Detection	Detection (A)	Limited Detection	No Detection	No Detection
Deformation							
	Sharp Dents	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) Sizing

[6] For additional information, refer to API 1163.[3]

Table 1: Types of ILI Tools and Inspection Purposes (Continued)

Anomaly	Imperfection/ Defect/Feature	Metal Loss Tools			Crack Detection Tools		Deformation Tools
	Flat Dents	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) Sizing
	Buckles	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) Sizing
	Wrinkles, Ripples	Detection(E)(G)	Detection(E)(L)	Detection(E)(G)	Detection(E)(G)	Detection(E)(G)	Detection,(F) Sizing
	Ovalities	No Detection	No Detection	No Detection	No Detection	No Detection	Detection, Sizing(B)
Misc. Components							
	In-Line Valves and Fittings	Detection	Detection	Detection	Detection	Detection	Detection
	Casings (Concentric)	Detection	Detection	No Detection	No Detection	Detection	No Detection
	Casings (Eccentric)	Detection	Detection	No Detection	No Detection	Detection	No Detection
	Bends	Limited Detection	Limited Detection	Limited Detection	Limited Detection	Limited Detection	Detection,(H) Sizing(H)
	Branch Appurtenances/Hot Taps	Detection	Detection	Detection	Detection	Detection	No Detection
	Close Metal Objects	Detection	Detection	No Detection	No Detection	Detection	No Detection
	Thermite Welds	No Detection	No Detection	No Detection	No Detection	No Detection	No Detection
	Pipeline Coordinates	No Detection	Detection(K)	Detection(K)	Detection(K)	Detection(K)	Detection(K)
Previous Repairs							
	Type A Repair Sleeve(6)	Detection	Detection	No Detection	No Detection	Detection	No Detection
	Composite Sleeve	Detection(I)	Detection(I)	No Detection	No Detection	Detection(I)	No Detection
	Type B Repair Sleeve(6)	Detection	Detection	Detection	Detection	Detection	No Detection
	Patches/Half Soles	Detection	Detection	Detection	Detection	Detection	No Detection
	Puddle Welds	Limited Detection	Limited Detection	No Detection	No Detection	Limited Detection	No Detection
Misc. Damage							
	Laminations	Limited Detection	Limited Detection	Detection, Sizing(B)	Limited Detection	Limited Detection	No Detection

Table 1: Types of ILI Tools and Inspection Purposes (continued)

Anomaly	Imperfection/ Defect/Feature	Metal Loss Tools			Crack Detection Tools		Deformation Tools
	Inclusions (Lack of Fusion)	Limited Detection	Limited Detection	Detection, Sizing(B)	Limited Detection	Limited Detection	No Detection
	Cold Work	No Detection	No Detection	No Detection	No Detection	No Detection	No Detection
	Hard Spots	No Detection	Detection(J)	No Detection	No Detection	No Detection	No Detection
	Grind Marks	Limited Detection(A)	Limited Detection(A)	Detection(A)(B)	Detection(A)(B)	Limited Detection(A)(B)	No Detection
	Strain	No Detection	No Detection	No Detection	No Detection	No Detection	Detection(J)
	Girth Weld Anomaly (voids, etc.)	Limited Detection	Detection	Detection	Detection(D)	No Detection	No Detection
	Scabs/Slivers/Blisters	Limited Detection(A)	Limited Detection	Detection(A)(B)	Detection(A)(B)	Limited Detection(A)	Limited Detection

(A) Limited by the detectable depth, length, and width of the indication.
(B) Defined by the sizing accuracy of the tool.
(C) Reduced probability of detection (POD) for tight cracks.
(D) Transducers to be rotated 90°.
(E) Reduced probability of detection (POD) depending upon size and shape.
(F) Also circumferential position, if tool is equipped.
(G) Sizing not reliable.
(H) If tool is equipped for bend measurement.
(I) Composite sleeve without markers is not detectable.
(J) If tool is equipped, dependent on parameters.
(K) If tool is equipped with mapping capabilities.
(L) Sizing is tool dependent.
(M) ILI technologies that can be used only in liquid environments, i.e., liquids pipelines or in gas pipelines with a liquid couplant.

4.3 Tool Environment

4.3.1 The product and the resulting environment that the tool is exposed to during inspection are important factors in determining which tool should be used. Because tools can be run while the line is in or out of service, consideration should be given to the following:

4.3.1.1 Tethered tools: Some ILI tools are available as wireline (tethered) tools, typically used for inspecting shorter pipeline sections. These tools are connected to a control unit via an umbilical and pumped through a line or pulled through the line by tethered cable trucks from either end. Tethered tools are used offline and usually operate at speeds much lower than the conventional online ILI tools (approximately 0.7 m/s [1.6 mph or 140 ft/min]). These tools represent a very different operation and should be discussed well in advance with the vendor.

4.3.1.2 Temperature and pressure: Most tools have specific temperature and pressure ranges for operations that are addressed in advance.

4.3.1.3 Fluid composition considerations: If the product contains chemicals such as H_2S, modification to the standard tool design should be considered to deal with the corrosive properties. Other chemicals may also require adaptation of the tool and should be addressed in advance.

4.4 Pipeline Features

4.4.1 Launching and receiving facilities must be adequate for the type of tool. Launchers and receivers may be installed with new construction or during modification of existing facilities and may be permanent or temporary installations. Consideration should be given to the following:

4.4.1.1 Work space availability: The work area is reviewed to ensure sufficient space for maneuvering tools and associated equipment (e.g., cranes and lifting equipment) during loading and unloading. Space requirements for any other ancilliary equipment, such as additional pumping units, flares, tanks, etc., should be identified.

4.4.1.2 Adequate barrel length: Sufficient room must be maintained between the door and the isolation valve such that the tool can be accommodated in that length. For launchers, the overbore section length should be greater than or equal to the tool length; nominal pipe length can be kept to a minimum. In cases in which the overbore section is shorter than the tool length, significant consideration must be given to alternative loading methods, such as pulling in a tool. For receivers, the nominal pipe section length must be greater than or equal to the tool length to ensure the entire tool will clear the isolation valve. The length of the overbore section must be sufficient to accommodate the tool stopping distance upon receipt. Actual length requirements may vary, depending on the tool used.

4.4.2 Many mechanical pipeline features present a hazard for ILI tools by damaging or lodging the tools. While the list below cannot account for every type of pipeline feature that poses a threat, it provides a description of the most commonly found problematic installations.

4.4.2.1 Internal diameter changes (e.g., buckles, dents, bore restrictions, reduced port valves, and check valves) can be present in the line for many different reasons and must be addressed before the internal inspection. Sometimes the tool is able to negotiate these types of restrictions, but each situation is considered on a case-by-case basis.

4.4.2.2 Probes intruding into the pipeline can restrict inspection tools. Neglecting to remove them can damage the facilities and the tools.

4.4.2.3 A review of areas with known geotechnical movement should be considered.

4.4.2.4 Wall thickness is an important parameter for which some tools need to be calibrated, and thus, must be considered by the vendor. ILI vendors should be alerted if line wall thickness is less than 6.4 mm (0.25 in) or greater than 13 mm (0.50 in). Smaller-diameter lines with heavy-wall pipe may severely limit the number and types of tools that can be successfully used.

4.4.2.4.1 Heavy-wall pipe can lead to speed excursions when MFL technology is used in gas lines (e.g., travel through a heavy-wall section can require more pressure differential relative to light-wall sections). Thus, when the tool transitions to a lighter-wall section, the larger pressure differential can result in excessive tool velocities (overspeed). These overspeeds can cause data degradation.

4.4.2.4.2 Wall thickness changes such as heavy-wall road and rail crossings can pose a problem for ILI tools, depending on the nature of the transition between the heavy- and light-wall sections. Specifically, step transitions present a cutting edge for ILI tools and can result in damage. Whenever possible, step transitions should be avoided, and tapered transitions should be used.

4.4.2.5 Short radius bends: The majority of inspection tools are capable of negotiating a 3 D[(7)] bend radius or greater. Any bends that are tighter should be addressed on a case-by-case basis, depending on the tool to be used and the wall thickness of the bend. An increasing number of tools are capable of passing a 1.5 D bend radius.

4.4.2.6 Back-to-back bends: Bends installed in a back-to-back configuration, e.g., without an intervening section of straight pipe between the bends, can present an impediment or sticking hazard for ILI tools.

4.4.2.7 Valves: Reduced port valves can result in tool damage, and in extreme cases, they can result in the tool becoming lodged in the line. Close attention must be given to the ability of tools to negotiate through check valves. Before ILI runs, check valve clappers should be locked in the open position whenever possible.

4.4.2.8 Field bends and river crossings must be reviewed thoroughly because older construction lines may contain tight radius bends, mitres, and step transitions. These locations are potentially more susceptible to geotechnical movement and may have pipeline deformations that may not be detected until ILI is attempted.

4.4.2.9 Internal coating can interfere with inspection. Conversely, certain tools can damage internal coatings. Thus, this factor must be considered prior to ILI.

4.4.2.10 Sales taps and feeds must be reviewed. In most cases, the sales taps and feeds must be isolated as the ILI tool passes. Factors affecting this decision include size and orientation of tap, amount of flow, single/dual connection (single-connection lines sometimes require the installation of additional feeds to sales taps and receipt points), amount of line debris, and type of tool.

4.4.2.11 Unbarred and back-to-back tees: Branch connections (30% of the pipe diameter or greater) should have scraper bars; however, larger unbarred branch connections may be tolerable, depending on tool geometry and orientation. Hot taps, also identified as sharp edges, can present a hazard to the tools. The dimensions between tees should be reviewed keeping the specific ILI tool in mind, because back-to-back tees can create a situation in which the ILI tool stalls. This results when the geometry of the tees, combined with the mechanical design of the tool, is such that the propelling product can follow a path around the tool without providing any driving force to the tool.

4.4.2.12 Installations such as mainline drips without orifice plates (gas lines), pressure pots (crude lines), vortex breakers, chill rings, y-branch connections, and mitre bends can present problems for ILI tools.

[(7)] D = pipeline diameter.

4.4.2.13 Hydrate precautions: When a line has the potential to form hydrates, provisions may be made for their collection, removal, and safe disposal.

4.4.2.14 Pyrophoric materials: Pyrophoric materials, particularly iron sulfides, can be produced from pipelines by the efficient cleaning action of ILI tools. If pyrophoric materials are present, additional vigilance is required to ensure that fires are not initiated. Provisions should be made for the collection, wetting, removal, and safe disposal of pyrophoric materials.

4.4.2.15 Facility piping and dimensions: Piping configurations including, but not limited to, the following should be reviewed to facilitate operations required for ILI:

4.4.2.15.1 Kicker line sizing may vary by diameter and service. However, in the case of gas transmission lines, the amount of gas available should be sufficient to propel a tool if the speed control fails in the open position. For liquid service, kickers should be sized to accommodate acceptable full-rate pressure drop and within company-specified erosion limits.

4.4.2.15.2 Appropriate location and size of fittings: Blowdowns (and silencers, if required), equalization, draining, and purging connections should be ensured. Connections should be such that the piping between the launcher isolation valve and the reducer can be vented to ensure tools are not propelled backwards during the period between loading of the tool and pressurizing the launcher prior to starting ILI operations. Any requirements for flaring should be considered at this stage.

4.4.2.15.3 Eccentric versus concentric reducers: Eccentric reducers allow for easier loading and unloading of the tool from the barrel. Vertical launchers should use concentric reducers.

4.4.2.15.4 Pig passage indicators should be installed on both the upstream and downstream sides of the isolation valve. If these are not available, an alternate method such as a compass for magnetic tools should be used to ensure tool passage.

4.4.2.15.5 Mechanical pipe supports and nonengineered pipe spans are investigated and evaluated to ensure that the weight of the in-line inspection tool can be supported during a tool passage. Considerations should be given to modify the existing support system or use temporary supports to maintain the integrity of the pipeline for an ILI.

4.5 Product, Product Flow, and Speed Requirements

4.5.1 The type of fluid is considered for several reasons. Some services can damage a tool. Sour service is an example in which failure to inform the ILI contractor of the substance present in the line during the survey can result in costly repair to the tool. Any chemical other than oil, sweet gas, odorant, or water must be reported to the vendor for tool suitability verification.

4.5.2 Insufficient product flow: Liquid lines usually operate at low enough speeds that ILI does not result in a throughput restriction. This can result in the converse problem in which normal product flow must be supplemented. When low-flow liquid lines are inspected using an MFL tool equipped with induction coils, the normal pipeline flow may need to be supplemented with additional product to achieve the minimum required inspection velocity.

4.5.3 Restricting normal product flow: The scheduling of any inspection should be coordinated to ensure that capacity restrictions, batching (e.g., liquid lines with multiphase liquids or gas pipelines), etc. are coordinated with customers and other concerned parties. A liquid products pipeline operator may not be willing to accept the risk of product contamination by running an ILI tool in certain critical batches, e.g., aviation fuel. Line conditions should be set up such that the tool speed is maintained in the optimal range for data collection.

4.5.4 Velocity-controlled tools: Gas lines often operate at speeds well in excess of the maximum allowable in-line inspection speeds. This is a primary consideration for magnetic flux tools in gas lines.

4.5.4.1 Variable bypass (speed control), available on certain tools, should be used to address this issue. The use of this feature requires a more complicated procedure (e.g., lengthening of the tool and limiting the bend capability of tools). The ramifications of using variable bypass should be considered carefully.

4.5.4.2 In some cases, fixed bypass is put into a tool to reduce the inspection speed and keep debris loose and circulating. The addition of fixed bypass should be done with caution. In certain situations, the addition of too much fixed bypass could result in insufficient drive to move the tool along the line. All these factors must be assessed and weighed against the need to reduce product throughput and the possible need to flare.

4.6 Surveys

4.6.1 MFL surveys can be conducted in either gas or liquid lines assuming that product velocity in the line is within the tool specifications. Product composition should be considered.

4.6.2 UT surveys: Liquid lines are best suited for UT tools because the product itself provides the coupling between the tool sensors and the pipe wall. Suitability of liquids for UT inspections must be verified prior to an inspection run.

4.6.2.1 In gas lines, UT tools must be run in a liquid medium to perform the survey because the product actually acts as a barrier to the UT signals. This may be accomplished either by total displacement of the line with a liquid, or encapsulating the UT tool in liquid within a liquid slug or batch. If liquid volumes can be handled reasonably, the line should be completely filled with liquid. The UT is then propelled with the same liquid.

4.6.2.2 If only a limited supply of liquid is available, UT tools should be run in a slug of liquid. This method requires in-depth planning and should include the following factors:

(a) Alternate choices for UT surveys;

(b) Elimination of gas entrapment;

(c) Gas contamination due to bypass from the driving gas;

(d) The amount of liquid that will be lost to valves, takeoffs, lateral lines, etc., along the line; and

(e) Adequate velocity control of the slug.

4.6.3 Pipeline geometry (caliper, gauging pig, or deformation tool) surveys

4.6.3.1 A caliper or bend tool should be run in the pipeline prior to an ILI tool. The purpose of this inspection is (1) to provide detailed data to prove the pipeline bore, (2) to evaluate the bend radii to ensure passage of the ILI tool, and (3) to obtain as much information as possible prior to sending in the more expensive and less flexible ILI tools. Lines that are good candidates for caliper surveys are those not previously inspected lines with repairs between surveys, lines subject to high risk of third-party damage, and lines subject to a high geotechnical risk.

4.6.3.2 A response plan to the caliper/bend data should be developed to handle potential restrictions that could be discovered.

4.6.3.3 If pipeline bend and bore information is current and reliable and an integrity management threat assessment does not require deformation assessment, a gauging plate pig or dummy tool may be used instead. The dummy tool should be designed to mimic the characteristics of the live tool. The purposes of the dummy run are to assess the potential for live tool damage by observing the condition of the dummy tool after the run and to provide an opportunity for field personnel to practice safe and proper handling and operation techniques prior to running the live tool. A successful dummy run should improve the likelihood that the live run will be successful.

4.6.3.4 Benchmarking or tracking should be used during the caliper/bend inspection. Some caliper/bend tools with inertial mapping capabilities that allow the information to be correlated with GPS are available.

4.7 Pipeline Cleanliness

4.7.1 When warranted, a cleaning program for the pipeline should be designed and implemented. The specific pigs for cleaning the pipeline should be identified.

4.7.2 Historical data should be evaluated for anticipated contaminant deposits such as scale, dust, sludge, paraffin, etc.

4.7.3 The results of regular maintenance pigging activities in the pipeline aid in the cleaning program design. Lines with regular maintenance pigging programs may require less cleaning before ILI tool inspections are conducted.

4.7.4 ILI service providers should provide guidelines for cleaning requirements.

4.8 Information Gathering

4.8.1 The following procedure can be used to assess pipeline compatibility:

4.8.1.1 As-built drawings should be reviewed to identify physical restrictions. If this information is inadequate, gauging or caliper pigs should be run.

4.8.1.2 It is important to provide as much information as possible to the vendor to avoid unforeseen problems, delays in the tool run, or both. To facilitate this, a pipeline questionnaire, usually provided by the vendor, shall be completed (see sample in Appendix A [Nonmandatory]).

4.8.1.3 Cleaning specifications are discussed with the vendor. If there is no cleaning history available for the pipeline, a suitability assessment is made after each progressive cleaning run is completed.

4.8.1.4 In older installations, anecdotal information at the field level should be obtained as an additional source of information regarding the compatibility of a pipeline.

4.8.2 Additional information that can be used to ensure the appropriate tool setup (both mechanically and from a software perspective) is used for inspecting a specific line includes the following lists:

(a) Internal review of documented sources:

- Drawings, survey books, and sample prerun;
- Weld tallies and joint length records;
- Purchasing records;
- Caliper survey run results;
- Routine pigging run data;

- Gauging plate runs;
- Bellhole inspection surveys or prior repair records;
- Third-party construction activity records; and
- Previous inspections.

(b) Site visits:

- Gathering of anecdotal information from operational staff, and
- Facility visit for vendor and operator.

Section 5: Logistical Guidelines

5.1 Primary Contracting Considerations

5.1.1 Contracting for ILI work is a significant effort. The roles of the vendor and owner/operator should be defined for all aspects of the work from implementation to delivery of the final report. The various stages of reporting and payment schedules associated with milestones should be established. Factors such as the implications of reruns, scheduling changes, and service interruptions should be addressed.

5.1.2 Definition of scope of work[(8)]

5.1.2.1 The scope of work is defined well in advance of any pricing discussions, contracting, or both. The scope of work should address all aspects of field operations including:

(a) Project specifications for data analysis;

(b) Roles and responsibilities, e.g., transporting, loading, cleaning, and tracking of tools;

(c) Related manpower;

(d) Any quality assurance issues, methods of ensuring quality, or both;

(e) Specific deliverables regarding corrosion sizing, shape, probability of detection, confidence limits, etc.;

(f) Impact of deliverables on data analysis for the specific line and resulting calculations; and

(g) Reporting requirements for anomalies meeting certain criteria (e.g., metal loss [MLOS] > 80%)

5.1.3 Liability issues

5.1.3.1 Liability issues should be fully addressed in the contract documents. This includes items such as replacement costs, tool handling, custody transfers, and related clauses.

5.1.3.2 Tool damage issues should be established in the contract documents. Values for most commonly occurring types of damage should be defined. Point of custody transfer should also be discussed.

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(8) For additional information, refer to API 1163.[3]

5.1.3.3 Clarification of liabilities and responsibility for tool retrieval (monetary and logistical) as well as the process for determining the cause of lodging the tool must be addressed in the contract.

5.1.3.4 All stakeholders should be aware of the possibility of stuck tools, discussion, and development of an action plan for tool retrieval should be in place if the event actually occurs.

5.1.4 Conformance to local, operator, and government regulations

5.1.4.1 The contract shall include specific wording to address health, safety, and environmental (HSE) standards and any company-specific guidelines that may go above and beyond the standard industry practice.

5.1.5 Survey-acceptance criteria[(9)]

5.1.5.1 A set of survey-acceptance criteria should be developed and agreed to by both parties prior to the start of the ILI survey. These criteria help to define when a rerun survey is required and include the following:

5.1.5.1.1 Physical damage to sensors after run: The tool should be visually examined as soon as possible following the run to give a quick indication of the potential need for a rerun. While sensor damage can occur at any point along the line, severe signs of wear on surfaces normally not exposed to that type of damage are an indication that the damage occurred early in the run and that significant information may not have been collected. The field log or data summary should be reviewed to confirm the time of the damage and the impact of that damage on data collected.

5.1.5.1.2 Lost sensor channels on data: When a field or preliminary log is reviewed, those channels that have stopped obtaining data should be readily evident. Loss of channels may be acceptable, especially in cases in which lost channels are not adjacent. Depending on the total number of channels on the tool, losses of 1 to 5% may be tolerated. Lines that have been inspected previously and have a good history may tolerate sensor loss near the upper limit. Lines that have never been inspected or lines that have significant integrity concerns may not tolerate even a 1% loss.

5.1.5.1.3 Sensor noise: Damaged sensors or bad electrical connections may make a channel noisy, thus creating signals that mask out adjacent good data channels. Noisy channels are also readily evident on the log and should be addressed in a manner similar to lost channels.

5.1.5.1.4 Distance inaccuracy: Inaccurate distance recording can create significant problems when operators are trying to locate anomalies for verification or repair. If the total line length varies by more than 1% from an accurate distance reference, a review of the footage should be conducted and an adjustment made if necessary.

5.1.5.1.5 Missed or not recorded features: Small line features such as pressure gauge fittings, small bore vents and drains, and other taps and fittings 25 mm (1.0 in) or less in diameter may not produce large signals, particularly when they fall between or across two sensors. Missing such features should not warrant a rerun. Missing known flange sets, valves, or large bore tees brings the veracity of all log information into question.

5.1.5.1.6 Velocity underruns or overruns: When tool velocities exceed the vendor's upper and lower limits, data loss can be excessive. Surging in gas or in crude lines with high gas content is often responsible for velocity excursions. If the total line distance affected by the excursions exceeds 1 to 2%, a rerun should be made. However, the rerun should not be conducted until the process parameters that led to the velocity problems can be addressed and modified to ensure that the rerun survey is conducted within the tool's velocity limits. If data with known velocity excursions are

(9) For additional information, refer to API 1163.[3]

accepted, the effect of the overspeed on data degradation (acquisition and sizing) must be defined to allow effective management of the issue.

5.2 Post-Run Operational Report

5.2.1 Requirements for the post-run operational report should be defined up front and should include items such as:

(a) Pipeline name;

(b) Date of run;

(c) Type of run;

(d) Length and diameter of run;

(e) Any significant tool modifications for run;

(f) Average speed of run, speed profile, or both;

(g) Run success or failure; and

(h) If failed, reason for failure (and associated remedial work).

5.3 Data Specifications

5.3.1 Data analysis specifications are discussed in detail in Section 8 and should be defined and understood by both parties before work is begun.

5.4 Reporting Schedule

5.4.1 The timeline for preliminary and final report deliverables, including exceptions such as longer line lengths or heavily corroded lines, should be established.

5.4.2 The timeline requirements for reporting for immediate conditions should be established.

5.5 Verification Requirements

5.5.1 Any expectations of both parties for correlation excavations to verify the data should be established in advance.

Section 6: Inspection Scheduling

6.1 Factors to be considered when scheduling the inspection include the following:

6.1.1 Access to sites

6.1.1.1 Consideration is given not only to launch/receive site access, size, and ground condition, but also to tracking locations. Tracking locations may be affected by length of daylight, wildlife corridors, weather, and other environmental and safety issues.

6.1.2 Throughput/outage considerations (including reruns)

6.1.2.1 Scheduling should account for system capacities and their effect on tool speeds and performance.

6.1.2.2 The timing of any resulting excavations should be considered as part of the planning process. This includes coordination with other related and unrelated outages on the system.

6.1.3 Manpower

6.1.3.1 The amount of manpower required should primarily be dictated by the location of the run, the complexity of the run procedure, and any environment and safety issues. As with any other field operation, the clarification of roles and responsibilities should be part of manpower planning.

6.1.4 Inspection run time

6.1.4.1 Each inspection tool has limitations regarding the amount of pipe that may be inspected in a single pass. These limitations are a function of battery life and data storage capacity. The nonhomogeneous nature of seamless pipe or spiral weld may result in higher than average signal density that consumes data storage capacity more rapidly than pipe of a more homogeneous material, such as ERW. For longer pipe segments, multiple runs may be required in order to obtain a complete inspection.

6.1.5 Land and access

6.1.5.1 Landowner issues may be involved during tool tracking operations and possibly during launch and receive operations as well. In populated areas, silencers may be required on gas lines due to noise restrictions. There may be additional concerns in crossing aboriginal or otherwise protected lands.

6.1.6 Environmental

6.1.6.1 Plans should be made for handling any waste during tool runs. Permits may be required for transportation of hazardous material as well as for accessing the pipeline rights-of-way in or through environmentally sensitive areas.

6.1.7 Procedural

6.1.7.1 Pumping with liquids obtains both operational predictability and consistent tool speeds. This requires planning such that customer impacts are minimized while good data are collected from the inspection. Procedures for pumping with liquids should consider the major factors listed below.

(a) Supplemental flow (see Paragraph 4.5);

(b) Dissolved gas in fluid;

(c) Purging/draining;

(d) Pyrophoric materials wetting, collection, and disposal (see Paragraph 4.4.2.14); and

(e) Freezing conditions: When water must be used as a propulsion fluid, ILI surveys should be scheduled during months when freezing cannot occur. If this is not possible, provisions should be made to address possible freezing of equipment.

6.1.7.2 Procedures in gas lines have the same objective as procedures in liquid lines: to maintain both operational predictability and consistent tool speeds. In gas lines, there is an added level of complexity resulting from the challenge of dealing with a compressible fluid. Factors to consider include:

(a) Speed control;

(b) Fluids in normal gas service lines;

(c) Launch;

(d) Receive; and

(e) Flow conditions.

6.1.7.3 Pigging bidirectional lines

6.1.7.3.1 Some lines are piggable in more than one direction. Subsequent ILI surveys should be run in the same direction as the first to simplify the tasks of feature correlation and field chainage. In this manner, an anomaly downstream from a given valve is always downstream from that valve, not downstream on one log and upstream on the next, etc.

6.2 Resourcing (Manpower and Equipment)

6.2.1 The speed of the tool and the length of the run are primary considerations in determining manpower numbers. Manpower in the pipeline operation control center should also be considered, because outages and procedures can involve more coordination of effort than is supported at normal staffing levels.

6.2.2 Access for heavy equipment (crane, dozer, backhoe, etc.) should be considered for launcher and receiver sites. Access to nearby workshop and tool cleaning facilities for the vendor are typically also required.

6.2.3 Pumping equipment sizing

6.2.3.1 When pumping equipment, as either sole propulsion or supplemental propulsion source, is required, the equipment should be sized to reduce the potential for failure to a minimum.

6.2.3.2 Equipment should not be run at over 80% of design capacity. Although most tools turn off if stopped for a sufficiently long time, battery capacity can be a concern in longer lines.

6.2.3.3 Time spent stationary in the line while a pump is repaired may impact the ability of the tool to collect data over the entire line. When the discharge capacity of a pump is near its maximum, at the minimum required flow rate for the tool, any decrease in pump efficiency could drop the tool below the minimum velocity. If this is not detected, the entire line may be run with no acceptable data acquired. In these cases, two pumps should be run at 75% capacity to avoid the possibility of the tool velocity's dropping below the minimum.

6.2.4 Liquid storage

6.2.4.1 When liquid must be used to propel an ILI tool, a minimum of 10% and preferably 25% excess over the calculated line fill volume should be on hand to cover bypass, passing isolation valves, unknown takeoff fill volumes, and other contingencies.

6.2.5 Slops collection

6.2.5.1 When ILI surveys produce nonnormal process fluids, e.g., liquid from a gas line or high-solids content product as a consequence of debris removal, provisions must be made for collection of this slops volume. Temporary tankage and piping connections may be required to divert and collect the material.

6.3 Benchmarking and Tracking

6.3.1 Use of GPS

6.3.1.1 Use of a GPS should be considered to facilitate and document ILI surveys. GPS is useful in reestablishing AGM benchmark locations that may become destroyed by unrelated activities or encroachments on the right-of-way. Because GPS uses a coordinate system independent of pipeline stationing or other traditional land-based coordinate systems, errors in pipeline stationing should be identified and corrected.

6.3.1.2 GPS offers an easy method of documenting all related ILI information in a single geographical reference format. This facilitates the integration of the collected ILI survey data into pipeline GIS.

6.3.1.3 Once an accurate GPS profile of the line is collected and verified, further GPS profiles may be unnecessary unless geotechnical or other outside force hazards are identified in which follow-up surveys can be used to check line movement. An accurate GPS profile may eliminate the future use of AGMs or benchmarks, if future surveys can be correlated to the GPS profile.

6.3.2 Surveying/benchmarking

6.3.2.1 Benchmarks are discrete survey points along the pipeline route for placing reference markers. These markers are either permanently attached to the pipeline (magnets, for example) or portable aboveground marker systems. Readily identifiable permanent pipeline installations, such as valves, are also used as benchmarks. If AGMs are used, special care should be taken to ensure that the pipeline cover does not exceed the maximum allowable depth for the AGM at the benchmark locations. If an AGM is placed on or above a casing, it may not detect the passage of the ILI tool.

6.3.2.2 Tracking locations should be established downstream from pipeline appurtenances, intermediate booster stations, and procedurally significant locations to ensure the pig negotiates and clears all in-line facilities. These tracking locations should be placed far enough downstream to avoid tool speed excursions that may cause failure in triggering the tracking device.

6.3.2.3 The purpose of benchmarking is to correct for measured distance inaccuracies caused by ILI tool odometer wheel slippage and significant changes in topographic elevations along the pipeline route. Benchmark locations on the pipeline are usually spaced at certain minimum intervals, typically 1 to 2 km (0.6 to 1.2 mi). Closer spacing provides a more accurate location definition. Benchmarking provides reference points for tracking the ILI tool and maintaining its appropriate speed as it progresses through the pipeline. It also provides references for use in surveying the location of excavations. Benchmarks should be placed in easily accessible locations on the pipeline route.

6.3.2.4 Benchmark locations should be surveyed, well documented, and maintained as part of the permanent pipeline record.

6.3.3 Marker activation (AGM)

6.3.3.1 A number of ILI tool vendors now have some form of portable marker system. These markers are time synchronized with the tool prior to launch. These not only detect passage of the tool, but are also used to locate the tool's relative position on the log through time comparison.

6.3.4 Pig tracking

6.3.4.1 An adequate number of individuals trained in the use of pig-tracking equipment, tracking calculations, line-finding equipment, etc., should be available.

6.3.5 Transmitters for tracking

6.3.5.1 When an electronic transmitter is used for tracking purposes, the proper mounting and operation of the device should be verified prior to launch. The device should be well secured and should not affect the bend-passing capability of the tool. MFL tools do not necessarily require devices, because the tool passage may be monitored using the magnetic fields generated by the tools.

6.3.6 Tracking milestones

6.3.6.1 The pipeline operations control center should be updated at the following times:

(a) When the tool is ready for launch;

(b) When the tool has been launched and tracking is under way;

(c) Any time irregularities are noted in the flow or pig travel;

(d) In advance of scheduled changes in pipeline flow conditions as identified in the inspection procedure;

(e) At regular intervals to confirm the pig position and that the tracking personnel are not incapacitated;

(f) Several times in advance of the pig arrival at any intermediate booster station, pig signal, or receiving location; and

(g) When the pig has been received, and the pipeline can be returned to normal operation.

6.3.7 Mechanical detection devices

6.3.7.1 There are a number of mechanical pig passage indicators on the market. Most are intrusive and are activated by physical contact of the pig with a protruding toggle. Recently, magnetically activated nonintrusive detection devices have entered the market. These devices require that a magnetic source be present in the ILI tool but have the benefit of being nonintrusive and are therefore portable. Thus, it is conceivably possible that one device could be used to monitor the passage of a tool along a line by confirming passage at one location and then moving the device to the next location along the line to confirm arrival and passage.

6.3.8 Monitoring passage at surface features

6.3.8.1 As ILI tools move through a line, their passage can normally be monitored at locations in which the line comes above grade, such as at line breaks, isolation valves, or at line tie-in risers. If the ambient noise levels in the area are relatively low, ILI tool passage can be readily heard.

6.3.9 Liquid volume monitoring

6.3.9.1 When ILI tools are propelled with a liquid and the total fill volume of the line is relatively well known, the approximate position of the tool and arrival times at given locations can be predicted by monitoring the volume of liquid discharged to propel the tool.

6.3.10 Initial subsea surveys

6.3.10.1 If an ILI inspection of an existing subsea line is being conducted for the first time, placement of magnets, markers, or other devices at regular intervals along the line to provide position indications may be a costly exercise. The cost of such placements should be compared to the cost of a line rerun. It may prove more economical to run an ILI survey to find out whether there is evidence of corrosion or other anomalies that appear to require followup examination. Placement of fewer magnets or markers, and bracketing the suspect area, can then be arranged. A rerun survey, which shows both the anomaly indication and new indications for the magnets or markers, can then be conducted.

6.4 Contingency Planning

6.4.1 A contingency plan should be considered to deal with the possibility of lodging an inspection tool in the line. The plan should cover aspects such as lines of communication, operational actions that could be used to dislodge the tool, interruption of service, and removal of the tool by means of a cutout. The contingency plan should also consider the possibility of a failure of the run (either caused by the tool or line conditions) and whether a rerun would be possible.

Section 7: New Construction—Planning for ILI Surveys

7.1 Planning for ILI surveys should begin with system design. Inclusion of ILI-compatible facilities in the construction of a new line is much more economical than attempting to retrofit those same facilities several years into the life of a line. Inclusion of some items in the original design, such as the installation of short pup joints, adds very little to the overall cost of a project during construction, but may be economically cost-prohibitive once the line is commissioned (see Paragraph 7.2.7). Components other than a launcher and receiver must be added to make a line ILI compatible. Often, those additional components have long delivery lead times. Paragraph 7.2 addresses some of the more costly or significant items that should be considered when planning for and constructing a new line to be ILI compatible.

7.1.1 Establishing the GPS coordinates of all valves, taps, tees, welds, etc., during construction is a good practice. This data can be utilized in locating anomalies. It may also reduce or eliminate the need for AGMs or benchmarks in future ILI runs.

7.2 Materials

7.2.1 Multiple-diameter line pipe

7.2.1.1 There are a number of different situations in which the installation of multiple pipe diameters within a single pipeline is a viable alternative to a single-diameter pipeline. However, this construction method can pose significant obstacles to future ILI surveys. The use of multiple pipe diameters should be avoided whenever possible. If there are no alternatives to a multiple-diameter line, the line should be installed using the following guidelines.

7.2.1.1.1 ILI tools are available to cover increases or decreases of one line-size diameter. When line segments between a single launcher and receiver are dual-diameter, the diameter change must be restricted to one line size, e.g., 560 and 610 mm (22 and 24 in) or 610 and 660 mm (24 and 26 in).

7.2.1.1.2 If design criteria are flexible, contact with ILI vendors prior to diameter selection may increase the number of vendors capable of providing the multiple-diameter inspection service.

7.2.1.1.3 Although dual-diameter tools are available on the market, not all vendors have tools to cover all the possible combinations. This may lead to a restricted vendor list for certain surveys. Additionally, even if the operator considers that a line is one continuous pipeline, the ILI vendors may charge for the use of multiple tools. The resulting overall cost for the inspection of the multi-diameter line is greater than the cost of a single-diameter line of the same length.

7.2.2 Offshore platforms may be fabricated in the yard with all anticipated future pipeline risers installed. Often, a single riser diameter is chosen for simplification of construction, and the diameter selected may be larger than that required by the final pipeline design.

7.2.2.1 Because the cost of retrofitting new risers, particularly risers installed inside the platform structure, can be quite high, the original risers are used, resulting in a mismatch between the riser and the pipeline diameters. This mismatch may make the line impossible to inspect. To avoid this problem to the greatest extent possible, risers should be sized to match the anticipated pipeline size closely. When the pipeline is constructed, strong consideration should be given to increasing or decreasing diameter to match the installed riser. The cost of doing so is more than recovered with the ability to clean and inspect the line successfully to detect potential defects prior to failure.

7.2.3 Valves

7.2.3.1 Whenever possible, valve bores should closely match the pipeline bore. For long large-diameter pipelines, mainline isolation and line break valves can represent a significant expenditure. To help reduce that expenditure, smaller-diameter valves may be specified, e.g., 1.0 m (40 in) valves may be used in a 1.1 m (42 in) line. The potential cost savings available from such a selection must be weighed against increased costs for ILI surveys and the associated risk of speed excursions affecting ILI tool data collection.

7.2.3.2 Smaller-diameter mainline valves should be addressed in a fashion similar to that used with multiple pipe diameters.

7.2.3.3 If check valves are to be used, through-conduit (i.e., full-bore) check valves with flappers that can be locked in the open position should be selected whenever possible.

7.2.4 High yield-strength bends and fittings

7.2.4.1 While it may be relatively easy to order line pipe in high-yield strengths, bends, tees, reducers, and other fittings may not be so readily available. Long lead times are often required for procurement of fittings to match the line pipe yield strengths. Failure to allow adequate lead time often results in heavy-wall lower-yield fittings being used as substitutes. The use of heavy-wall fittings should be balanced against the modification of ILI tools to facilitate inspection and potential requirement to use specialized dual-diameter tools. Use of heavier-wall fittings also results in a higher risk of unavoidable speed excursions (causing degradation of data) and stuck tools.

7.2.5 Bends and bend radius

7.2.5.1 A significant number of currently marketed ILI tools can negotiate bends with radii 3 D or larger. Some tools may negotiate 1.5 D bends.

7.2.5.2 Prior to placing an order for bends, the compatibility of those bends for ILI must be verified. Wall thickness of bends becomes critical as the radius of the bend becomes tighter.

7.2.5.3 CAUTION: The smaller the diameter of the line to be inspected, the larger the bend radius required to accommodate the ILI tool. Smaller-diameter tools incorporate multiple segment designs, and the hard body or maximum segment diameter is a greater percentage of the available line pipe internal diameter. Greater bend radii should allow the ILI tool to pass without damage or without becoming stuck.

7.2.6 Consistent wall-thickness pipe

7.2.6.1 If MFL tools are used for inspection, attention should be given to ensuring that sufficient pipe of one wall thickness is available to complete the construction. Short sections of heavy-wall pipe for road or railroad crossings, or for risers into and out of facilities with different design factor requirements are not a major concern; however, significant wall-thickness changes may restrict the tools that can be used to inspect the lines or cause unavoidable speed excursions leading to degradation of data. Heavy-wall fittings pose a higher risk of these problems.

7.2.7 Pup joint installation

7.2.7.1 To reduce the number of AGM required for a survey or to reduce the negative impact of a failed or undetected AGM unit, significantly shorter than average pups should be installed at regular intervals following the method described in Paragraphs 7.2.7.2 through 7.2.7.4.3. Alternative methods such as the use of magnets can also be considered in the appropriate situations.

7.2.7.2 When feasible, pup joints 1.2 to 1.8 m (4 to 6 ft) in length should be installed every 2 km (1.2 mi) along a line. This limits the distance that must be chained to a maximum of 1 km (0.6 mi), i.e., one-half the distance between two pups.

7.2.7.3 The location of the upstream or downstream weld of each pup can be marked either on the surface or through the establishment of GPS coordinates prior to burial.

7.2.7.4 Similar installations should be made for subsea lines; however, a little more preinstallation planning is required. Lay barges normally work with fixed distances between welding station locations, making the installation of short pup joints difficult. The following procedures should be used for subsea lines:

7.2.7.4.1 The pup joint must be prewelded to a longer joint so that the combined length of the two falls within the welding station spacing.

7.2.7.4.2 Composite joints (i.e., standard length joints composed of pup joints) should be made in advance and installed at preset regular spacings approximately every 2 km (1.2 mi).

7.2.7.4.3 Depending on the configuration of the lay barge stinger, it may be possible to mark a pup joint girth weld for future underwater identification with a stainless steel plate attached with polymer fabric rope or stainless steel banding prior to the joint leaving the barge. If it cannot be guaranteed that the marker can successfully pass the stinger, the weld should be temporarily identified, and divers or remote operating vehicles (ROV) should install the permanent identification at a later date.

7.3 Collection of Construction Information

7.3.1 During construction, records of the lengths of joints installed, radiograph identification, and any number of related pieces of information that will be of value during future ILI surveys should be routinely kept.

7.3.2 GPS coordinates may be obtained for every weld along the line as it lies in the trench prior to burial. Many types of GPS services are available to meet the accuracy requirements of the operator.

7.3.3 All documentation should be collected and filed in a common location and maintained for the life of the pipeline. Current technologies may allow the large volumes of material to be reduced significantly through scanning and subsequent storage in another media format. Regardless of the format, construction data are a valuable asset and they should be safeguarded for future reference. When possible, it is ideal to incorporate this information as part of a GIS.

7.4 Baseline Surveys

7.4.1 True baseline ILI surveys, i.e., those conducted prior to or very shortly after the start of service, offer a number of benefits that may significantly reduce the workload required following future surveys, but are not required.

7.4.2 A caliper survey or metal-loss survey can be conducted as part of the preservice work. If a sufficient fill rate can be obtained, the caliper survey or metal-loss survey may be completed as the pipeline is filled with water for the preservice hydrostatic test. Alternatively, other propulsion methods such as compressed air may be used.

7.4.2.1 An additional benefit of a baseline ILI survey in conjunction with the hydrostatic test is the data obtained can be used to confirm the construction contractor's delivery of the system as required by the contract.

7.4.3 Gauging-plate or deformation-tool surveys can be run first with compressed air.

7.4.4 The pumps used to fill the line must be capable of maintaining the required flow rate for inspection.

7.4.5 Sufficient water must be available to fill the section in question. With the arrival of the ILI tool, not only is the line filled for hydrostatic test, but the baseline information on line condition is obtained. If water is to be left in the pipeline for an extended period of time, appropriate chemicals (biocides, corrosion inhibitors, oxygen scavengers, etc.) in sufficient concentrations should be added to the hydrostatic test water to minimize corrosion.

7.5 Repair Records

7.5.1 If repairs are made to a pipeline during construction following a baseline survey or hydrostatic test, the location of these repairs should be recorded and incorporated into the permanent pipeline records.

Section 8: Data Analysis Requirements

8.1 Data Analysis Methodologies[(10)]

8.1.1 General components of ILI data analysis

8.1.1.1 After the raw data collected are considered acceptable, the ILI service company takes the data, analyzes them, and produces a report.

8.1.1.2 The ILI service company has applicable algorithms and software to analyze the data. The results of the analysis should be within the tool specifications for detection capabilities, accuracies, confidence intervals, minimum detection levels, and the detection thresholds.

8.1.1.3 The priorities and criteria for anomalies of concern should be predetermined as part of the inspection contract and pipeline operator integrity plan or code, taking into account the limitations of the inspection tool. The discussion should include definitions and clarification regarding defect geometry, probability of detection, sizing, tool specifications, and report timing as they relate to these criteria. For cracking, this is typically based on predicted crack depth or a combination of depth and length. For corrosion, pressure calculations should be performed using ASME[(11)] B 31 G,[7] RSTRENG,[4] or other assessment algorithm appropriate for the detail of ILI data available. For dents and dent-like anomalies, codes normally indicate any anomalies that exceed a certain threshold must be removed. The discussion should include definitions and clarification regarding defect geometry, probability of detection, sizing, and tool specifications as they relate to these criteria.

[(10)] For additional information, refer to API 1163.[3]
[(11)] ASME (formerly American Society of Mechanical Engineers) International, Three Park Ave., New York, NY 10016-5990.

8.1.1.4 Correlations should be made between field assessment information and ILI data. All accuracy errors associated with field measurement and ILI data must be taken into account in integrity assessment and planning.

8.2 Pipeline Features Listed and Reported(12)

8.2.1 The detection, classification, and sizing capabilities of nondestructive evaluation techniques depend on the type and characteristics of the pipeline anomalies. Any given feature can have a large variety of shapes. Features are classified according to their shape and other potential characteristics, e.g., profile.

8.2.2 For a given feature type, the POD should be defined as a statistical probability of positively detecting that type of feature. (Recommended values should be stated for POD = 90%.)

8.2.3 The reported features are those that are specified as being able to be found with a given tool/technology specification. The format, level, and method of reporting should be predetermined as part of the contracting process. The following elements are universally reported by all service providers:

(a) Odometer distance (also called absolute distance);

(b) Upstream reference girth weld identifier;

(c) Feature type and identifier;

(d) Circumferential (clock or degree) position;

(e) Distance to upstream girth weld (also called relative distance);

(f) Odometer distance of upstream benchmark;

(g) Odometer distance of downstream benchmark; and

(h) Feature-specific details (see Paragraph 8.4).

8.2.4 More details of features reporting may be found in the document developed by the European Pipeline Operators Forum, "Specifications and Requirements for Intelligent Pig Inspection of Pipelines."[8]

8.2.5 Anomaly location

8.2.5.1 Nearby features and benchmarks

8.2.5.1.1 When an anomaly on an ILI log is required to be located for examination, the location of the anomaly is referenced from readily identifiable features or benchmark locations, such as surface valve, marker magnet location, aboveground marker location, takeoff, flange set, an underground short joint, a heavy-wall pipe section, or when available, GPS coordinates.

8.2.5.2 GPS Coordinates

8.2.5.2.1 When a GPS coordinate ILI survey is conducted using submeter GPS equipment in the field, it is often the most efficient and accurate way of locating excavation sites. A secondary verification technique, such as joint length, long-seam position, or distance to reference girth weld can be used to verify that the proper anomaly is investigated.

(12) For additional information, refer to API 1163.[3]

8.2.5.3 Surface chaining

8.2.5.3.1 It must be recognized that surface chainage of distance along a pipeline may not match the distance the ILI tool travels inside the pipeline. Ground surface profile does not always mimic the actual pipeline profile. It is often advantageous to chain from both an upstream and a downstream reference feature or benchmark to bracket the anomaly location.

8.2.5.4 Short joint excavation

8.2.5.4.1 Short pup joints may be located throughout the pipeline either intentionally installed during construction or as the result of tie-ins, make-up, or a repair. If short joints are close to the location of the anomaly to be examined, they may be used in the same manner as any nearby reference feature. There may be more than one short joint in a particular location, and confirmation of the joint length is essential to ensure the correct joint is used to chain to the anomaly.

8.2.5.5 Excavation of affected joint

8.2.5.5.1 Even after chaining an anomaly location using nearby reference features, it is still possible to be on the wrong pipe joint or on the wrong weld of the affected joint. Therefore, the length of the pipe joint could be verified before an attempt is made to measure out to the anomaly location. Often, an anomaly location can be verified by comparing the distance from the anomaly (and other uncovered anomalies) to the upstream or downstream weld. Another method of location verification is the excavation of a girth weld and comparison of both the upstream and downstream long seams. This may be accomplished by excavating the entire joint or just the girth welds of the joint. Additional assurance may be obtained by verifying the orientation of the pipe long-seam weld, or spiral weld, when it is available.

8.3 Geometry Tool—Specific Analysis and Prioritization Methods

8.3.1 Localized deformations such as dents should be stated as absolute deflection from nominal circular pipe and as a percent of internal diameter.

8.3.2 Traditional caliper-type geometry tools can be used to determine restriction size, wall-thickness change, and other potential deformation restrictions.

8.3.3 More sophisticated deformation tools are capable of providing more accurate quantification of deformation features. Maximum deflection, circumferential (o'clock) position, curvature, shape, buckles, and wrinkles are identifiable.

8.4 Metal Loss (Corrosion)—Tool-Specific Analysis and Prioritization Methods

8.4.1 MFL technology

8.4.1.1 The exact level of reporting is affected by the resolution level of the technology used. Refer to NACE Publication 35100[1] for details of tool capabilities. Only a general guideline is provided as follows.

8.4.1.2 Conventional resolution allows for the detection and grading of features to provide some idea of number, density, and priority of corrosion features.

8.4.1.3 High resolution allows for detailed discrimination and localization of feature geometry, thereby allowing for clustering. Hence, more advanced defect assessment methods may be used. Some tools in this category may also be referred to as extra- or ultra-high resolution. The user should understand that tool capabilities vary within this category, primarily due to sensor density.

8.4.1.4 Transverse MFL tools magnetize the pipe in the circumferential direction. These tools are sensitive to different defect geometries than the axial MFL and should be used accordingly.

8.4.2 Ultrasonic technology

8.4.2.1 Ultrasonic inspection results are collected as a pipeline wall thickness scan and are available as such for viewing and analysis. The topology and river-bottom profile (i.e., profile of how anomaly depths vary along the length of the metal loss area) are inherent in the data that can be used for integrity assessments. The detailed topology allows advanced defect assessment methods to be used.

8.4.3 Clustering and interaction rules (applies to all metal-loss technologies)

8.4.3.1 Clustering is the grouping of anomalies according to interaction criteria based on mechanical or stress interaction considerations. The allowed methods for determining defect interaction may be dictated by code (e.g., ASME B31.4).[9]

8.4.3.2 The effect of corrosion indications in close proximity should be accounted for using interaction rules when dealing with ILI data. These rules must be predetermined as part of the contracting process, and one of several methods may be used. Some examples are:

8.4.3.2.1 Fixed distance method: Two metal-loss features interact when the axial or circumferential spacing between features is less than a specified distance (e.g., 100 mm [3.9 in]).

8.4.3.2.2 Relative distance method: Two metal-loss features interact when the axial spacing between the metal-loss edges is less than the smallest metal-loss feature length or the circumferential spacing is less than the smallest metal-loss width.

8.4.3.2.3 Expanded box/fixed multiple of wall thickness method: The length and width extents of metal-loss features are expanded in all directions by a fixed amount that is a multiple of wall thickness (e.g., three times the wall thickness [3T]). Two metal-loss features interact if and when the expanded boxes overlap.

8.4.4 Pressure-based analyses and calculations (MFL and UT)

8.4.4.1 Based on the basic length, width, depth, and depth profile information, a burst pressure or safe operating pressure calculation should be specified as part of the reporting specification to aid in the prioritization of anomalies for excavation or further assessment.

8.4.4.1.1 The algorithms to be used for this purpose depend on the detail of ILI data available, e.g., bulk metal loss, river-bottom profile, etc.

8.4.4.1.2 An anomaly box represents the basic metal-loss feature (length [L], width [W], and depth [D]). The L of an individual feature is that of the overall projected length in the axial direction. The W of a feature is that of the overall projected width in the circumferential direction. The detection and measurement thresholds of the tool may result in different reported values than those observed visually. The ILI contractor should specify the thresholds. The D of the metal loss should be determined by the maximum wall loss in a metal-loss feature and should be given as a depth from or a percentage of the reference wall thickness.

8.5. Crack Detection Technology—Tool-Specific Analysis

8.5.1 Crack information is supplied categorically as a crack or crack-like feature, its length, and its predicted depth range. Due to the large volume of information collected by the resolution required to detect cracks, reporting timelines are longer than they are for corrosion technology tools. The topology and river bottom profile (i.e., profile of how crack depth varies along the length of the crack) are inherent in the data that can be used for integrity assessments.

8.6 Inertial Tools/Mapping Technology—Tool-Specific Analysis and Prioritization Methods

8.6.1 Real-world spatial coordinates should be provided for a given resolution (e.g., every 0.50 m [1.6 ft]) to a specified accuracy (e.g., ± 1.0 m [3.3 ft]), assuming that the corresponding aboveground survey has been conducted to sufficient accuracy. Coordinate systems are already standardized and should be available in latitude/longitude or universal transverse mercator (UTM) datum. The data reported by these tools typically provide the following information:

8.6.1.1 Coordinates for all features in the line (as detected by the other technologies potentially on the same tool or a different tool).

8.6.1.2 Bending strain/curvature monitoring; bending strain that results from geotechnical movement, external forces, out-of-straightness survey.

8.6.1.3 Absolute bending strains that results from curvature are available for engineering analysis against allowable limits.

8.6.1.4 Strain monitoring is the process of comparing strains and curvature observed year to year when geotechnical or external forces may have significantly shifted within the inspection interval, causing unacceptable loading on the pipeline.

8.6.1.5 An out-of-straightness survey provides results for areas that are not within the original design/construction specifications.

8.7 Correlation of ILI Reported Results with Field Measurements

8.7.1 Field assessment of corrosion: After sufficient sampling and cleaning of the pipe surface to remove deposits and residual coating, a grid method can be used to provide corrosion detail over the area of interest for the feature. This can be achieved by a variety of methods including pencil probes, pit probes, etc. The gridded data can then be plotted as contours of depth. This corrosion profile information collected should then be utilized for (a) defect assessment by an engineering code to determine acceptability, and (b) compared with the ILI tool information as verification of analysis.

8.7.2 Field assessment of cracks: After sufficient sampling of the soils, pipe, and associated media, consideration must be given to cleaning the pipe surface to allow inspection using a technique such as magnetic particle inspection to determine the location of cracking. To optimize the effectiveness of the inspection technique, the pipe surface must be clean, dry, and free of surface contaminants (e.g., grease or dirt). The cleaning technique should not alter the pipe surface such that cracking is obscured (e.g., scraping or peening).

8.7.2.1 Each individual crack colony should then be documented and photographed. An accepted technique, destructive or nondestructive, should be used to establish crack depth for a sufficient sample size to establish tool confidence and establish whether repairs are required.

8.7.3 An important part of closing the loop is the feedback of the field inspection results to the ILI service provider. Using this information, the ILI vendor can continuously improve the validity and accuracy of the data analysis.

Section 9: Data Management

9.1 The inspection data should be incorporated into an overall integrity plan. The inspection data should be maintained and kept reasonably accessible. It should be correlated with excavation data, cathodic protection (CP) data, and any existing construction, coating, soils, and relevant operating history of the pipe. This exercise allows for more cost-effective decision making in future integrity work.

9.2 Operational and implementation information for successful and unsuccessful inspection can be of significant benefit for reinspections. Examples of this type of information include, but are not limited to:

(a) Pipeline modifications;

(b) Debris volume and analysis;

(c) Pre-run questionnaire;

(d) Repair history;

(e) Tool types;

(f) Operational issues;

(g) Procedures; and

(h) Aboveground marker locations.

9.3 Use of Growth Rates for Corrosion Inspections

9.3.1 ILI offers the pipeline operator the ability to define specific maintenance at discrete locations to repair active corrosion that is, or could become, an integrity concern. By applying growth rates to identified corrosion features, one can plan the maintenance schedule over a period of time. There could come a point when a reinspection is performed, either to define growth rates accurately or to address economic considerations when planned excavations cost more than the cost of another inspection. Multiple inspections allow for a more accurate determination of growth rates on a per-feature basis and lead to a well-defined maintenance plan. A risk-based inspection (RBI) approach is sometimes used to define inspection frequency.

References

1. NACE Publication 35100 (latest revision), "In-Line Nondestructive Inspection of Pipelines" (Houston, TX: NACE).

2. ANSI/ASNT ILI-PQ (latest revision), "In-Line Inspection Personnel Qualification and Certification" (Columbus, OH: ASNT, 2005).

3. API 1163 (latest revision), "In-Line Inspection Systems Qualification Standard" (Washington, DC: API).

4. J.F. Kiefner, P.H. Vieth, RSTRENG 3.0 (Windows Version) User's Manual and Software (Includes: L51688B, Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe) (Washington, DC: PRCI, 1993).

5. J.F. Kiefner, P.H. Vieth, RSTRENG2 (DOS Version) User's Manual and Software (Includes: L51688, Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe) (Washington, DC: PRCI, 1993).

6. “Updated Pipeline Repair Manual,” PRCI R2269-01, Final Report, August 28, 2006.

7. ASME B 31 G (latest revision), “Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to ASME B31 Code for Pressure Piping” (New York, NY: ASME).

8. European Pipeline Operators Forum, “Specifications and Requirements for Intelligent Pig Inspection of Pipelines.” Shell International Exploration and Production B.V., RPT-OM; Rijswijk, The Netherlands, November 6, 1998.

9. ASME B31.4 (latest revision), “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids” (New York, NY: ASME).

Bibliography

NACE SP0502 (latest revision). “Pipeline External Corrosion Direct Assessment Methodology.” Houston, TX: NACE.

Appendix A: Sample Pipeline Inspection Questionnaire (Nonmandatory)

Company Name	
Completed by	
Name	Fax
Office phone	Date
Checked by	
Name	Fax
Office phone	Date

Site Information	
Pipeline name	
Line length (km) (mi)	Line OD (mm) (in)
Launch site	L station #
Launch phone	Receive phone
Receive site	R station #
Base location	Base station #
Base shipping address	
Base contact	Base phone
Type of inspection required: SCC MFL Dent Profile clean	
Dummy tool required?	Locator required?
Pipeline alignment maps available?	

Product Details				
Product type	H_2O content			
Wax content	Slackline?			
CO_2 content	Hazardous?			
H_2S content	Protective equipment?			
Type of flow: Laminar Turbulent Two-Phase (Transitional)				
Flow property: Liquid Gas Two-Phase (Both)				
Will the line be isolated?	Constant velocity?			
Flow rate controllable?				
Line Conditions		Min.	Normal	Max.
Launch pressure	(kPa)			
	(psi)			
Launch velocity	(km/h)			
	(mph)			
Launch flow rate	(m^3/d)			
	(MMcfd)			
Launch temperature	(°C)			
	(°F)			

Appendix A: Sample Pipeline Inspection Questionnaire (continued)

Receive pressure	(kPa)			
	(psi)			
Receive velocity	(km/h)			
	(mph)			
Receive flow rate	(m^3/d)			
	(MMcfd)			
Receive temperature	(°C)			
	(°F)			

Note: These values are recorded for regular line conditions. Pressures and velocities vary during the pig run.

Pipe Details	
Last inspection year	MAOP
Design pressure	Type of cleaning pig
Cleaning program?	Frequency
Known/suspected damage	
Relevant historical data	

Pipeline Conditions			
Year of construction			Sphere tees installed?
Pipe cover depth	Max.	Min.	Type of pipe cover?
Are there high-voltage lines in the vicinity of the pipeline?			Where?
Insulating flanges in the pipe?		Where?	
R.O.W. access (road, air, etc.)			
Does pipe have hot taps?			
Relevant historical data			

Pipe Features	Yes	No		Yes	No
Does the pipeline contain the following features?					
Thread and collar couplings			Chill rings		
Bell and spigot couplings			Hydrocouples		
Stepped hydrocouples			Stopple tees		
Nontransitioned wall-thickness changes			Wye fittings		
			Mitre joints		
Corrosion sampling points			Acetylene welds		
Internal probes			Vortex breakers		

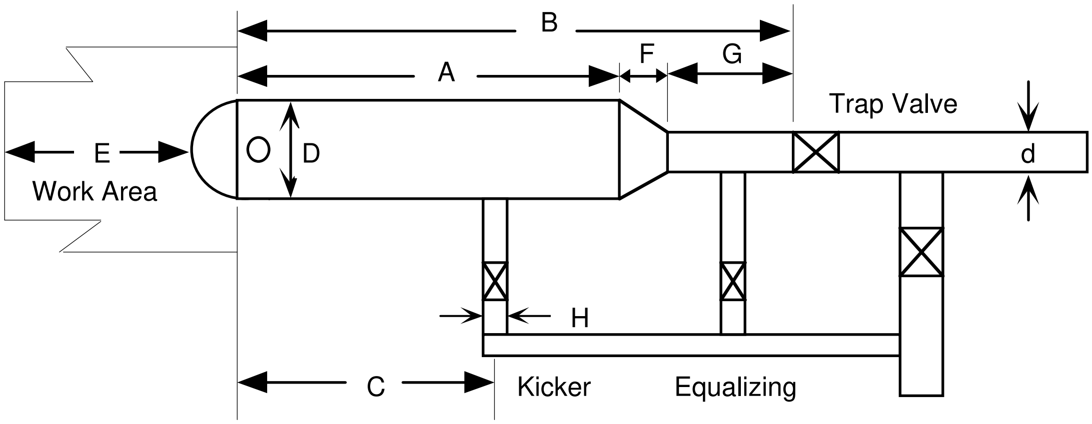

Figure A1: Plan view of a generic pig trap.

Trap Details		Launch Length	Receive Length
A	Closure to reducer (m/ft)		
B	Closure to trap valve (m/ft)		
C	Closure to bridle CL (mm/in)		
d	Pipeline diameter (mm/in)		
d'	Pipeline internal diameter (mm/in)		
D	Overbore (NPS # or mm/in)		
D'	Overbore internal diameter (mm/in)		
E	Axial clearance (m/ft)		
F	Reducer length (mm/in)		
F'	Reducer wall thickness (mm/in)		
G	Reducer to valve (m/ft)		
H	Kicker line (NPS # or mm/in)		

Trap Conditions	Launcher	Receiver
Orientation		
Type/internal diameter of trap valve (mm/in)		
Centerline height of trap (Aboveground) (mm/in)		
Is hoist available?	Yes No Capacity Lift Height	Yes No Capacity Lift Height
Is trap equipped with: Pig-Sig? Sphere Tee? Coupons or Internal Fittings?		
Trap closure type		
Trap pressure rating (kPa/psi)		
Concentric or eccentric reducer?		
Workshop near trap?		
Access limitations (due to available area or ground conditions)?		
AC power at trap site?		
Intrinsic safe area, level?		
Site drawings available?		

Figure A1: Plan view of a generic pig trap (continued)

Pipe Information					
Nominal Wall Thickness of Pipe (mm [in])	Length of Each Wall Thickness (km [mi])	Pipe Weld Type	Pipe Grade (MPa/psi)	Mill	OD (mm [in])
Total Length =					
Repair History					
Nominal Wall Thickness and Grade of Pipe (mm/MPa [ksi/in])	Length of Each Wall Thickness (km [mi])	Start Chainage	End Chainage	Comments	Date of Repair
Total Length =					

Bends					
Type	Chainage of Bend (km [mi])	Angle (degrees)	Bending Radius	Minimum Bore (mm [in])	Comments

Tees/Off Takes/Branches					
Type (Forges, Stopple, etc.)	Chainage of T/OT/B (km [mi])	O'clock Position	Max. Off-Take Diameter (mm [in])	Barred or Unbarred	Comments

Figure A1: Plan view of a generic pig trap (continued)

Valves				
Type	Chainage of Valve (km [mi])	Manufacturer	Model	Minimum Bore (mm [in])

Diameter Changes					
Type of Reducer	Chainage of Diameter Change (km [mi])	Upstream Diameter (mm [in])	Downstream Diameter (mm [in])	Diameter Transition Length (mm [in])	Comments

Coatings (If concrete coated, is there any magnetic content?)	
Internal	
External	

Aboveground References Can any of the following be located from above ground for references?			
Line valves		Large bends	
CP connections		Off tees	
Major WT changes		Sleeves	
Anodes		Casings	
Girth welds		Insulation flanges	

Known Metal-Loss Information	
Internal	
External	
Mechanical damage	
Other	

Special Attention

Figure A1: Plan view of a generic pig trap (continued)

Comments

Completed by ____
Name Signature Date

Checked by ____
Name Signature Date

Updated by ____
Name Signature Date

Figure A1: Plan view of a generic pig trap (continued)