

Hydrostatic Testing as an Integrity Management Tool

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Introduction

This technical report provides guidance to pipeline operators on the appropriate use of hydrostatic testing within the integrity and risk management process. It considers, as key elements within a hydrostatic test program design process, topics such as known or assumed pipe material properties, threat type and flaw populations, operating and failure history, potential risks and unintended or detrimental effects, and the importance of a clear understanding of test program objectives. This document does not attempt to provide practical guidance for the onsite implementation of a hydrostatic testing program.

This document is primarily focused on pressure test design to achieve objectives, the effect of pressure testing on line pipe steels, and considerations for subsequent pressure testing intervals and reliability. Water, other liquids, air, natural gas, and inert gas are all acceptable test media (as permitted by applicable regulation) for pipeline pressure testing, and identical parameters of physics with respect to the hoop stresses and material properties apply. Due to the relatively high stresses that are generally targeted to achieve integrity testing objectives, water is the preferred test medium for pipelines. For this reason, pressure testing in this document is referred to as “hydrostatic testing.” It is acknowledged that when using any form of pneumatic test media (e.g. gases) or liquid product (e.g. refined petroleum products) versus water, vastly different considerations shall be applied for public and personnel safety during testing to account for the potential consequence of a test failure. These are beyond the scope of this work.

This technical report was based upon the extensive hydrostatic testing knowledge that exists today in the form of API recommended practices (RPs), American Society of Mechanical Engineers (ASME) code documents, the body of work of industry consultants, standard practices of operating companies, regulatory language, and other resources. This body of knowledge was supplemented with hydrostatic testing program experience derived from discussion with representatives from a broad group of hazardous liquid and natural gas pipeline operating companies and review of case studies involving several hydrostatic testing programs.

At the time of this guideline development, several parallel pipeline industry initiatives with a focus on hydrostatic testing have been recently completed or are currently ongoing. Such initiatives include work performed by the Pipeline and Hazardous Materials Safety Administration (PHMSA)¹, the American Petroleum Institute (API), the Association of Oil Pipe Lines (AOPL)², and the Interstate Natural Gas Association of America (INGAA)³. While this completed or ongoing work is of considerable value to the pipeline industry, lacking within these industry initiatives is a focus on the specific application of hydrostatic testing as a pipeline assessment tool to support integrity management plan (IMP) requirements and objectives.

Background

Hydrostatic testing of pipelines has been historically used by the pipeline industry to ensure quality of manufacture and construction, to establish maximum operating pressures, and for management of certain threats to integrity of pipeline systems.

The first version of API 5L for the manufacture of line pipe, issued in 1928, specified requirements for manufacturing specifications, including standard pipe sizes, minimum tensile and chemical content requirements, and required mill pressure tests. In 1942, the voluntary American Standards Association (ASA) Code B31.1 first recommended pressure testing after installation of a pipeline to 1.1 times the maximum operating pressure (MOP), not to exceed 90 % SMYS. In 1959, ASA segmented the code and issued two documents, with one specific to liquids pipelines (B31.4) and the other for gas pipelines (B31.8). These currently exist as ASME B31.4 and B31.8. By the 1960s, most pipeline

¹ On October 7, 2009, NTSB issued Recommendation P-09-1 to PHMSA on the safety and performance of ERW pipe. The recommendation called on PHMSA to conduct a comprehensive study to identify actions that can be implemented by pipeline operators to eliminate catastrophic longitudinal seam failures in ERW pipe.

² The API-AOPL Pipeline Safety Excellence™ 2015 Strategic Plan includes two Strategic Initiatives to develop industry-wide guidance on the appropriate uses of hydrostatic pressure testing of pipelines.

³ Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines, December 5, 2013.

operators had instituted the practice of hydrostatically testing a newly completed pipeline in the field post-construction.⁴ In 1970, Department of Transportation (DOT) federal regulations for pipelines in the U.S. went into effect with 49 CFR §192 and §195 for regulation of gas and liquids pipelines, respectively, requiring the use of hydrostatic testing at construction.

Current uses for hydrostatic testing include original construction testing, integrity assessment of existing pipelines, and pipe material verification when records may be missing or incomplete. Operators should consider the potential for in-service failures of ERW and flash welded pipe that occur after a hydrostatic pressure test is performed in design and implementation of a hydrostatic test program, and guidance on practical consideration of these potential effects is needed.

The benefits, limitations, and appropriateness of pressure testing as an integrity management tool for each recognized threat need to be clarified. Available procedures and references for implementation of a hydrostatic test do not fully account for future operational concerns. The design of a hydrostatic test program can vary based upon the objectives of the test program, specifically the threats considered by the operator for the subject pipe within a test section. For example, managing longitudinal seam integrity versus managing the threat of stress corrosion cracking requires different approaches, as do considerations when testing gas pipeline versus liquid pipeline systems. Many industry references used for guidance in development of hydrostatic test programs do not distinguish these differences sufficiently. It was requested that this effort through PRCI emphasize the differences.

Guidance is also needed to understand the conservatism and variability of current methods for determination of test intervals. Safety factors can be compounded many times through deterministic approaches generally used within the industry. While these may be the simplest from an analytic standpoint, pipeline operators need to develop a thorough understanding of the cumulative effect of applying multiple safety factors when developing hydrostatic pressure testing plans and analyzing data. Safety factors when compounded can sometimes exceed 20, leading to repeat tests at short intervals and potentially exacerbating detrimental effects of testing.

Value

This technical report provides a source of knowledge for pipeline operators, consultants, and contractors tasked with managing or being involved with pipeline hydrostatic testing programs. It is also anticipated that regulatory and industry bodies contemplating the adoption of industry consensus standards and/or regulations pertaining to pipeline hydrostatic testing will view this document as a valuable resource within those development processes.

This technical report provides guidelines to pipeline operators for use in selection and application of hydrostatic testing as an integrity assessment. Specifically discussed are development of test objectives and design considerations when determining the target hydrostatic test pressure(s) to achieve test objectives. Such guidance will aid in achieving the goal of reducing in-service failures, and will assist operators in limiting the number of pressure test failures, providing for increased public safety and reduced environmental impact.

The distinct value that this project brings to the pipeline industry is to supplement the existing standards and body of knowledge in the area of hydrostatic testing with guidelines developed from a pipeline operator perspective and supported by application of hydrostatic testing through the case studies.

Approach

This project began in early 2015 and was managed by Dynamic Risk Assessment Systems, Inc. (Dynamic Risk). The PRCI membership for the IM-3 program at the time the project began consisted of 59 members. A short timeline for completing the project was desired, with a goal to create a guideline document within approximately one year. A smaller core working team was established that consisted of a group of 12 project team members, each of whom committed to have representatives attend monthly face-to-face working meetings through the spring and summer of 2015.

⁴ Kiefner, J.F. and Trench, C.J. Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction, 2001.

To gather operator experiences and develop practical case studies, in addition to the working meetings among the project team, a series of five meetings were held with pipeline operator representatives from 17 individual operating companies to exchange information and share industry best practices on the design, implementation, data analysis, and evaluation of hydrostatic pressure testing for integrity management. These were held between March 10, 2015 and May 7, 2015. The working team also invited consultants representing five separate pipeline consulting firms to an additional meeting held in conjunction with the PRCI Spring Technical Committees meeting in New Orleans, Louisiana, in May 2015. The purpose of this meeting was to invite these respected researchers to challenge this work and to provide their unique perspectives from their experience in this subject-matter area.

Hydrostatic Testing as an Integrity Management Tool

1 Scope

This technical report provides guidelines related to hydrostatic testing as a tool for integrity management in gas and liquids pipelines. It specifically focuses on program design and key parameters for consideration in hydrostatic test programs, as well as potential detrimental effects of hydrostatic testing. Several case studies (see Annex A) supplement the guidelines provided.

2 Normative References

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

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

API Specification 5L, *Specification for Line Pipe*

API Specification 5LX, *High-Test Line Pipe*

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

API Recommended Practice 1160, *Managing System Integrity for Hazardous Liquids Pipelines*

ASME B31.4, *Pipeline Transportation Systems for Liquids and Slurries*

ASME B31.8, *Gas Transmission and Distribution Piping Systems*

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

ASME STP-PT-011, *Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas*

AGA NG-18 Report 194, *Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations*

Michael Baker Jr., Inc. *Spike Hydrostatic Test Evaluation*. July 2004. OPS TT06

U.S. DOT Title 49, CFR Part 192, Subpart J—*Test Requirements*

U.S. DOT Title 49, CFR Part 195, Subpart E—*Pressure Testing*

Leis, B.N., et al. *Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures-Phase One*. Washington DC: s.n., 2013. G0060804.

McAllister, E.W. *Pipeline Rules of Thumb Handbook: A Manual of Quick Accurate Solutions to Everyday Pipeline Engineering Problems*. Gulf Professional Publishing: 2013

3 Terms, Definitions, Acronyms, and Abbreviations

3.1 Terms and Definitions

3.1.1

double stroke

The point where twice as many pump strokes are required to achieve the defined incremental increase in pressure as compared with when the pipe is in the elastic range, which can be shown to occur when the relationship between strokes and pressure increase is no longer linear and the slope of the line has been halved.

3.1.2

high-pressure test

A test undertaken at pressures potentially greater than necessary for qualifying test minimum requirements to address or assess for an identified or targeted pipeline threat. Similar in use to a “spike” test, an alternative when spike testing may not be advised or warranted.

3.1.3

hydrostatic test failure

A test failure that occurs when the pipeline, either due to leak or rupture of the line pipe, cannot either reach or sustain (if required) the target pressure of the hydrostatic test.

3.1.4

in-line inspection

ILI

The inspection of a pipeline using an internal inspection tool, commonly referred to as a “smart pig.”

3.1.5

leak test

A test that can be performed with hydrostatic pressure (e.g. during a qualifying test) or in-service methods such as flame ionization (e.g. gas), in-line inspection (e.g. acoustic) means, or any other method suitable for discovery of leaks associated with the pipeline.

3.1.6

legacy pipe

Pipe manufactured with now-obsolete manufacturing methods, including low-frequency or DC ERW process, single submerged arc-weld, electric flash weld, wrought iron, lap welded, hammer welded, butt welded, and pipe made from Bessemer steel, or any pipe with a longitudinal joint factor less than 1.0 as defined in 49 CFR §192.113⁵.

3.1.7

Maximum Allowable Operating Pressure

MAOP

Used when referencing natural or other gas pipelines operated under 49 CFR §192.

NOTE For the purposes of discussion of pressure test parameters, within this report this term is used interchangeably with MOP.

3.1.8

mill hydrostatic test

The hydrostatic pressure test of short duration (typically 5–10 seconds) applied in the pipe mill as part of the quality control process during original pipe manufacture.

⁵ http://www.phmsa.dot.gov/staticfiles/PHMSA/DownloadableFiles/Files/NPRM_Safety_of_Gas_Trans_and_Gathering_Pipelines_3_15_16_final.pdf

3.1.9

mill test pressure

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

3.1.10

Monte Carlo simulation

A statistical method of analysis that uses for input parameters a range of values (a probability distribution) that have inherent uncertainty. The subject calculation is performed using random values from the probability functions and repeated to produce a distribution of probable outcomes.

3.1.11

maximum operating pressure

MOP

MOP is the maximum operating pressure and is used when referencing hazardous liquids pipelines operated under 49 CFR §195.

NOTE For the purposes of discussion of pressure test parameters, within this report this term is used interchangeably with MAOP.

3.1.12

qualification test

A hydrostatic test that establishes at least the minimum required safety factor for the operating pressure of the pipeline based on accepted industry standards and regulatory requirements.

3.1.13

qualifying hydrostatic test

A test used for validation of the maximum operating pressure (MOP) of a pipeline system per regulatory requirements.

3.1.14

spike hydrostatic test

A pressure test conducted at a level significantly above maximum operating pressure and held for a short duration.

3.1.15

test pressure

A pressure above the working pressure of the pipe (such as MOP or MAOP) which the pipe is tested to verify pressure integrity.

3.1.16

specified minimum yield strength

SMYS

The minimum yield strength prescribed by the specification under which the material is purchased from the manufacturer.

3.2 Acronyms and Abbreviations

ACVG	alternating current voltage gradient
ANSI	American National Standards Institute
AOPL	Association of Oil Pipelines
API	American Petroleum Institute
ASA	American Standards Association

ASME	American Society of Mechanical Engineers
CEPA	Canadian Energy Pipeline Association
CFR	United States Code of Federal Regulations
DA	direct assessment
DCVG	direct current voltage gradient
DOT	United States Department of Transportation
ECDA	external corrosion direct assessment
EFW	electric flash welded (long seam)
ERW	electric resistance welded (long seam)
HAZ	heat-affected zone
HVL	highly volatile liquid (e.g. propane, butane, natural gas liquids)
INGAA	Interstate Natural Gas Association of America
ILI	in-line inspection
IMP	Integrity Management Plan
LFERW	low frequency electric resistance welded (longitudinal seam)
LOF	lack of fusion
MAOP	maximum allowable operating pressure
MFL	magnetic flux leakage (ILI technology)
MOP	maximum operating pressure
MP	mile-post or mile-point (on a pipeline)
NDE	nondestructive examination (e.g. radiography, ultrasonic inspection)
NTSB	United States National Transportation Safety Board
PCFA	pressure cycle fatigue analysis
PHMSA	United States Pipeline and Hazardous Materials Safety Administration
PRCI	Pipeline Research Council International
SSAW	spiral submerged arc welded
SCC	stress corrosion cracking
SMYS	specified minimum yield strength

4 Uses of Hydrostatic Testing—Understanding the Benefits

4.1 General

Hydrostatic testing of pipelines has been applied by the pipeline industry to establish maximum operating pressures and to manage specified threats to the integrity of pipeline systems. It is currently universally used to validate construction and pipe manufacturing practices prior to the commissioning of new pipelines. However, the use of hydrostatic testing for re-qualification (e.g. following change of service or establishing increased MOP or MAOP) or for integrity assessment varies greatly among pipeline operators; some companies rarely hydrostatically test lines under these circumstances, while others test hundreds of miles per year. Figure 1 illustrates that the use of hydrostatic testing as an integrity assessment is low when compared with ILI for both hazardous liquids and gas pipeline operators.

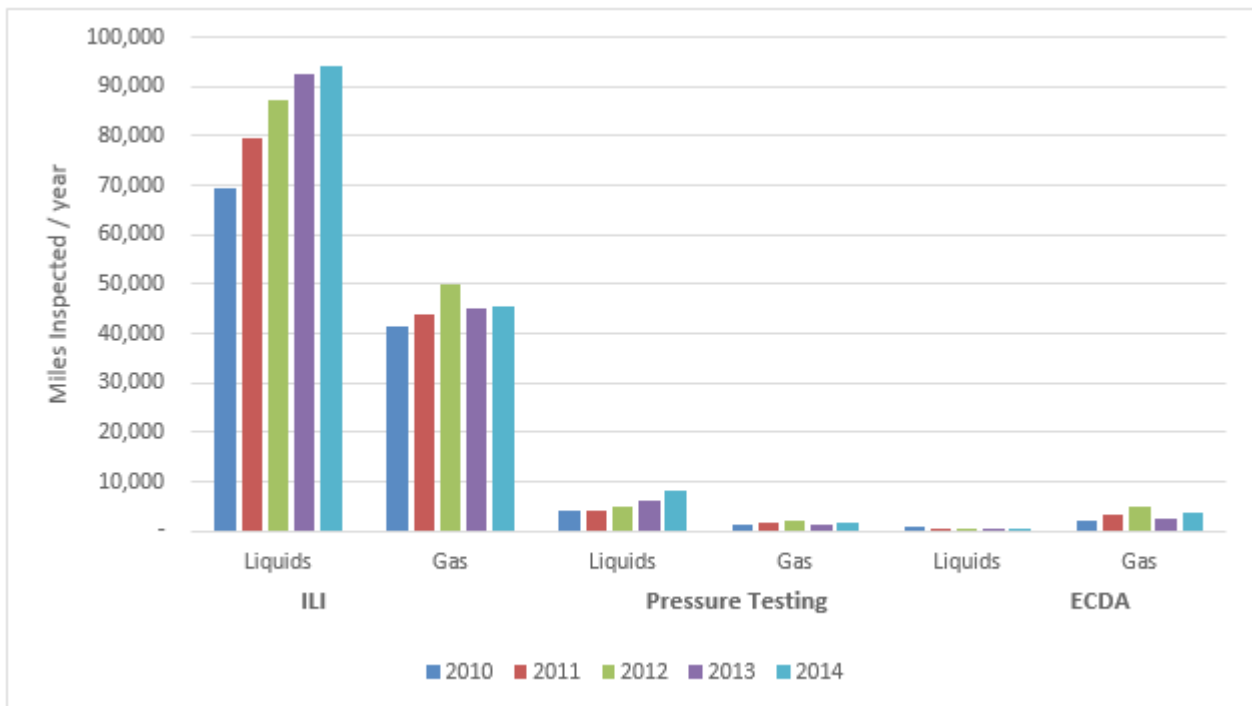


Figure 1—Transmission Pipeline Integrity Assessments 2010–2014

Pipeline operators generally choose hydrostatic testing as an integrity assessment tool when the following conditions exist:

- a pipeline segment is not configured for assessment using ILI;
- flow conditions make ILI impractical (e.g. low flow or low pressure or bi-directional);
- restrictions in the pipeline that limit the ILI ability to accurately detect or size anomalies;
- technology is not available to evaluate the identified threat(s) using ILI, or to qualify/validate a specific ILI technology;
- a large population of flaws is known or is suspected to exist that, based on conservative assumptions of material properties, would require an impractical remediation response.

Considering the range of conditions, objectives, and purposes that can apply to a hydrostatic test, the design of each test is an important element. The development of a test program and test objectives to support both integrity and operational objectives is also discussed in Section 6.

4.2 Qualification

In conjunction with applicable design requirements based on regulatory codes, qualifying hydrostatic tests are used to establish qualification for service based on minimum pressure test requirements. Both the United States and Canada have federal regulations requiring pressure testing to verify integrity and establish the MOP or MAOP of a newly constructed pipeline. A qualifying test can also be used to verify integrity at other times during a pipeline life cycle. A qualifying test is typically a one-time event that does not require subsequent testing unless so dictated by engineering assessment. Examples of where a qualifying test may be used include the following:

- new construction or pipeline replacement;
- change of operating conditions:
 - a significant increase in normal operating pressure;
 - reversal of flow direction.
- increase in MOP or MAOP (uprating);
- conversion to service or change in product;
- class location changes (gas pipelines); or
- validation of missing⁶, unverifiable, or incomplete records used to support MOP or MAOP.

4.3 Integrity Assessment

Hydrostatic tests may be used as a means of confirming reliability of a previously in-service pipeline. A properly designed hydrostatic test can verify that pipeline threats have been adequately managed. Depending upon the threats assessed through the hydrostatic test program, these reliability tests may serve as a one-time assessment of threats or, alternatively, they may be part of a series of iterative integrity assessment steps.

ASME B31.8S and API 1160 provide guidance on applicability of hydrostatic testing for integrity assessment. These references state that hydrostatic testing can be used as an assessment for time-dependent threats⁷ and threats that have the potential for enlargement by pressure cycle-induced fatigue. Time-dependent threats require periodic reassessment to ensure effective threat management. When used to assess time-dependent threats, each test should be designed to specifically target the relevant threat(s), with an objective to establish a reassessment interval with a desired safety factor. Gas pipeline operators are currently more likely than liquid operators to use hydrostatic testing to manage the threat of SCC due to difficulty with use of ultrasonic crack-detection tools in dry gas pipelines.

Hydrostatic testing can additionally be used as a one-time event to assess resident material threats such as manufacturing flaws not susceptible to time-dependent flaw degradation mechanisms, including evaluation of the pipe against the threat of defective longitudinal seam welds. For example, an operator may use a test to verify that ERW or other seam workmanship (e.g. legacy⁸ manufacturing methods such as a lap-welded or hammer-welded seam) is not causing an unacceptably low factor of safety. Limited benefit is realized through hydrostatic testing for the assessment of circumferentially oriented defects, such as defective girth welds, as there is relatively little resulting stress in the pipe's axial direction and the primary stress is oriented in the hoop direction.

⁶ This does not imply that a test is required any time records are missing. An effective strength of a pipeline system can be established by demonstrating an applied stress level without yielding of the pipe (refer to Section 6.5.4 for use of double stroke to limit yielding during hydrostatic testing).

⁷ As defined by ASME B31.8S and API RP 1160.

⁸ All seam types and manufacturing methods are subject to material flaws; however, "legacy" or pre-regulation pipe (prior to 1970) is typically deemed more susceptible due to manufacturing process and lower mill test pressures.

Hydrostatic testing can be used to establish confidence in an integrity management program, or in a process within an integrity management program. For instance, a test may be used to validate an ILI process. This validation objective could extend beyond that of ILI data analysis processes to include vendor selection, qualification, inspection, excavation, field nondestructive examination (NDE), and repair methods.

5 Elements of a Test Program—Definitions

5.1 General

There is broad interpretation within the pipeline industry regarding requirements and definitions for various aspects of pressure test programs.

The focus of this section is to provide consistent parameters for consideration to aid in classification of a hydrostatic test, and the definitions below are presented to provide consistent terminology for application in consideration of pressure testing. It should be noted that “integrity test,” a widely-used generic testing term, has not been specifically applied within this report; it is considered that each of the tests described below are a form of integrity test.

This section of the document does not include provisions for determining when and how to apply a hydrostatic test, recommendations on which testing type is most appropriate, or defining the test’s objectives. Target hydrostatic pressures are driven by the hydrostatic test’s goals, the pipeline’s characteristics, the integrity threats being evaluated, consideration of all associated risk factors, and the supporting engineering analyses.

A theoretical application of testing definitions is provided in Section 5.9 of this document.

5.2 Test Pressure Stress Level

When discussing hydrostatic test stress levels, it is common in the pipeline industry to refer to the test pipe that will be exposed to the highest ratio of the stress levels during the test and SMYS (e.g. a test to 90 % SMYS). The location of this limiting pipe is not necessarily associated with the location of maximum test pressure. It is noted that stress level is a measurable component of the pipe material; this useful shorthand is important to understand for anyone designing a hydrostatic test.

5.3 Mill Test Pressure

Mill test pressure is the test pressure applied in the pipe mill as part of the original pipe manufacturing process. Since 1928, every joint of pipe manufactured to API 5L specifications has been required to pass a mill pressure test. Over the years, the test pressure specified has increased, and the test hold time has varied between 5 and 10 seconds. For situations where pipeline historical records are incomplete, yet the manufacturing or installation date is known, the API 5L or 5LX specification applicable at the time of pipe manufacturing may be used to estimate mill test pressure.

For larger pipe diameters (20 in. and larger OD), current API 5L mill test minimum requirements generally achieve equivalent stresses near 100 % SMYS, even when the uniaxial hoop stress may not be that high. Compressive longitudinal force applied to seal the ends of the pipe during the test sequence effectively brings the applied stress during the test closer to yield. Refer to Annex C.2.1 for additional explanation of von Mises equivalent stress.

5.4 Leak Test

A leak test can be performed via either hydrostatic test (e.g. as part of a qualifying test), flame ionization (gas) survey, in-line inspection (acoustic methods), or any other method suitable for discovery of leaks on the right-of-way. This is typically done in conjunction with any hydrostatic test program.

5.5 Qualifying Hydrostatic Test

A qualifying hydrostatic test establishes at least the minimum required safety factor for the MOP or MAOP of the pipeline based on the achieved ratio between test pressure and MOP or MAOP as per accepted industry standards and regulatory requirements.

5.6 High-pressure Test

A high-pressure test is undertaken at pressures potentially exceeding minimum requirements of a qualifying test to address or assess an identified or targeted pipeline threat. Testing to pressures consistent with minimum requirements for a qualifying hydrostatic test may not provide the targeted level of reliability assessment, especially for pipelines with low operating stress at MOP or MAOP. There is no maximum level for a high-pressure test, but it should be noted that test pressures may be limited by design strengths of limiting components such as pipe or pressure- and temperature-rated components.

High-pressure testing, like spike testing, can serve as a basis for the extension of reassessment intervals by removing subcritical-sized flaws, thus reducing the dimensions of surviving flaws and increasing the time to failure for remaining time-dependent threats. Spike testing, which is discussed below in the context of minimum pressures based on material properties, may not always be warranted or advised; high-pressure testing, in conjunction with engineering analysis, is intended to provide a viable alternative to spike testing in these cases.

The following minimum requirements should be met to perform a high-pressure hydrostatic test:

- test pressure level at or above that of a qualifying hydrostatic test; and
- test pressure established is based on the integrity threat and the estimate of the continuing deterioration rates to ensure reliable future operations.

High-pressure tests, unless also being used for the purposes of a qualifying test, may be of any duration necessary for management of a target integrity threat.

5.7 Spike Hydrostatic Testing

5.7.1 General

A spike hydrostatic test achieves a test pressure at a level significantly above maximum operating pressure and held for a short duration to identify and eliminate near-critical resident imperfections and limit unnecessary growth/damage to any remaining imperfections. The sustained hold period that usually follows a spike test is typically at least 10 % below the spike test level. Spike testing has application for addressing time-dependent cracking threats, such as SCC, selective seam corrosion, and manufacturing threats such as seam weld anomalies susceptible to growth through fatigue. Pipeline operators may also perform a spike test to establish in-place yield strength or, if yielding does not occur, to establish a lower bound for the yield strength (refer to Section 6). From a technical standpoint, the strength of the pipe is established during the spike test period, and the qualification test period is essentially a leak test. The likelihood of a test failure at the lower hold pressure following a successful spike test of any duration is low, and the advantage is that for simplicity, the test records can be considered distinct.

A spike test is not performed on a stand-alone basis, but instead is generally a sub-element within an established hydrostatic test program, as described within this document. The spike portion of the test program is not generally considered the final element in the testing sequence. A qualifying test or leak test should follow the spike test⁹. The purpose of this testing sequence is to ensure that any existing leak-type flaws that remain in the pipeline following the spike test are discovered during subsequent testing.

⁹ The qualifying test, or leak test, is not required to immediately follow the spike portion of the test. Some operators discussed test sequences where, due to operational considerations, the spike test and qualifying test were performed days or weeks apart as part of an overall test program.

Using the terminology established within this report, a spike test and a high-pressure test have similar utility. Both are intended to eliminate near-critical flaws and to achieve a higher level of reliability than is possible at lower test pressures. Test pressure targets are based on the target integrity threat(s) and (if required) an assessment interval is established based on an estimate of the continuing deterioration rates.

5.7.2 Spike Test Pressure Level

Pipeline operators report varied interpretations of “spike,” including 1.25 x MOP, a percentage over 1.25, a pressure level (e.g. 50 psig) above qualifying test, or a pressure to produce a stress level in the nominal pipe between 100 % and 110 % SMYS.

It has been recognized in this work that any test pressure greater than 125 % of MOP or MAOP would meet the API RP 1110 definition of a spike test, and subsequent minimum spike test targets could vary from 25 % to 90 % SMYS (assuming normal MOPs ranging from 20 % to 72 % SMYS). The term “spike test” carries a certain connotation that a pipeline subjected to a pressure test greater than the qualifying test is safer and more reliable, yet consistent application of the term presents a challenge for the pipeline industry, as such widely applied test pressure targets provide varied assessments of pipeline integrity, especially when considering the threat of manufacturing defects.

5.8 Spike Testing Pipelines with Planned Low Operating Stress

Testing to pressures that correspond to hoop stress levels between 100 % and 110 % SMYS is discussed in the American Gas Association (AGA) Topical Report NG18 Number 194¹⁰ for removal of flaws that might cause failure in service. It was recognized that these stress-level targets were not necessarily meant to apply to pipelines operating at lower stress levels. The report further stated that the test pressure should be lowered by 10 % following the spike test to minimize the likelihood of flaw growth.

TTO 6 (TTO6)¹¹, a report funded by the U.S. DOT in 2004, provides spike test guidance for application to pipelines operating at lower stress levels. The report notes that the concept of a spike test is valid for pipelines operating at less than 72 % SMYS; however, test pressure targets of 139 % to 153 % of MOP (equivalent to a stress level of 100 % to 110 % SMYS when operating at 72 % SMYS), do not necessarily result in an optimum assessment of pipeline integrity, due to the potential for remaining flaws (e.g. flaws that survive the spike test and subsequent test program) to undergo slow ductile tearing and grow in size to become susceptible to fatigue in service.

Two formulae are presented in TTO6 that identify spike test pressure targets from 139 % to 264 % of MOP depending on the target threat and the operating stress of the pipeline. However, the report cautions that it is “unrealistic to expect an operator to pressurize a pipeline comprised of older ERW pipe to a pressure level exceeding the equivalent of 100 % of SMYS.”

When spike testing to assess the threat of manufacturing defects, such as the potential for defective ERW longitudinal seams, it is beneficial to consider a stress-level target based on the pipe material rather than simply a multiple of MOP or MAOP. It is presented here that selected target spike test stress levels should be benchmarked for feasibility against the actual stress levels achieved during mill testing (if known), previous field hydrostatic testing, or the minimum mill test pressures required within the applicable version of API 5L or API 5LX. The rationale and objectives for this consideration are twofold, and are as follows:

A spike test that achieves a stress level equal to or greater than prior stress levels should do the following:

- 1) Demonstrate that no significant time-dependent degradation has occurred to resident flaws that could exist in the longitudinal seam.
- 2) Suggest a reasonable test pressure target level based on the expected material properties of the line pipe steel, which should not result in an excessive number of test failures when applied.

¹⁰ Leis, B.N. and Brust, F.W. *Hydrotest Strategies for Gas Transmission Pipelines Based on Ductile-Flaw-Growth Considerations*. s.l.: PRCI, 1992. Catalog No. L51665.

¹¹ Baker, Michael Jr. Inc. *TTO-6 – Spike Hydrostatic Test Evaluation*, July 2004.

The following criteria should be considered for a spike hydrostatic test:

- a test pressure level at or above that of a high-pressure test; and
- a test pressure level established based on the target integrity threat and an estimate of the continuing deterioration rates to ensure reliable future operations.

When testing for the purposes of evaluating seam weld manufacturing threats, a test pressure level at least equal to the minimum required mill test pressure is necessary if a test objective is to demonstrate that no significant time dependent degradation has occurred. If mill test pressures are unknown or unavailable, applicable minimums required by the API 5L or API 5LX version at the time of pipe installation can be used. (These are summarized in Table 1 and Table 2).

Although there is no upper limit to spike test pressure levels, test pressure levels that greatly exceed historical mill test pressures or are above 100 % SMYS should be carefully considered to ensure that the benefits outweigh the potential detrimental effects.

Table 1—API 5L Minimum Mill Test Pressures

Year	API 5L Edition	Specification	Mill Test Pressure (min)
1928–1941	1st	Varies by process/grade	40 % SMYS
1942–1982	8th	Varies by process/grade	60 % SMYS
1983–Present	33rd incorporated 5L, 5LX, and 5LS	Grade A25, A, B	60 % SMYS
		X42–X80	60 % SMYS for OD $\leq 8 \frac{5}{8}$ in. 85 % SMYS for OD $> 8 \frac{5}{8}$ in. and < 20 90 % SMYS for OD ≥ 20

Table 2—API 5LX Minimum Mill Test Pressures

Year	API 5LX Edition	Specification	Mill Test Pressure (min)
1948–1952	1st	X42	85 % SMYS
1953–1956	4th	X42, X46, X52	75 % SMYS for OD $\leq 8 \frac{5}{8}$ in. 85 % SMYS for OD $> 8 \frac{5}{8}$ in.
1956–1961	6th	X42, X46, X52	75 % SMYS for OD $\leq 8 \frac{5}{8}$ in. 85 % SMYS for OD $> 8 \frac{5}{8}$ in. 90 % SMYS for seamed pipe OD ≥ 20 in.
1959	Supp. to 8th	X42, X46, X52	90 % SMYS for seamless pipe OD ≥ 20 in.
1962–1982	10th	X42, X46, X52	60 % SMYS for OD = 4.5 in. 75 % SMYS for OD $\leq 8 \frac{5}{8}$ in. 85 % SMYS for OD $> 8 \frac{5}{8}$ in. 90 % SMYS for OD ≥ 20 in.

5.8.1 Spike Test Duration

Stabilization of the test pressure is not required during a spike test; it is only necessary to verify that the test pressure remains above the target minimum pressure for the duration of the spike test period. This approach is supported by the following guidance taken from API 1160: “A spike test is not intended to be a leak test, and generally no attempt is made to look for leaks.” The hold-time portion of the test to look for leaks can be performed after the spike test by lowering the test pressure to the minimum required value for a qualifying test.

Various accepted industry resources recommend various hold times though no source recommends durations longer than one hour. NG-18 Report 194 recommends a one-hour maximum hold time for spike testing. ASME B31.8S recommends a 10-min minimum test duration when testing for management of SCC. TTO6 recommends a 30-min test duration; however, that reference acknowledges that the best hold time for integrity purposes depends upon factors that include the numbers and sizes of defects present in the pipeline. Other references also cite hold times; the above are presented to illustrate the wide variance in recommendations.