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DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 4: Pressure Test Planning Guidelines

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DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 4: Pressure Test Planning Guidelines

to

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Pipeline and Hazardous Materials Safety Administration

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INTRODUCTION

The scope of this Task 4 report is to document the developed guidelines related to the planning phase, or pre-execution phase, of pressure tests. Kiefner and Associates, Inc. (Kiefner) developed these guidelines for best practices based on a review of currently available industry documents, interviews with pipeline operators and pressure test contractors, and Kiefner's own experience with pressure testing.

SUMMARY

This Task 4 report intends to provide the industry with clear guidance related to pressure test planning. The key design aspects of pressure test planning covered by this document include the following:

- Effectiveness of pressure testing
- Test pressure to operating pressure ratios - minimum and maximum test limits
- Spike testing - when spike testing is advisable, inadvisable, or discretionary as well as providing guidance on appropriate pressure levels
- Effect of known defect types on pressure testing and planning
- Test media comparisons and selection considerations
- Effect of biaxial loads

Work related to providing guidance for pressure test execution (Task 5), pressure test evaluation (Task 6) and other topics, including safety (Task 7) is ongoing. Developed guidelines for Tasks 5 through 7 will be provided in separate reports.

BACKGROUND

The objective of the Development of Comprehensive Pressure Test Design Guidelines Project (DTPH5615T00009, Prj# 645) is to develop comprehensive guidelines for the design of pipeline pressure tests that could be incorporated into industry standards and operator procedures. A

goal of this project is to provide guidance on how to plan, execute and evaluate pressure tests based on the most current knowledge and industry needs. The work takes into account the significant amount of research on pressure testing that has been carried out from the 1960s through the present by government, private, and industry organizations.

Task 2 was a review of existing industry standards, recommended practices, research papers and other literature related to the pressure testing of liquid and natural gas pipelines. Task 2 determined the scope of the information already covered in existing guidance documents and identified deficiencies or disagreements, or both, between reviewed documents. The results of Task 2 were reported on January 26, 2016 in Kiefner Final Report No. 16-009, "DTPH5615T00009 Development of Comprehensive Pressure Testing Guidelines – Task 2: Review of Existing Industry Standards and Recommended Practices". The following documents were reviewed:

- ASME B31.8-2014 Gas Transmission and Distribution Piping Systems
- ASME B31.8S-2014 Managing System Integrity of Gas Pipelines
- ASME B31.4-2012 Pipeline Transportation Systems for Liquids and Slurries
- API 1160-2013 Managing System Integrity for Hazardous Liquid Pipelines
- API 1110-2013 Recommended Practice for the Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids, or Carbon Dioxide
- INGAA Report No. 2013.03 "Technical, Operational, Practical, and Safety Considerations of Hydrostatic Pressure Testing Existing Pipelines"
- TTO Number 6 "Spike Hydrostatic Test Evaluation", July 2004

The results of the review specific to pressure test planning related topics are summarized in Table 1. The table shows which pressure test planning related topics are currently covered in each of the above listed documents. A topic is considered covered (denoted with a "yes" in Table 1) if relative language is introduced in the document with some level of detail or discussion, a covered topic does not necessarily imply a prescriptive guideline is provided. The key concepts related to pressure test planning identified for clarification by Task 2 are:

- test pressure to operating pressure ratios – particularly the concept that for lower operating pressures, existing ratios may not be adequate,
- spike testing – when spike testing is advisable, inadvisable, or discretionary as well as providing guidance on appropriate pressure levels,
- maximum test pressure guidelines, and
- effects of known defect types on pressure testing and planning – providing guidance for electric resistance welded (ERW) pipe or stress corrosion cracking (SCC), for example.

Table 1. Test Planning Topical Comparison of Industry Documents

	Title 49 CFR Part 192	Title 49 CFR Part 195	ASME B31.8	ASME B31.8S	ASME B31.4	API 1160	API 1110	INGAA Report	TTO No. 6
Minimum Test Pressure Requirements	Yes	Yes	Yes	Refers to ASME B31.8	Yes	Yes	Yes	Refers to Title 49 CFR Part 192	No
Maximum Test Pressure	Yes[1]	No	Yes	Refers to ASME B31.8	No	No	Yes	Yes	No
Minimum Spike Test Pressure	No	No	No	Yes[2]	No	Yes	Yes	Yes	Yes
Maximum Spike Test Pressure	No	No	No	No	No	No	No	Yes	Yes
Test Medium Selection	Yes	Yes	Yes	Refers to ASME B31.8	Yes	Yes	Yes	No	No
Threat Assessment for Pressure Testing	Refers to ASME B31.8S	Yes	Yes	Yes	No	Yes	Yes	No	Yes
Vintage Pipe Considerations	Refers to ASME B31.8S	Yes	No	Yes	No	Yes	No	No	Yes
Testing of Components	Yes	Yes	Yes	No	Yes	No	Yes	Yes	No

The goal of Task 3 was to capture knowledge from liquid and gas pipeline operators and pressure testing service contractors relevant to pressure testing guidelines, as well as identify inconsistencies or gaps in pressure testing practices. Interviews with three pipeline operators and two pressure test services contractors were conducted by telephone and by written correspondence. The results of Task 3 were reported on June 30, 2016 in Kiefner Final Report No. 16-091, "DTPH5615T00009 Development of Comprehensive Pressure Test Design Guidelines - Task 3: Interview Pipeline Operators and Pressure Test Service Contractors".

Through the interviews conducted during Task 3, it can be concluded that pressure testing is a topic of broad industry interest. It was determined that the industry needs education on and consistent procedures for the following topics related to pressure test planning:

- spike testing – when spike testing is advisable, inadvisable, or discretionary as well as providing guidance on appropriate pressure levels,
- potential damage due to high pressure testing versus the benefits, and

[1] Pressure test limitations only apply to pneumatic testing.
[2] Minimum spike test pressure is specified for the assessment of SCC.

- design of hydrostatic test projects.

Clarification on the key topics summarized here is necessary in order to provide the industry with one comprehensive document that provides clear guidance in the case of conflicts and dispels any misinformation or inappropriate guidance.

Note that the scope of this project is to develop guidelines related to pressure testing. Pressure testing encompasses two forms of pipeline pressurization: pneumatic which uses a compressible gas as the test medium and hydrostatic which uses a liquid as the test medium. The most common test medium for a pneumatic pressure test is nitrogen and the most common test medium for hydrostatic testing is water. Some guidelines documented by this task will distinguish between hydrostatic or pneumatic testing and the broader category of pressure testing.

DEFINITIONS

Pressure Test: A pressure test is the application of internal pressure above the normal or maximum operating pressure to an isolated pipeline segment (or assembly), under no-flow conditions (static), for a fixed period of time utilizing a fluid medium (either liquid or gas) for the purpose of proving the integrity of the pipeline segment.

Pneumatic Test: A pneumatic test is a pressure test where the test medium is a compressible gas such as nitrogen, air or other gas.

Hydrostatic Test: A hydrostatic test is a pressure test where the test medium is a liquid. Hydrostatic testing most commonly utilizes water as the test medium, however other liquids, such as petroleum products, may be used in some instances as the test medium.

Hydrostatic Pressure: Hydrostatic pressure is the pressure exerted by a static fluid due to the force of gravity. In a static, pressurized pipeline segment filled with an incompressible fluid the applied internal stress will vary relative to elevation. Pipe located at a higher elevation will experience a lower internal pressure than pipe at a lower elevation within the same contiguous pipe segment filled with liquid. For the purpose of hydrostatic testing, where a uniform fluid density can be assumed and a pressure value is known at a reference location, Bernoulli's equation can be simplified and solved for a location-specific hydrostatic pressure:

$$P = P_o + \gamma(z_o - z)$$

Equation 1

where:

P	is the static pressure at a specific location (psig)
P_o	is the known static pressure at a reference location (psig)

γ is the fluid specific weight (psig/ft)
z is the elevation at the same specific location as P (ft)
z_o is the elevation at the same reference location as P_o (ft)

The specific weight of water is approximately 62.4 lbs/ft^3 (corresponding to a specific gravity of 1). To express in units of psig/ft, the specific weight of 62.4 lbs/ft^3 is divided by a factor of 144 to give a specific weight of 0.433 psig/ft. Therefore if a hydrostatic test is to be conducted using water as the test fluid, Equation 1 becomes

$$P = P_o + 0.433(z_o - z)$$

Equation 2

where:

P is the static pressure at a specific location (psig)
P_o is the known static pressure at a reference location (psig)
z is the elevation at the same specific location as P (ft)
z_o is the elevation at the same reference location as P_o (ft)

The specific weight of sea water is approximately 63.9 lbs/ft^3, giving a specific weight of 0.444 psig/ft. Therefore if a hydrostatic test is to be conducted using seawater as the test fluid (for instance potentially for an offshore test), Equation 1 becomes

$$P = P_o + 0.444(z_o - z)$$

Equation 3

where

P is the static pressure at a specific location (psig)
P_o is the known static pressure applied at a reference location (psig)
z is the elevation at the same specific location as P (ft)
z_o is the elevation at the same reference location as P_o (ft)

Maximum Operating Pressure (MOP): The pressure an operator is not to exceed during normal pipeline operation. The term applies to liquid pipelines and is covered under 49 CFR 195.406.

Maximum Allowable Operating Pressure (MAOP): The pressure an operator is not to exceed during normal pipeline operation. The term applies to gas pipelines and is covered under 49 CFR 192.619.

Specified Minimum Yield Strength (SMYS): The specified minimum stress tolerance to which the steel material was manufactured. This corresponds to the minimum stress the material will tolerate prior to yielding (yield strength) and is typically given in units of psi. SMYS

is often expressed in terms of the corresponding hoop stress or internal pressure carrying capacity for the pipe (see Equation 4).

Barlow's Formula: The design formula for the internal pressure carrying capacity of pipe, or hoop stress. The formula is

$$P = \frac{2St}{D}$$

Equation 4

where:

P	is internal pressure (psi)
t	is the wall thickness of the pipe (inch)
D	is the outside diameter of the pipe (inches)
S	is allowable stress, depending on the application this can be SMYS, flow stress, or actual measured yield stress (psi)

Internal Design Pressure (IDP): Working pressure as defined by federal regulations and is a function of Barlow's pressure, modified by a longitudinal seam joint factor, a temperature factor (for gas operated pipelines only) and a design factor in accordance with applicable design codes or standards. Reference 49 CFR 192.105 for gas operated pipelines and 49 CFR 195.106 for liquid operated pipelines. The minimum IDP of a pipeline system is not to be exceeded during normal operation (except as allowed for surge conditions for liquid pipelines). IDP is given as

$$IDP = \frac{2St}{D} xFxExT$$

Equation 5

where:

IDP	is internal design pressure (psi)
t	is the nominal wall thickness of the pipe (inch)
D	is the nominal outside diameter of the pipe (inches)
S	is the SMYS of the pipe (psi)
F	is the design factor determined in accordance with CFR 192.111 or 195.106 (a)
E	is the longitudinal joint factor determined in accordance with CFR 192.113 or 195.106 (e)
T	is the temperature factor determined in accordance with CFR 192.115

Table 2, Table 3 and Table 4 are excerpts from 192 Subpart C and 195 Subpart C and cover factors *F*, *E* and *T* from Equation 5. Note that if the longitudinal seam joint type cannot be determined the factor must not exceed that designated for "Other". Also, for intermediate gas temperatures, the derating factor is determined by interpolation.

Table 2. Design Factors (*F*)

49 CFR Part	Class Location/Condition	Design Factor (*F*)
192.111 (a)	Class Location 1	0.72
	Class Location 2	0.60
	Class Location 3	0.50
	Class Location 4	0.40
195.106 (a)	Pipe not meeting one of the two requirements below for *F*=0.60 or *F*=0.54	0.72
	Offshore platforms or inland platforms on navigable waters	0.60
	Subject to cold expansion[3]	0.54

Table 3. Longitudinal Seam Joint Factors (*E*)

Specification[4]	Pipe Class	Longitudinal Joint Factor (*E*)
ASTM A 53/A 53M	Seamless Electric resistance welded Furnace lap welded (part 195 only) Furnace butt welded	1.00 1.00 0.80 0.60
ASTM A 106	Seamless	1.00
ASTM A 333/A 333M	Seamless Electric resistance welded	1.00 1.00
ASTM A 381	Double submerged arc welded	1.00
ASTM A 671	Electric fusion welded	1.00
ASTM A 672	Electric fusion welded	1.00
ASTM A 691	Electric fusion welded	1.00
API 5L	Seamless Electric resistance welded Electric flash welded Submerged arc welded Furnace lap welded (part 195 only) Furnace butt welded	1.00 1.00 1.00 1.00 0.80 0.60
Other (part 192 only)	Pipe over 4 inches	0.80
Other (part 192 only)	Pipe 4 inches or less	0.60

[3] Paragraph 195.106 (a) states a design factor of 0.54 is used for pipe that has been subjected to cold expansion to meet the specified minimum yield strength and is subsequently heated, other than by welding or stress relieving as part of welding, to a temperature higher than 900°F for any period of time or over 600°F for more than 1 hour.
[4] Longitudinal joint factors (E) for other pipe grades are also found in ASME B31.4 and B31.8.

Table 4. Temperature Factors (*T*)

Gas Temperature in degrees Fahrenheit (Celsius)	Temperature Derating Factor (*T*)
250 °F (121 °C) or less	1.000
300 °F (149 °C)	0.967
350 °F (177 °C)	0.933
400 °F (204 °C)	0.900
450 °F (232 °C)	0.867

PRESSURE TEST PLANNING GUIDELINES

When to Perform a Pressure Test

Pressure tests are conducted for a variety of reasons, some mandated in US pipeline regulations or industry standards, and others elective. The following is a list of recognized purposes for executing a pressure test on a pipeline:

- MOP or MAOP establishment prior to commission (new construction pressure test).
- MOP or MAOP re-verification of an idled pipeline prior to re-activation.
- MOP or MAOP verification prior to a change of service, operating demands, or flow direction.
- Identification of pipe yield point.
- Verification that no leaks are present; a possible response to an overpressure event.
- Threat identification and remediation (or integrity management/assessment) of time-dependent anomalies and stable anomalies. Commonly implemented for the reassessment of corrosion, stress-corrosion cracking (SCC), and longitudinally oriented anomalies associated with pipe seam manufacturing processes.
- Revalidating the integrity of a pipeline following a release (e.g., as a corrective action required by a pipeline regulatory authority).
- In-line inspection (ILI) verification.

The decision to conduct a pressure test when the purpose is related to a regulatory requirement (such as MOP or MAOP establishment) is straight forward. However, the choice of whether to conduct a pressure test versus ILI in response to the management of pipeline integrity can be more complex. Situations in which pressure testing provides positive benefits versus marginal value must be considered. A pressure test can address several integrity threats including:

- time dependent threats such as internal corrosion, external corrosion, fatigue cracks, and longitudinally-oriented SCC,

- time-independent (i.e., random) threats such as mechanical damage and outside force damage,
- manufacturing defects such as longitudinal seam weld defects and laminations, and
- some construction related defects.

While the threats listed above cover a wide range of defects, there are limitations to pressure testing and categories of defects for which no pressure test can assure long term immunity from leaks after a test[i]. Such defects include electric resistance welded (ERW) seam penetrators or other short-deep bondline defects, fast-growing localized pitting due to microbial induced corrosion (MIC) or stray current interference, girth weld pinholes, and defects which may have been leaking during the test but were so small that they were not identified. Circumferentially oriented defects are not stressed to the level that longitudinally oriented defects are in an internally pressurized pipeline. (The longitudinal stress due to internal pressure in a buried pipeline is nominally 30% of the hoop stress. Thus even a test to a hoop stress of 100% SMYS imposes at most a longitudinal stress of only 30% of SMYS in addition to any preexisting longitudinal stress and which is low in most circumstances. Moreover, the longitudinal stresses due to pressure and other sources in a buried pipeline are displacement- or constraint-controlled are not necessary to maintain static equilibrium. As a result, longitudinal stresses due to pressure testing do not challenge the integrity of the girth weld. The firm represented by the author has observed many instances of significantly defective girth welds that successfully underwent hydrostatic pressure tests to high levels of circumferential stress but which later did fail or would have been expected to fail under high external loading.) This means that circumferentially oriented defects (i.e., girth weld cracks, circumferential SCC) are less likely to be exposed during testing, unless already leaking or on the verge of failure. Moreover, a successful pressure test does not establish the ability of girth welds to withstand elevated levels of axial stress caused by external loadings. Also, pressure testing is not a dependable means of controlling or preventing failures from hard spots or hydrogen blisters. For a number of threats, ILI is potentially a more reliable assessment of the integrity of the pipe; especially for the remediation of corrosion, hydrogen blisters, mechanical damage, deformation and circumferentially oriented defects.

There are still benefits to pressure testing. Pressure testing is particularly effective at eliminating longitudinally oriented defects such as seam weld cracks or axial SCC. Also any severe defects, such as mechanical damage, on the verge of failure at operating pressure should be exposed by a pressure test. (However, pressure testing cannot prevent damage after a test. Only a damage prevention program is capable of mitigating an ongoing integrity threat from excavator damage.) And ultimately a pressure test can demonstrate the immediate fitness for service of a pipeline.

It is recommended that operators incorporate the following elements into their assessment method selection process:

- threat type of concern,
- expected defect population,
- pipeline failure, assessment, and operation history,
- pipe manufacturer, vintage, seam type, and material characteristics,
- suitability of pipeline configuration for pressure testing,
- suitability of pipeline configuration for ILI,
- probability of failure predictions based on past assessments (such as a comparison of the likelihood of failure during a pressure test to the likelihood of failure in-service, post ILI or post pressure test), and
- potential risk reduction of each assessment option.

The assessment method selection process should allow for multiple outcomes, including:

- selecting hydrostatic testing alone,
- running a single ILI technology,
- running multiple ILI technologies,
- combining hydrostatic testing with ILI, or
- occasionally adjusting operating conditions in combination with one of the aforementioned assessments.

Pressure testing can be a supplement to ILI for a variety of integrity threats, or applied as a method of ILI verification. American Petroleum Institute (API) Recommended Practice (RP) 1176 offers the following on using hydrostatic testing for ILI verification[ii]:

> "When the verification of crack features by excavation results does not sufficiently correlate with the ILI for detection or severity, hydrostatic testing, possibly of a segment or segments of a pipeline, could be required to verify the possible population of remaining cracks. Verification by hydrostatic test is demonstrated when a pipeline segment that could not be verified by excavation successfully passes a hydrostatic test without any failures. If failures occur, the testing of additional segments should be considered depending on the failure cause (i.e., could be unrelated to cracking). In some cases, an operator may elect to perform a verification hydrostatic test on only a portion of a line section inspected by ILI. When only a portion of the line is tested this way, the test section should be representative of the entire segment regarding crack type, growth mechanism, and pipe properties. If one hydrostatic test section is used to verify multiple ILI runs, then the operator must ensure that the critical characteristics of each ILI run (such as vendor, technology, and run media) are similar so that the results are not affected."

While API RP 1176 is specific to crack threats, the same logic for ILI verification by means of pressure testing could be adopted for other integrity threats, such as selective seam weld corrosion.

Background Information Review

Background information must be reviewed to adequately and safely plan for a pressure test. Most of the information necessary to review is synonymous with both new construction tests and reassessments of existing pipelines; however distinctions are noted where applicable.

Regulatory Requirements and Company Policy

Regulatory requirements at the federal, state, and local level must be reviewed and followed. If testing requirements differ among regulatory authorities, the most conservative or restrictive requirements should be implemented. Review any active corrective action orders or directed recommendations from regulators specific to the asset being pressure tested.

Operators should review their own company policies to insure the most current pressure test procedures are being followed. Any variance from stated company policy should be widely communicated and approved during the planning phase as well as thoroughly documented with sound justification.

Pipeline Attributes

Information on the following should be gathered when preparing for a pressure test:

- Service type (gas or liquid)
- Regulatory jurisdiction
- Current and desired MOP or MAOP
- Installation date
- Mill Test Report (MTR)
- Outside diameter
- Wall thickness
- Grade, SMYS
- Elevation profile
- Seam type, including:
    - lap welded
    - low-frequency or high-frequency ERW
    - direct current (d.c.) ERW
    - electric flash welded (EFW)
    - double submerged arc welded (DSAW)
    - single submerged arc welded (SSAW)

  - helical (or spiral) welded
  - seamless (SMLS)
- Pipe Manufacturer (potentially critical if identified as a pipe type of concern based on failure history or when other information is missing, such as seam type)
- Date of manufacture (to establish mill test pressure if MTRs are unavailable)
- ANSI rating of system components
- Pump or compressor station locations
- Valve locations
- Other potential isolation locations
- Total length of exposed pipe
- River or water crossing locations
- Bore and road crossing locations
- Foreign line crossing locations (particularly if heated pipeline)
- Locations of buildings or public spaces in close proximity
- For re-inspection only (not applicable for new construction)
  - Pressure test history (previously achieved test pressures, segmentation and the location, pressure and cause of any failures)
  - Service rupture or leak history (cause of failure, failure pressure and failure location)
  - ILI history (past inspection results, field observations and remaining defect size and location)
  - Material test results (such as actual yield strength, tensile strength, and toughness determined by destructive testing)
  - Operating pressure history

Unknown Pipe Properties

There are instances when some pipeline attributes are unknown; this could be due to lack of documentation or conflicting documentation. Two parameters that can have a significant impact on the outcome of a pressure test are material strength and longitudinal seam weld properties; so if either of these two parameters is unknown a conservative yet plausible assumption of yield strength and seam type should be made. Representative material properties can be obtained by in-situ testing on a sampling basis or by lab testing of offcuts where the pressure test manifolds are to be inserted.

A chief concern with pipe of unknown grade is that federal regulations stipulate that the yield strength be taken as 24,000 psi (unless determined otherwise by CFR 195.106(b) or CFR

192.107(b)) for the calculation of IDP and determination of MOP or MAOP[5]. While missing information on yield strength will affect MOP and MAOP, it does not negate the value of achieving a high test-pressure-to-operating-pressure ratio (TPR) from the standpoint of demonstrating a margin of safety. To achieve this, the upper limit on test pressure can be determined during testing by monitoring for yielding and stopping after some amount of yielding has occurred. Pressuring until yielding has occurred can benefit the pipeline by allowing the highest possible TPR to be achieved. Pressure-volume plotting will be covered in detail by Task 5, the pressure test execution phase of this work.

When no information is known about the seam type it is recommended to assume the material has toughness and seam type consistent with what may be known about the pipe, such as an early vintage, low-frequency ERW pipe. This assumption is for test planning only. For MAOP and MOP determination refer to 49 CFR 192.105 or 49 CFR 195.106 for valid longitudinal seam joint factors when seam type is unknown.

To a certain degree assuming properties during the test planning phase comes down to judgment. That decision should take into account what information is known about the pipe in question, what is known about the pipeline system as a whole and what impact the assumed value will have on the overall test plan. Previous tests and operational history, and results of testing of prior cutouts, can be studied to make postulations as to the material strength for the purpose of establishing a target test pressure. A review of industry requirements in place during the era of construction (such as API 5L or API 5LX) can provide useful information, if one can make a sound assumption industry practices were followed. Another useful resource is the ASME Research Report, *History of Line Pipe Manufacturing in North America*[iii], which includes summaries of many common pipe manufacturers that may narrow the possible range of variables in missing information. Consideration should be given to the possibility of pipe having been salvaged or reused and being older than its installation date of record.

Optimal test effectiveness, as well as public or worker safety during testing, may depend on having accurate knowledge of pipe strength and seam type. Where deductive analysis cannot provide needed confidence in the test design, selective material sample testing may be prudent.

Manufacturers' Hydrostatic Test Pressures

API Specifications 5L and 5LX require a brief hydrostatic test be conducted at the time of manufacture, referred to as a mill test. Specifications for mill test pressure vary by pipe seam type, size, grade and year of manufacture (relevant to the existing edition of specification).

[5] 24,000 psi corresponds to the yield strength for wrought iron pipe, the lowest common grade of line pipe manufactured historically.

Depending on pipeline design, construction, and elevation, it is possible that the highest level a pipe has been (or will be) pressurized to occurred at the time of manufacture. On the other hand, conditional to the operational or integrity management requirements for a pipeline, a pressure test may need to exceed mill test pressures. A review of minimum mill test pressures can help determine appropriate target test pressures, particularly in the absence of construction or post-construction pressure test information.

Table 5 and Table 6 were developed from API 5L Line Pipe Specifications and give the minimum pressure test levels required based on pipe type and grade. If actual MTRs are unavailable for review, these tables may indicate the minimum mill test pressure achieved, assuming the vintage and grade of pipe are known. The effectiveness of the mill test should be discounted 5% to 10% due to the test being so brief (5 seconds) that it could end before the pipe has a chance to fail. The discount is derived from the observation in lab tests that stable tearing can occur if a defect is held to within 90% of its immediate-failure stress, and unstable tearing can occur if it is held within 95% of its immediate-failure stress[6]. Thus a latent defect could remain that, if stressed at a slower rate, could fail at perhaps 81% to as low as 77% of SMYS even if the pipe had survived a test to 85% at the pipe mill.

Table 5. Manufacturers' Minimum Hydrostatic Tests for API 5L Line Pipe Manufactured Prior to 1942

Type and Grade of Pipe	Year of Manufacture	Yield Strength, psi	Minimum Mill Test Pressure, % SMYS
Seamless, Grade A	1928, 1931	30,000	46.6
Seamless, Grade B	1928, 1929	40,000	45.0
Seamless, Grade C	1928, 1931	45,000	40.0
Lap-welded	1928 - 1941	25,000	56.0
Lap-welded	1928 - 1941	28,000	50.0
Lap-welded	1928 - 1941	30,000	46.6
Seamless, Grade B	1930, 1931	38,000	47.4
Seamless or Electric Welded, Grade A	1932 - 1941	30,000	46.6
Seamless or Electric Welded, Grade B	1932 - 1941	35,000	45.7
Seamless or Electric Welded, Grade C	1932 - 1941	45,000	40.0

[6] Kiefner, J.F., Maxey, W.A., and Eiber, R.J., "A Study of the Causes of Failures of Defects That Have Survived a Prior Hydrostatic Test", NG-18 Report No. 111, November 3, 1980.

Table 6. Manufacturers' Minimum Hydrostatic Tests for API 5L Line Pipe Manufactured After 1941

Type and Grade of Pipe	Diameter, inches	Year of Manufacture	Standard Mill Test Pressure, % SMYS
Lap-welded Steel Pipe	all	1942 - 1962	60.0
Grades A and B	all	1942 - 1982	60.0
Grades A and B	2⅜ and larger	1983 - present	60.0
Grade C (45,000 psi)	all	1942 - 1954	60.0
X Grades, all types	all	1949 - 1952	85.0
X Grades, all types	< 8⅝	1953 - 1961	75.0
X Grades, all types	4½	1962 - 1969	60.0
X Grades, all types	4½ and smaller	1969 - 1982	60.0
X Grades, all types	6⅝ - 8⅝	1962 - 1999	75.0
X Grades, all types	10¾ and larger	1953 - 1955	85.0
X Grades, all types	10¾ - 18	1956 - 1999	85.0
X Grades, all types	$5^{9}/_{16}$ and smaller	1983 - present	60.0
X Grades, all types	>$5^{9}/_{16}$ and <8⅝	2000 - present	75.0
X Grades, all types	8⅝ - 18	2000 - present	85.0
X Grades, all types	20 and larger	1956 - present	90.0

Service Failure and Pressure Test Failure History

A study of service failures and pressure test failures should be performed. The quality of documentation for failures may vary; however, if available, the following information should be gathered:

- Service or pressure test failure analysis
- Failure date
- Failure location (mile post, stationing)
- Pipe properties (diameter, wall thickness, grade, vintage, seam type, manufacturer)
- Failure pressure at the failure location (in psig and %SMYS)
- Cause of failure
- Failure location on the pipe (weld, longitudinal seam, pipe body, clock position)
- Mode of failure, rupture or leak
- Evidence of growth
- Distance from upstream discharge location
- Years of operation since previous pressure test
- Amount of time on test before failure discovered (if test rupture)
- Size of pressure reversal (if test rupture)
- Material testing results (yield strength, tensile strength, toughness and chemistry)

Based on the review of the failures certain conclusions on the pipeline could be made, including:

- Evidence of a common cause of failure
- Evidence of a common mode of failure
- Pipeline section(s) that exhibits a higher rate of failure
- Identification of primary threats
- Evidence of susceptibility to pressure reversals
- Evidence of substandard pipe material

Assessment History

At a minimum, the most recent pressure test conducted on the pipeline system should be reviewed. The following information shall be gathered:

- Test date
- Segmentation
- Maximum test pressures and range of %SMYS achieved
- Range of TPR achieved
- Number of test failures per segment
- Number and size of pressure reversals
- Significant pressure fluctuations due to temperature affects

For pipeline systems with an extensive history of pressure testing a progressive analysis of pressures achieved and failures experienced can provide insight into the effectiveness of the pipeline's integrity management of time-dependent threats. If past testing programs were not effective in the prevention of service failures caused by time-dependent threats, a higher test pressure should be considered or supplemental activities to the pressure test should be executed. If a higher test pressure than ever previously achieved is considered, the operator should be aware of the increased likelihood of test failures. Failure predictions will be covered in detail by Task 5, the pressure test execution phase of this work.

ILI inspection results should be studied. Whether the ILI performed reasonably well with respect to management of active integrity threats should be established. The hydrostatic test should be developed to address any short comings of the ILI assessment if possible. ILI results could be used to minimize the occurrences of test breaks and leaks during a pressure test. The following should be determined based on a review of ILI assessment results:

- Pipeline section(s) that exhibits a higher concentration of defects (consider type)
- Identification of primary threats
- Location of remaining defects on the pipeline
- Size of remaining defects on the pipeline

- Vendor stated sizing tolerance
- ILI validation results for detection, identification or characterization and sizing
- Predicted failure pressure of remaining defects on the pipeline

An appropriate fitness-for-service (FFS) calculation method should be applied for each unrepaired feature type identified by ILI. There are several valid FFS methods covered by industry documents; the PRCI Project PR-218-0540 report, *Pipeline Defect Assessment – A Review & Comparison of Commonly Used Methods*[iv], is broadly applicable. Additive sizing tolerance should be included in the failure pressure predictions if the ILI validation results indicate the tool performed outside of specification. The estimated failure pressure of the unrepaired features should be compared to the planned test pressure (accounting for hydrostatic pressure if testing with liquid). If the estimated failure pressure is less than the planned test pressure an operator can elect to repair the feature prior to executing the test in an effort to prevent test failures and minimize downtime. Alternatively, features with an estimated failure pressure below the planned test pressure can be allowed to remain unrepaired. If a feature was oversized by ILI or is located on a joint of pipe with higher than minimum specified material properties it should survive the pressure test.[7] Otherwise the feature will fail during testing and can be removed for further evaluation. The decision as to which features to repair prior to testing relies on the consequence of failure, confidence in ILI sizing and management of operation downtime. If the consequence of failure is severe, an effort should be made to repair most if not all features estimated to fail. If the consequence of failure is minor, and the confidence in ILI performance is high, an attempt to test at the planned target pressure without further repair could be made. If pipe containing an ILI feature passes a pressure test without failure, then it has demonstrated its integrity for immediate serviceability.

All ILI feature types identified should be studied and their effect on the integrity of the pipeline understood. That said, the most critical ILI features recommended for FFS review prior to pressure testing are longitudinal seam weld cracks, longitudinal SCC, and selective seam weld corrosion (SSWC) because these defects are more likely to be identified by pressure testing.

Pipeline Operation

Test objectives shall take into consideration future operational needs, as well as past pipeline operation. Future operational needs are inherent to the minimum test limitations with respect to MOP or MAOP determination. If a pipeline operates with aggressive pressure cycles it may be at higher risk for fatigue related failures. If the operating regime has changed, or is

[7] Unless destructive testing of a pipe joint is performed, absolute feature size and actual material properties can only be estimated statistically.

expected to change, threats that may have been dormant could become active (or vice versa) possibly changing the objectives of the current assessment as compared to past assessments. It is also recommended to review actual operating data in addition to documented MOP or MAOP, because there are instances where the normal operating pressure is significantly lower than the stated MOP or MAOP. Understanding the margin between the normal operating pressure and the planned test pressure allows for better insight into the likelihood of failures.

Pipeline operation has an impact on the logistics of a pressure test. If possible, testing should be executed when downtime on the pipeline will have less of an impact on product supply. Sometimes this corresponds to a scheduled refinery turnaround. In other instances pipeline utilization may vary seasonally. When developing test plans minimizing downtime on highly utilized pipelines is generally an objective. However, equal consideration should be given to the risk of service failures on such pipelines if the test plan does not aggressively target active threats.

Test Pressure

Once a review of the above considerations is complete, one should have a solid understanding of the goals of the pressure test in terms of integrity management and operational requirements. Planned test pressures should be established to best facilitate those goals, while ensuring federal, state and local regulations are met. This section of the guidance document will cover general minimum and maximum test pressure bounds for pipelines. The minimum bound test pressures discussed here only apply to a conventional (or hold) pressure test, however the concepts introduced for maximum bound test pressures are applicable to spike test pressures as well and will be explained in the subsequent section of this report. Hold times will be introduced here in order to categorize test types, but appropriate hold times will be discussed comprehensively in the Task 5 report on pressure test execution.

Concepts

Pressure tests should be designed uniquely to address pipeline specific threats and operational needs. Pipeline attributes, operating history, failure history, past assessment results, integrity threats and desired time to re-inspect should all be integrated into the process of determining the appropriate test level and test segmentation. Integrating these key factors into a test plan should maximize the effectiveness of a pressure test.

A pressure test should be carried out to the highest possible pressure levels feasible in order to maximize the benefits of the test. Test-pressure-to-operating-pressure ratio (TPR) is the most important factor; the higher the ratio the greater the margin of operational safety. The higher the ratio the greater the margin between defects small enough to survive a test and those large enough to fail at MOP or MAOP. This principal theory is the basis for the following guidelines on

test pressure determination and is discussed extensively in, "The Benefits and Limitations of Hydrostatic Testing" by J.F. Kiefner and W.A. Maxey[v].

The value of having a large TPR is apparent when considering the effect on re-inspection intervals for the control of time-dependent defect growth. The time that it takes for a defect that survives a pressure test to grow in service to a size that endangers the pipeline will increase as the margin between test pressure and MOP or MAOP increases.

Maximum Bound Pressure

Based on the above principles pressure test procedures should allow for the possibility of a maximum test pressure of 110% SMYS. Pipe that meets the specified minimum yield strength is not likely to be appreciably expanded even if tested to hoop stress levels of 110% SMYS[8]. Information gathered specific to the pipeline may suggest a target test pressure lower than 110% SMYS is more appropriate, especially if the material has demonstrated the inability to maintain high levels of hoop stress without incurring ruptures. The stress levels on low toughness materials or pipe with lap-welded seams, low-frequency-welded or dc-welded ERW seams, flash-welded seams, and single-submerged-arc-welded seams should not exceed 100% of SMYS unless it is found that no seam failures have occurred in the past or provisions are made to lower the target test pressure if seam failures occur during testing. If multiple seam failures have occurred on such pipe, it may be difficult even to exceed the mill test pressure.

If a pressure-rated component, such as a flanged fitting or a valve, is to be pressurized during testing the rated working pressure should not be exceeded by 150%[vi] or a marginal value above this limit (see Limitation of Components section of this report). The potential effects of biaxial loading should also be considered when determining the maximum pressure bound (see Biaxial Loading Effects section of this report).

Minimum Bound Pressure

Minimum requirements for pressure testing are outlined in 192 Subpart J for gas pipelines and 195 Subpart E for liquid pipelines. Subparts J and E cover hold time and safety factors for the determination of MAOP and MOP, respectively. These tests are commonly designated as conventional or hold tests.

Federal regulation 195 Subpart E[vii] pressure testing requirements stipulate a strength test be held at a minimum of 1.25 times the MOP for four hours; and, in the case of a pipeline that is

[8] Statistically, there is some probability of a small number of pipe joints not meeting SMYS even where the production of the pipe met all requirements of API 5L. This statistic will be discussed in the Task 6 report on pressure test evaluation.

not visually inspected for leakage during the test (such as a buried or partially buried pipeline segment), for at least an additional four continuous hours at a minimum of 1.10 times the MOP.

Unless stated otherwise, Federal regulation 192 Subpart J[viii] pressure testing requirements stipulate a pressure test be held for at least eight continuous hours for MAOP certification. Table 7 has been reproduced from CFR 192.619 (2)(ii) and specifies factors for MAOP determination of steel pipelines in gas service to operate at or above 100 psig. The minimum test pressure achieved during an 8-hour Subpart J test shall be divided by the factors given below to determine the MAOP for the pipeline segment. Additional requirements apply for pipelines to certify for alternative operating stress levels under §192.620.

Table 7. Factors by Class Location per CFR 192.619 (2)(ii)

Class Location	Factors[9], if segment -		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under 192.14
1	1.10	1.10[10]	1.25
2	1.25	1.25	1.25
3	1.40	1.50	1.50
4	1.40	1.50	1.50

Planned Test Pressures

Once the minimum pressure and maximum pressure bounds are known, the planned (or target) test pressure can be developed for the pipeline segment. The planned test pressure should be defined such that the minimum pressure is exceeded by at least 10 psig at the high point elevation location and the maximum pressure less 10 psig is not exceeded at the local low point elevation for each respective pipe type and component. For example, if the minimum pressure bound is P_{min} and the maximum pressure bound is P_{max} the planned test pressure (P_{plan}) at the high point elevation is suggested to be greater than or equal to P_{min} plus 10 psig and P_{plan} at the low point elevation is suggested to be less than or equal to P_{max} minus 10 psig at the low point elevation. The 10 psig margin is a precaution or allowance for potential error, such as unintended, high rate pressure increases or decreases due to thermal changes. The planned test pressure should fall at a value between these two constraints. It is recommended that the planned test pressure value is closer to the higher bound to maximize the benefit of the test;

[9] For offshore segments installed, uprated or converted after July 31, 1977 that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977 that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.
[10] ASME B31.8 increased the minimum test pressure ratio from 1.10 to 1.25 for both pneumatic and hydrostatic pressure tests in 2012 because of the conclusion 1.10 is inadequate to assure stability of manufacturing defects for an indefinite period of time.

unless a spike test is to be conducted prior to the conventional test, and then the test value may be closer to the lower bound (see Spike Test Pressure section of this report). It is recommended that the planned test pressure be expressed at a unique reference point (such as the planned deadweight location) rounded up to the nearest 5 psig for conservatism and communicated in a written test plan. Allowable pressure fluctuation above or below the planned pressure during testing will be addressed in the Task 5 report on pressure test execution.

Spike Testing

A short-term pressure test at a higher pressure than, and implemented just immediately prior to, a conventional pressure test is commonly known as a spike test. The following four resources significantly helped shape the guidelines related to spike testing presented herein:

- Rosenfeld, M.J., "Hydrostatic Pressure Spike Testing of Pipelines: Why and When?", Journal of Pipeline Engineering, December 2014;
- "Recommended Practice for Assessment and Management of Cracking in Pipelines", API Recommended Practice 1176, July 2016;
- Michael Baker, Jr., Inc. and Kiefner & Associates, Inc., "Spike Hydrostatic Test Evaluation", Report No. TTO-6, Contract DTRS56-02-D-70036, July 2004; and
- Kiefner, J.F., Maxey, W.A., and Eiber, R.J., "A Study of the Causes of Failures of Defects That Have Survived a Prior Hydrostatic Test", NG-18 Report No. 111, November 3, 1980.

It is recommended that the technical support reported and discussed within each of the above references be reviewed by the user.

Spike Test Duration

The topic of pressure test hold time, including recommendations on the duration of a spike test, will be discussed at length in the Task 5 report on pressure test execution. However, spike test duration is briefly addressed below as an introduction to the subject of spike testing for context of when to consider spike testing during the planning phase of pressure testing.

The duration of a pressure test is not critical to the effectiveness of an assessment in terms of integrity management. This statement is based on fracture mechanics principles and experience, and is supported by industry research[ix]. There is little to no benefit in holding a spike test longer than necessary to verify the pressure being measured is stable. This depends on the conditions of the test, but a timeframe of three to ten minutes is recommended[x]. The benefit of longer hold times is for the detection of leaks and does not improve the integrity of the pipeline. A leak test performed at a pressure that is less than the maximum strength test pressure level can be effective and is less damaging.

When to Perform a Spike Test

Spike testing, though not currently required by regulations, can be beneficial and therefore recommended in certain specific circumstances[ii, xi]. It is possible to consider three categories for the appropriateness of a spike test: (1) advisable, (2) unnecessary or discretionary, and (3) undesirable. These are described below.

1. Spike testing is beneficial and therefore recommended in certain specific circumstances, namely:
    a. Where crack-like defects such as SCC, selective corrosion of ERW seams, bond line defects in older-vintage ERW seams, and seam fatigue cracks are expected to exist based on evidence from inspections or failures; or
    b. Where it is desired to increase the retest interval for time-dependent defects; or
    c. Where documentation is unable to confirm the attributes of the pipe and also unable to confirm that a prior hydrostatic test has occurred.
2. Spike testing is unnecessary though not harmful, and is therefore discretionary, in the following situations:
    a. Where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present;
    b. Where the standard test margin is 1.4 or greater; or
    c. Where the pipe being tested is new.
3. Spike testing would be undesirable in certain specific circumstances, including:
    a. Where the spike pressure above the minimum required standard test level could damage pipe;
    b. Where the spike pressure level would exceed the recommended maximum test pressure levels of components such as flanges or valves; or
    c. Where the margin above the spike pressure level could be insufficient to prevent damage to the pipe due to a pressure increase caused by fluid thermal expansion effects during the test, which could be the case where the test encompasses a large elevation spread, the test section is very short, or the test temperatures are high.

The National Transportation Safety Board (NTSB) has recommended conducting a spike test followed by a standard hydrostatic strength test (or conventional pressure test) specifically in high-consequence area pipeline segments where records are unable to confirm the pipe attributes and also unable to confirm that a prior hydrostatic pressure test took place, as listed in (1)(c) above[xii]. The NTSB's recommendation to conduct spike testing is reasonable within the suggested scope, but it cannot be generalized to all testing situations. A spike test should be considered unnecessary in many conventional testing situations, such as those listed in category (2) above. Note that this includes situations where the standard test margin is 1.4 or greater, as listed in (2)(b) above. The rationale for (2)(b) is that pressure reversals as large as 30% of

the test pressure have been shown to be statistically exceedingly improbable. Therefore, a reduction in pressure for the leak test from the high pressure is unnecessary, so whether the test is performed in a spike format is irrelevant. Finally, there are situations listed above in category (3) where a spike test could be harmful and is therefore not recommended.

Spike Test Pressure

The effectiveness of the spike test is gauged by the TPR.[xiii] Analysis has shown that where a defect growth mechanism can act on defects that survive a hydrostatic pressure test, pipelines operating at lower stress levels require a larger test pressure ratio than pipelines operating at higher stress levels in order to achieve assurance of the integrity of the pipe for the same length of time. In other words, a test to 1.25 times MOP is not as effective a test in a pipeline operating at a low stress as it is in a pipeline operating at a high stress. The logic behind this is as follows. Where the operating stress is high, 1.25 times that high stress is a very high stress that only small defects could withstand; where the operating stress is relatively low, 1.25 times that low stress is still a low stress which relatively large defects can withstand. Given a defect growth mechanism, whether corrosion or pressure cycle fatigue, large defects grow to failure in less time than small defects. To offset this effect, lower stress pipelines must be pressure tested to higher levels relative to the operating pressure to achieve the same time to failure or reassessment interval.[xi]

Relying on a series of pressure cycle fatigue analyses using standard fracture mechanics concepts, the referenced TTO-6 report recommends that the spike test pressure to MOP (or MAOP) ratio be calculated as:

$$TPR = -0.00736\ (\%\ SMYS\ at\ MOP) + 1.919 \qquad \textbf{Equation 6}^{11}$$

when pressure-cycle-induced fatigue is anticipated, and

$$TPR = -0.02136\ (\%\ SMYS\ at\ MOP) + 3.068 \qquad \textbf{Equation 7}^{11}$$

when SCC or selective seam corrosion are anticipated.

A research study on test pressures for mitigating the pipe manufacturing defect integrity threat in natural gas pipelines offers additional support for larger TPR for pipelines operating at lower stresses[x]. The study compared TPRs necessary for a practical safe operating life prediction (as determined by deterministic and probabilistic failure models) to CFR 192 pressure test requirements and TTO-6 recommendations for the management of fatigue-crack growth. The

[11] TTO-6 defines "HTP/MOP" rather than the naming convention of TPR utilized throughout this document.

results confirm that lower operating stress or greater TPR reduce the probability of failure at any given time to failure, however TPR has the significantly stronger influence. While not matching precisely, it was concluded that there is general agreement between the deterministic model and the probabilistic model that seeks to equalize risk by accounting for population density. In fact, the probabilistic approach suggests that the dual criterion (whereby the test pressure must exceed the lessor of a hoop stress level or TPR) from the deterministic approach should standardize on the greater, rather than the lesser, of the two criteria. The probabilistic results also support the recommendations from TTO-6 for pipelines operating at stress levels of 60% SMYS or greater, but suggest a slight increase in TPR would be appropriate for pipelines operating at lower stress levels in order to maintain uniform risk levels accounting for higher density land development in gas pipeline Class 3 or 4 locations. While this study and corresponding conclusions are specific to manufacturing defect integrity in natural gas pipelines, it is reasonable to assume that similar results could be found for liquid pipelines and an analogous study is merited.

Target test pressures developed for integrity management purposes may not correspond to pressure levels required for conventional pressure tests (i.e. 8 continuous hours for MOP determination). Therefore, if the target test pressure levels determined in the previous section of this report exceed minimum requirements for the certification of MOP or MAOP by approximately 5% or more consider conducting a spike test. Essentially, after a spike test is completed, the pressure should be reduced by at least 5% and preferably 10% of the spike test pressure achieved, while still meeting the minimum regulatory requirements[xi]. For instance, if a pipeline subject to 195 Subpart E pressure testing requirements is limited to an MOP of 1,440 psig but a target test pressure of 2,200 psig is determined to best address integrity concerns for the pipeline, it is recommended to conduct a spike test at 2,200 psig then reduce pressure for the conventional test to a level that would result in a minimum pressure of 1,800 psig (1.25 times 1,440 psig) on the segment.

Limitation of Components

Test pressures must not exceed the tolerable limits of flanges, valves, or other pressure rated components included within a test section. A common tolerable limit instituted by pipeline operators in the past is 1.5 times the stated working pressure of the component, yet there are instances when this limitation either restricts operating pressure or integrity related goals. The 1.5 factor is derived from the requirements of long standing flange[xiv,xv] and valve[xvi,xvii] product standards which generally state that the flange or flanged component must be capable of withstanding a system pressure test without impairment to 1.5 times the rated working pressure. There is good experimental[xviii] and analytical[xix] evidence that a flanged connection can withstand pressure considerably in excess of 1.5 times the rated working pressure, provided it is properly assembled and not acted on by high external loadings. That conclusion

may not extend to mechanical components such as valves. Manufacturers generally limit excess pressure recommendations to the specified test capability. The amount of pressure in excess of 1.5 times the room temperature pressure rating is a matter of judgement and the user is cautioned that higher pressures may exceed a component's expected performance capability, or void a manufacturer's warranty. If the flanged joint does not leak during an overpressure test, then it was probably not harmed.

Prior to any pressure test, 1.5 times the specified rated pressure for each component within the test section should be compared to the intended maximum pressure (including effects of elevation) as determined by either the Test Pressure or Spike Testing sections of this document. For locations of components where the planed maximum test pressure exceeds 1.5 times the rated pressure, one or more of the following options should be considered:

- Temporary or permanent removal of the component from the test section (could be justified if the pressure rating is significantly lower than test targets)
- Reconfigure the test segmentation (may only be effective for pipeline segments having large elevation differentials or variable MOP or MAOP);
- Reduce the test pressure (may result in a reduction of MOP or MAOP, or overall effectiveness of pressure test);
- Allow the test pressure to marginally exceed 1.5 times the specified rated pressure and confirm absence of leakage during the test.

In addition to the considerations for tolerable test pressure, components should be inspected and confirmed in good condition prior to pressure testing. Inspection results may suggest that new gaskets, seals and/or packing should be installed on flanged components and valves prior to pressure testing (proper bolt tightening procedures should be observed with any modification to separated flanges). With gas pipelines, an observed minor leak at a flange does not invalidate the strength test if the pressure can be maintained throughout the mandatory test period and the leak must be corrected after the test; this topic, along with options on when to terminate and correct a flange leak will be addressed in the Task 5 report.

Test Segmentation

Test segmentation is dependent on the goals of the test and pipeline design. Each pressure test design will be unique; however the following general guidelines represent best practices implemented for many pressure testing projects and are provided as a starting point for test segmentation development. If a pipeline has significant elevation changes or multiple pipe types of varying strength, a best effort should be made to minimize the range of %SMYS across a test section. Minimizing the allowable range of %SMYS can be necessary to achieving consistent integrity benefits for a pipeline system. The test section length should be limited to prevent an elevation difference from exceeding approximately 300 feet (equivalent to a 130

psig pressure differential if testing with water). In general, segmentation lengths of 30 miles or less can accommodate these goals. New construction projects which utilize heavier wall pipe at lower elevations can accommodate larger elevation changes in a test and achieve cost savings by reducing the number of test sections. Examples on how to calculate pressures at various locations along an elevation gradient for a test segment are provided in the *Pipeline Rules of Thumb Handbook*[xx]. It may be necessary to install vents at intermediate hilltops (high point elevations) in an effort to reduce the amount of entrapped air within a test segment; this topic is relative to leak detection and will be addressed by the Task 5 report.

Above ground valve locations typically serve as good test boundaries (or end points) for a segment. Boundary locations should be selected to facilitate positive isolation of the test section and for safe, convenient access for personnel and equipment needed to install headers, source test media, and de-pressure. The potential need of further segment isolation in the event of a leak search should be considered. Ideally a segment will have a valve between the upstream (US) and downstream (DS) boundaries that can be closed in the event further segmentation is needed to locate a leak. If a pipeline has a history of small leaks, or a primary threat of defects that are known to fail as small leaks, shorter test sections should be planned in order to reduce the amount of volume per test section. The smaller the test volume the greater the pressure drop will be if a leak does occur, making it easier to verify the existence of a leak. Detailed recommendations specific to leak detection will be addressed by Task 5 of this project.

Test Media

A pneumatic test is a pressure test where the test medium is a compressible gas such as nitrogen, air or any other gas. A hydrostatic test is a pressure test where the test medium is a liquid, such as water, petroleum products, or crude oil. Water is the most commonly used test medium for pressure testing, and is the exclusive test medium stipulated in many operator policies on pressure testing. However there are instances where other media are equally viable or preferred. Some pipelines are not optimized to be pressure tested using water due to issues with filling, dewatering, drying, weight of test liquid in spans, providing and maintaining service to downstream customers and extended line downtime. Inert gas testing offers advantages for downtime of the pipeline, cost, as well as post-test dewatering and drying issues. The hazards and risk prevention and mitigation measures applicable to pressure testing pipelines are critical to determining which test medium or fluid is best suited for each pipeline circumstance.

Safety Considerations

Hydrostatic or pneumatic pressure testing is performed routinely and usually without incident. However, despite the routine practice, there are many sources of potential hazard. Testing with natural gas, air or nitrogen has obvious dangers from the stored compression energy of the

gas. Testing with water also presents hazards. Also, incidents of personal injury, fatality, or property damage associated with pressure testing, including both pneumatic and hydrostatic pressure tests have occurred. Many involve failures of test equipment or materials other than the pipe being tested.

Note: The safety issues discussed herein in conjunction with pneumatic testing are intended to address situations where any failure that might occur will occur in a ductile mode. If a failure were to occur in a brittle mode during a pneumatic test, the extent of fracture propagation could be significantly greater than that which would accompany a failure in a ductile mode. An operator intending to employ pneumatic testing should consider the potential for a brittle fracture to occur. The potential for a brittle fracture is likely limited to older vintage materials such as lap-welded pipe, dc-or LF-ERW pipe, flash-welded pipe or, in general, pipe materials manufactured prior to 1960. Temperature is also a factor, and tests conducted in cold weather would present more of a risk. If the potential for brittle fracture is believed to exist, the operator may want to consider hydrostatic testing or to employ enhanced measures to protect personnel and structures in the event of a failure during a pneumatic test.

Test Monitoring and Setback Distances

The Potential Impact Radius (PIR) calculated in accordance with 192.903(4)(c) is adopted by some operators or testing contractors for determining a safety zone around a test section. The PIR is calculated as:

$$\mathrm{R} = 0.69\sqrt{P\,D^2} \qquad \textbf{Equation 8}$$

where:

P = Absolute Test Pressure (psig)
OD = Outside Diameter (in)
R = Radius of Potential Impact (ft).

The PIR concept was developed as a method for defining the length of natural gas pipeline requiring special integrity management measures based on proximity to sites containing concentrations of people.[xxi] The PIR formula was created by determining the amount of natural gas that would escape from a pipeline after rupture but before reaching an ignition source. The resulting flame jet's effects, considering heat flux directed at objects at a variable distance from the rupture site, were then computed. The PIR has been set at a heat flux intensity of 5,000 Btu/hr-ft^2, which corresponds to a value at which wooden structures would not be expected to ignite and fatalities of unsheltered persons subject to 30 seconds exposure would be a 1% probability. The radius calculated by the PIR does not have a basis that relates to the safety radius of a pipeline containing an inert gas, other than the fact that they both are dependent on

pipeline diameter and pressure. A method for calculating a safety radius for pneumatic testing is discussed below.

When testing with water, a minimum 25-foot exclusion radius is recommended around all above ground test sections. This is not based on calculations but in part by reviewing prior hydrostatic testing safety incidents that resulted in injuries or fatalities at less than a 25-ft radius. The Interstate Natural Gas Association of America recommends in their document titled Pressure Testing (Hydrostatic /Pneumatic) Safety Guidelines that a 100-ft or greater exclusion zone for workers and test equipment be used around hydrostatic and pneumatic tests. No mention is made as to whether those requirements apply to only above ground test sections or all test sections. Many operators and pressure test contractors implement a minimum 50-foot exclusion radius for hydrostatic pressure tests, which is considered acceptable.

Appendix A gives safe distance calculation models for short and long length pressure tests. The models are provided for consideration. However, alternative safe distance calculation models are under development in the industry whereby empirical equations are used to describe the safety radii for above and below ground test segments during testing for potential human or structural impacts. Results of that research will be reviewed once available and included in the Task 7 report for this work.

A resource for test medium selection guidance for pressure and tightness testing of piping and equipment is provided in ASME PCC-2[xxii] Article 5.1. The procedure is relative to pressure and tightness testing of pressure equipment, including tubular heat exchangers, pressure vessels, and piping systems. Included is a decision flow chart for "test type selection" where the inputs include:

- alterations and repairs,
- possibility of brittle fracture,
- stress relief,
- weld procedure and quality,
- NDE,
- safety consideration,
- application considerations and test purpose,
- potential energy, and
- risk and consequences,

The possible outcomes of following the decision flow chart include the following actions:

- perform a tightness test,
- perform an in-service leak test,
- conduct a hydrostatic pressure test,

- perform a tightness test with additional NDE, or
- perform NDE per applicable code.

Understanding the Hazard

Pressure testing is usually accomplished without test breaks occurring (although the likelihood of test breaks can vary greatly depending on circumstances), and test breaks usually are an inconsequential nuisance. Nevertheless, the authors are aware of a number of test failures occurring on liquid and gas pipelines that resulted in property damage, injury near miss, personal injuries, or fatalities as listed in Table 8. This list is illustrative but is not set forth as comprehensive or complete.

The majority of these consequential failures occurred with water because most testing is done with water due to the typically high target test stress levels. These incidents indicate that testing with water at high pressure is not without hazard. Many consequential test failures involved failure of components other than the line pipe being tested.

The information in Table 8 in most cases was known from direct involvement by the authors or other Kiefner personnel. A few were provided by Kiefner clients by request or were found in an on-line search.

All incidents listed in Table 8 involved testing of natural gas or hazardous liquid pipelines or associated facilities. Additional consequential pressure testing incidents are widely reported to have occurred in vessel or fabrication shops, piping in process or power facilities, storage tanks, plastic piping systems, and oil or gas field equipment. These events were not included in Table 8.

Certain patterns of causal factors are evident. These include:

- Personnel in close proximity to piping or equipment at the time of failure;
- Failure of components other than the pipe being tested. Prominent among these are couplings (usually of the 2-bolt type with cleats that engage grooves machined at the end of temporary piping). The cleats may become damaged, cracked, or worn such that they are unable to sustain the thrust forces from pipe pressure;
- Pipe whip upon sudden separation of joints; and
- Jet and debris impingement from a leak or rupture.

Test failures that involve injury or death more frequently occur due to a failure in either test equipment or pipeline fittings and equipment because workers are most likely to be in close proximity. Ensuring that only pressure rated approved components that are within their service life and in good condition are being used as well as ensuring no pipeline equipment is being

exposed to pressure above its rating is one of the easiest ways to reduce the chance of an incident during a test.

Some recurring preventive and mitigative measures include:

- Observe and maintain safe separation distances for all personnel;
- Restrict public exposure to beyond a suitable exclusion zone;
- Inspect and confirm fitness of all test equipment and components prior to use; and
- Restrain or anchor flexible or movable piping.

Many factors are involved in the considerations for safety measures. One hazard not specifically identified in the listing due to insufficient incident details available is associated with dewatering. Dewatering can involve using compressed air to propel polyurethane cleaning pigs through the line to push test water out of the line and into the next test section or into tanks for treatment and disposal. Changes in pipe elevation or direction may create variations in pig speed that prompt the compressor operator to increase pressure; or the pipe alignment may create air pockets capable of building up stored energy of compression. The sudden dislodging of the pig and collapse of air pockets may produce large pressure transients and thrust forces that can fracture components or separate pipe joints, particularly at temporary connections.[xxiii] The effect can be similar to a test break that occurs during a pneumatic test. Fatalities have reportedly occurred.

ASME B31.8-2016 contains several clauses that speak to the hazards of pressure testing in general, with some emphasis on pneumatic testing[xxiv]. Clause 841.3.1 outlines general provisions for pressure testing after construction. Pressure testing with water is recommended whenever possible (Clause 841.3.1(c)), however when a gas is used as the test medium the test pressure shall not exceed either 1.25 times the design pressure (Table 841.3.2-1), 30% of SMYS if flammable gas is used, or 40% to 75% of SMYS depending on the class location if air or nonflammable nontoxic gas is used (Table 841.3.3-1).[12] Additionally, Clause 841.3.1(d) states: "When pipeline systems are installed in unstable soils or the mass of the test medium contributes to additional stresses in the pipeline system, the stresses and reactions due to expansion, longitudinal pressure, and longitudinal bending shall be investigated prior to testing. This investigation shall confirm that the test pressures and loads do not produce unacceptable stresses, strains, deflections, or other conditions that could adversely impact the ability of the system to perform as required." Finally, precautions for public and employee safety are addressed by Clause 841.3.6. Safety precautions will be addressed in detail by the Task 7 report on other considerations.

[12] 49CFR192, Paragraph 192.503(a) also limits pneumatic test pressure stress levels similarly to these limits in B31.8.

Table 8. Pressure Testing Failures

Test Medium	Pipe Size (in.)	Pressure	Consequence	Description	Preventive or mitigative measures
Air fill to 100 psig, balance nitrogen	10″ NPS	600 psig (approx.)	Property damage, facility damage, injury near miss	Welding on line while under test caused detonation at interface between compressed air and residual gas, resulting in loss of several hundred feet of pipe and public property damage	Prohibit welding or mechanical work on pipe while on test, restrict entry to ditch during test
Water	6″ NPS	< 200 psig	Injury near miss	Coupling on fill line broke, unrestrained pipe whip narrowly missed several workers who had to take evasive action to avoid injury	Inspect test equipment before testing
Water	6″ NPS (30″ OD test pipe)	< 200 psig	Property damage, facility damage	Coupling at swivel joint on test header fill riser broke, caused loss of control of test water, test site flooding, and damage to test header assembly	Inspect test equipment before testing
Water	30″ OD	996 psig	Property damage	Pipe rupture water jet knocked down large tree limbs	Restrict access over the pipeline during test
Water	14″ NPS	1850 psig (approx.)	Property damage	Instability of non-engineered artificial slope during the test overstressed pipe, pipe rupture water jet damaged adjacent house	Evacuate houses in close proximity to pipe during test
Water	36″ OD	Unknown	Facility damage	Contractor used HDD pulling head as a test header which failed under pressure	Test heads must be designed to work safely at test pressure
Water	24″ OD	320 psig (approx.)	Personal injury	Buried Dresser coupling separated during test of new pig launch facility, injured worker standing directly over coupling	Tie down unrestrained pipe, reinforce Dresser couplings, restrict access over the pipeline during test
Nitrogen	42″ OD vessel and	2100 psig (approx.)	Fatality and injury	Pipe whip caused when filter-separator quick-opening closure door	Check and secure mechanical equipment, verify PRVs are

Test Medium	Pipe Size (in.)	Pressure	Consequence	Description	Preventive or mitigative measures
	24″ OD piping			blew off, possible overpressure due to PRV isolation and lack of test operator communication, test station set up in close proximity to tested piping	open, monitor and communicate pressure, observe personnel separation, follow safety procedures
Water	36″ OD	Unknown	Facility damage	Pressure sense line froze while testing in cold weather, over-pressured pipe to rupture	Use antifreeze or heat trace pressure sense lines
Water	6″ or 8″ NPS	Unknown	Facility damage	Pressure sense line froze while testing in cold weather, over-pressured pipe to rupture	Use antifreeze or heat trace pressure sense lines
Water	14″ NPS	1160 psig	Property damage, injury near miss	Pipe failure in road crossing damaged roadway and moved a parked car against a pole	Restrict access over the pipeline during test
Water	2″ NPS plug	Unknown	Personal injury	Pressure washer used to pressure up 100 ft of replacement pipe in yard, pressure unknown, threaded 2″ plug separated from valve	Use proper pressure equipment and gauges, inspect condition of threaded joints, observe personnel separation
Water	6″ NPS (20″ test pipe)	Unknown	Fatality	Coupling separation on test fill pipe caused unrestrained pipe whip	Inspect test equipment before testing, observe personnel separation
Water	30″ OD	Unknown	Injury near miss	Flange fractured during test of above-ground piping moments after site workers walked past	Observe personnel separation
Water	24″ OD	550 psig	Injury near miss	Spray and debris from test rupture near freeway created traffic hazard, reported vehicle damage from debris	Restrict traffic in close proximity, test during low traffic hours

The testing incidents summary in Table 8 highlights the fact that no testing medium is free from hazards. Some hazards exist irrespective of the test medium; for example, sudden separation of temporary coupled joints and resulting pipe whip. Other hazards are unique to the pressurizing medium, such as flooding with water, suffocation with nitrogen, broken glass due to ambient overpressure with any compressed gas, or fire with natural gas. If all test media were compared considering like conditions, the probability of failure would likely be the same because pressure provides the driving force. Different safety and pressure test execution procedures and practices are used by many operators therefore the consequences of known failure incidents cannot be directly compared to find if the test medium results in worse (or higher consequence) failures if all conditions were the same. Therefore, since it is difficult to make numerical comparisons between test media due to differing conditions, no absolute determination of which is the most dangerous can be made. All test media are safe with suitable precautions and all present hazards if suitable precautions are not observed.

All test media hold unique hazards. Testing with water can also present hazards even though the stored energy of compression is much less than that of gas. When testing with water the consequences can be injury or death to surrounding personnel, damage to nearby structures and possible flooding or undermining the ground support for the pipeline or nearby structures. Testing with air or nitrogen holds hazards for nearby personnel and property that could be impacted by the blast wave of a sudden rupture or projected objects. When testing with nitrogen, there exists a possibility of creating an oxygen deficient area or confined space that could be a danger to workers. When testing with air inside an existing natural gas pipeline, a possibility of creating an explosive air/gas mixture exists.

Table 9 details the specific hazards most closely associated with pressure test media. Maintaining appropriate separation distances during testing is also important.

Table 9. Test Media Hazards

Hazard	Category	Water	Nitrogen	Air	Natural gas
Mechanism	Fire	--	--	X	X
	Shock wave	--	X	X	X
	Projectiles	X	X	X	X
	Jetting	X	--	--	--
	Flooding	X	--	--	--
	Suffocation	--	X	--	X
Consequence	Equipment damage	X	X	X	X
	Property damage	X	X	X	X
	Fatality or injury	X	X	X	X
	Cratering	--	X	X	X

Test Medium Selection

Selection of the optimal pressure test medium must consider a number of factors including: the likelihood of a test failure; possible failure mechanisms; the potential consequences; regulatory limits; feasibility; and impact on operations. A critical factor is the maximum hoop stress allowed as percentage of SMYS. In accordance with 49 CFR Part 192.503, natural gas and air or inert gas tests are limited to lower maximum test pressures than tests conducted with water as the medium.[13] Table 10 details the maximum test pressure and factors per the Part 192 section referenced above. The choice of test medium could therefore affect operating stress levels. Due to this factor, some tests have no alternative other than water testing. Other tests could be conducted using water or gaseous media.

Also, 49 CFR Part 195.306 allows liquid petroleum that does not vaporize rapidly, air, carbon dioxide or inert gas as the test medium given a number of criteria are met that are more restrictive than testing with water. Table 11 outlines the conditions that must be met per 49 CFR Part 195.306 when using a test medium other than water. Because exact maximum test pressure limits are not specified per regulation for liquid operated pipelines, as they are for gas operated pipelines, a column for maximum operating stress is not provided in Table 11. However, it can be implied that for many scenarios the operating stress will be limited to a maximum pressure notably less than 72% of SMYS. For example, if the maximum test stress is limited to 50% of SMYS, the operating pressure cannot exceed 40% of SMYS.

Table 10. CFR 192 Testing Requirements and Restrictions for Test Media other than Water

Class	Max test stress, % SMYS		Test Factor	Max operating stress, % SMYS	
	Natural Gas	Air or Nitrogen		Natural Gas	Air or Nitrogen
1	80	80	1.25[14]	64	64
2	30	75	1.25	24	60
3	30	50	1.5	20	33
4	30	40	1.5	20	26

[13] The additional restrictions on maximum pressure test stress levels imposed for natural gas, air or inert gas tests are in place to reduce the risk of failure because failure with test media other than water can have higher safety and environmental consequences.
[14] Part 192 allows a test factor of 1.1 for testing with air or gas in Class 1. However ASME B31.8-2010 revised the minimum test factor to 1.25 based on research and analysis.

Table 11. CFR 195 Testing Requirements and Restrictions for Test Media other than Water

Pipeline	Conditions	Test Medium	Max test stress, % SMYS
Onshore	1. Entire section under test is outside of cities and populated areas 2. Each building within 300 feet is unoccupied 3. Test section is kept under surveillance by regular patrols during the test 4. Continuous communication is maintained along entire section	Liquid Petroleum[15]	≥ 50
Onshore	1. Entire section under test is outside of cities and populated areas 2. Test section is kept under surveillance by regular patrols during the test 3. Continuous communication is maintained along entire section		< 50
Carbon Dioxide	1. Entire section under test is outside of cities and populated areas 2. Each building within 300 feet is unoccupied 3. Continuous communication is maintained along entire section 4. Pipe being tested is new and has a longitudinal joint factor of 1.00	Air or Carbon Dioxide	< 80 and ≥ 50
Carbon Dioxide	1. Entire section under test is outside of cities and populated areas 2. Continuous communication is maintained along entire section 3. Pipe being tested is new and has a longitudinal joint factor of 1.00	Air or Carbon Dioxide	< 50
Low-Stress	1. The pipeline is operated in its entirety at a stress level of 20% or less of SMYS.	Air or Inert Gas	Not Specified

[15] Liquid petroleum that does not vaporize rapidly. Same condition is provided by ASME B31.4-2016 section A37.4.1.

Test method selection might also be affected by the relative possibility of failure during the test. Table 12 shows an example of a method of ranking the relative probability of a test failure due to the three most likely possible causes of failure in the pipe, applied by an operator contemplating extensive pneumatic testing. The test-break susceptibility score is calculated as the product of the scores for pipe vintage, test stress level, prior test history, and prior integrity assessments. The scores were informed in part by relative rates of occurrence in PHMSA's reportable incident data as well as engineering judgement. In this model, a relative likelihood of test failure is calculated as the ratio of the aggregated score divided by a maximum possible score of 3240. A "probability" below 10% is low enough to suggest that a test break is unlikely, while a "probability" greater than 30% is high enough to warrant some expectation of a test break. This risk ranking process was designed to accentuate differences in likelihood of a test break due to prevalent causes, and does not address the potential for a test failure occurring due to causes such as damaged or defective test equipment or procedural error.

Table 12. Relative Possibility of Test Failure

	Cause of Test Break			
	Mechanical Damage	**Corrosion**	**Seam**	**Score**
Pipe vintage				
New or after 2000	1	0	0	1
1970 – 2000	1	1	1	3
1961-1970	1	1.5	1.5	4
1942-1961	2	2	2	6
Before 1942	3	3	3	9
Test pipe stress ranges				
Less Than 50% SMYS	0.5	1	0.5	2
50% - 90% SMYS	2	2	2	6
Greater Than 90% SMYS	3	3	3	9
Prior Hydrostatic Test or Mill Test				
Current Test is Less than Prior Test	1	1	1	3
Current Test Greater than Prior Test	1	1	3	5
Prior Assessment				
ILI,DA <= 10 yrs	1	1	2	4
10 yrs< ILI,DA <20 yrs	2	2	2	6
None or >20 yrs	3	3	2	8

The relative model described above was used by a pipeline operator as part of a process for screening pipeline segments for pneumatic testing. Another operator relied on a probabilistic fault-tree analysis that considered construction QA practices, nondestructive inspection

sensitivity, and equipment failure rate data in a process for screening large piping systems within a facility for pneumatic testing.

Each test method has different consequences and all the factors of the test should be considered. Required MOP or MAOP, proximity to populated areas, product type, onshore versus offshore, class location, minimum depth of cover over the pipeline, occupied structures within a potentially affected radius, minimum distances from structures that could be structurally compromised by over saturated soil, as well as numerous other factors all contribute to determining the best test medium to use. Table 13 details the considerations that favor either pneumatic or hydrostatic tests. No single factor can be used when determining the best test medium. All factors should be considered before a determination is made. Table 13 does not include considerations that favor hydrostatic testing with liquid petroleum. Pressure testing with liquid petroleum should be limited to values below MOP or MAOP for verifying an absence of leaks, commonly referred to as a standup test. There may be some instances under the feasibility section that would favor liquid petroleum for a test medium, however the associated risks and consequences shall be carefully considered.

Considerations for evaluating whether a line can be easily dewatered and dried include: restrictions on passage of swabbing pigs exist; the number of branch lines or non-pipe equipment present; elevation changes; and end usage. Considerations for evaluating whether a line can be readily isolated from the public include presence of pedestrians, heavy traffic, and homes or businesses in close proximity, among other factors.

Yet another set of concerns is for the ability of the test to detect a leak. Tests conducted with water are very sensitive to small volume changes caused by a leak. However, a small leak may be masked by the thermal expansion or contraction of the test water. By monitoring the temperature throughout the test it is usually possible to infer whether changes in pressure are due to temperature effects or due to a leak. Tests conducted with a compressible gas medium tend to be less sensitive to small leaks. Although not required by regulations, consideration should be given to conducting a leak test in service after completing a pneumatic test. Recommendations specific to leak detection will be addressed by Task 5 of this project.

Table 13. Test Media Selection Checklist

Consideration	Favors Pneumatic Test	Favors Hydrostatic Test with Water
	Feasibility	
Line can operate within Code stress limits for pneumatic test	Yes	No
Line cannot be easily cleaned, dewatered and dried due to multiple diameters, many branches or unbarred tees, in-line equipment	Yes	No
A source of clean water is not readily available in sufficient quantity	Yes	No
Freezing temperatures expected during testing	Yes	No
A water test would cost more than pipe replacement	Yes	No
Elevation change is larger than can be covered in one or two test sections	Yes	No
The weight of test water requires pipe support considerations	Yes	No
Duration of outage for testing adversely affects customer	Yes	No
The public and workers can be easily excluded from the pneumatic test hazard radius	Yes	No
	Risk	
Adverse effects from water jet or spill	Yes	No
There is some possibility of a rupture due to vintage seams, damage, or corrosion	No	Yes
Other parts of the same line have had test or service failures	No	Yes
A leak missed during the test poses a hazard based on location after pipe is back in-service	No	Yes
Blast mats or K-Rail would be necessary over or near the pipeline to protect adjacent structures	No	Yes

Biaxial Loading Effects

Yielding of a ductile material, such as carbon steel, happens when the von Mises stress (also known as equivalent or combined stress) reaches the material yield stress. Equivalent combined stress under biaxial loading is calculated as

$$\sigma_{eq} = \sqrt{\sigma_L^2 + \sigma_H^2 - \sigma_L \cdot \sigma_H}$$ **Equation 9**

where:

σ_L is the longitudinal stress,

σ_H is the hoop stress, and

σ_{eq} is the von Mises stress.

Equation 8 ignores through-thickness stress. This relationship is shown in Figure 1 which plots the combination of longitudinal and circumferential stress that would result in yielding.

From the biaxial stress equation and Figure 1 it can be understood that when both the hoop stress and the longitudinal stress are tensile it is possible for one of these stress components to exceed the yield strength slightly without yielding occurring. To show this we consider a pipe with longitudinally restrained and unrestrained conditions, subject to internal pressure and no significant external loadings. Under restrained conditions the longitudinal stress which is generated by the internal pressure is Poisson's ratio (0.3 for carbon steel) times the hoop stress. Using $\sigma_L = 0.3\sigma_H$ and solving Equation 8 for $\sigma_{eq} = \sigma_y$ where σ_y is the yield stress, results in a hoop stress of $1.125\sigma_y$. Therefore, yielding does not happen until the hoop stress exceeds the yield stress by 12.5%. In an unrestrained straight pipe the longitudinal stress is 50% of the hoop stress. Under the unrestrained condition yielding occurs when the hoop stress exceeds the yield stress by 15.5%. The actual yield strength in most pipe is greater than SMYS, further elevating the pressure capacity before yielding. Therefore, yielding of a pipe during a pressure test to hoop stress levels somewhat above 100% SMYS is not expected provided the pipeline as-installed is not subjected to large external loadings at the time of the test.

The curve in Figure 1 to the left of the vertical axis also shows that if the hoop stress is high, it takes very little longitudinal compression to result in yielding (or conversely if the axial compressive stress component is large, it takes little circumferential stress to cause yielding). Thus if a portion of the pipeline undergoing high level testing experiences large external loadings which may place the pipe section in net longitudinal compression or bending, yielding may occur. Situations where such external loadings could affect lengths of buried pipeline may include, but are not limited to:

- Zones of post-installation settlement or uneven support below the pipeline;
- elastic bends or where pipe was roped to the ground contour;
- at the entry or exit to swampland or having unevenly spaced weight such that it is subjected to differential buoyancy;
- at the toe of steep slopes.

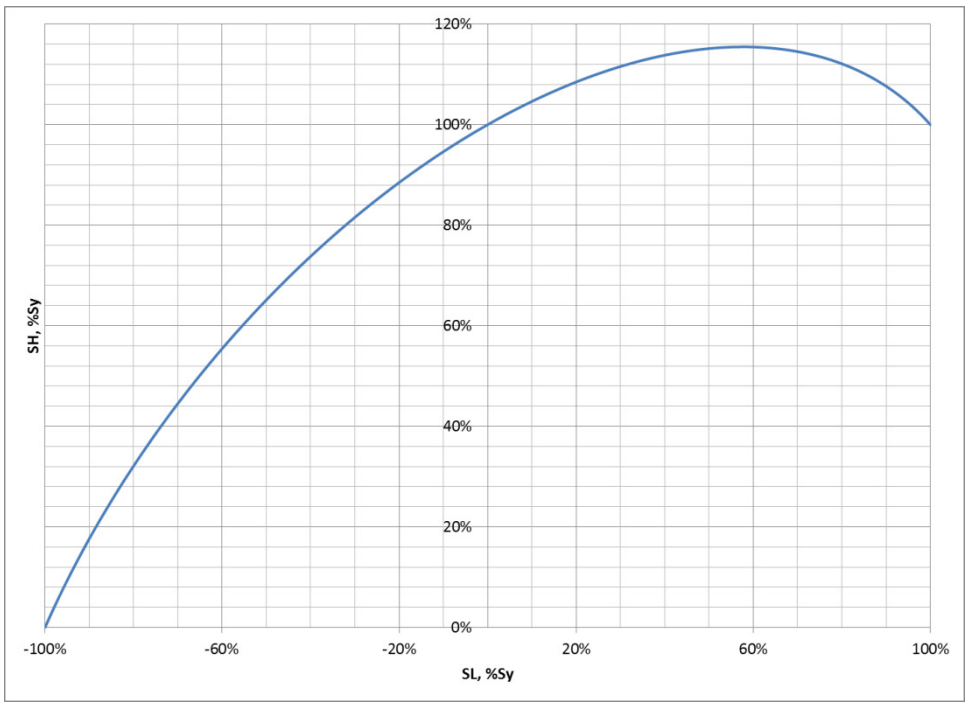

Figure 1. Relationship for yielding in biaxial loading

The consequence of yielding, if it occurs, depends on the extent of the yielded zone and the amounts of plastic deformation. A uniform axial stress usually does not change rapidly along a buried pipe. A uniform compressive axial stress (for example from long-wall subsidence or moving slope), if it is high enough, can cause a long segment of a pipe to yield during a pressure test. Under this scenario the entire pipe cross-section is expected to yield, leading to expansion of the pipe diameter and potentially reduction of the pipe wall thickness. Ambient temperature creep is another potential consequence of excessive yielding. Yielding of a long pipe segment during a pressure test can be detected by measuring fluid volume, and location(s) of the yielded segments can be determined by means of inline inspection (ILI) using a geometry tool.

Bending stress usually changes rapidly along a pipe, while it varies from compressive to tensile around the pipe circumference. As such, the yielded zone resulted from combined hoop and compressive bending stress is expected to be relatively small and only affect a portion of the pipe circumference with the utmost distance from the bending neutral axis.

The normality principal states that the strain vector will be perpendicular to the yield curve. This vector, normal to the left half of the curve in Figure 1, will exhibit a positive circumferential component indicating that the pipe will swell or bulge radially outward, which is consistent with experience and observation.

Planning and Communication Tools

Pressure tests require the direct input or oversight of multiple personnel. Understandably, the larger the scale of the project, the more key personnel are involved and the promptness and clarity of test plan communications is critical. API 1110 section 4.1.5 provides the following on proper communication for the pressure test planning phase[xxv]:

- A written site-specific test procedure with all pertinent details associated with the project should be developed as part of the pressure test planning process. The written plan should be distributed to appropriate company personnel, contractors, and others directly involved with the test for review and comment during the early stages of the planning process.
- Prior to the test, the operator should notify the proper authorities, governmental agencies, potential emergency response personnel and landowners along the right-of-way.
- Prior to the test, the operator should secure applicable permits.
- The operator should clearly outline the roles of the various personnel involved in the pressure testing process. This includes the following:
    - operating personnel,
    - contractor and/or maintenance personnel, and
    - person(s) responsible for certifying the results of the pressure test.

ASME B31.8 provides similar guidance for testing of natural gas pipelines.

To build on the guidelines of API 1110, examples of key personnel and project stakeholders include regional project managers, pipeline integrity engineers, compliance engineers or representatives, logistics representatives, managers of critical customer facilities, pipeline inspectors, maintenance crews, pressure test services contractors, and corresponding pipeline management. There are some instances when additional communication is required outside an Operator's organization (or hired contractors); examples include when a pressure test is funded by a third party (such as a relocation project in response to highway expansion), or co-owned or jointly-operated pipelines.

For comprehensive planning an electronic profile of the pipeline attributes studied during the background review should be generated in a software program capable of data management and computations. Since most parameters can relate to a pressure value, a graphical profile of the pipeline attributes critical to test planning can be generated in terms of distance (log-distance, measured or relative stationing) and pressure (generally in units of psig). For instance, valve locations can be plotted in terms of pressure rating, known defects from ILI results can be plotted in terms of predicted failure pressure and pipe properties can be plotted in terms of 100% SMYS values. Expressing the integrated information into a common term

(psig) facilitates a meaningful evaluation and communication of the target test pressure. Figure 2 is an example of a test plan profile. Depending on the pipeline system and goals of the pressure test, more or less information may need to be included on a similar plot.

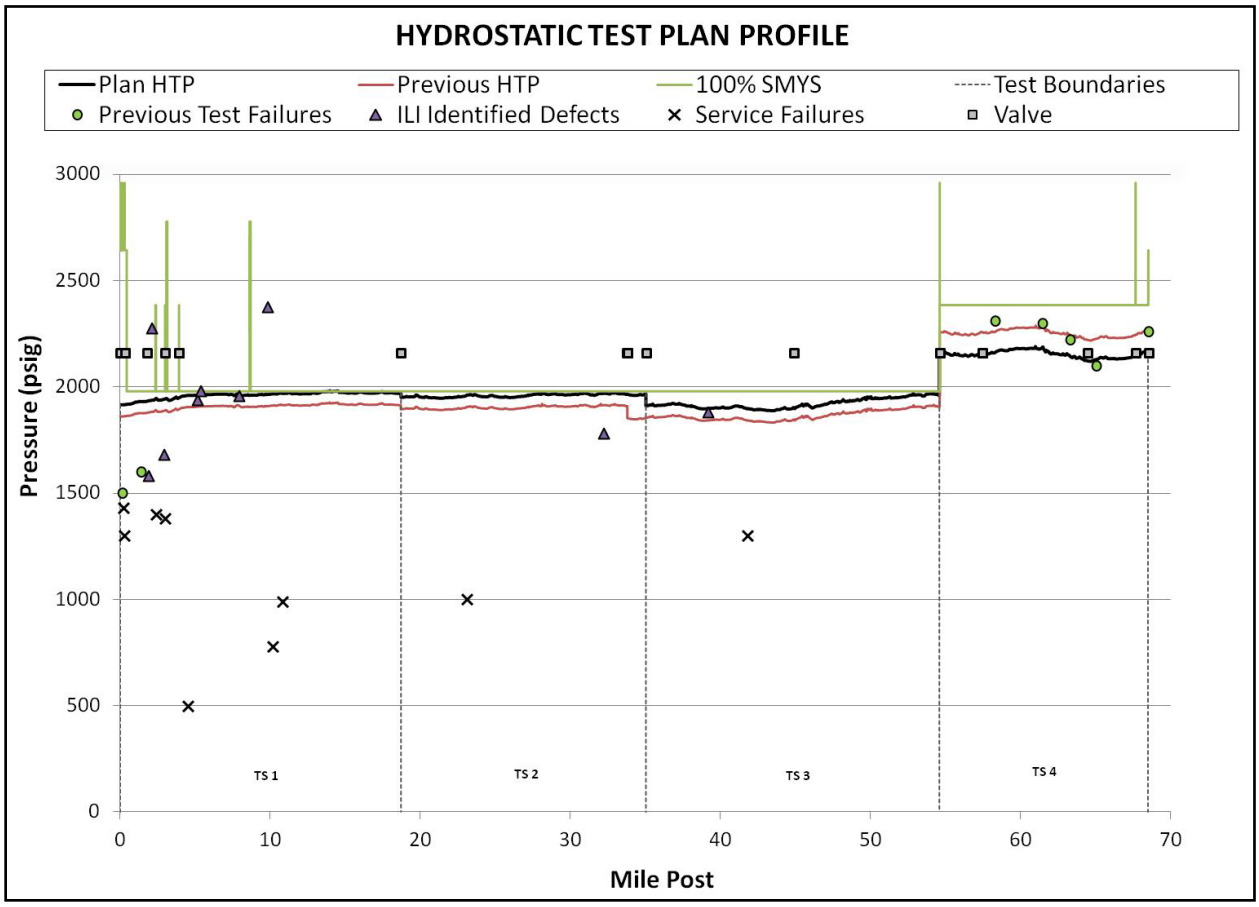

Figure 2. Example of a Profile Utilized in Test Planning

At a minimum the following information should be clearly communicated in a table as part of the test plan:

- Test section name (typically expressed numerically).
- Upstream and downstream test boundary locations of each segment (mile post, station, common name or reference).
- Test section length.
- Target pressures (at upstream and downstream locations, and intended location of deadweight and pressure recorder). For each location, provide a target test pressure, minimum bound pressure and maximum bound pressure for each phase of testing (spike, strength, and leak).
- Range of pressures for the entire segment (in terms of psig and %SMYS). This includes the values at the high and low point elevations.

- Range of TPR for the entire segment.
- Other distinguishing characteristics of the segment (such as start location of a pipe of interest or number of previous failures).

Table 14 is an example of information to be communicated during the planning phase of a pressure test. The example demonstrates a possible strength test for a liquid operated pipeline under CFR 195 jurisdiction. Similar tables to the example table should be generated for each phase of a planned test: spike, strength and leak.

Table 14. Example Table for Communicating a Strength Test Plan

Description	Test Section 1	Test Section 2
Start Location	MP 0 – Pump Station A	MP 15 – Valve Site
End Location	MP 15 – Valve Site	MP 30 – Pump Station B
Length	15 miles	15 miles
Target Pressure at US Location	2,025 psig	2,025 psig
Target Pressure at DS Location	2,015 psig	1,900 psig
Min Pressure in Test Section (high elevation)	1,795 psig	1,795 psig
Max Pressure in Test Section (low elevation)	2,030 psig	2,030 psig
Range of Test Stresses, % SMYS	95% - 100%	90% - 100%
Range of TPR	1.30 – 1.39	1.25 – 1.39
Number of Failures during Previous Test	0	3
Number of Remaining Crack Features from ILI Listing	0	16

APPENDIX A – SAFE DISTANCE CALCULATION MODELS

Short Length Pressure Tests

One of the foremost hazards of testing with any gaseous medium is the threat of rupture resulting in a shock wave emanating from the rapidly decompressing pipe. To determine the safe distance from a pressure vessel filled with compressed air or gas, ASME PCC-2 (2011)[xxii] Article 5.1 can be used as follows:

The energy in pressurized gas can be expressed as:

$$E = \left[\frac{1}{k-1}\right] \times \mathrm{P}_{at} \times \mathrm{V}\left[1 - \frac{P_a}{P_{at}}^{\frac{k-1}{k}}\right]$$ **Equation A-1**

where:

P_{at} = Pressure of Atmosphere (Pa)
P_a = Absolute Test Pressure (Pa)
k = ratio of specific heat of test fluid, 1.4 for Nitrogen or Air
k = 1.32 for Natural Gas
E = Stored Energy (J)
V = total volume under test pressure, m^3

The energy equivalency of the compressed gas to weight of TNT in an explosion can be expressed as:

$$TNT = \frac{E}{4{,}266{,}920}$$ **Equation A-2**

where:

TNT = Equivalent Energy mass of TNT (kg)
E = Stored Energy (J)

The Scaled Consequence factor can be found from the TNT equivalency as:

$$z = z' \times TNT^{1/3}$$ **Equation A-3**

where:

TNT = Equivalent Energy mass of TNT (kg)
z' = Scaled distance ($m/kg^{1/3}$)
z = Actual distance (m)

Table A-1. Effects of Overpressure Events

z' m/(kg$^{1/3}$)	z' ft/(lb$^{1/3}$)	Physiological Effect	Structural Failure
20	50	No Effect Listed	Glass Windows
12	30	Eardrum Rupture	Concrete block panels
6	15	Lung Damage	Brick Walls
2	5	Fatal	No Effect Listed

This calculation measures the storage of energy in a compressed gas by the ratio of specific heats for that gas at atmospheric and test pressures. The compression energy to be released if a failure occurred can be scaled to the energy release from a quantity of explosive. The ensuing effects can be used to establish appropriate separation distances to minimize consequential harm.

The ASME PCC-2 equations are suitable for a vessel as the contained energy in the test would be rapidly released in the explosion, and can be conservatively applied to relatively short lengths of pipe. The ASME PCC-2 equations are not suitable for long lengths of pipe pressurized with a compressible gas, because in the event of a test rupture the entire volume does not decompress all at once. Table displays the cut-off distance between short and long length tests, with the given distances, in feet, being the maximum effective length of pipe contributing to the exclusion radius.

The mitigating effects of soil cover have not be accounted for in the calculations for a number of reasons, among them:

- pipeline service ruptures demonstrate that soil cover in usual depths is incapable of containing a high pressure rupture;
- where significant depths of soil cover could partially mitigate the effect of a pipe failure, the benefit may depend on soil type and moisture content that must then be verified shortly before the pressure test;
- a pipeline rupture at high pressure would likely eject material from the ground and create dangerous projectiles.

ASME PCC-2 states that a minimum 100-ft exclusion radius for personnel should be used for test sections with a stored pressure energy of less than 1 x 10^8 ft-lb; for test sections with a stored pressure energy of between 1 x 10^8 ft-lb and 2 x 10^8 ft-lb, a minimum 200-ft exclusion radius should be used.

Long Length Pressure Tests

When considering a long test section for pneumatic pressure testing, the ASME PCC-2 methodology is not applicable, as the contained energy in the test section would be released over a longer period of time due to the fact that a long pipeline does not decompress at once. The use of ASME PCC-2 Article 5.1 for a long length of pipe would result in excessively conservative calculations for the safe radius from the test section. An alternative approach that considers the effective decompression length of test pipe is described below.

The critical or effective decompression length of piping, which is the point wherein the length of the test section exceeds the contributing length of compressed gas pack to influence the maximum blast wave intensity, determines the necessary safety radius around the test section. The cutoff between short and long sections of pipe is given in Table A-2 and Figure A-1. This can be evaluated by comparing the internal decompression wave speed to the external shock wave characteristics created during the failure. This calculation has many permutations based on gas composition, pipe diameter and size of discontinuity of pipe at the rupture location. Additionally, no specific studies to complete this calculation have been developed by industry, but using principles from ASME PCC-2 along with an equation for overpressure versus scaled distance, and decompression analyses reported in the literature[xxvi], an approximate length can be ascertained dependent on the pressure of the test section and internal pipe diameter. By comparing the rate at which the decompression wave inside the pipe travels with the speed of the external transient pressure at different length and time intervals from the rupture point and time, the peak quantity of decompression energy impacting the explosive radius that is deemed to be the threshold of harm can be found.

Table A-2. Cutoff Length for Short Length Inert Gas Test Safety Radius (feet)

Pressure (psig)	Nominal Diameter (in)													
	2 & less	**3**	**4**	**6**	**8**	**10**	**12**	**16**	**20**	**24**	**30**	**34**	**36**	**42**
100	500	700	840	1,140	1,500	1,860	2,120	2,680	3,420	4,080	5,040	5,620	5,900	6,880
200	580	900	1,140	1,620	2,120	2,700	3,220	3,940	4,980	5,940	7,280	8,260	8,720	10,080
300	720	1,080	1,380	2,100	2,700	3,360	3,960	4,980	6,100	7,340	9,120	10,220	10,760	12,420
400	900	1,300	1,640	2,460	3,160	3,920	4,620	5,780	7,200	8,560	10,580	11,880	12,540	14,440
500	980	1,440	1,820	2,760	3,560	4,420	5,240	6,480	8,040	9,620	11,900	13,340	14,040	16,200
600	1,140	1,620	2,140	3,220	4,100	5,060	6,040	7,480	9,300	11,060	13,700	15,420	16,220	18,760
700	1,340	1,940	2,480	3,700	4,840	5,940	6,980	8,760	10,820	12,900	15,940	17,900	18,840	21,720
800	1,540	2,260	2,920	4,200	5,480	6,720	8,000	9,960	12,340	14,660	18,100	20,300	21,420	24,700
900	1,760	2,500	3,260	4,780	6,120	7,600	8,960	11,180	13,860	16,420	20,260	22,740	23,920	27,620
1000	1,880	2,820	3,620	5,280	6,780	8,400	9,900	12,400	15,320	18,200	22,380	25,160	26,540	30,580
1100	2,080	3,060	3,980	5,760	7,420	9,200	10,860	13,540	16,780	19,900	24,500	27,540	28,980	33,360
1200	2,300	3,280	4,320	6,280	8,080	10,000	11,840	14,780	18,260	21,620	26,620	29,820	31,440	36,260
1300	2,500	3,600	4,680	6,860	8,820	10,820	12,800	15,920	19,640	23,340	28,660	32,220	33,920	39,080
1400	2,720	3,840	4,940	7,360	9,380	11,620	13,680	17,080	21,120	25,060	30,820	34,540	36,420	41,840
1500	2,840	4,180	5,300	7,860	10,140	12,440	14,660	18,240	22,540	26,720	32,800	36,880	38,840	44,700

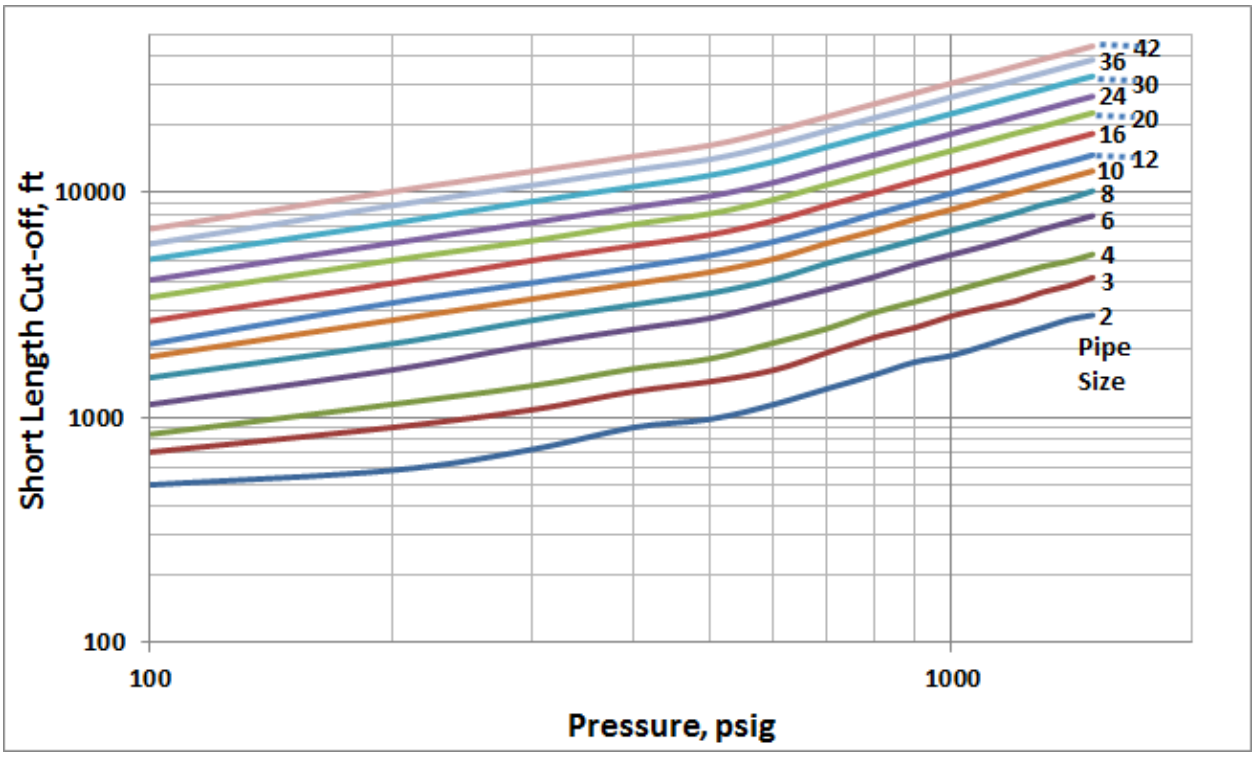

Figure A-1. Cutoff Length for Short Length Inert Gas Test Safety Radius

In the paper by Burlutskiy[ii], it was shown that the decompression wave in the pipe travels at approximately 385 meters per second. This number was calculated when considering nitrogen at 1,480 psig however, in the absence of data to determine the decompression wave of air in a pipe, this value was used for both air and nitrogen. Additionally, factors were included to account for the maximum flow rate from pipe, assuming a guillotine type rupture. (Alternatively, this admits a longitudinal rupture with an opening at least equal to the cross-sectional area of the pipe, or larger.) These factors considered both the maximum initial flow rate as well as a flow rate decay factor as discussed by Stephens (2000)[xxvii]. Equations to determine the maximum flow rate are presented below:

$$Q_{in} = C_d \frac{\pi d^2}{4} p \frac{\phi}{a_0}$$ **Equation A-4**

$$\phi = \Gamma \left[\frac{2}{\Gamma+1}\right]^{\frac{\Gamma+1}{2(\Gamma-1)}}$$ **Equation A-5**

$$a_0 = \sqrt{\frac{\Gamma R T}{m}}$$ **Equation A-6**

where:

C_d = 0.62
Γ = specific heat ratio of gas (1.4 for nitrogen or air)
R = 8,310 J/(kg-mol)/K
T = 288 K
m = Gas Molecular Weight (28 kg/mol for nitrogen gas)
d = Pipe Diameter
p = Pipeline Gauge Pressure

An equation to determine the decay factor of flow rate was deduced by curve-fitting a pressure versus time plot given by Stephens (2000). The equation used was:

$$FR = -0.125(\ln t) + 0.7355$$ **Equation A-7**

where:

FR = Mass flow rate fraction of initial flow-rate
t = time (sec)

The overpressure of the air outside of the pipe was calculated using fitted equations provided by a study on overpressure versus scaled distance[xxviii]. The equations used for the overpressure calculation are:

$$Ps = 1.13E6 \times z'^{-2.01} \text{ for } z' \geq 1 \text{ and } < 10$$ **Equation A-8**

$$Ps = 1.83E6 \times z'^{-1.16} \text{ for } z' > 10 \text{ and } \leq 200$$ **Equation A-9**

where:

Ps = Overpressure (Pa)
z′ = Scaled distance ($m/kg^{1/3}$)

Several simplifications were made to the model to make the results more conservative for all but the worst case scenario. The rupturing pipe was assumed to be exposed at ground level, the rupture opening area was assumed to be the full diameter of the pipeline in both directions and the entire gas compression energy of the effective length test section was assumed to be released instantaneously. In real world scenarios, particularly buried mainline testing, this worst case will never be achieved. The maximum contributing length of pipe varies based on diameter, test pressure and the physiological effects or property damage deemed to be tolerable. ASME PCC-2 gives a table of physiological effects and property damage for various scaled consequence factors. If the threshold was set to the level corresponding to no permanent physiological effects to humans, a scaled consequence factor of 50 $ft/lb^{1/3}$ TNT equivalence would be used to calculate the maximum contributing length of compressed air or gas pack.

Figure A-2 shows the safe distance, in feet, from the pipeline at a scaled consequence factor of 50 $ft/(lb^{1/3})$ TNT equivalence on the vertical axis when using nitrogen or air. The other axes show the test pressure in psig and the nominal pipe diameter in inches. A minimum exclusion radius of 25 feet is recommended for instances in which the calculated value is less. Those cells are highlighted in Table A-3.

Table A-3. Long Length Test Exclusion Radius Matrix for Inert Gas (feet)

Pressure (psig)	Nominal Diameter (in)													
	2 & less	3	4	6	8	10	12	16	20	24	30	34	36	42
100	18	26	32	46	60	74	86	108	136	162	200	224	236	274
200	24	36	46	66	86	108	128	158	198	236	290	328	346	400
300	30	44	56	84	108	134	158	198	244	292	362	406	428	494
400	36	52	66	98	126	156	184	230	286	340	420	472	498	574
500	40	58	74	110	142	176	208	258	320	382	472	530	558	644
600	46	66	86	128	164	202	240	298	370	440	544	612	644	744
700	54	78	100	148	192	236	278	348	430	512	632	710	748	862
800	62	90	116	168	218	268	318	396	490	582	718	806	850	980
900	70	100	130	190	244	302	356	444	550	652	804	902	950	1,096
1000	76	112	144	210	270	334	394	492	608	722	888	998	1,052	1,212
1100	84	122	158	230	296	366	432	538	666	790	972	1,092	1,150	1,324
1200	92	132	172	250	322	398	470	586	724	858	1,056	1,184	1,248	1,438
1300	100	144	186	272	350	430	508	632	780	926	1,138	1,278	1,346	1,550
1400	108	154	198	292	374	462	544	678	838	994	1,222	1,370	1,444	1,660
1500	114	166	212	312	402	494	582	724	894	1,060	1,302	1,462	1,540	1,772

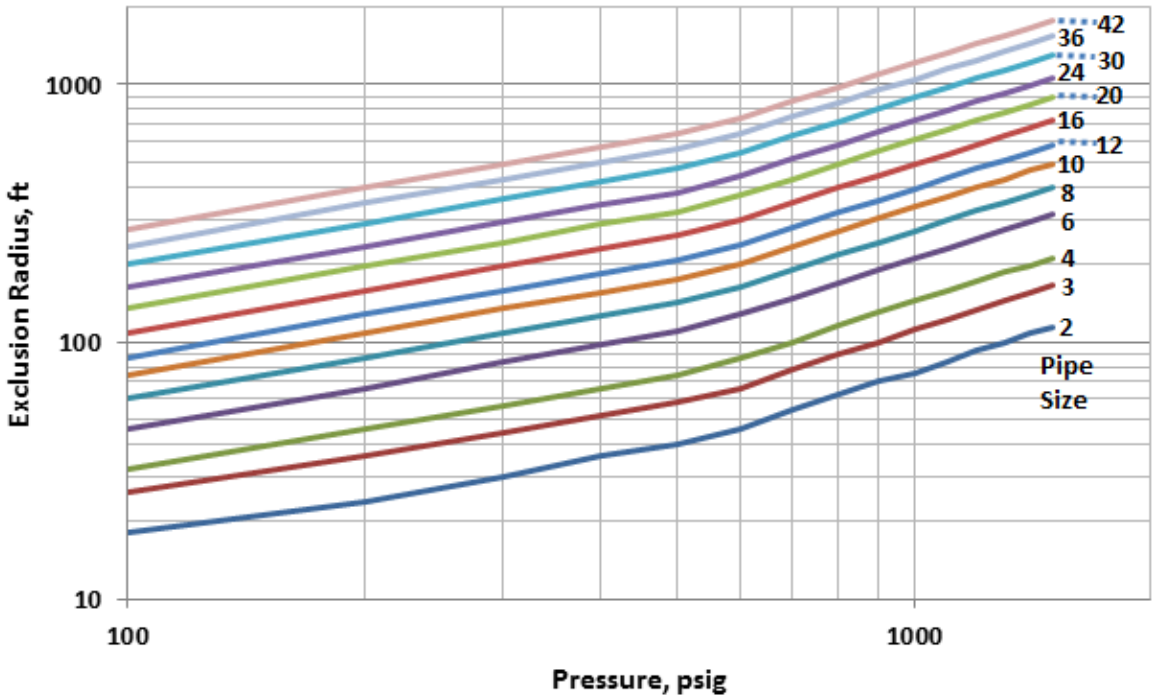

Figure A-2. Main Test Exclusion Radius Diagram when using Inert Gas

While this chart and graph can be used to determine a safe distance from a pneumatic test with air or nitrogen for workers and the public, some workers may have need to be temporarily inside this exclusion zone. As is discussed in a later section of this report, "Understanding the Hazard," there are many different modes of failure that can occur. Hydrostatic or pneumatic pressure testing can be routine for many veteran workers and a sense of complacency can occur. By learning from previous failures and understanding the possible modes of failure, implementing additional procedural steps or checks could help to reduce the probability of failure.

Note also that in the event that a test is performed using natural gas, the PIR should be calculated. The PIR is not a "safe" distance for those outdoors. The separation distance for anyone in the general public should be at least double the PIR for a test with natural gas. The exclusion radii for tests conducted using natural gas are shown in Table A-4 and Figure A-3. The values in the table incorporate the factor of two on the calculated PIR.

Table A-4. Minimum Exclusion Radii for the general public during Natural Gas tests (feet)

		Nominal Diameter (in)													
		2 & less	**3**	**4**	**6**	**8**	**10**	**12**	**16**	**20**	**24**	**30**	**34**	**36**	**42**
Pressure (psig)	**100**	33	48	62	91	119	148	176	221	276	331	414	469	497	580
	200	46	68	88	129	168	210	249	312	390	468	585	664	703	820
	300	57	84	108	158	206	257	305	382	478	574	717	813	860	1,004
	400	66	97	124	183	238	297	352	442	552	662	828	938	994	1,159
	500	73	108	139	204	266	332	393	494	617	741	926	1,049	1,111	1,296
	600	80	118	152	224	292	363	431	541	676	811	1,014	1,149	1,217	1,420
	700	87	128	164	242	315	392	466	584	730	876	1,095	1,241	1,314	1,533
	800	93	137	176	259	337	420	498	625	781	937	1,171	1,327	1,405	1,639
	900	98	145	186	274	357	445	528	662	828	994	1,242	1,408	1,490	1,739
	1000	104	153	196	289	376	469	556	698	873	1,047	1,309	1,484	1,571	1,833
	1100	109	160	206	303	395	492	584	732	915	1,098	1,373	1,556	1,648	1,922
	1200	114	167	215	317	412	514	610	765	956	1,147	1,434	1,625	1,721	2,008
	1300	118	174	224	330	429	535	634	796	995	1,194	1,493	1,692	1,791	2,090
	1400	123	181	232	342	445	555	658	826	1,033	1,239	1,549	1,756	1,859	2,169
	1500	127	187	241	354	461	575	681	855	1,069	1,283	1,603	1,817	1,924	2,245

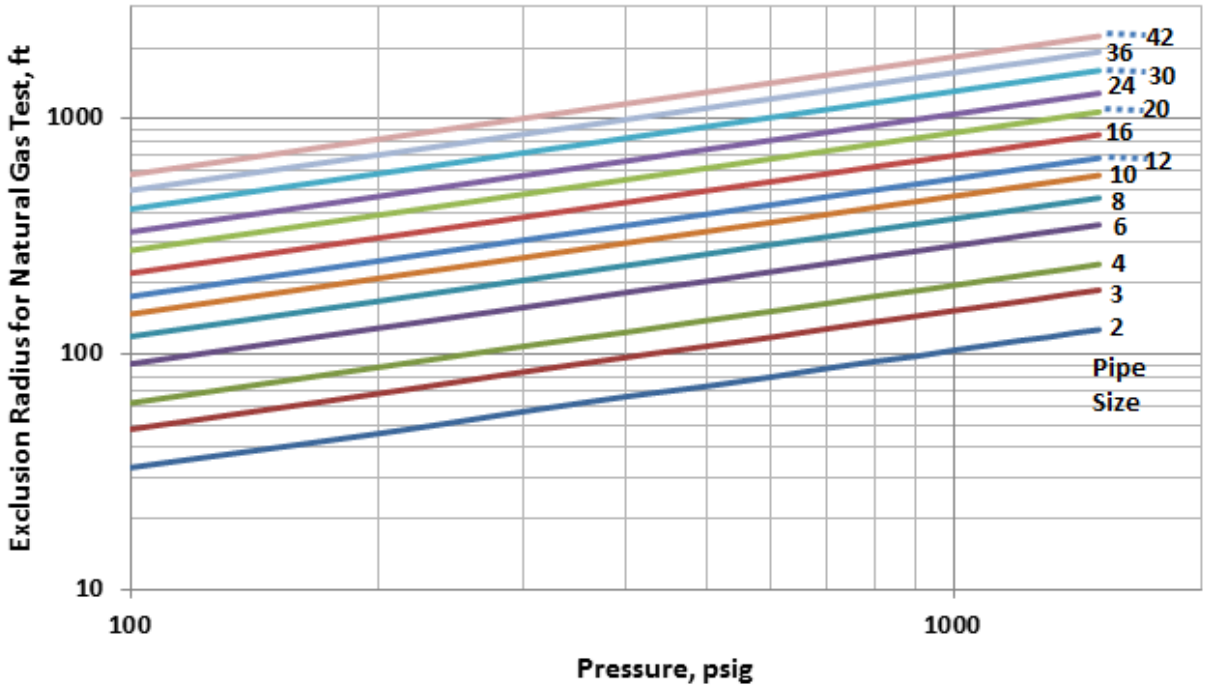

Figure A-3. Main Test Exclusion Radius Diagram when using Natural Gas

For small volume tests, the equations from ASME PCC-2 Article 5.1 can be used to determine a safe exclusion radius. K-rail (portable concrete barriers) could be used to demark exclusion zones in urban areas where extra safety precautions are desired. The farther away from the pipeline the K-rail is placed, the less protection it provides due to its low height. However, if placed too close, it might fall within a crater caused by the released air or gas, and therefore could be ineffective or cause damage. Therefore, to determine the best compromise of distance, the potential crater size was calculated using sizing equations from Gould and Tempo (1981)[xxix] as

$$V_{a=} V_0 \times w \times e^{[-5.2\times H(V_0\times w)^{-1/3}]}$$ **Equation A-10**

where:

V_a = expected apparent crater volume (ft^3)
V_0 = cratering efficiency of explosive for a zero height-of-burst (ft^3/ton)
W = TNT-equivalent explosive weight (tons)
H = height of burst of the explosive charge (ft)

In urban areas, glass breakage can be a potential source of injury. Certain types or dimensions of window glass could break at overpressure levels below what can cause physical harm to humans. The minimum distances at which certain types of glass would have a 50% probability

of failure were developed by Fletcher (1981)[xxx], reproduced here as Figure A-4. A worst-case glass type should be assumed if the actual type of glass installed at a particular site is unknown.

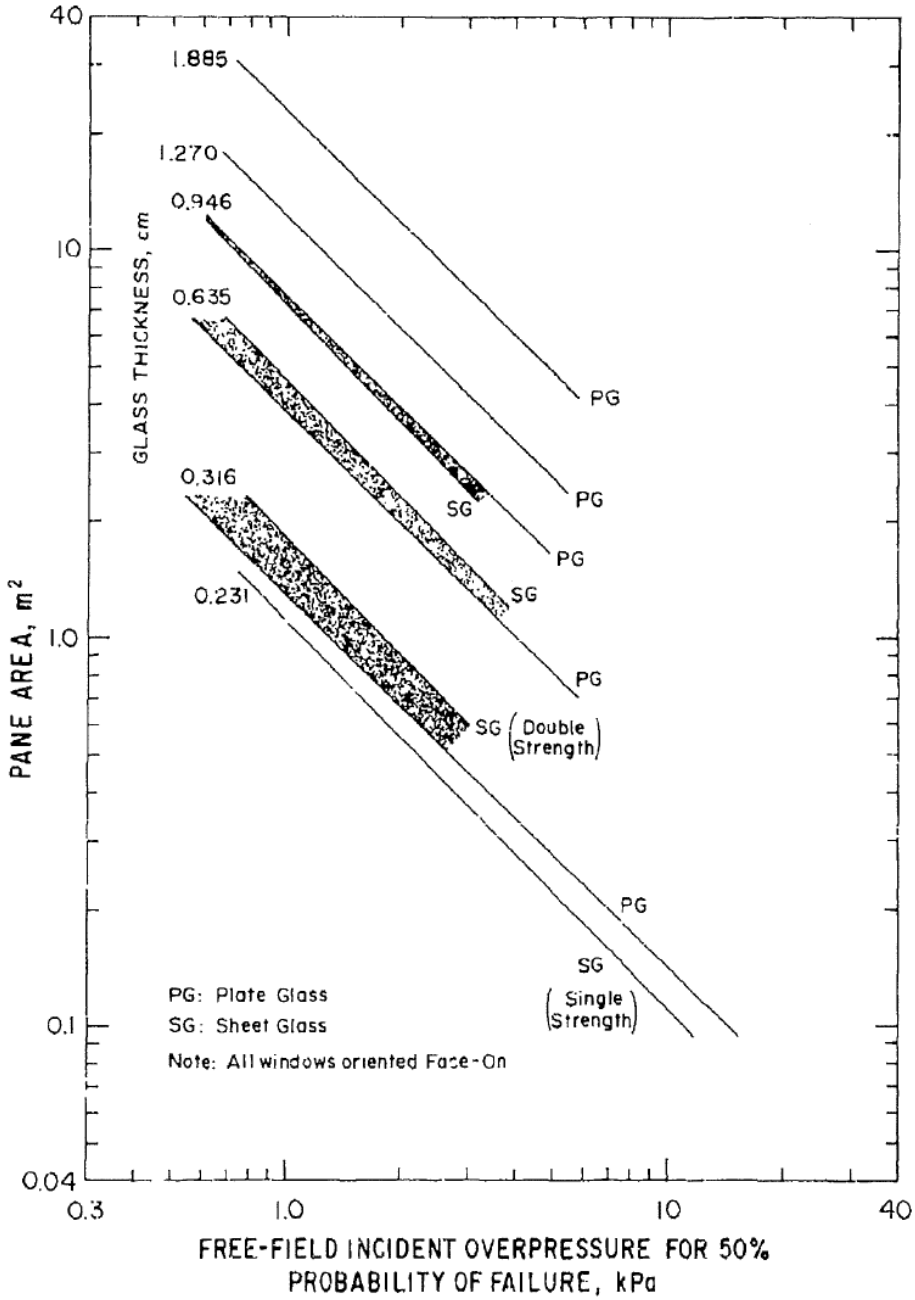

Figure A-4. Glass Pane Area versus Overpressure (from Fletcher)

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