In-line Inspection Systems Qualification Standard

API STANDARD 1163
FIRST EDITION, AUGUST 2005

American Petroleum Institute

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Pipeline Segment

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FOREWORD

Pipeline operators, service providers, and the regulatory community continuously strive to improve the safety and integrity of gas and liquid pipelines.

In-line inspection of pipelines is a key technology utilized by the industry to help maintain systems safety and integrity.

This Standard serves as an umbrella document to be used with and complement companion standards. NACE RP0102 *Standard Recommended Practice, In-Line Inspections of Pipelines*; and ASNT ILI-PQ *In-Line Inspection Personnel Qualification & Certification* all have been developed enabling service providers and pipeline operators to provide rigorous processes, that will consistently qualify the equipment, people, processes and software utilized in the in-line inspection industry. The teams that have worked so diligently in the development of these three standards expect improvement in the results from in-line inspections with accompanying improvements in the safety and integrity of gas and liquid pipelines.

Appreciation is extended to the Pipeline Operators Forum for the use of their guide for in-line inspections, "Specifications and Requirements for Intelligent Pigging of Pipelines," Version 2.1, Nov. '98. Portions of this guide were incorporated directly into this Standard.

Appreciation is also extended to the In-Line Inspection Association, whose draft guide provided a running start to develop this and the companion standards referenced herein.

This Standard states that performing in-line inspections requires agreements and close cooperation between service providers and operators. This Standard establishes requirements of all parties for the implementation of in-line inspections, and these must be recognized by organizations utilizing the three standards. Service providers and operators must have a clear definition of assigned responsibilities to successfully apply these standards.

These three standards are neither regulatory documents nor can or should they address commercial issues.

During the development of this Standard, a number of issues of technical significance arose. A process-oriented format was adopted to incorporate the many different technologies applied in various aspects of the exploration and transportation of gas and hazardous liquids. The Standard does not require specific qualification processes to accommodate the differences in the broad range of industry activities. The Standard encourages the development and implementation of new and improved technologies in the future.

The definitions in this Standard are taken from previously developed and accepted documents wherever possible. A significant number of definitions have been modified or clarified for this specific application. Industry is strongly encouraged to uniformly utilize these definitions so that integrity management efforts can be effectively implemented in the future. This committee recognizes the value of standardized reporting terminology.

The committee expects that the requirements established in these three standards will continue to improve the results from in-line inspections and thus the safety and integrity of gas and liquid pipelines.

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Qualification of In-line Inspection Systems

1 Introduction

1.1 GENERAL

This Standard provides requirements for qualification of in-line inspection systems used in gas and hazardous liquid pipelines. The Standard assures the following:

a. Inspection service providers make clear, uniform, and verifiable statements describing in-line inspection system performance.
b. Pipeline operators select an inspection system suitable for the conditions under which the inspection will be conducted. This includes, but is not limited to, the pipeline material characteristics, pipeline operating conditions, and types of anomalies expected to be detected and characterized.
c. The in-line inspection system operates properly under the conditions specified.
d. Inspection procedures are followed, before, during and after the inspection.
e. Anomalies are described using a common nomenclature, as described in this Standard.
f. The reported data and inspection results provide the expected accuracy and quality in a consistent format.

Users of this Standard should be aware that further or differing requirements may be needed for some applications. Nothing in this Standard is intended to inhibit the use of inspection systems or engineering solutions that are not covered by the Standard. This may be particularly applicable where there is innovative developing technology. Where an alternative is offered, the Standard may be used, provided any and all variations from the Standard are identified and documented.

1.2 GUIDING PRINCIPLES

Personnel and equipment used to perform in-line inspections and analyze the results shall be qualified according to this Standard and its companions, ASNT *In-Line Personnel Qualification and Certification* Standard No. ILI-PQ, and NACE Standard Recommended Practice *In-Line Inspection of Pipelines* RP0102. Combined, these three standards provide requirements and processes for the qualification of in-line inspection systems, including the in-line inspection tools, their software, and the personnel to operate the systems and analyze the results. This Standard is an umbrella document covering all aspects of in-line inspection systems, incorporating the requirements of ASNT ILI-PQ and NACE RP0102 by reference.

This Standard is not technology specific. It accommodates present and future technologies used for in-line inspection systems.

This Standard is performance-based and provides requirements for qualification processes. It does not, however, define how to meet those requirements.

This Standard defines the documentation of processes for in-line inspection system qualifications.

One objective of this Standard is to foster continuous improvement in the quality and accuracy of in-line inspections.

Wherever possible, this Standard utilizes existing terms and definitions from other applicable Standards. Section 4 provides definitions of terms.

The use of an in-line inspection system to manage the integrity of pipelines requires close cooperation and interaction between the provider of the inspection service (service provider) and the beneficiary of the service (operator). This Standard provides requirements that will enable service providers and operators to clearly define the areas of cooperation required and thus ensure the satisfactory outcome of the inspection process. While service providers have the responsibility to identify in-line inspection system capabilities, their proper use, and application, operators bear the ultimate responsibility to:

a. Identify specific risks (threats) to be investigated.
b. Choose the proper inspection technology.
c. Maintain operating conditions within performance specification limits.
d. Confirm inspection results.

Following the Standard provides a consistent means of assessing, using, and verifying results from in-line inspection systems such that acceptable inspection results are obtained.

2 Scope

This Standard covers the use of in-line inspection systems for 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, The Standard applies to both existing and developing technologies.

This Standard is an umbrella document that provides performance-based requirements for in-line inspection systems, including procedures, personnel, equipment, and associated software.

The Standard includes the following sections:

- *Terms and Definitions*.
- *Systems Qualification Process and Incorporated Standards*—Overall process description with referenced qualification requirements for in-line inspection personnel and equipment.

- *In-Line Inspection System Selection*—Requirements for selecting an in-line inspection system for a specific pipeline application.
- *Qualification of Performance Specifications*—Requirements for establishing, documenting, and validating performance specifications of in-line inspection systems.
- *System Operational Validation*—Requirements that must be met before, during, and after running an in-line inspection system to assure that the system functioned properly.
- *System Results Verification*—Requirements for verifying that the results of an inspection are consistent with the performance specification.
- Reporting Requirements.
- *Quality Management System*—Requirements for documentation, quality control, continuous improvement, and system review.

3 References

API

5T1	*Standard on Imperfection Terminology* November 1996
1160	*Managing System Integrity of Hazardous Liquid Pipelines*

ASME[1]

B31.8S	*Managing System Integrity of Gas Pipelines*
B31.4	*Pipeline Transportation Systems for Liquid Hydrocarbons And Other Liquids*
B31.8	*Gas Transmission And Distribution Piping Systems*

ASNT[2]

ILI-PQ	*In-Line Inspection Personnel Qualification and Certification*

NACE[3]

RP0102	*In-Line Inspection of Pipelines*
TR 35100	*In-Line Nondestructive Inspection of Pipelines*

European Pipeline Operators Forum *Specifications and Requirements for Intelligent Pig Inspection of Pipelines* Version 2.1 November 1998—Shell International Exploration & Production B.V. EPT-OM

[1]ASME International, 3 Park Avenue, New York, New York 10016-5990. www.asme.org
[2]American Society for Nondestructive Testing, Inc., 1711 Arlington Lane, P.O. Box 28518, Columbus, Ohio 43228-0518. www.asnt.org
[3]NACE International (formerly the National Association of Corrosion Engineers), 1440 South Creek Drive, P.O. Box 218340, Houston, Texas 77218-8340. www.nace.org

4 Terms & Definitions

4.1 above-ground 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.

4.2 actionable anomaly: Anomalies that may exceed acceptable limits based on the operator's anomaly & pipeline data analysis (see Figure 1).

4.3 AGM: See **above-ground marker.**

4.4 anomaly (See Figure 1): An unexamined deviation from the norm in pipe material, coatings, or welds. See also **imperfection, defect, and feature**.

4.5 anomaly & pipeline data analysis: The process through which anomaly & pipeline data are integrated and analyzed to further classify & characterize anomalies.

4.6 appurtenance: A component that is attached to the pipeline; e.g., valve, tee, casing, instrument connection.

4.7 ASME: American Society of Mechanical Engineers, also known as ASME International.

4.8 ASNT: American Society for Nondestructive Testing, also known as ASNT.

4.9 bend: A physical pipe configuration that changes pipeline direction.

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

4.11 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**.

4.12 caliper tool: A type of tool used to measure the internal diameter of a pipeline.

4.13 casing: A cylinder surrounding the pipeline, installed for the purpose of protecting the pipeline from external damage.

4.14 certainty: As used in this document, the probability that a reported anomaly characteristic is within a stated tolerance. See also **tolerance**.

4.15 certification: A written testimony of qualification

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

4.17 characteristic: Any physical descriptor of a pipeline (e.g., grade, wall thickness, manufacturing process) or an anomaly (e.g., type, size, shape).

4.18 characterize: To identify the type of pipeline anomaly, component or characteristics or estimate the size of the pipeline anomaly.

4.19 classify: To identify the cause of an inspection indication (e.g., anomaly, nonrelevant indication, feature, component or type of imperfection/defect).

4.20 cold work: Permanent strain in a metal accompanied by strain hardening.

4.21 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.

4.22 confidence interval: A range of values around the statistical mean.

4.23 confidence level: A statistical term used to describe the mathematical certainty with which a statement is made.

4.24 corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

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

4.26 data analysis: The evaluation process through which inspection indications are classified and characterized.

4.27 defect: A physically examined anomaly with dimensions or characteristics that exceed acceptable limits. See also **imperfection**.

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

4.29 deformation tool: An instrumented in-line inspection tool designed to measure deformations in the pipe. See **geometry tool**.

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

4.31 detect: To sense or obtain a measurable indication from a feature.

4.32 detection threshold: A characteristic dimension or dimensions of an anomaly that must be exceeded to achieve a stated probability of detection. See also **measurement threshold** and **reporting threshold**.

4.33 DSAW: Double submerged arc welding. A welding process used in the manufacture of pipe.

4.34 electromagnetic acoustic transducer (EMAT): A type of transducer that generates ultrasound in steel pipe without a liquid couplant using magnets and coils for inspection of the pipe.

4.35 EMAT: See **electromagnetic acoustic transducer**.

4.36 ERW: Electric resistance welding. A welding process used in the manufacturing of pipe.

4.37 essential variables: The common set of characteristics or analysis steps for a family (series) of in-line inspection tools that may be covered within one performance specification.

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

4.39 examination: A direct physical inspection of an anomaly by a person, which may include the use of nondestructive examination techniques.

4.40 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.

4.41 flash welding: A form of electric resistance welding used in the manufacturing of pipe.

4.42 gas: Natural gas, flammable gas, or gas which is toxic or corrosive.

4.43 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.

4.44 geometry tool: An instrumented in-line inspection tool that measures deformations in the pipe. See **deformation tool**.

4.45 girth weld: A complete circumferential butt weld joining pipe or components.

4.46 gouge: Elongated grooves or cavities usually caused by mechanical removal of metal. See also **cold work**.

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

4.48 hazardous liquid: Petroleum, petroleum products, CO_2, or anhydrous ammonia.

4.49 ILI: See **in-line inspection**.

4.50 imperfection: An anomaly with characteristics that do not exceed acceptable limits. See also **defect**.

4.51 indication: A signal from an in-line inspection system. An indication may be further classified or characterized as an anomaly, imperfection, or component. (See Figure 1)

4.52 inertial tool: A type of in-line inspection tool used to map the centerline of a pipeline using sensors that respond to inertial changes. See also **mapping tool**.

4.53 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.

4.54 in-line inspection report: A report provided to the operator that contains a comprehensive analysis of the data from an in-line inspection.

4.55 in-line inspection system: An inspection tool and the associated hardware, software, procedures, and personnel required for performing and interpreting the results of an in-line inspection.

4.56 in-line inspection technology: A class of inspection methodologies (i.e., EMAT, MFL, ultrasonic, caliper, etc.) used in the performance of an in-line inspection.

4.57 in-line inspection tool: An instrumented device or vehicle that uses a nondestructive testing technique to inspect the pipeline from the inside or that uses sensors and other equipment to size one or more characteristics of the pipeline. Also known as intelligent or smart pig.

4.58 inspection: The use of a nondestructive testing technique.

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

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

4.61 lap weld: A welding process used in the manufacture of line pipe.

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

4.63 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.

4.64 magnetic particle inspection (MPI): A nondestructive examination technique for locating surface flaws in steel using fine magnetic particles and magnetic fields.

4.65 management of change (MOC): A process that systematically recognizes changes of a technical, physical, procedural or organizational nature and communicates them to the appropriate parties.

4.66 mapping tool: An in-line inspection tool that uses inertial sensing or other technology to collect data that can be analyzed to produce an elevation and plan view of the pipeline route.

4.67 measurement threshold: A dimension or dimensions above which an anomaly measurement can be made. See also **detection threshold** and **reporting threshold**.

4.68 mechanical damage: A generic term used to describe combinations of dents, gouges, and/or cold work caused by the application of external forces. Mechanical damage can also include coating damage, movement of metal, and high residual stresses.

4.69 metal loss: Any pipe anomaly in which metal has been removed. Metal loss is usually due to corrosion or gouging.

4.70 MFL: See **magnetic flux leakage**.

4.71 MIC: See **microbiologically influenced corrosion**.

4.72 microbiologically influenced corrosion (MIC): Corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

4.73 mill related anomalies: Anomalies in pipe or weld metal resulting from the manufacturing process.

4.74 MOC: See **management of change**.

4.75 MPI: See **magnetic particle inspection**.

4.76 NACE: Previously known as the National Association of Corrosion Engineers, also referred to as NACE International.

4.77 NDE: See **nondestructive examination**.

4.78 NDT: See **nondestructive testing**.

4.79 nominal wall thickness: The wall thickness specified for the manufacture of the pipe. Actual wall thickness will vary within a range permitted by the pipe manufacturing standard/specification and sometimes will vary outside that range if the manufacturing was not performed within the stated tolerance.

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

4.81 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.

4.82 operator: A person or organization that owns or operates pipeline facilities.

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

4.84 performance specification: A written set of statements that define the capabilities of an in-line inspection system to detect, classify and characterize features.

4.85 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.

4.86 pipeline: A continuous part of a pipeline facility used to transport a hazardous liquid or gas. Includes pipe, valves, and other appurtenances attached to pipe.

4.87 pipeline component: A feature or appurtenance, such as a valve, cathodic protection connection, or tee that is a normal part of the pipeline. See **component**.

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

4.89 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, breakout tanks, holders, and other fabricated assemblies.

4.90 pitting: Localized corrosion of a metal surface that is confined to small areas and takes the form of cavities called pits.

4.91 POD: See **probability of detection**.

4.92 POFC: See **probability of false call**.

4.93 POI: See **probability of identification**.

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

4.95 probability of exceedence: The probability of a defect larger than critical size, given an anomaly of the size predicted by the ILI inspection tool.

4.96 probability of false call (POFC): The probability of a non-existing feature being reported as a feature.

4.97 probability of identification (POI): The probability that the type of an anomaly or other feature, once detected, will be correctly identified (e.g., as metal loss, dent, etc.).

4.98 provider: See **service provider**.

4.99 QC: Quality Control.

4.100 qualification (personnel): The process of demonstrating skill and knowledge, along with documented training and experience required for personnel to properly perform the duties of a specific job.

4.101 qualification (system): The process of validating, through tests and analysis, the performance specifications of an in-line inspection system.

4.102 receiver: A pipeline facility used for removing a pig from a pressurized pipeline; may be referred to as trap, or pig trap or scraper trap.

4.103 reference point: A well-documented point on the pipe or right of way that serves as a measurement point for location of anomalies.

4.104 reporting threshold: A parameter that defines whether or not an anomaly will be reported. The parameter may be a limiting value on the depth, width, or length of the anomaly or feature.

4.105 ripple: A smooth wrinkle or bulge visible on the outside wall of the pipe. The term "ripple" is sometimes restricted to wrinkles or bulges that are no greater in height than 1.5X wall thickness. See also **buckle and wrinkle**.

4.106 seam weld: The longitudinal or spiral weld in pipe, which is made in the pipe mill.

4.107 seamless: Pipe made without a seam weld.

4.108 service provider: Any organization or individual providing services to operators.

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

4.110 should: "Should" or "it is recommended" is used to indicate that a provision is not mandatory but recommended as good practice.

4.111 sizing accuracy: The accuracy with which an anomaly dimension or characteristic is reported. Typically, accuracy is expressed by a 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).

4.112 SMLS: Seamless pipe.

4.113 SMYS (Specified Minimum Yield Strength): The minimum yield strength prescribed by the specification under which pipe is purchased from the manufacturer.

4.114 spiral weld: A longitudinal DSAW that traverses helically around the pipe. A welding process used in the manufacture of pipe.

4.115 stress corrosion cracking (SCC): A form of cracking of a material produced by the combined action of tensile stress (residual or applied), a corrosive environment, and steel that is susceptible to SCC.

4.116 stress: Tensile, shear or compressive force per unit area.

4.117 third-party damage: Damage to a pipeline facility by an outside party. For the purposes of this document, third party damage includes damage caused by an operator or contractor working for the operator. See **mechanical damage**.

4.118 tolerance: The range with which an anomaly dimension or characteristic is sized or characterized. See **certainty**.

4.119 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.

4.120 trap: A pipeline facility for launching or receiving tools and pigs. See **launcher and receiver**.

4.121 ultrasonic testing (UT): A type of inspection technology that uses ultrasound for inspecting pipe.

4.122 verification dig: An excavation made to verify the reported results of an in-line inspection. See **calibration dig**.

4.123 verification measurement: Characteristics of an anomaly as physically measured when the anomaly has been exposed for measurement or repair during a dig.

4.124 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 also **buckle and ripple**.

4.125 wrinkle bend: A field bend that contains smooth and localized bulges on the inner radius of the bend.

5 Systems Qualification Process

5.1 GENERAL

Section 5 describes the processes and personnel qualification requirements for the activities involved in using an in-line inspection system. The requirements are grouped according to the section of this Standard that defines or governs each activity. A description is given for each activity, and an activity sequence is illustrated in Figure 2—ILI Systems Qualification Process Flow Diagram.

The process of successfully performing an in-line inspection begins with the operator defining inspection goals, objectives and the pipeline system characteristics to service providers. Based on this information, the service provider recommends specific in-line inspection tools to meet the operators requirements. Section 6 of this standard and NACE RP0102 provide the details of the process required to select an appropriate in-line inspection tool or tools.

Section 7 describes the processes that service providers shall use to determine the performance specifications of a family of tools that have identical essential variables. These performance specifications define what types of anomalies can be found as well as the associated inspection accuracies and certainties.

Section 8 describes the requirements for preparing tools prior to physically performing inspections. It also describes the activities that shall be performed by the operator and/or the service provider during the inspection.

Section 9 describes processes that shall be used for verifying whether or not the tool meets the performance specifications. It also describes what shall be done if the performance specifications are not met.

Section 10 provides reporting requirements for the results of the inspections performed.

This Standard and the 2 standards incorporated by reference into this Standard provide the information and processes to enable operators and service providers to perform in-line inspections with greater consistency and accuracy.

5.2 PERSONNEL QUALIFICATION

ASNT ILI-PQ is incorporated by reference as a requirement in this Standard. The personnel operating the ILI systems and the personnel taking, reducing, analyzing and reporting the resultant data shall be qualified in accordance with ASNT ILI-PQ.

5.3 OPERATOR & SERVICE PROVIDER RESPONSIBILITIES

NACE RP0102 is incorporated by reference as a requirement in this Standard. Service provider and operator responsibilities are enumerated in NACE RP0102.

6 In-line Inspection System Selection

6.1 GENERAL

This section covers the selection of an in-line inspection system. When selecting an in-line inspection system, both the in-line inspection system capabilities and the pipeline operational and physical characteristics shall be considered.

The process of selecting an in-line inspection system requires:

- Defining the goals, objectives and required accuracies of the inspection;
- Considering the physical and operational characteristics and constraints of the pipeline; and
- Selecting an appropriate in-line inspection system based on the requirements of the inspection and performances capabilities of the in-line inspection system.

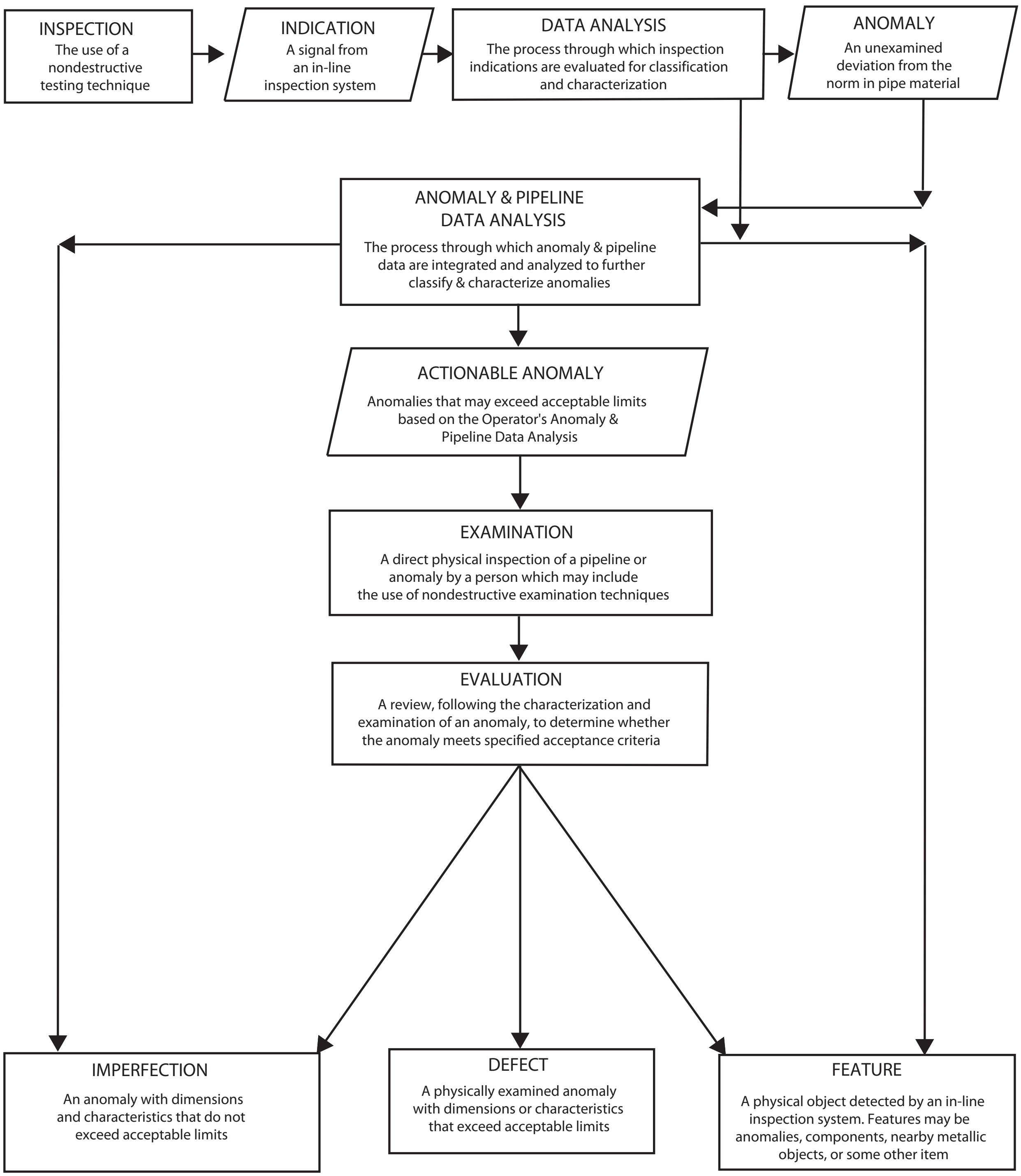

Figure 1—Inspection Terminology

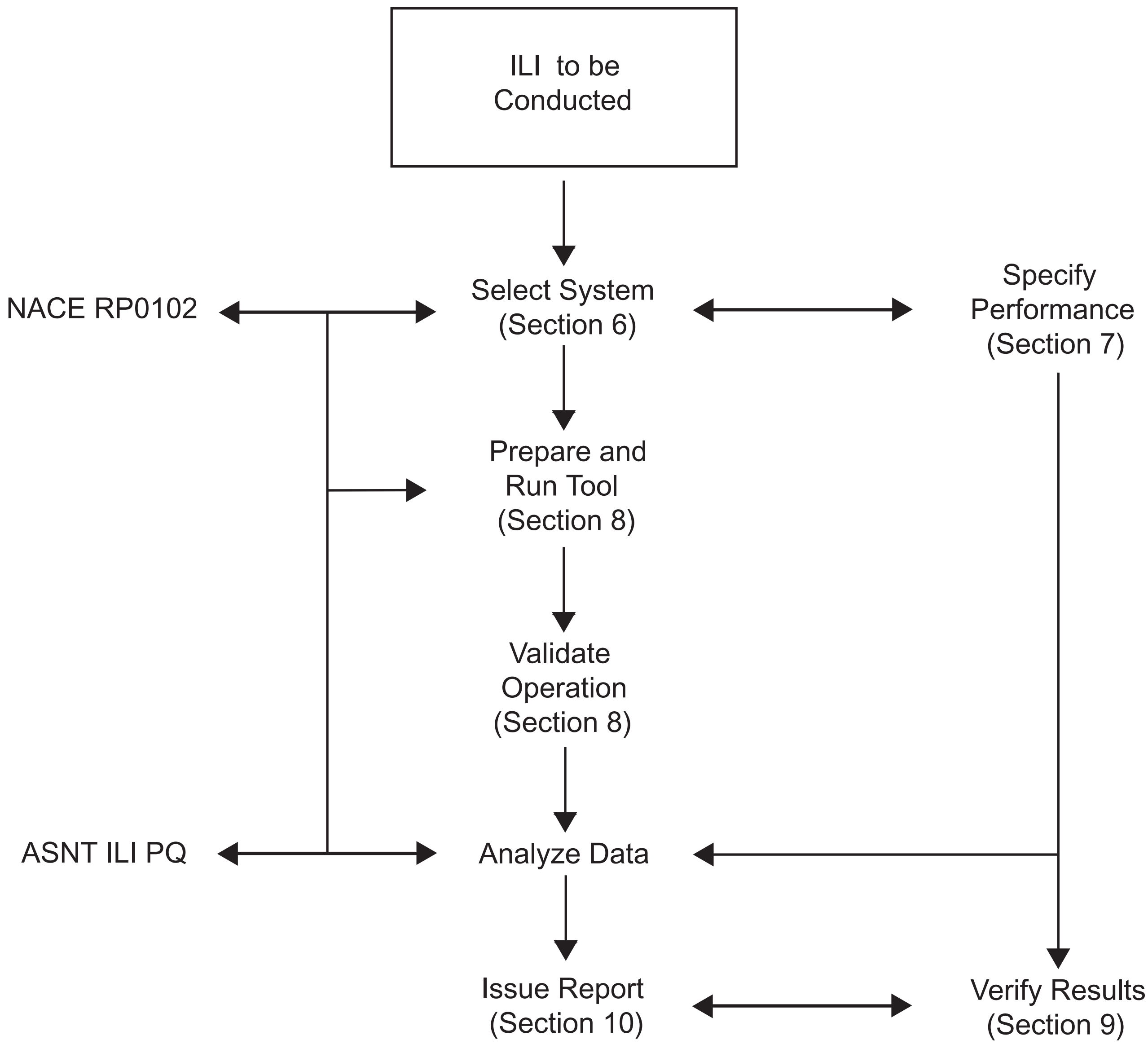

Figure 2—In-line Inspection Process Flow Diagram

In addition to the requirements given in this section, the requirements in NACE Standard RP0102 shall be followed.

Characteristics of available in-line inspection technologies and tools are discussed in the NACE Publication TR 35100.

6.2 INSPECTION GOALS AND OBJECTIVES

The goals and objectives of an in-line inspection shall be defined. Goals and objectives shall include, but are not limited to, characteristics of anomalies and features to be detected, identified, and sized and the required accuracies.

The procedures used to define the goals and objectives of an inspection are not covered in this Standard. The operator should follow the requirements included in documents such as API 1160 and ASME B31.8S.

6.3 PHYSICAL AND OPERATIONAL CHARACTERISTICS AND CONSTRAINTS

Consideration of physical and operational characteristics and constraints is covered in detail in NACE Standard RP0102.

The operator shall provide information on physical characteristics and constraints of the pipeline to the ILI service provider, which is typically done through a pipeline questionnaire. Characteristics of the pipeline that shall be provided for assessing the compatibility of the in-line inspection system with the inspection goals and objectives are described in NACE RP0102.

They include:

1. Physical properties of the pipeline section, such as length, diameter, wall thickness, valves, bends, known physical restrictions, openings, launchers and receivers, etc.
2. Characteristics of the fluid such as type and composition, chemical properties (e.g., corrosivity), flow rate, temperature, pressure, and cleanliness of the pipeline.

For two-way flow, such as in storage operations, upstream and downstream flow directions should be clearly defined.

The service provider shall define the constraints under which the in-line inspection tool will operate, such as:

a. Restrictions on temperature, pressure, minimum bend or elbow radii.

b. Minimum spacing of bends or elbows to each other.

c. Maximum and minimum velocities.

d. Minimum and maximum wall thickness.

e. Any known product characteristics that would limit or preclude a successful inspection.

f. Tool weight and overall length.

g. Special launching and receiving constraints especially for launching and receiving facilities.

h. Requirements for check valve positions.

i. Minimum bore requirements and drive cups compression.

j. Anticipated run length and any concomitant limitations on battery life, data storage capacity and/or mechanical wear.

6.4 SELECTION OF AN IN-LINE INSPECTION SYSTEM

Typically, the service provider will recommend an in-line inspection system based on the operator's goals and objectives. Before making a recommendation, the service provider shall evaluate and make available to the operator:

a. Expected performance of the in-line inspection system with regard to detection, identification, sizing, locating, and coverage capabilities for the anomalies of interest and pipeline to be inspected.

b. Physical characteristics of the in-line inspection tool, including its size, weight, and environmental limitations.

c. Reporting requirements.

d. Operational reliability of the tool (history, operational success, etc.).

e. Performance on other types of anomalies other than those of interest.

f. Additional operational constraints.

If the inspection goals include looking for multiple anomalies or characteristics (e.g., corrosion in dents, cracking with associated corrosion and/or dents, etc.), a service provider may recommend more than one tool or system that can best assess the overall condition of the pipeline.

The operator shall select the appropriate in-line inspection systems that meet the goals and objectives established in 6.2. The operator may select multiple systems that, when used in combination, meet the goals and objectives of the inspection.

6.5 PERFORMANCE SPECIFICATION

Prior to selecting an inspection system, the service provider shall provide the operator with a written performance specification for the inspection. Based on the service providers' review of the pipeline to be inspected and existing conditions, (see 6.4), the service provider shall state whether the chosen in-line inspection system can meet the performance specification in that pipeline and under the existing operating conditions. Requirements for a performance specification are given in Section 7.

7 Qualification of Performance Specifications

7.1 GENERAL

This section covers requirements for the qualification of performance specifications for an in-line inspection system. The requirements of this section shall be met prior to an inspection run.

The requirements in this section are written so that all concerned have a clear understanding of the in-line inspection system's capabilities as defined in a performance specification for an in-line inspection run. Within this section, the party that is typically responsible for meeting a requirement may be identified. Nothing in this section should preclude service providers and operators from agreeing that one party is responsible for activities or requirements that are typically performed by the other.

7.2 PERFORMANCE SPECIFICATIONS

Performance specifications shall define, through the use of statistically valid methods, the ability of the in-line inspection system when run in a specific pipeline to detect, locate, identify, size pipeline anomalies, components, and features. An in-line inspection system may be capable of addressing more than one type of anomaly or characteristic during an inspection run. If so, the performance specification shall address each type of anomaly or characteristic.

The performance specification shall define the capabilities of the in-line inspection system to detect, locate, identify and size anomalies and characteristics in terms of the following parameters:

a. The type of anomaly or characteristic covered by the performance specification.
b. Detection thresholds and probabilities of detection, (See Appendix A).
c. Probabilities of proper identification (See Appendix A).
d. Sizing or characterization accuracies.
e. Linear (distance) and orientation measurement accuracies.
f. Limitations.

This Standard recognizes that the capabilities listed above are interrelated. To provide uniformity and minimum requirements, this Standard requires individual value or values for each parameter be given and requires that all significant interactions be defined and addressed under "Limitations."

The performance specification shall state how the system will measure distance and how reference points will be utilized/required.

The performance specification shall state the geometrical limitations of the system in terms of passage capabilities through straight pipe, bends, and fittings.

An example format for a performance specification is given in Appendix A. This appendix is largely based on a similar format developed by the Pipeline Operators Forum.

7.2.1 Anomalies, Components, Features and Characteristics

The performance specification shall clearly state the type or types of anomalies, components, and characteristics that are to be detected, identified and sized by the in-line inspection system in the line to be inspected.

Types of anomalies may include, but are not limited to:

a. Metal loss.
  1. Corrosion (external and internal).
  2. Gouges.
  3. Grooves.
b. Crack-like anomalies, such as stress-corrosion cracking (SCC).
c. Seam weld cracks.
d. Girth weld cracks.
e. Deformation:
  1. Dents.
  2. Pipe ovality.
  3. Wrinkles or 'ripples'.
  4. Buckling.
f. Metallurgical:
  1. Cold working.
  2. Hard spots.
  3. Manufacturing anomalies (such as laminations, slugs, scabs, and slivers).

Components or other features may include, but are not limited to:

a. Valves, tees, fittings, and casings.
b. Other appurtenances, taps, metallic sleeves.
c. Girth, seam welds or other end connections (couplings, bell/spigot connection, chill rings).

Characteristics may include, but are not limited to:

a. Geographic position of the centerline of the pipe.
b. Wall thickness and diameter changes.
c. Strain.
d. Pipe characteristics, such as manufacturing process (e.g., seamless, DSAW).
e. Locations of components or anomalies.

7.2.2 Detection Thresholds and Probabilities of Detection

The performance specification shall clearly state one or more detection thresholds and probabilities of detection (POD) that are statistically derived, for each type of anomaly or characteristic covered by the specification.

The detection threshold(s) as a function of anomaly type should include, where applicable:

a. Metal loss.
  1. *Corrosion (external and internal)*: minimum depth, length, width, and orientation.
  2. *Gouges*: minimum depth, length, width, geometry and orientation.
b. Crack-like anomalies (pipe body or weld). Minimum depth, length, width (opening), orientation, and proximity to other cracks, anomalies, or pipeline components.
c. Deformation.

1. *Dents:* minimum depth, or reduction in cross-section, or reduction in diameter and orientation.
2. *Pipe ovality*: minimum ovality.
3. *Wrinkles or 'ripples'*: minimum height and spacing & orientation.
4. *Buckles*: minimum depth or reduction in cross-section or diameter & orientation.

d. Metallurgical.
1. *Cold work*: presence of and severity.
2. *Hard spots*: minimum diameter of hard spot and difference in hardness between the hard spot and the base material.
3. *Manufacturing anomalies (such as slugs, scabs, and slivers)*: minimum dimensions and position.

e. External coating faults: minimum dimensions.
f. Girth welds, seam welds.
g. Other anomalies, conditions, or pipeline components as required, dependent on industry standards or practices.

For example, the detection threshold(s) and POD(s) may be stated in one of the following manners:

1. Minimum dimension or characteristic that can be detected at a given POD. For example, a depth detection threshold and POD for metal loss could be stated as:

Table 1—Examples of How to Characterize PODs for Depth Detection

Depth Detection Threshold	POD	Qualifiers and Limitations
10% t	90%	Extended metal loss length and width > $3t$
15% t	90%	Pits t < length and width < $3t$
35% t	90%	Axial grooves width < t, length > $3t$
Etc.		

Note: t= pipe wall thickness

2. POD as a function of one or more characteristics of the anomaly. For example:

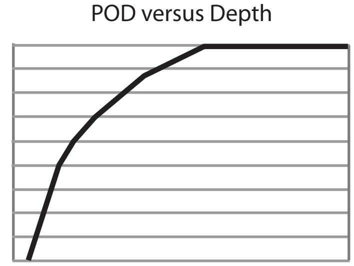

Figure 3—POD Function vs. Metal Loss

3. The use of a reference anomaly or anomalies. For example:

Table 2—Reference Anomalies

Reference Anomaly (length by width)	Detection Threshold	POD	Qualifiers and Limitations
$5t$ by $5t$	10%	90%	Extended metal loss Length and width > $3t$
$2t$ by $2t$	15%	90%	Pits t < Length and width < $3t$
$5t$ by $1t$	35%	90%	Axial Grooves Width < t, length > $3t$

Note: t = pipe wall thickness

In all cases, both detection threshold(s) and POD(s) must be given. The detection threshold(s) and POD(s) must be statistically valid for the distribution of anomaly dimensions or characteristics reasonably expected for the inspection to be conducted.

When the detection threshold(s) and POD(s) significantly vary with anomaly dimensions or characteristics, individual detection thresholds and POD's shall be given for the range of anomaly dimensions or characteristics for which they are valid.

7.2.3 Probability of Identification

The performance specification shall clearly state a statistically derived and valid probability of identification (POI) or a range of POI's for each type of anomaly, component, and characteristic covered by the Specification. A POI refers to the probability of correct identification of anomalies, components, or characteristics that are detected by an in-line inspection system.

For example, refer to Table 4 in Appendix A.

7.2.4 Sizing Accuracy

The performance specification shall clearly state the sizing accuracies for each type and range of anomalies covered by the Specification. A sizing accuracy refers to how closely the reported dimensions agree with the true dimensions.

Sizing or characterization accuracies shall include a tolerance (e.g., ± 5% or 10% on depth sizing), a certainty (e.g., 80% or 90% of the time), and the confidence level (e.g., 95%). The sizing or characterization accuracies, as a function of anomaly type, should include:

a. Metal loss.
1. *Corrosion (external and internal)*: depth, length, width.
2. *Gouges*: depth, length, width.

b. Cracks in the pipe body: depth, axial length, and proximity to other cracks (if applicable). For crack colonies, the overall colony axial length and circumferential width, along with the depth and axial length of the largest crack or cracks in the colony.
c. Cracks in welds and other weld anomalies: depth, length, and proximity to other cracks (if applicable).
d. Deformation.
   1. *Dents*: depth, or reduction in cross-section or diameter and length.
   2. *Ovality*: percent ovality or minimum cross-section or diameter.
   3. *Wrinkles and 'ripples'*: wrinkle or 'ripple' height and spacing between adjacent wrinkles or 'ripples'.
   4. *Buckles*: reduction in cross-section or diameter.
e. Metallurgical
   1. *Cold work*: presence of and severity.
   2. *Hard spots*: diameter of the hard spot, and if applicable, estimated hardness (or difference in hardness between that of the hard spot and that of the base pipe material).
   3. *Manufacturing anomalies (such as slugs, scabs and slivers)*: dimensions (or other characteristics) and position through the wall.

For an example, refer to Table 5 in Appendix A.

The sizing accuracies must be statistically valid for the distribution of anomaly dimensions reasonably expected for the inspection to be conducted. When the sizing accuracies significantly vary with anomaly dimensions or characteristics, individual sizing accuracies shall be given for the range of anomaly dimensions for which they are valid.

7.2.5 Sizing Capability

The performance specification shall clearly state the sizing capabilities for characteristics that are not covered above but are included in the Specification. Where appropriate, sizing capabilities shall include a tolerance (e.g., ± 0.1% on reported location), a certainty (e.g., 80% of the time) and a confidence level (e.g., 95%). The performance specification shall state a location accuracy from a fixed location and an orientation accuracy. Where appropriate, the performance specification should state the system's ability to compare repeat runs with the same tools or other suppliers' tools. This can be stated as an accuracy specification.

7.2.6 Limitations

Physical and operational factors or conditions that limit the detection thresholds, PODs, POIs, and sizing accuracies shall be identified in the performance specification. Examples of physical and operational factors that can limit detection thresholds, PODs, POIs, and sizing accuracies include:

a. Anomaly orientation angle and proximity to other anomalies or pipeline components.
b. Anomaly shape and area affected.
c. Maximum and minimum pipe wall thickness (e.g., within a bend or in a 'casing').
d. In-line inspection system speed outside of the specified range.
e. Pipeline cleanliness.
f. Pipe metallurgy.
g. Pipe curvature, field bend or elbow.
h. Pipe wall coverage.
i. Acceptable sensor loss or data degradation from sensor loss.

The following table is an example of how limitations may be reported.

Table 3—POD Limitations

	POD Limitations		
	Extended L&W > 3t	Pitting 1t < L&W < 3t	Axial Grooves L > 3t, W < 1t
Depth	Velocity < 12mph; t < 0.75"; 1 < L/W < 6; > 1" from girth welds	Velocity < 8mph; t < 0.75"; 1< L/W < 3; >1"from girth welds	Velocity < 6mph; t < 0.75"; > 1" from seam welds
Width	t < 0.75"; 1< L/W< 6;	t < 0.75"; 1 < L/W < 3;	t < 0.75"; > 1" from seam welds
Length	t < 0.75;	t < 0.75"	t < 0.75"; > 1" from seam welds

The change in detection threshold, POD, POI, and sizing accuracy that results from operation outside the range of acceptable conditions should be provided in the performance specification. Alternatively, no detection threshold, POD, POI, or sizing accuracy should be implied outside the range of acceptable conditions. Results for an inspection (or portion of an inspection) that are outside the range of acceptable conditions should be considered advisory.

7.2.7 Geometric Passage Capabilities

To assess the risk of the in-line inspection system becoming lodged in the pipeline to be inspected, the inspection systems' passage limitations shall be stated in terms of pipe geometry, taking into consideration the diameter of the inspection systems' hardware components required to negotiate the pipeline without incurring damage. Such geometric limitations shall be measured or calculated for straight pipe runs, bends, and other fittings through which the system may pass during the inspection. Calculations shall consider the minimum clear diameter required by the inspection system for passage without damage and the most limiting dimensional tolerances allowed by industry standards in the manufacture of pipe, bends, and fittings. Considerations of pipe geometry tolerances may include diameter, wall thickness, ovality, bend radius, and branch/offtake diameter.

The performance specification shall state the in-line inspection system's geometric limitations for straight pipe, bends, and fittings. The specification shall state these limitations in terms of allowable pipe physical parameters, such as minimum inside diameter, maximum wall thickness, minimum bend radius, maximum branch/offtake diameter, minimum required straight pipe length between bends. The performance specification shall also contain a statement, when applicable, that industry standards manufacturing tolerances were utilized in specifying these limitations. If other tolerancing mechanisms are used, these shall be specified in the performance specification.

A gauging pig run should be conducted before an in-line inspection tool run is conducted in that segment for the first time.

Additional constraints or limitations that shall be stated are:

a. Run length.
b. Data storage capacity.
c. Launching & receiving trap requirements.
d. Required check valve positions or tool limitations with respect to valves.

7.2.8 Other Capabilities

Nothing in this Standard precludes a service provider from including additional capabilities in a performance specification.

7.3 QUALIFICATION REQUIREMENTS

Each performance specification shall be qualified by the service provider using a methodology that is defined by the service provider.

The methodology used to qualify a performance specification shall be based on sound engineering practices, be statistically valid, and include a definition of essential variables (see 7.3.1) for the in-line inspection system.

The methodology used to qualify the performance specification shall be based on at least one of the following methods:

a. Verified historical data,
b. Large-scale tests from real or artificial anomalies, and/or
c. Small-scale tests, modeling, and/or analyses.

7.3.1 Essential Variables

The performance specification shall define and document the essential variables for the in-line inspection system being qualified. Essential variables are characteristics or analysis steps that are essential for achieving desired results. Essential variables may include, but are not limited to:

1. Constraints on operational characteristics, such as inspection tool velocity.

2. Inspection tool design and physical characteristics, such as:

- Inspection parameters (e.g., magnet strength, magnetization system components and dimensions, ultrasonic frequency, amplitude, and angle).
- Sizing system components (e.g., sensor type, spacing, and location relative to the source of the inspection energy).
- Analysis algorithms (e.g., steps used in preprocessing, classification and characterization of signals, interaction rules).

Changes to the essential variables of a system shall require a new performance specification and qualification.

7.3.2 Data and Analyses Requirements

The data and analyses used to qualify a performance specification shall cover the full range of each essential variable defined for the specification. Data and analyses that are not within the range of essential variables defined for a performance specification shall not be used to qualify the specification.

Data and analyses used to qualify a performance specification shall be selected to generate a representative distribution of anomaly dimensions, components, and characteristics reasonably expected for the inspection to be conducted.

The analyses used to define the statistical quantities, such as PODs, POIs, and sizing accuracies, shall be in accordance with standard statistical analysis methods, and the confidence levels given shall be consistent with the amount of data used in the analyses.

Data and analyses used to qualify a performance specification shall be documented and maintained. For anomalies, the data shall include values of the essential variables during the inspection, inspection conditions (e.g., pressure, velocity), reported anomaly characteristics, and verified anomaly characteristics.

When an in-line inspection system is used for multiple inspections (as is the normal case), a database shall be established for the data and analyses used to qualify performance specifications. The database shall be used to improve accuracies, certainties, and confidence levels when such values are included in future performance specifications. Changes in design or analysis procedures must be accounted for and documented in all databases.

The qualification of a performance specification shall be considered valid for the range of essential variables defined for the Specification. If data indicates the in-line inspection system does not meet the performance specification for any values or combinations of essential variables, the essential variables must be redefined, or the performance specification must be restated.

7.3.3 Validation Based on Historic Data

Verification measurements from previous runs of an in-line inspection system may be used to qualify a performance specification. Verification measurements are dimensions and characteristics that have been physically measured after anomalies have been exposed.

7.3.4 Validation Based on Full-scale Tests

Data from full-scale tests on real or artificial anomalies may be used for qualification provided the data is correlated or calibrated to field data. An example of a full-scale test used for qualification is a pull test. The methods by which the data are correlated or calibrated shall be documented.

7.3.5 Validation Based on Small-scale Tests, Modeling, and Analyses

Data from small-scale tests, modeling, and/or analyses may be used to demonstrate that the performance of a system component, such as a type of sensor, is consistent with data used for qualifying performance specifications.

Data from small-scale tests, modeling, and/or analyses must be correlated or calibrated with historical field data or full-scale test data. The methods by which the data is correlated or calibrated shall be documented.

Data from small-scale tests, modeling, and/or analyses that are consistent with historical data and full-scale data may be used to qualify a change in system components and to extend the range of essential variables.

7.4 DOCUMENTATION AND OTHER REQUIREMENTS

The methodology and data used to qualify a performance specification shall be fully documented and available for review.

7.4.1 Detection Thresholds, PODs, and POIs

Detection thresholds, PODs, and POIs shall be based on historic or full-scale test data. If a statistically significant amount of historic or full-scale test data is not available, the detection thresholds, PODs, and POIs shall be estimated using prior experience with other inspection systems, provided the estimates are clearly identified as such in the performance specification.

When using historical or full-scale data, detection thresholds shall represent the anomaly dimension(s) that must be exceeded to achieve the POD. When the in-line inspection system is operated within its essential variables and under the conditions planned for the inspection, it must be able to detect anomalies that exceed the detection thresholds with the stated POD.

7.4.2 Sizing Accuracies

Sizing accuracies shall be based on verification measurements from prior inspections or full-scale tests. If a statistically significant amount of historic or full-scale test data is not available, sizing accuracy may be estimated using statistically homogeneous small-scale test data, modeling results, analyses, and/or prior experience with other inspection systems, provided the estimates are clearly identified as such in the performance specification.

Sizing accuracies may be determined by comparing reported characteristics with verification measurements. Sizing accuracies should be determined using a linear or nonlinear regression analysis (e.g., a least-squares best fit) of reported and measured dimensions or characteristics with the reported ILI characteristics plotted as the independent variable (x axis) and field verified characteristics plotted as the dependent variable (y axis) unless the alternative is known to be statistically valid.

- Tolerances should be stated as the difference between a one-to-one relationship of the reported dimensions and verification measurements. Tolerances may be stated as an absolute value (e.g., ± 0.5" or ± 10% of the wall thickness) or a relative value (e.g., ± 10% of the reported dimension).
- Certainties should be calculated based on the frequency with which the reported dimension or characteristic is within tolerance. Certainties may include the frequency with which out-of-tolerance errors are over-predicted or under-predicted.
- The confidence level should be calculated as the statistical confidence level that applies to the tolerance or certainty.

Sources of differences between reported and measured characteristics should be identified, documented, and accounted for in the statistical analyses used to determine the tolerances, certainties, and confidence levels where practical. Sources of errors include those due to the in-line inspection system, as well as those due to hands-on measurements made of a given characteristic. The tolerances and certainties required in this Standard refer to errors due to the in-line inspection system only. These errors include, but are not limited to, systematic errors (errors that result from known, but unaccounted for causes, such as sensor liftoff), random errors (lack of repeatability and other errors with no identified cause), and anomaly-specific errors (errors in sizing particular to geometries or assemblies of anomalies).

7.4.3 Review and Revision Requirements

The qualification methodology shall be reviewed on an annual basis to ensure its continued validity. If the methodology is found to be no longer valid, any performance specifications that were validated by the methodology must be revalidated by an acceptable methodology.

All reported significant errors in detection, identification, and sizing shall be investigated. Significant errors are those that are outside the performance specification.

The root cause(s) of all reported significant errors shall be determined and used to modify, as necessary, the analysis procedures and future performance specifications.

8 System Operational Validation

8.1 GENERAL

This section defines requirements for validating that an in-line inspection system is prepared and run in the manner defined as necessary to achieve the performance specifications as outlined in Section 7. Four sets of requirements are given:

1. Project requirements.
2. Pre-inspection requirements.
3. Inspection requirements.
4. Post-inspection requirements.

All in-line inspection project requirements, pre-inspection, inspection, and post-inspection requirements and procedures shall be documented.

8.2 PROJECT REQUIREMENTS

Project requirements assure that the in-line inspection system and operating conditions are consistent with those required to achieve the performance specifications defined in Section 7.

For additional information, see NACE Standard RP0102.

Prior to the actual inspection, the pipeline geometry and planned pipeline operating conditions shall be reviewed to ensure they are consistent with the information previously provided.

The operator shall disclose to the service provider any and all changes in geometry or planned operating conditions before the in-line inspection system is launched into the pipeline.

The service provider shall work closely with the operator to minimize the likelihood of damage to the pipeline or the inspection system.

The service provider shall confirm that the in-line inspection system to be used for the inspection is consistent with that used to define the required performance specifications. The service provider shall verify that a qualified crew, per ASNT ILI-PQ, is available to support running the in-line inspection system.

8.3 PRE-INSPECTION REQUIREMENTS

Pre-inspection requirements are defined as the activities that are to be completed before launching an in-line inspection tool into a pipeline.

8.3.1 Function Tests

The service provider shall define and document necessary steps to prepare and validate proper operation of the in-line inspection tool prior to an inspection run. The steps shall include a function test to ensure the tool is operating properly. Pre-inspection function tests may include, but are not limited to:

a. Confirmation that an adequate power supply is available and operational.
b. Confirmation that all sensors, data storage, odometers, and other mechanical systems are operating properly.
c. Confirmation that adequate data storage is available.
d. Confirmation that all components of the inspection tool are properly initialized.

Records of the pre-inspection function tests should be made available to the operator, if requested.

8.3.2 Mechanical Checks

Prior to an inspection run, the in-line inspection tool shall be checked visually to ensure that it is mechanically sound. The electronics shall be checked to make sure that they are properly sealed and functional.

8.3.3 Above Ground Markers

Reference locations for above-ground markers, when utilized, shall be established and validated to ensure they are sufficient to meet the location accuracy stated in the performance specification.

The service provider shall set the appropriate tool detection threshold on the above-ground markers to ensure proper detection.

8.4 INSPECTION REQUIREMENTS

Inspection requirements are intended to ensure successful running of the in-line inspection tool. The requirements include activities that occur from the time the in-line inspection tool is placed into the launching device until it has been removed from the receiving device.

8.4.1 Launching

The requirement for handling, as well as other requirements associated with placing the in-line inspection tool into the launching device and launching the tool, shall be defined.

The in-line inspection tool shall be placed into the launching device and shall be launched in accordance with defined requirements and proper procedures.

All system handling, placement, and launching activities shall be carefully monitored.

8.4.2 Running

The pipeline operating conditions shall be monitored while the in-line inspection tool is in the launcher, the pipeline, and/or the receiver. Efforts shall be taken to ensure the operating conditions are consistent with those required to meet the performance specification. Variations from the required operating conditions shall be identified and documented.

8.4.3 Above Ground Markers

Above-ground markers, when utilized, shall be placed as close as practical to the planned reference locations defined earlier.

The actual location of each above-ground marker shall be measured and documented.

If the above-ground markers are not placed at the planned reference points, the actual locations shall be identified and documented.

8.4.4 Receiving

Handling and other requirements associated with the removal of the in-line inspection tool from the receiving device shall be defined.

The in-line inspection tool shall be removed from the receiving device in accordance with predefined requirements and proper procedures.

All handling and removal activities should be carefully monitored.

8.5 POST-INSPECTION REQUIREMENTS

Post-inspection requirements cover activities that are to be completed, if required, on site after an inspection run has been completed and the inspection tool is retrieved from the pipeline. These activities are intended to validate that the in-line inspection tool has operated correctly during the inspection run.

8.5.1 Function Tests

The service provider shall define and document steps necessary to validate the proper operation of the in-line inspection tool after an inspection run. These steps shall include a function test to ensure the tool has operated properly during the inspection. Post-inspection function tests may include but are not limited to:

a. Tool cleanliness visual inspection.
b. Confirmation that adequate power was available and operational.
c. Confirmation that all sensors, data storage, odometers, and other mechanical systems operated properly.
d. Confirmation that adequate data storage was available.
e. Examination of tool for damage and significant wear.

Deviations from these function checks shall be noted, and their effects shall be included in the inspection report.

Continuously monitored in-line inspection tools should not require post inspection function tests.

8.5.2 Data Checks

The service provider shall define and document the steps necessary to check the quality and quantity of the data collected during the inspection run. These steps shall include but are not limited to:

a. Confirmation that a continuous stream of data was collected during the inspection.
b. Confirmation that the data meets basic quality requirements.

Data checks are typically based on direct measurement data, data completeness, and data quality. Deviations shall be noted and their effects communicated to the operator and included in the report.

8.5.2.1 Direct Measurement Data

Direct measurement data may include information regarding system speed, operating temperature, operating pressure, and technology-specific data, such as magnetization levels for a magnetic flux leakage tool. Direct measurement data is typically used to make general judgments about the basic operation of an inspection tool during a run. Such data shall be utilized as one of the post-inspection data checks.

8.5.2.2 Data Completeness

The amount of data to be collected during an inspection is a function of line length and circumference. The amount of data collected allows an initial assessment of data completeness. The amount of data collected is typically accessible after processing the recorded data. Completeness of data shall be checked after the initial processing of the data. This will be considered one of the data checks.

8.5.2.3 Data Quality

Data quality can be demonstrated using a variety of data integrity checks, such as verification that the data taken was within the operating ranges of the sensors used. Such data checks shall be included in the data checking process. Post-inspection data quality checks do not cover the interpretation of the obtained data.

9 System Results Verification

9.1 INTRODUCTION

This section describes the methods that shall be applied to verify that the reported inspection results meet or are within the performance specification for the pipeline being inspected. Requirements for establishing a performance specification are given in Section 7.

Verification activities may require agreement between the operator and the service provider as to the extent of verification work, such as verification digs, and who will perform or be assigned to specific activities. Such assignments are not within the scope of this Standard.

9.2 EVALUATION OF SYSTEM RESULTS

The process shown in Figure 4 shall be used to verify that the reported inspection results have been met and are consistent with the performance specification for the pipeline being inspected.

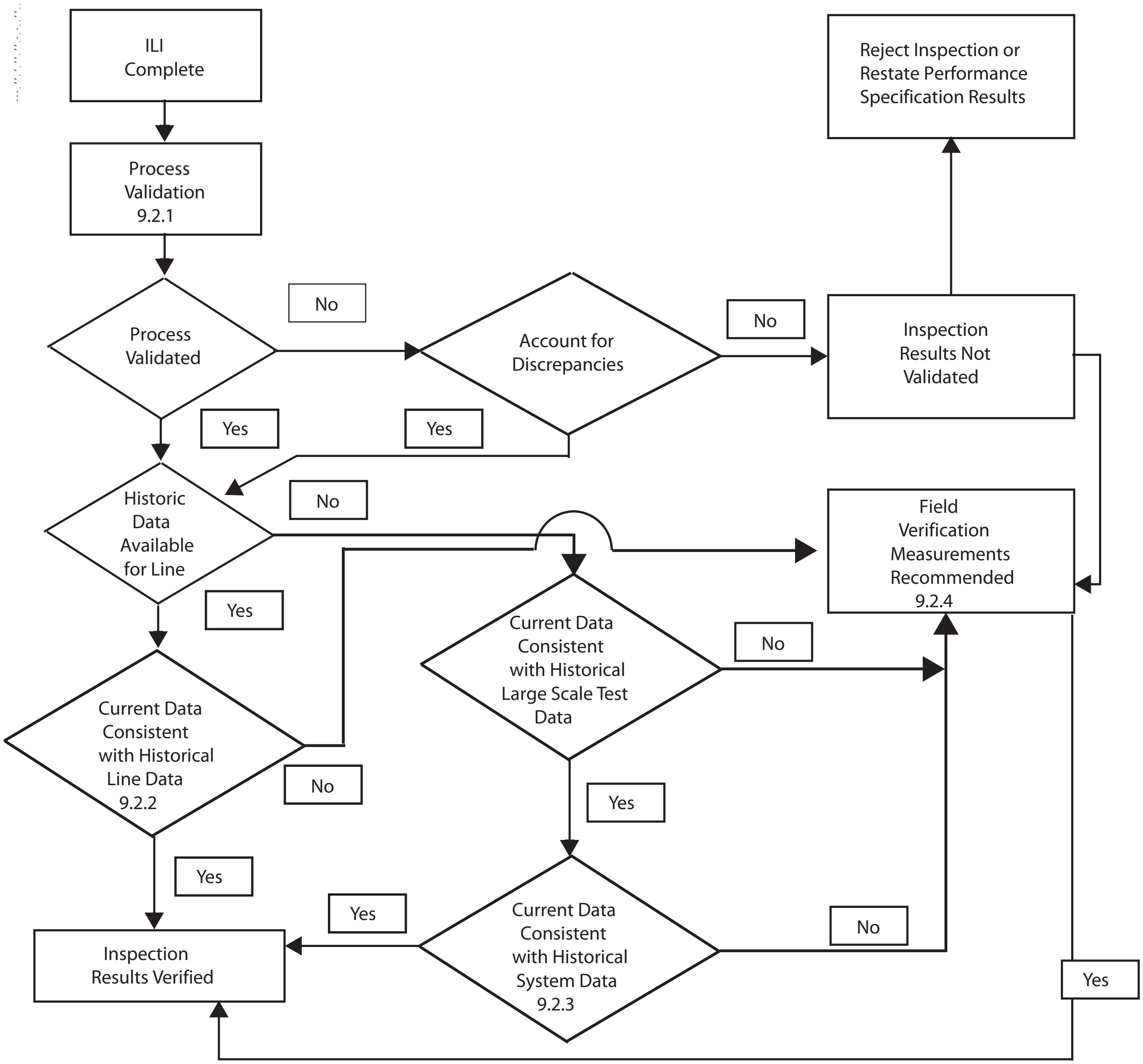

Figure 4—Inspection Results Verification Process

The process shall include

a. A process validation, and
b. A comparison with historic data (if available) for the pipeline being inspected, and/or
c. A comparison with historic data or large-scale test data from the inspection system being used.

Based on these steps, verification measurements may be required. Not all inspections require verification measurements, as discussed later in this section.

9.2.1 Process Validation

A process validation shall be conducted for all inspections. The process validation shall include (1) a confirmation of the data analysis processes, (2) a comparison of recorded data to previous data or that used to establish the performance specification, and (3) a comparison of reported locations and types of pipeline components with the actual locations and types of components.

The process validation may include, but is not limited to:

a. A review of the pipeline route, geometry, and operating conditions during the inspection relative to those planned for the inspection and the essential variables of the inspection system.
b. A review of the set-up and operation of the inspection tool relative to that planned for the inspection and the essential variables of the inspection system.
c. A review of the processes used for:
   1. Bulk data handling, conditioning, and filtering.
   2. Automated analyses (grading) (if used).
   3. Manual or other adjustments of data or grading.
   4. Identification, evaluation, and integration of supplemental data relative to the processes required for compliance with the performance specification.
d. A review of any additional requirements for the inspection, including any standards or codes applicable to the inspection.
e. A review of the reported anomaly types and characteristics relative to the data used to establish the performance specification.
f. A comparison of reported locations and types of pipeline components and equipment, such as above-ground markers, anchors, bends, casings, flanges, girth welds, magnets, pig passage indicators, metal repair sleeves, taps, tees, and valves, relative to actual locations of components and appurtenances.

Appendix B gives an example of a quality assurance program used for process validation.

Inconsistencies uncovered during the process validation shall be evaluated and resolved. If the inconsistencies cannot be resolved, the inspection results are not verified. If the inspection results are not verified, the performance specification may be restated or all or parts of the inspection data may be rejected.

9.2.2 Comparison with Historical Information on Line Being Inspected

After process validation, the reported inspection results shall be compared to prior historical data on the pipeline being inspected if such data is available. Types of prior historical data that can be used for comparisons may include, but are not limited to:

a. Prior in-line inspection results.
b. Results from prior excavations and measurements of anomalies similar to those covered by the inspection.
c. Other data and analyses, when supported by sound engineering practices.

If prior in-line inspection data is available for the specific pipeline, the reported results can be considered verified if:

a. Differences in the reported locations, and characteristics of the anomalies are within the tolerances, certainties and confidence levels stated in the performance specification, or
b. Differences in the reported locations, and characteristics are outside the tolerances stated in the performance specification but the differences can be explained using sound engineering practices (e.g., growth of corrosion anomalies, advancements in tool technology).

The reported results can also be verified by comparisons with results from prior excavations and measurements, provided (1) the data from such excavations and measurements represents the range of reported anomaly types and characteristics and (2) any differences are within the tolerances, certainties and confidence levels stated in the performance specification or can be explained using sound engineering practices.

If the reported results are not verified using comparisons with prior historic data, additional comparisons with other inspection data (as defined below) or verification measurements are recommended. Alternatively, the performance specification can be restated or all or parts of the inspection data can be rejected.

9.2.3 Comparisons with Other Data from the Same Inspection System

When historic information on the line being inspected is not available or the reported results are not verified by the comparisons with historic information, the reported results may be verified through comparisons with prior data from the inspection system being used on other lines supplemented with data from large-scale tests as warranted.

The reported results can be considered verified by comparisons with the results from prior validated inspections on other lines, provided (1) the prior data represents the range of reported anomaly types and characteristics, and (2) the prior essential variables match those used in the current inspection.

If the reported inspection results are not consistent with prior data, verification measurements are recommended as discussed below. Alternatively, the performance specification can be restated or all or parts of the inspection data are not validated.

9.2.4 Verification Measurements

Verification measurements are a common method for evaluating in-line inspection results. Appendices C and D provide examples of verification measurement procedures. NACE Standard RP0102 also provides additional information on verification measurements.

When verification digs are performed, information from the measurements shall be given to the service provider to confirm and continuously refine the data analysis processes. The information to be collected from the verification measurements and given to the service provider shall be agreed upon by both the operator and the service provider and shall include the measurement techniques used and their accuracies. Information to be provided by the service provider to the operator should include the measurement threshold, reporting threshold, and interaction criteria, if any. Appendix D lists types of information that should be provided to the service provider.

Any discrepancies between the reported inspection results and verification measurements that are outside of performance specifications shall be documented. The source of the discrepancies should be identified through discussions between the service provider and the operator and through analyses of essential variables, the dig verification process, and data analysis process.

Based on the source and extent of the identified and analyzed discrepancies, one of the following courses of action may be taken:

a. The inspection data may be reanalyzed taking into account the detailed correlations between anomaly characteristics and the inspection data.
b. All or part of the inspection results may be invalidated.
c. The performance specification may be revised for all or part of the inspection results.

9.2.5 Other Methods

Other methods of evaluating reported inspection results may be used if they are based on sound engineering practices and are statistically valid.

9.3 USING VERIFICATION MEASUREMENTS

When verification measurements are used, a comparison shall be made between reported and measured anomaly characteristics to verify the accuracy of the reported inspection results and to demonstrate that the reported results are consistent with the performance specification. The comparison analysis shall be statistically valid and based on sound engineering practice. Listed below are examples of statistical analysis methods that may be used for verifications.

1. *Comparison of Verification Measurements with the Performance Specification*. This is the simplest method of assessing inspection results. Reported results are considered verified if the verification measurements meet the performance specification. If the reported results do not meet the performance specifications, further analysis shall be performed. The accuracy of the verification measurements must be considered in the comparison. (See Appendix D for an example.)
2. *Comparison of a Population of Verification Measurements with Distributions*. This method assesses whether the verification measurements are statistically consistent with the performance specification by determining the probability of meeting the performance specification through the use of distribution functions such as binomial or normal distribution functions. It becomes more accurate as the number of verification measurements increases. This method is attractive when there is a high confidence level on the tolerance and certainty given in the performance specification. If the test population can be considered representative and if an appropriate number of measurements are consistent with the performance specification, the results are considered verified. (See Appendix D for an example.)
3. *Confidence Intervals*. This method compares the range of certainties indicated by the verification measurements to the certainty level in the performance specification. Confidence intervals provide an estimate of the precision with which the true certainty is known. This method is attractive when there is a low confidence level on the tolerance and certainty levels given in the performance specification. If the confidence interval reasonably bounds the stated certainty, the results are considered verified.
4. *Other Methods of Assessing Verification Results*. Other methods include combinations and modifications of the methods listed above.

Separate verification comparisons based on different types of metal loss geometries are permissible.

9.4 CONCLUSIONS ON USING VERIFICATION RESULTS

The methodologies available to assess verification results cannot, in general, guarantee the performance specification has been met unless every reported anomaly is verified. This is the case in all verifications in all industries. As a consequence, heavy emphasis must be placed on historic data, especially the data used to establish the performance specification. (See Section 7 for details on establishing performance specifications.)

As the size of the databases used to establish performance specifications increases, the specifications themselves should become more accurate. Consequently, verification activities tend to concentrate on identifying situations where there are clear problems. For inspections under unusual conditions or conditions not before seen, it may be beneficial to use a larger number of comparisons.

10 Reporting Requirements

This section describes requirements for reporting in-line inspection system results after the analysis of data has been completed. Reports shall include anomaly or feature identification and dimensions for which the performance specification has been qualified (Section 7) and also the results verified (Section 9). Other features or anomalies may be included but must be clearly identified as "unqualified."

For consistency, the definitions provided in Section 4 should be utilized in all reports for clarity and comparisons from one inspection to another.

The following reporting requirements are provided to clearly tie the ILI systems qualifications to the inspection results.

10.1 IN LINE-INSPECTION SYSTEM PERFORMANCE SPECIFICATIONS

Performance specifications shall be included in each report.

10.1.1 Performance Specification

10.1.1.1 The performance specification to be reported shall include, as applicable, the capabilities of the in-line inspection system to detect, identify, and size anomalies and characteristics (see 7.2):

a. Type of anomaly or characteristic which may be limited to (for MFL):
   1. Metal loss.
   2. Deformation with metal loss.
   3. Manufacturing indication.
   4. Crack like indication.
   5. Metal loss at weld seam.

b. Detection thresholds and probabilities of detection.
c. Probabilities of proper identification.
d. Sizing accuracies.
e. Anomaly measurement accuracies.
f. Location and orientation accuracies.
g. Limitations.

Additional information may be provided about anomalies that are not included in the performance specification, based on past experience, but these shall be qualified as "experience based" observations.

10.1.1.2 Also included are the essential variables (see 7.3.1) for the in-line inspection:

a. Constraints on operational characteristics, such as inspection tool velocity.
b. Inspection tool design and physical characteristics, such as:
   1. Inspection parameters (e.g., magnet strength, magnetization system components and dimensions, ultrasonic frequency, amplitude, and angle).
   2. Sizing system components (e.g., sensor type, spacing, and location relative to the source of the inspection energy).

c. Analysis algorithms (e.g., steps used in preprocessing, classification and characterization of signals, interaction rules).

10.1.2 Qualification Method

A description of the method used to qualify the performance specification shall be included in the report (see 7.4). The description shall identify the source of data or analyses used for qualification:

a. Verified historical data,
b. Large-scale tests from real or artificial anomalies, and/or
c. Small-scale tests, modeling, and/or analyses.

The description should also summarize the statistical techniques used to determine the performance specification.

10.1.3 Equipment Specifications

The report shall include any other parameters for which the in-line inspection system is qualified.

These may include:

a. Wall thickness range.
b. Temperature range (inside pipeline).
c. Maximum and minimum pressure.
d. Minimum bend radius.
e. Minimum internal diameter.
f. Tool length, weight.
g. Maximum length of pipeline that can be inspected in one run (may be coupled with run times and pipeline conditions).
h. Axial sampling frequency or distance.
i. Circumferential sensor spacing in nominal pipe.
j. Location accuracy of features with respect to reference girth weld, reference marker, orientation of the pipe, or a local/geodetic coordinate system.

10.2 REPORT CONTENTS

10.2.1 Summary

The report should include an executive summary that includes:

a. Date of survey.
b. Pipeline parameters:
 1. Pipe manufacturing method.
 2. Outside diameter.
 3. Nominal wall thickness.
 4. Pipe grade.
 5. Line length.
c. In-line inspection data quality.
 Any quality issues with the in-line inspection data, such as sensor malfunction, should be stated within the summary and described in the report.
d. Data analysis parameters.
 Clear communication of data analysis parameters should be included. At a minimum, measurement threshold, reporting threshold, and interaction criteria should be included. (See Appendix D.)

The executive summary may also contain observations that, while exceeding the reporting requirements based on the system's performance specification, could be of interest to the operator.

10.2.2 Inspection Results

The following information shall be provided for each feature reported in the report of the in-line inspection system results where appropriate or applicable:

a. Odometer distance (or absolute distance).
b. Identification of upstream girth weld.
c. Distance from feature to upstream girth weld.
d. 3 upstream and 3 downstream joint lengths.
e. Feature classification (e.g., anomaly, component, non-relevant indication).
f. Circumferential position.
g. Identification of upstream and downstream markers.
h. Distance from anomaly to upstream and downstream markers.
i. Tool speed.
j. Feature characterization.
 1. *Metal-loss features (e.g., corrosion, gouges)*.
 Depth or depth range (% wall thickness or depth measurement) and length.
 Width profile or shape.
 2. *Deformation features (e.g., dents, buckles, ovality, ripples, wrinkles)*.
 Depth (% of outside diameter or measurement of deflection from concentric pipe), or reduction in cross-section.
 Length, width.
 3. *Crack features (e.g., individual cracks, colonies of cracks, weld cracks)*.
 Depth or depth range (% wall thickness or depth measurement), length.
 Width (colonies), proximity to welds.
 4. *Metallurgical features*.
 Dimension(s).
 Position through the wall, hardness.
k. Inspection survey parameters:
 Changes in the essential variables may affect the quality and accuracy of the data recorded by an in-line inspection system (see 7.3.1). If any of these are different during the inspection from the values given in the performance specification, they shall be listed within the summary.

10.3 REPORTING FORMATS

The following tables and plots should be included in the final report. These options are recommended to aid in the integration of inspection results with pipeline integrity assessment programs.

10.3.1 A table of all girth welds, joint lengths, pipeline components, and markers should be included in the final report.

10.3.2 Summary and statistical data should be included. The following paragraphs provide some examples for metal loss ILI system results reporting. Modifications can be made for other ILI technologies.

10.3.2.1 One report could include the total number of metal-loss features:

1. Number of internal metal-loss features.
2. Number of external metal-loss features.
3. Number of metal-loss features with depth reportable to 19%*t*.
4. Number of metal-loss features with depth 20 – 29%*t*.
5. Number of metal-loss features with depth 30 – 39%*t*.
6. Number of metal-loss features with depth 40 – 49%*t*.
7. Number of metal-loss features with depth 50 – 59%*t*.
8. Number of metal-loss features with depth 60 – 69%*t*.
9. Number of metal-loss features with depth 70 – 79%*t*.
10. Number of metal-loss features with depth Š 80%*t*.

10.3.2.2 The following report may be provided over the entire pipeline length:

1. Number of metal-loss features in defined sections.
2. Number of metal-loss features in defined sections with depth Š 0.4*t*.
3. Number of metal-loss features in defined sections with depth Š 0.6*t*.
4. Histograms of range of data scatter for each type of anomaly, based on the statistical data obtained from the inspection.

10.3.2.3 The following plots may be provided in the report:

1. Circumferential position plot of all metal-loss features over the full pipeline length.
2. Circumferential position plot of all internal metal-loss features over the full pipeline length.
3. Circumferential position plot of all external metal-loss features over the full pipeline length.
4. Circumferential position plot of all metal-loss features as function of relative distance to the closest girth weld.
5. Circumferential position of all deformation features over the full pipeline length.

10.3.3 The report may include pressure-based assessment of metal loss anomalies or cracks and strain calculations for deformations. If this option is applied, the following information should be included in the report of ILI system results:

1. Assessment methodology.
2. Severity Ratio and definition (if a severity ratio is used).
3. Pipeline parameters used in calculations (i.e. MAOP, MOP, OD, wall thickness, safety factor, SMYS).

10.3.3.1 A quality process should be employed in order to ensure the accuracy of pressure and strain calculations.

10.3.4 The ILI system results may be provided in a database format that is easily imported into a pipeline integrity assessment application.

10.3.5 If dig data has been incorporated into the results, the report shall clearly show how the field measurements from the dig(s) have been incorporated into the report.

11 Quality Management System

11.1 SYSTEM SCOPE

This section establishes the quality system standards that are required of organizations that perform the services used for in-line inspection systems and in-line inspections, utilizing those systems. An effective quality management system includes processes that assure consistent products and services are being delivered, that those processes are properly controlled to prevent delivery of unsatisfactory services, and that adequate measures are in place to ensure that the products and services provided continue to meet the needs of a pipeline operator.

11.1.1 Limitations and Inclusions

The quality management system shall apply to all activities involved in the design, testing, field operations, data analysis, and support services provided that specifically relate to the use of an in-line inspection tool as covered in the scope of this document.

Organizations that have an existing quality management system that meets or exceeds the requirements of this section can incorporate these requirements within their existing system. For those organizations without a quality management system, this section provides a basis for establishing a quality system to meet specific in-line inspection system needs.

11.1.2 Quality Management System Perspectives

The quality management system shall take into consideration regulatory, safety, and environmental requirements.

11.1.3 Requirements Review

The quality system shall include processes that review the specified requirements of an inspection project, prior to and including the formal agreement between the pipeline operator and the organizations providing services within the scope of this document. As a minimum, this review shall, where applicable, include:

a. Identify which parties involved will be responsible for performing the specific tasks required for successful completion of the in-line inspection project.

b. A review of procedures to determine if they were followed during the entire inspection process.

c. A review to ensure the pipeline operator's in-line inspection needs can be met by the organization providing the services.

d. A review of the pipeline data provided by the pipeline operator to ensure the free passage of the in-line inspection tool.

e. A determination that inspection capabilities of the specified in-line inspection tool meet the specific objectives of the pipeline operator.

f. Evaluation of the analysis requirements of the pipeline operator, including any specific codes or standards used to ensure that the pipeline operator receives correct and accurate results from the in-line inspection.

11.1.4 Communications and Interfaces

Throughout the in-line inspection process, procedures shall include provisions to establish the necessary communication interfaces at the organizational and functional levels of the pipeline operator and the service provider(s) necessary to ensure any issues can be resolved in a timely manner.

11.2 QUALITY SYSTEM DOCUMENTATION

The organizations shall have a documented quality system for the scope of activities encompassed in this standard. The quality system documentation shall be made available to the pipeline operator upon request.

Records of qualification processes and procedures and personnel qualifications records in accordance with ASNT ILI-PQ shall be made available to the operator upon request.

The Quality Management System manual shall be reviewed and approved by the organization's senior officer.

11.2.1 Procedures and Work Instructions

Written procedures are required that describe the design, testing, contracting, field operations, data reduction and analysis processes as well as any support services necessary to successfully perform in-line inspections. Provisions shall be included for maintaining the quality of developed and utilized software applications. Software maintenance, configuration management and auditing should be performed in accordance with accepted industry practices. These procedures shall document the steps required to ensure that the individuals assigned to perform the task can perform the work in a consistent manner. The detail deemed necessary will depend on the task as well as the training and qualification requirements established by the supplying organization.

Training and personnel qualifications requirements shall be included in the procedures. Any procedure or work instruction that is required shall be available to the individual performing the work. Those procedures should also be available for review by the pipeline operator upon request. Procedures shall be reviewed and modified on a periodic basis.

11.2.2 Record-keeping

Each organization shall maintain adequate records of the in-line inspection relevant to their area of responsibility. Minimum record keeping-requirements shall be documented. These records shall include not only the inspection data related to the pipeline, but shall also include records pertaining to the setup of the equipment, personnel involved in the performance of the inspection and analysis of data, and a record of the inspection equipment used for the inspection. Records shall be maintained to the level that will allow the recreation of the system set up for inspection system verification and validation purposes. Additional information may also be maintained as part of the inspection record as determined between service providers and the pipeline operator.

Inspection records shall be retained for a time period no less than that required for legal or regulatory purposes. Adequate measures shall be taken to protect the records from loss or damage. When developing storage and regeneration procedures for inspection data, changes in data collection technology should be considered.

11.2.3 Document and Revision Control

All documents that are a part of the quality system shall be controlled to ensure that the latest revisions are available to those performing the work. A revision control system shall include procedures for withdrawal of outdated information, including documents, files, forms, and software. Procedures shall also be in place that allow the user to be able to identify the revision level of the document being used. This includes documents and software internal to the organization as well as documents, files, and software released to the end-user.

11.2.4 Design Change Control

Procedures shall be established to document and record changes in the design of the electrical, mechanical, and software components of an in-line inspection system. These records shall sufficiently document the changes to allow an evaluation of the effects on the essential variables of the previous design.

The same procedures apply to the design of services provided to a pipeline operator. Service process changes shall also be documented to review the effectiveness of the change.

Feedback from the pipeline operator should be a component of any design change procedure to be used when evaluating the effectiveness of changes to the design of either an in-line inspection system or service.

11.3 QUALITY CONTROL

Quality control procedures shall be included in the quality system to ensure that the project requirements are being fulfilled. This shall include the checks required to ensure the proper equipment has been selected, qualified, properly calibrated, and successfully operated in the field. This shall also include the checks required to ensure that the data has been properly analyzed, and the date successfully delivered to the pipeline operator.

Quality control procedures shall also include those procedures necessary to demonstrate that all personnel are qualified in accordance with the requirements of this standard.

Procedures shall contain provisions for personnel to have the ability to interrupt the process when a quality control nonconformance is discovered and initiate immediate corrective action procedures to prevent further or more severe nonconformance.

Records shall be maintained of these quality checks and retained in the record keeping system selected by the organization.

11.3.1 Personnel Qualifications

In accordance with this standard (Section 5) and ASNT ILI- PQ for ILI Inspections, records of all personnel qualifications, including qualification levels, test scores and training records, shall be maintained for any individual performing the tasks identified in this standard. Qualification processes and procedures shall also be maintained as part of the Quality Management System.

11.3.2 Calibration and Standardization

To ensure a consistent and accurate inspection, service providers shall have documented procedures for the qualification and calibration of an in-line inspection system and analysis software. These procedures shall include requirements for the identification of all equipment used, requirements of the individuals performing the task, and provisions for the calibration of applicable test equipment that is traceable to a national standard.

11.3.3 Traceability

Each inspection project performed shall be uniquely identified to ensure all information pertaining to that project can be referenced for future use without confusion with other projects.

The equipment used for the inspection shall be uniquely identified to permit traceability. The use of serial numbers or other tracking references provides a history of equipment used and a way to monitor that equipment for changes in operation and functionality that may affect proper operation. If the historical information process is used for verifying inspection results, the data collected for this purpose shall be matched to the traceability of the ILI System utilized under this section.

Equipment traceability requirements shall extend to support equipment that directly affects the successful completion of a project when used in conjunction with the in-line inspection tool. Such devices typically include above ground marker systems, locating systems, playback and data processing equipment, data reduction and analysis software, and associated test equipment.

11.4 CONTINUOUS IMPROVEMENT

Provisions for continuous improvement shall be included in the quality system to facilitate the continuous improvement of the products and services provided to the pipeline operator. Effective improvement requires feedback from employees and the pipeline operator, a review of new technology developments, and a continuous observation and measurement of the results of the output of the organization.

11.4.1 Process Measurement

The key to any improvement process is the ability to measure the effectiveness of that process through quantitative measures. The relevant organization will provide indicators of the success of their processes. Key measures of those indicators shall be established. The process measures selected shall include measures relevant to the products and services provided. Basic measures include:

a. The run success percentage that measures the number of acceptable runs made versus the total number of runs made over a selected period of time.
b. A measure of the turn-around time of inspection data as measured from completion of the fieldwork to the time of delivery of the in-line inspection report.
c. The accuracy of the inspection results compared to verification dig inspections.
d. An analysis of the number and types of erroneous calls over a period of time, for each type of inspection system, based upon the stated performance specification or service requirement.

Other performance measures should be developed to further analyze the effectiveness of the processes being measured.

11.4.2 Corrective and Preventive Action

The quality system shall include procedures for correcting a nonconforming product or service. These procedures should include steps to prevent the nonconformance from recurring. This requires provision for adequate supervision commensurate with personnel experience and peer review crosscheck as necessary to assure accuracy of data.

Processes to prevent nonconformance from initially occurring shall also be part of the quality system. These processes are often included in the research and development program.

11.5 QUALITY SYSTEM REVIEW

The organizations shall periodically evaluate the Quality Management System in place within their organization. These reviews are performed to ensure the overall effectiveness of the Quality Management System is maintained and continues to meet the goals of the organization.

11.5.1 Internal Audit

The quality management system shall include provisions to allow management to periodically evaluate the effectiveness of the procedures and processes within the quality system. These internal audits shall be performed at defined intervals, and the records of the audits shall be maintained. Records of any corrective actions taken shall also be maintained.

11.5.2 External Audit

A pipeline operator or an independent entity may perform an audit of a service provider's quality system. Consideration may be given to parties that have no financial, competitive, or other incentive that may be in conflict with the financial, proprietary or intellectual nature of the organization being audited. Prior to performing the audit, the scope and procedure of the audit shall be clearly defined, discussed, and approved by the service provider.

APPENDIX A—PERFORMANCE SPECIFICATION EXAMPLE

Performance specifications will state Probabilities of Detection (POD) and Probabilities of Identification (POI). These terms are algebraically defined as follows:

POD = [# times detected/total # of anomalies x 100] per anomaly/feature type & size

POI = [# times correctly identified/total # of detected anomalies x 100] per feature type

This appendix provides a sample format for performance specifications as stated in Section 7.2.1 – 7.2.7. Table 4 lists features that may be detected along with their POIs. Table 5 lists PODs and sizing accuracies for metal-loss anomalies.

Table 4—Features and POIs

Feature	POI > 90%	50% > POI < 90%	POI < 50%
ANOMALIES:			
Metal Loss			
Cold Work			
Deformation			
Deformation with metal loss			
Axial pipe-body crack			
Axial seam crack			
Other seam-weld anomaly			
Circumferential pipe-body crack			
Girth weld crack			
Other girth weld anomaly			
Crack colony			
Ovality			
Wrinkle or ripple			
Buckles			
Hard spot			
Metallurgical anomaly (scabs, slivers, laminations, other surface and mid-wall anomalies)			
Grinding mark			
Disbonded coating			
Other anomalies			
COMPONENTS:			
Concentric pipeline casing			
Eccentric pipeline casing			
Sleeve repair			
Fitting			
Valve			
Tee			
Attachments			
Other appurtenances			
Bends			
CHARACTERISTICS:			
Internal/external discrimination			
Centerline location			
Strain			
Other pipeline characteristics			

Table 5—Example PODs and Sizing Tolerances for Metal Loss*

	Extended	Pitting	Pinholes	Axial Grooves	Axial Slots	Circumferential Grooves	Circumferential Slots
PIPE BODY:							
Threshold depth at POD = 90%							
Depth tolerance at 80% certainty							
Width tolerance at 80% certainty							
Length tolerance at 80% certainty							
GIRTH WELDS:							
Threshold depth at POD = 90%							
Depth tolerance at 80% certainty							
Width tolerance at 80% certainty							
Length tolerance at 80% certainty							
SEAM WELDS:							
Threshold depth at POD = 90%							
Depth tolerance at 80% certainty							
Width tolerance at 80% certainty							
Length tolerance at 80% certainty							

*At a specified confidence level.

APPENDIX B—EXAMPLE: PROCESS CHECKLIST FOR IN-LINE INSPECTION SYSTEMS

Verify the Quality of In-Line Inspection Data

	Initial	Date
a. Were survey-acceptance criteria met?	☐	

____

____

____

____

	Initial	Date
b. Verify inspection length	☐	☐
c. Were Data Quality checks completed (when applicable)?	☐	
1. Sensor Response	☐	
2. Speed Check	☐	
3. Marker Placement	☐	
4. Orientation	☐	
5. ________________		

Verify Pipeline Parameters That Were Utilized

	Initial	Date
a. Outside diameter and wall thickness		☐
b. Method that pipe was manufactured and pipe grade	☐	
c. Changes in wall thickness, pipe grade, and class locations (if applicable)	☐	
d. Confirm report reflects correct information	☐	

Verify Sample of Pipeline Components

	Initial	Date
a. Confirm appurtenances/components are correctly identified	☐	
b. Review orientation of taps, tees, etc.	☐	
c. Check for abnormal joint lengths	☐	

Review Historical Information

	Initial	Date
a. Check for previous assessments (i.e. hydrostatic test, ILI)	☐	
b. Review previous dig information	☐	

[Further review is required if significant differences in anomaly characteristics or location accuracy are identified.]

APPENDIX C—EXAMPLE: ONSITE FEATURE LOCATION/VERIFICATION ACTIVITIES

Clear and documented procedures should be used to ensure the quality of the results of field verification activities. This appendix provides a sample set of procedures that have been successfully used in prior field verifications. Other mutually agreed upon procedures may also be used.

Field verifications involve two different distance measures: aboveground measurements and distances as measured by an inspection tool. Aboveground measurements are typically made from known position of pipeline components, welds, or other physical items whose location relative to the pipeline location and chainage is known. In-line inspection distances are determined from odometer wheel counts and represent (approximate) chainage values.

Significant sources of errors in aboveground measurements can result from:

- Effects of the topography over which the aboveground measurements are made.
- Differences between the actual pipeline route and the aboveground route at, for example, pipeline bends, etc.
- Erroneous placement or interpretation of AGMs.

Errors in distances measured by in-line inspection tools can result from problems with the odometer wheels due to debris, slippage, or sticking. In-line inspection distances can often be recalibrated using as-built pipeline data or other information.

Basic Procedure for Feature Location

In typical inspection reports, the location of a feature is referenced to fixed aboveground pipeline components (e.g., tees, valves), above-ground markers, or other known references. Below ground components are not typically used for reference points because they cannot be easily located aboveground.

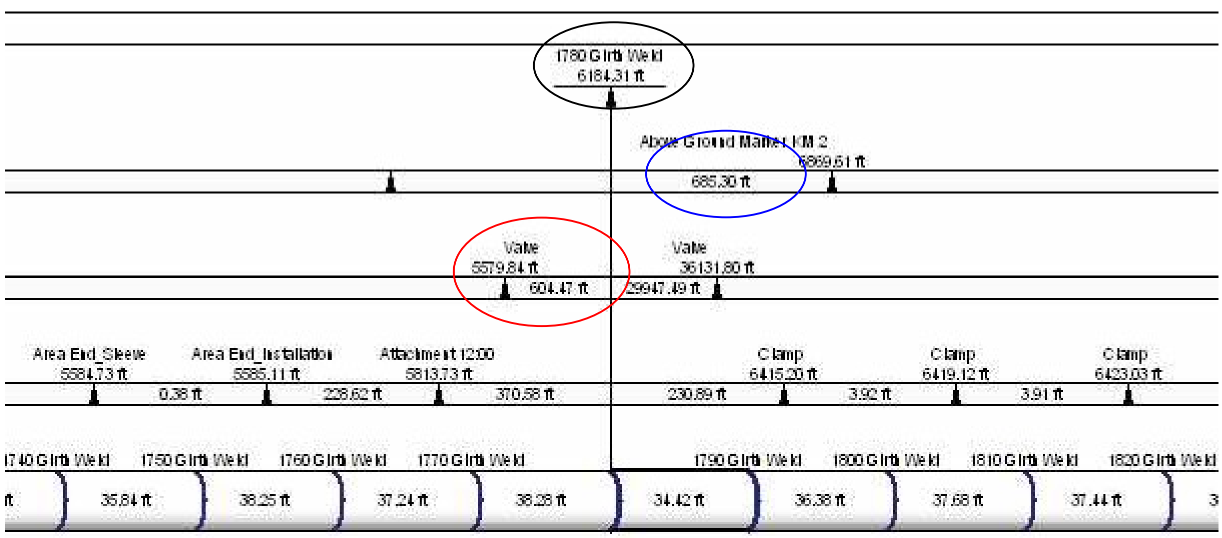

Figure 5—Feature Location Example

PROCEDURE

***Step 1*:** From the inspection report, identify and determine the distances to the nearest known upstream and downstream reference points.

For the example shown in Figure 5, weld #1780 (the target location) is 604.47 ft. from an upstream valve and 685.30 ft from a downstream marker.

***Step 2*:** Mark off and stake the aboveground distance from both reference points. A gap or overlap is common. The length of the gap or overlap is affected by the accuracy of surface measurements and the odometer counts.

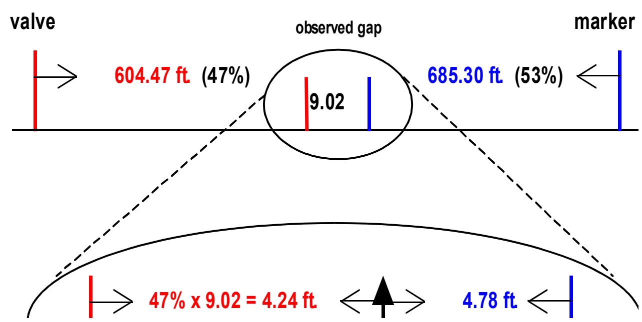

Figure 6—"Gap" Interpolation Example

Typically, a gap or overlap is seen with a length between 0 and 1% of the distance between the reference points. For the example shown in Figure 6, the gap is 9.02 ft. If a very large gap is seen, check to determine that the correct reference points have been used in marking off the aboveground distances. Discussions between the service provider and the operator should be used if there are gaps or overlaps that are greater than the location accuracy in the performance specification.

Step 3**:** Interpolate across the gap (or overlap) following the "percentage rule" using the same ratio as the distances to the reference points. In the example, the interpolated location is 47% or 4.24 ft from the upstream stake.

REMARKS

Using both upstream and downstream reference points and interpolating gaps or overlaps increases the accuracy with which a target feature is located.

Targeting an upstream or downstream girth weld for an anomaly located within a pipe joint provides a ready reference from which to measure a short relative distance to locate the anomaly.

When the location of a target feature is in doubt, individual pipe joints can sometimes be identified by comparing the physical distance between upstream and downstream girth welds with the distance noted on the inspection report. The reported and actual position of the longitudinal weld can also help verify locations.

Basic Procedure—Verification Measurements

1. Clean pipe thoroughly, preferably by abrasive blasting, etc. (note abrasive blasting may hide low level SCC).
2. Inspect for cracking (e.g., magnetic particle inspection). Measure depth of anomaly.
3. Measure length (longitudinal) and width (circumferential) of anomaly.
4. Provide a rubbing of the anomaly geometry including the surrounding area and take a photo, if possible.
5. Measure the actual wall thickness in multiple areas close to the anomaly.
6. Mark on sketch/photo feature type (also, anomalies like dents, gouges, mill anomalies, etc. have to be described), log distance, circumferential position (o'clock looking downstream).
7. Mark on Feature Location Sheet actual measured distance to girth weld, circumferential position, feature type, feature dimensions, actual wall thickness, etc.
8. Measure and document exposed anomalies.

Field data useful in comparing verification results with reported data

1. Field distance measurement system used.
2. All modifications applied to the original Feature Location Sheet.
3. Distances measured in the field (typically at least one upstream and one downstream is necessary).
4. Length of gap and/or overlap respectively of the up-/downstream distance measurements.
5. Observed difference between aboveground location and found position.
6. Length of the joint.
7. Position of the longitudinal weld if applicable.
8. Length of neighboring pipe joints and their longitudinal weld position if possible.
9. Position and extent of pipe area investigated.
10. Method used to measure the actual defect geometry.
11. Specifications of the method, e.g., Ultrasonic Tool characteristics: calibration procedure, sampling rates, effective transmitter size.
12. Photos of the location with scales and remarks of dimensions.

APPENDIX D—EXAMPLE VERIFICATION DIG ANOMALY DOCUMENTATION (FOR METAL LOSS ANOMALIES)

This appendix gives examples of the types of data collected at verification digs for metal-loss anomalies. A data record for each verification anomaly should be prepared. The data record may include, but not be limited to:

a. Pipeline system identifier.
b. Right-of-way number.
c. Pipeline stationing.
d. Job number.
e. Anomaly item number (from inspection report).
f. Excavation date.
g. Person who measured (assessed) the target feature/anomaly.
h. Nominal Pipeline O.D.
i. Pipe grade.
j. Pipe manufacturing method.
k. Pipe nominal wall thickness.
l. Actual pipe wall thickness (clean pipe close to anomaly).
m. Clock (circumferential) position of longitudinal weld (facing downstream: top = 12, bottom = 6).
n. Direction of flow/Tool travel.
o. Distance to upstream and downstream girth welds.
p. Distance to upstream and downstream aboveground reference points.
q. Metal loss profile (including the spacing increments and depth measurements); alternatively, an etching of the anomaly and or a diagram with the maximum depth indicated.
r. Metal loss interaction (Figure 7): Whether or not multiple measured metal loss anomalies interact to form a larger single anomaly; the criteria governing the relationship between the distances *X*1 and *X*2 (and *Y*1 and *Y*2) is specified for each inspection.
s. Information on the accuracy of field measurements.
t. Photographs: Label each photograph with the following information, as a minimum.

1. Date of photo.
2. Pipeline identification, i.e., line name, stationing, valve section, etc.
3. Anomaly item number.
4. Actual depth, length, width and clock orientation.
5. Direction of flow/tool travel.
6. Distance to nearest girth weld.

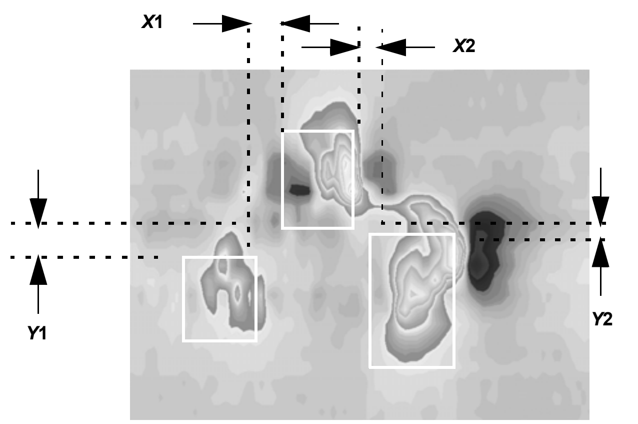

Figure 7—Metal Loss Profile for Interaction Criteria

APPENDIX E—COMPARISON OF INDIVIDUAL VERIFICATION MEASUREMENTS USING THE PERFORMANCE SPECIFICATIONS

A "unity" graph is the simplest tool to implement this verification method. For example, a graphical view of the sizing accuracy can be created by plotting the comparison of depth of individual anomalies as reported by the ILI service provider and the measurement results of a field excavation. Figure 8 shows an example of a graph that supports ILI system results are consistent with the performance specification.

To enable a valid comparison, the physical units and statistical parameters of the different measurement methods must be unitized at the beginning.

Gauging and UT devices usually assess the general wall thickness and the remaining wall independently while MFL ILI provides relative wall loss values instead. The accuracy specification for UT wall thickness devices is typically given as a standard deviation, and MFL uses an 80% certainty level.

One approach is to calculate the relative wall loss deviation expected for the UT or Gauging devices in percent wall loss at 80% confidence level. Once this is calculated it becomes rather obvious how and where these typical field measurement techniques depend on the wall thickness and how this compares to the ILI accuracy.

d	=	absolute depth [in./mm]
t	=	general wall thickness [in./mm]
d/t	=	relative depth [%]
$t–d$	=	remaining wall thickness [in./mm]
σ	=	standard deviation (i.e. 67% confidence)
Δ	=	deviation on the basis of 80% confidence

Based on Gaussian error propagation and a Gaussian distribution, the accuracy of the field measurement is as follows:

$$\Delta(d/t) = 1.28{*}(Ð\{[(\sigma(d))/d]^2 + [(\sigma(t))/t]^2\})^{*}(d/t)$$

with $$\sigma(d) = Ð\{\sigma(t-d)^2 + \sigma(t)^2\}$$

An individual measurement violates the common 80% confidence expectations, if the purported total tolerance is violated:

$$|(d/t)_{\mathrm{ILI}} - (d/t)_{\mathrm{FIELD}}| > \sqrt{\{\Delta(d/t)_{\mathrm{ILI}}{}^2 + \Delta(d/t)_{\mathrm{FIELD}}{}^2\}}$$

Typical example:

A UT device was used. The specified accuracy was 0.2 mm for the appropriate calibration. It can be assumed that the accuracy of the wall thickness measurement increases with repeated measurements σ(t). The fact that the anomaly geometry was poorly defined gave cause to slightly increase the interval for the remaining wall measurement accuracy σ(t – d). For a gauging device, the fabrication tolerances of the nominal wall must be considered σ(t) as well as the possible misalignment of the apparatus for the individual measurement σ(d).

Referring to Figure 8, the total tolerance criterion is visualized by an ellipsoid defined by the individual 80% confidence values.

Table 6—Example: Agreement Test of Two Independent Measurements

ILI Report		Ultrasonic Field Investigation										Comparison
d/t [%] meas	Δ(d/t) [%] given	t [mm] meas	t-d [mm] meas	d [mm] calc	d/t [%] calc	σ(t) [mm] given	σ(t-d) [mm] given	σ(d) [mm] calc	Δ(d/t) [%] calc	$\lvert (d/t)_{ILI} - (d/t)_{Field} \rvert$	$\sqrt{\Delta(d/t)_{ILI}^2 + \Delta(d/t)_{FIELD}^2}$	violates 80% criterion
42	10	6.4	3	3.4	**53**	0.15	0.25	0.29	6.0	11.1	11.7	no
57	12	8.2	2.5	5.7	**70**	0.15	0.25	0.29	4.8	12.5	12.9	no
21	5	4.9	4.3	0.6	**12**	0.15	0.25	0.29	7.6	8.8	9.1	no
33	10	6.3	4	2.3	**37**	0.15	0.25	0.29	6.0	3.5	11.7	no
33	10	6.3	5.8	0.5	**8**	0.15	0.25	0.29	5.9	25.1	11.6	yes

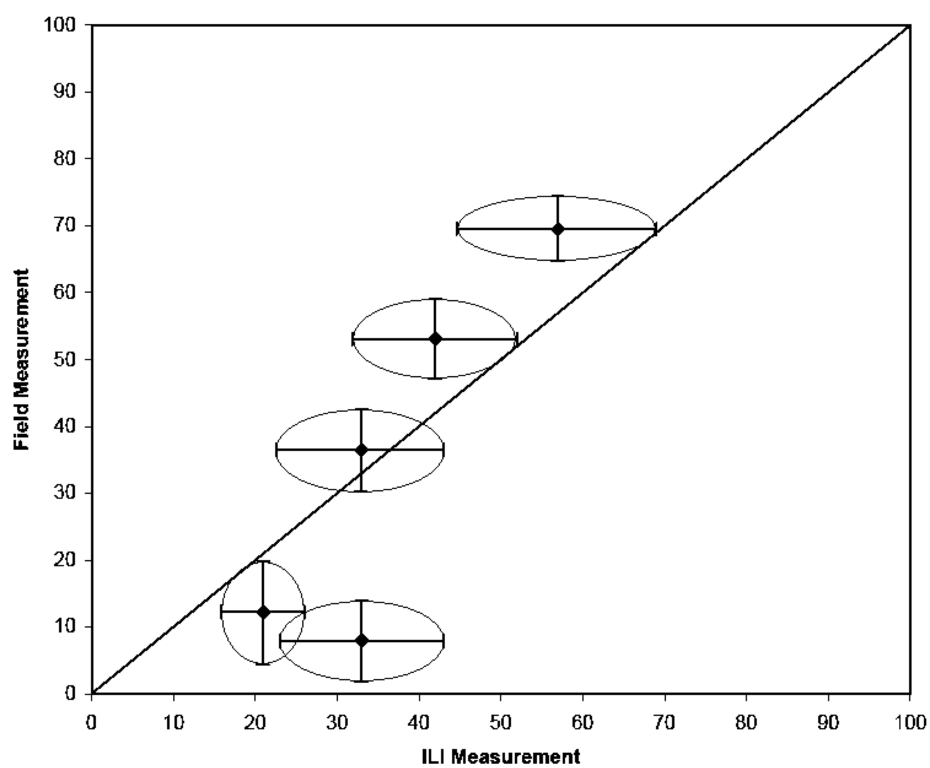

Figure 8—Example: Unity Graph of Two Independent Sets of Measurements

Comparison of a Population of Verification Measurements with Distributions

If some of the verification measurements do not meet the performance specification, they can be further assessed using various types of distributions such as binomial distributions. Binomial distributions represent the probability of a particular outcome based on an initial assumption or hypothesis. The outcome is the set of reported anomalies found to be within tolerance through verification measurements with the initial assumption that the performance specification has been met.

Binomial distributions may be used to show the probability "*p*" of finding "*x*" cases where the performance specification is met out of "*n*" comparisons. The probability "*p*" is given as:

$$p(x) = n!p^x((1-p)^{n-x}/((x!)(n-x)!))$$

p = the probability of being within specification

Binomial distribution tables generally show the probability of sizing "*x*" anomalies or less within specifications:

$$\sum_{i=0}^{x} p(i)$$

In all cases, the performance specification is assumed to be the same for all measurement locations, and the measurement results are assumed to be independent of each other. It is recommended that the number of verification measurements (n) is such that n x p Š 5.

Table 7 gives a sample binomial distribution table based on an 80% certainty of meeting a given tolerance. Each percentage entry is the probability of the number of comparisons or less within tolerance out of the total number of comparisons. For example (see the shaded box in Table 7), there is a 12% probability of seeing 0, 1, 2, 3, 4, 5, or 6 comparisons out of 10 within tolerance given a certainty of 80%.

Typically, if the probability given in a binomial distribution table is small (e.g., 1%, 5%, or 10%), the initial assumption (the certainty is at least 80%) is rejected. In other words, the performance specification has not been met. The break point below which the assumption is rejected is calculated by 100% -confidence level. For example, if the confidence level is defined as 95%, then the break point below which the assumption is rejected is 5%. Distribution tables can be used to demonstrate that the verification results are consistent with the performance specification.

Distribution tables show "Type I" errors and are useful for determining if the performance specification can be clearly rejected. A Type I error is the probability of rejecting the initial assumption (the performance specification was met) when it is, in fact, true. As discussed above, the rejection level is typically small, i.e. 1%, 5% or 10%, to reduce the likelihood of incorrectly rejecting the assumption (that the performance specification was met). Type I errors are related to the consistency of the verification measurements with the performance specification.

A "Type II" error occurs when the initial assumption is not rejected when it should have been (i.e., the performance specification is not rejected even though it was not met). The probability of a Type II error reflects the precision with which the true certainty is known. Decreasing the likelihood of a Type I error increases the likelihood of a Type II error. Type II errors are possible whenever the performance specification is not rejected. They are a function of the number of comparisons ("n"), the value of the Type I error, and the true value of the certainty. The smaller "n" is the more likely a Type II error may occur. Tables listing the probabilities of Type II errors are large, cumbersome, and not generally used.

Table 7—Sample Binomial Distribution Table (Based on a certainty of 80%)

	Number of Comparisons "*n*"		
Number of comparisons within tolerance "*x*"	6	10	25
0	0%	0%	0%
1	0%	0%	0%
2	2%	0%	0%
3	10%	0%	0%
4	35%	1%	0%
5	74%	3%	0%
6	100%	12%	0%
7		32%	0%
8		62%	0%
9		89%	0%
10		100%	0%
11			0%
12			0%
13			0%
14			1%
15			2%
16			5%
17			11%
18			22%
19			38%
20			58%
21			77%
22			90%
23			97%
24			100%
25			100%

Based on this, Table 8 can be derived as more practical for use. It provides the overall number of verification measurements (N) versus the number of verification measurements, that must be in tolerance (N_{in}) in order to establish consistency with performance specifications. If the number of verification measurements in tolerance are less than (N_{in}), then

Table 8—Table to Establish Consistency with Performance Specifications (Certainty = 0.80 and Confidence Level = 95%)

N	N_{in}	N	N_{in}	N	N_{in}
5	2	21	14	37	25
6	3	22	14	38	26
7	4	23	15	39	27
8	4	24	16	40	28
9	5	**25**	17	41	28
10	6	26	17	42	29
11	6	27	18	43	30
12	7	28	19	44	31
13	8	29	20	45	31
14	9	30	20	46	32
15	9	31	21	47	33
16	10	32	22	48	34
17	11	33	22	49	34
18	11	34	23	50	35
19	12	35	24	51	36
20	13	36	25	52	37

the ILI results are not consistent with the performance specifications.

Following are some examples of how to use distributions to verify if the performance specification has been met.

Example 1: An ILI system performance specification claims that depths will be sized within ± 10% (t) with 80% certainty and a 95% confidence level. Twenty-five verification measurements are made. It was determined that the field measurement tolerance is 6% (t).

- Calculate the total tolerance. *Sqrt*(102 + 62) = 11.66. This means that if the absolute value of the field measurement minus the reported measurement is less than or equal to 12% (t), the reported depth prediction would be within tolerance.

With n = 25, there are 19 comparisons within tolerance

- Using Table 7: Determine if the assumption that the certainty is at least 80% should be rejected using a 95% Confidence Limit. The probability given in the binomial table is 38%. Since this value is well above the 5% rejection level (100% – 95%), then one would fail to reject the assumption that the certainty is at least 80%. The ILI system results are consistent with the performance specification.
- Or, using Table 8: There are 19 comparisons in tolerance. Since 19 is larger than 17, the ILI system results are consistent with performance specifications.

Example 2: An ILI system performance specification claims that depths will be sized within ± 10% (t) with 80% certainty and a 95% confidence level. Ten verification measurements are made. It was determined that the field error measurement was 5% (t).

- Calculate the total tolerance. *Sqrt*(102 + 52) = 11.18. This means that if the absolute value of the field measurement minus the reported measurement is less than or equal to 11%(t), the reported depth prediction would be within tolerance.

With n = 10, there are 5 comparisons within tolerance.

- Using Table 7: Determine if the assumption that the certainty is at least 80% should be rejected using a 95% Confidence Limit. The probability given in the binomial table is 3%. Since this value is below the 5% rejection level (100% – 95%), then the assumption that the certainty is at least 80% is rejected. The ILI system results are not consistent with the performance specification.
- Or, using Table 8: There are 5 comparisons in tolerance. Since 5 is less than 6, the ILI system results are not consistent with performance specifications.

Example 3: An ILI system performance specification claims that depths will be sized within ± 10% (t) with 80% certainty and a 90% confidence level. Ten verification measurements are made. It was determined that the field error measurement was 4% (t).

- Calculate the total tolerance. *Sqrt*(102 + 4) = 10.77. This means that if the absolute value of the field measurement minus the reported measurement is less than or equal to 11% (t), the reported depth prediction would be within tolerance.

With n = 10, there are 6 comparisons within tolerance.

- Using Table 7, determine if the assumption that the certainty is at least 80% should be rejected using a 90% Confidence Limit. The probability given in the binomial table is 12%. Since this value is above the 10% rejection level (100% – 90%), then one would fail to reject the assumption that the certainty is at least 80%.

Due to the location of the pipeline and the fact that 12% is very close to the 10% rejection level, it was decided to complete 15 more verification measurements. With n = 25, there are 20 comparisons within tolerance.

Using Table 7, the probability given in the binomial table is 58%. Since this value is well above the 10% rejection level, then one would fail to reject the assumption that the certainty is at least 80%. The ILI system results are consistent with the performance specification.

- Table 8 is not applicable because it is based on a 95% Confidence Level. Another table would need to be generated.

Confidence Intervals

Confidence intervals provide an alternative way of determining the precision of which the true certainty is known. For example, a 95% confidence interval computed for certainty implies that the true certainty of the ILI system lies somewhere between the upper and lower limit of the interval. When computing a confidence interval for certainty, the number of verification measurements must be "large." For the purpose of this example, "large" is considered greater than 20.

Table 9 shows an example of confidence intervals based on a confidence level of 95% and 25 comparisons. Here, a confidence level of 95% implies there is a 95% probability the true ILI system certainty is between the lower and upper limits.

For the same example shown in the shaded boxes in Table 9, with 19 comparisons within tolerance out of 25 verification measurements, there is a 95% probability the true ILI system certainty is between 59% and 93%.

There are many ways of using confidence intervals to assess whether the ILI system results are consistent with the Performance. These methods are generally Service-Provider or operator-specific, and as such, are not discussed in detail in this Standard. Common methods consider the lower range of certainty, the position of the certainty stated in the performance specification within the confidence interval, and the amounts of data used to develop the performance specification.

Table 9—95% Confidence Intervals

25	Lower Limit	Upper Limit
0	0%	11%
1	0%	12%
2	0%	19%
3	0%	25%
4	2%	30%
5	4%	36%
6	7%	41%
7	10%	46%
8	14%	50%
9	17%	55%
10	21%	59%
11	25%	63%
12	28%	68%
13	32%	72%
14	37%	75%
15	41%	79%
16	45%	83%
17	50%	86%
18	54%	90%
19	59%	93%
20	64%	96%
21	70%	98%
22	75%	100%
23	81%	100%
24	88%	100%
25	89%	100%

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