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Leak vs. Rupture Thresholds for Material and Construction Anomalies

Husain M. Al-Muslim, PhD; and Michael J. Rosenfeld, PE

December 15, 2013

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on

LEAK VS. RUPTURE THRESHOLDS FOR MATERIAL AND CONSTRUCTION ANOMALIES

to

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

AND

AMERICAN GAS ASSOCIATION

December 15, 2013

by

Husain M. Al-Muslim, PhD; and Michael J. Rosenfeld, PE

Kiefner and Associates, Inc.
585 Scherers Court
Worthington, Ohio 43085

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Leak vs. Rupture Thresholds for Material and Construction Anomalies

Husain M. Al-Muslim, PhD;and Michael J. Rosenfeld, PE

INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) has recently proposed a "Draft Integrity Verification Process" (IVP), part of which requires hydrostatic testing to establish the maximum allowable operating pressure (MAOP) and verity the integrity of pipelines that were either not tested after construction or for which such tests cannot be reliably confirmed. This study reviews pipeline incident data and fracture mechanics models that may support limited exemptions or alternative measures from the requirement for hydrostatic pressure testing to 1.25 times the MAOP in order to assure the stability of pipe manufacturing or construction related features. This study was performed at the joint request of the Interstate Natural Gas Association of American (INGAA) and the American Gas Association (AGA).

CONCLUSIONS

Analysis of pipeline failure incidents and review of applicable fracture mechanics models determined that there is justification for a limited exemption of a requirement to conduct hydrostatic pressure testing in order to assure stability of pipe manufacturing or construction-related integrity threats.

In view of the above findings, the authors believe that a hydrostatic pressure test to 1.25 times the MAOP is unnecessary to reasonably assure the stability of pipe manufacturing or construction related features in pipe meeting all of the following conditions:

- Ductile fracture initiation is assured by showing that the pipe has an operating temperature above the brittle fracture initiation temperature;
- Interaction with in-service degradation mechanisms such as selective seam corrosion or previous mechanical damage is absent;
- Hoop stress is 30% of SMYS or less;
- Mill pressure testing was conducted at 60% of SMYS or more, established by documented conformance to applicable pipe product specifications (e.g., API 5L) or company specifications;
- Pipe size is 6 NPS or smaller.

For pipes that are 8 NPS or larger but still meeting the first four conditions mentioned above, there might be merit to hydrostatic pressure testing to 1.25 the MAOP as theoretical analysis as well as full-scale laboratory tests show that failure as a rupture is possible for stress thresholds below 30% of SMYS. However, NPS 8 pipe may be prioritized lower than larger pipe because there were no reported incidents of service rupture in pipe that size where all other criteria were met.

OBJECTIVE AND SCOPE

Objective

The objective of this study was to determine whether an operating stress threshold exists, perhaps tied to pipe diameter or other attributes such as operating stress level, type of seam, or manufacturing quality steps, below which a hydrostatic pressure test to 1.25 the MAOP is unnecessary to reasonably assure the stability of pipe manufacturing or construction related defects.

Scope

The study reviewed and accounted for the following knowledge areas to define a category of natural gas pipelines for which a post-construction hydrostatic pressure test to 1.25 MAOP is unnecessary:

- GTI study on leak-rupture boundary
- AGA study on pressure reversals in ERW pipe
- Ongoing Kiefner analysis of pressure cycle fatigue in gas pipeline systems
- PHMSA reportable incident database
- Kiefner failure investigation database

The report discusses the work in the above order. The theoretical work based on fracture mechanics provided a technical basis for the proposed hydrostatic pressure testing exemption. The analysis of incident data then substantiated the theoretical approach.

TECHNICAL REVIEW OF KNOWLEDGE AREA

Defining the Leak and Rupture Modes of Failure

Natural gas pipeline leaks, while not desirable, present a significantly lesser magnitude hazard than pipeline ruptures. Not all leaks are hazardous or require immediate correction. The occurrence or discovery of leaks after in-line inspection (ILI) or pressure testing is not uncommon and does not necessarily indicate instability of a defect condition or an impairment of the strength of the affected pipe. For these reasons, it is appropriate to discuss defect stability for integrity purposes in the context of immunity to ruptures but not necessarily to leaks. If a pipeline can be found to not be susceptible to rupturing due to initial manufacturing or construction defects, then the integrity threat such defects pose can be considered to be stable.

Three factors affect whether a defect in a pipeline will fail as a leak versus a rupture: material toughness, applied stress, and flaw size. The ratio of diameter to wall thickness (D/t) directly relates stress level to operating pressure, implying that lower D/t (and in fact smaller diameter pipe) may have lesser susceptibility to rupturing, all other things being equal. Most pipeline materials, even vintage ones, possess significant ductility with the exception of certain types of weld seam (namely low-frequency ERW seams without post-weld heat treatment manufactured prior to 1964), but sufficiently low operating stress provides significant protection against catastrophic failure. Absent an interacting in-service degradation condition such as corrosion[1], whether a manufacturing-related condition will rupture in service is influenced by the operating stress and the test pressure ratio. The mill test pressure can be a factor, if the pipe age and specification is known with confidence.

The factors cited above can be taken together to identify a category of gas pipelines defined primarily by pipe diameter and operating stress level, and perhaps supplemented or extended where other information about vintage and manufacturing process is known, for which an initial hydrostatic test to 1.25 MAOP is unnecessary to assure stability of manufacturing-related and construction-related conditions.

It is essential to clearly define a rupture versus a leak as there were occasions of misreporting in the reportable incident database. A rupture is an event in which the pipeline cannot contain pressure or transport product or gas. It is typically characterized by lengthwise unstable fracture propagation beyond the original length dimension of the initiating defect. In contrast, a leak is an event where the release of product or gas is low enough to potentially allow the continual service of the pipeline because of the small size of the breach of the pressure boundary. There is no unstable propagation of a fracture in the axial direction under the influence of hoop stress beyond the dimensions of the originating defect. The term "rupture," however, includes various types described below as quoted from reference [2]

[1] Presence of interactive in-service degradation, such as selective seam corrosion, has been reported to cause ruptures in very low stresses below 20% of SMYS [1].

- Propagating ductile rupture – unstable axial crack propagation that propagates at a velocity less than the acoustic velocity of the pressurizing medium that is driven by pressure acting on the walls of the pipe behind the advancing crack front (likely to arrest as the pressure decays)
- Propagating brittle rupture – unstable axial crack propagation that usually propagates at a velocity greater than the acoustic velocity of the pressurizing medium and is driven solely by hoop stress (unlikely to arrest unless the fracture encounters a tougher material)
- Tearing shear fracture – a crack that advances along the axis of the pipe by taking a helical path and that is driven by radial shear force from pressure (arrests quickly).
- Circumferential rupture – a fracture that propagates in the circumferential direction that is driven by longitudinal stress in the pipe and that is virtually unaffected by the pressure level in the pipe
- Puncture - a leak or opening created by the impact of mechanical equipment which has insufficient axial length to initiate a propagating rupture (the opening may be sufficiently large that the pipeline must be shut down)
- Hole - a feature usually created by a fitting or branch connection being torn off which has insufficient axial length to initiate a propagating rupture (the opening may be sufficiently large that the pipeline must be shut down)

The first three types of ruptures are relevant to setting the leak/rupture boundary in terms of a hoop stress threshold, and therefore relevant to the integrity verification by hydrostatic testing. The last three types are not hoop-stress driven modes of failure, and therefore, they are not relevant to integrity verification by hydrostatic testing.

GTI Study on Leak-Rupture Boundary

Kiefner performed a study in 2010 [2] on the leak-rupture boundaries for low stress pipelines to identify as a technical basis for considering which low-stress pipelines could reasonably be included under U.S. federal pipeline integrity management regulations known as "Distribution Integrity Management" regulations. The study is comprehensive and its objectives resemble the ones targeted in this report, except that this report is concerned strictly with manufacturing and construction related defects or conditions.

The GTI study involved review of several theoretical models to predict the stress threshold for leak-rupture boundary as well as review of full-scale tests and reportable incident data between 1985 and 2000 to validate the findings. To summarize briefly, the study concluded that pipelines operating at stress levels of 30% SMYS or below are not likely to be subject to a propagating ductile rupture. However, they might have rupture at such low stresses due to brittle fracture, tear fracture, circumferential rupture, or puncture. The study highlighted that the root causes related to ruptures at a stress level of 30% SMYS or less are external corrosion, internal corrosion, third party damage, and previously damaged pipe. The latter could happen during construction activities or during transportation or installation of the pipe, e.g. rock damage.

In terms of manufacturing defects, the GTI study pointed out that pipelines manufactured after 1941 are not subject to rupture if they operate at stress levels of 30% or less. This is due to the fact that API 5L required all line pipe to be subjected to a hydrostatic pressure test of at least 60% SMYS at the pipe mill and the argument that there is little or no likelihood that a defect will grow larger in natural gas service. Unfortunately, this low likelihood occurred and caused a major incident with significant consequences which will be discussed in the "On Going Kiefner Fatigue Analysis of Pressure Cycle Fatigue". In the same section, the probability of defects growing or initiating after the mill hydrostatic test and before being in service during transportation, known as "transit fatigue", will also be discussed.

The study emphasized that the use of leak/rupture boundary models and results is valid only for cases where ductile fracture initiation behavior is assured. This is because brittle fracture initiation can lead to pipe ruptures at hoop stress levels well below 30% of SMYS. To avoid such brittle fracture, a pipeline must be operated at a minimum temperature equal or greater than the fracture initiation transition temperature of the material. The fracture initiation transition temperature is the temperature below which a line pipe material might be expected to fail suddenly in the presence of a very small defect. Therefore it is a key parameter in determining the applicability of the ductile fracture initiation leak/rupture boundary with respect to the operating hoop stress level of a pipeline. The brittle fracture initiation temperature can be established using a standard Charpy V-notch (CVN) impact test, which is used to find the upper shelf energy as well to define toughness. The test is conducted at several temperatures to determine the temperature at which the fracture behavior changes from ductile to brittle. It is customary to consider the temperature corresponding to 85% shear appearance in a CVN test, adjusted to account for specimen size if the test coupon is smaller than about 2/3 of the actual pipe wall thickness, as the "shear appearance transition temperature" [3]. This temperature corresponds to the lowest temperature at which the CVN upper shelf absorbed energy is available. Studies have shown that the brittle fracture initiation temperature is less than the brittle fracture propagation transition temperature by at least 60 F and generally by a larger margin [4, 5].

Finally, while no evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less, the Maxey arrest model shows that ductile ruptures can occur at hoop stress levels less than 30% of SMYS. This model which was validated on the basis of full-scale lab tests clearly indicate that ductile ruptures at stress levels below 30% of SMYS can occur for some combinations of pipe materials and geometries.

Summary of the Theoretical Analysis

The leak/rupture boundary for a given pipe material can be determined by finding the minimum operating hoop stress above which the mode of defect failure could be a rupture. A leak/rupture boundary can be established based on fracture initiation models or fracture propagation models. The fracture initiation models predict the hoop stress level at which an axially-oriented through-wall defect will suddenly propagate in an unstable manner along the axis of the pipe. The fracture propagation models, or fracture arrest models, predict the level of hoop stress below which insufficient energy is available to support a propagating rupture.

Fracture Initiation Models

The common characteristic of the fracture initiation models is that the leak/rupture boundary depends on the defect length. The GTI report reviewed the following models:

- Maxey/Folias
- Pipeline Axial Flow Fracture Criteria (PAFFC)
- Texas A&M J-Integral
- Mechanical Damage

The GTI report recommends using the Maxey/Folias model among the first three models concerned with axial crack or crack-like flaws which will be discussed in more details herein. This is because all three models give similar results with the Maxey/Folias having the advantage of being a closed form solution based on applied stress, pipe yield strength, Charpy toughness and defect length. The PAFFC and Texas A&M models are based on the *J*-integral concept, a measure of stress distribution at the crack tip, exceeding the *J*-resistance of the material. The approach requires a special test to find the *J*-resistance of the material and detailed stress-strain data in the plastic regime of the material which often requires the use of finite element analysis to find the *J*-integral. For the mechanical damage of gouge and dent, the report highlights that the same criteria for the Maxey/Folias should be applied as that model was validated based on simulated gouge defects. However, other types of mechanical damage were not discussed as there were no reliable models the authors were aware of. Therefore, criteria will be based on PHMSA incident reports.

The Maxey/Folias model was proposed by Maxey [6] as a practical case of a pipeline containing an axial through-wall defect based on Folias study of effects of curvature on cracked sheet [7].

The flaw type in his study is created when the remaining ligament beneath a corroded area or a stress corrosion crack fails. Based on full-scale tests of pressurized pipes containing artificially induced through-wall defects, Maxey was able to show that the Folias equation provides a good approximation of the boundary between leaks and ductile ruptures when the concentrated stress at the tip of the crack is equal to the "flow stress" of the material. The Maxey/Folias failure stress equation as in Reference [6] is:

$$\boldsymbol{\sigma = \bar{\sigma}/M_T} \qquad \text{Equation 1}$$

$$\boldsymbol{M_T = \left[1 + 1.255\frac{\left(\frac{L}{2}\right)^2}{Rt} - 0.0135\frac{\left(\frac{L}{2}\right)^4}{R^2t^2}\right]^{1/2}} \qquad \text{Equation 2}$$

where:

σ is the hoop stress level at instability (in a flow-stress dependent material), psi
$\bar{\sigma}$ is the flow stress of the material (actual yield + 10,000 psi), psi
L is the length of the flaw, inches
R is the outside radius of the pipe, inches
t is the wall thickness of the pipe, inches

Equation 1 is "flow-stress-dependent" and is applicable for material with high-enough toughness that can resist unstable crack propagation in the presence of a defect until failure takes place by plastic instability. As many pipe materials, especially those installed prior to 1980 have a lower toughness values than the one required to be "flow-stress-dependent", Maxey also introduced a Folias leak/rupture model that is "toughness-dependent" based on a "Dugdale Ln-Secant" plastic zone size correction factor. Maxey was also able to represent the ductile toughness in terms of Charpy V-notch upper shelf energy. The "toughness-dependent" model is presented in Equation 3 and Equation 4.

$$\boldsymbol{\sigma = (\bar{\sigma}/M_T)\left(\frac{2}{\pi}\right) arccos(e^{-x})} \qquad \text{Equation 3}$$

$$\boldsymbol{x = \frac{12\left(\frac{CVN}{A_c}\right)E\pi}{4L\bar{\sigma}^2}} \qquad \text{Equation 4}$$

where:

CVN is the Charpy V-notch upper shelf energy, ft-lb
A_c is the fracture area of the Charpy specimen, in^2

The leak/rupture boundaries for both flow-stress-dependent and toughness-dependent materials are shown in Figure 1 for pipe material grade X52.

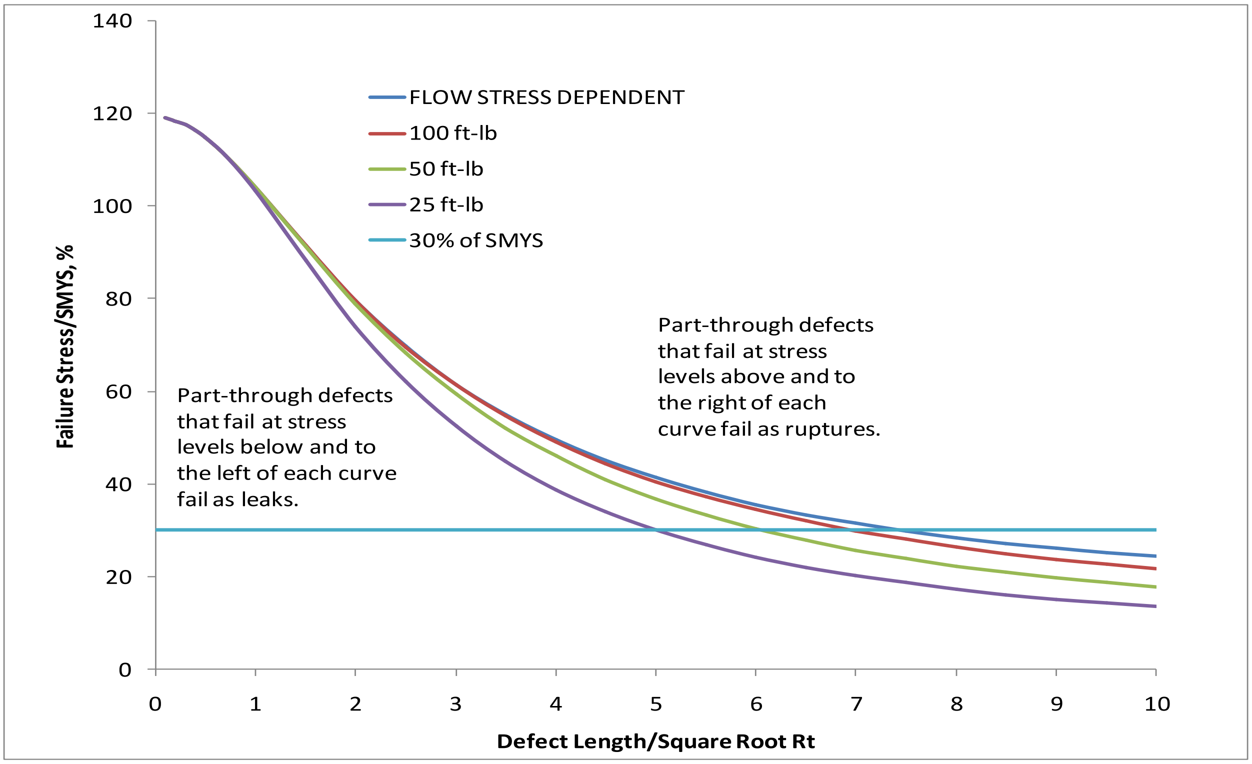

Figure 1. Leak/Rupture Boundary as Affected by Material Toughness for X52 Materials Based on Maxey/Folias Model [2]

Figure 1 indicates that the longer the defect, the lower stress level at which rupture could occur. This is true even for the curve that is based on the "flow-stress-dependent" equation. The figures show that rupture can occur below 30% SMYS and even below 20% SMYS for longer than 6√Rt. The model has this characteristic because it is a fracture initiation model and does not consider whether the crack will propagate or be arrested. Moreover, although the model does not set an upper limit on the defect length, physical reality suggests that there should be a finite upper "effective" length as the driving energy which is based on the length cannot grow infinitely and must have an upper bound.

Fracture Propagation, or "Fracture Arrest", Models

The GTI report reviewed two fracture propagation, or "fracture arrest", models:

- Maxey's Arrest Stress model
- SWRI Arrest Stress model

The authors recommended the Maxey's Arrest Stress model as it predicts the leak/rupture boundary for ductile fracture for any given pipe material for which the Charpy V-notch upper shelf energy is known. It defines the nominal hoop stress level at the tip of a decelerating ductile fracture when the crack velocity decays to zero. The SWRI model, on the other hand, predicts the arrest/propagate boundary for ductile fracture. This is the nominal hoop stress that separates those that will decelerate and eventually arrest from those that would continue to propagate indefinitely. As such it is inherently higher than the leak/rupture boundary (defined by zero crack velocity) and therefore, its use to find the leak/rupture boundary for low-stress pipelines was not recommended.

The Maxey's arrest model was triggered by empirical evidence from pipeline failures in the 1950s which showed that ductile fractures in natural gas pipelines would arrest before the pipelines had fully depressurized. This implied that an axial crack will not propagate when the crack driving force created by internal pressure falls below some limiting level. The Maxey arrest model was derived empirically from full-scale pipe rupture tests. His analysis showed that ductile fracture arrest was associated with characteristic hoop stress levels depending on pipe geometry, material strength, and material toughness. It is a simple, but reliable, model to use for predicting the leak/rupture boundary for material up to Grade X70 with toughness up to 75 ft-lb which should suffice for material used in low-stress pipelines.

Maxey plotted the full-scale test results, as shown in Figure 2, which is taken from reference [6], where he differentiated "propagate" failures against "arrest" failures. Based on the dimensionless parameters he chose, Maxey was able to identify a distinct boundary between the "propagate" zone and the "arrest" zone. The first parameter, which is the ordinate, is the ratio of the "decompressed" stress level to the "flow" stress, which is the stress level available to drive a propagating ductile fracture. This is not the nominal hoop stress level defined by Barlow's equation, but the nominal hoop stress level at the tip of the propagating fracture inferred from the speed of fracture propagation. Maxey found that a propagating ductile fracture is always a single crack and that measurements of fracture velocity indicated that ductile fractures in a given material propagate at a constant value. He postulated that the constant velocity implied a maximum effective crack length, which should be predictable by means of the Folias equation.

The second parameter, which is the abscissa, is based on the fracture initiation model parameter defined in Equation 4. The full-scale tests were conducted for several trial values of the dimensionless crack length $L/\sqrt{Rt}$. The boundary curve shown in the figure was plotted using Equation 3. Maxey selected a best-fit curve separating propagate data from arrest data which corresponded to an $L/\sqrt{Rt}$ value of approximately 6.

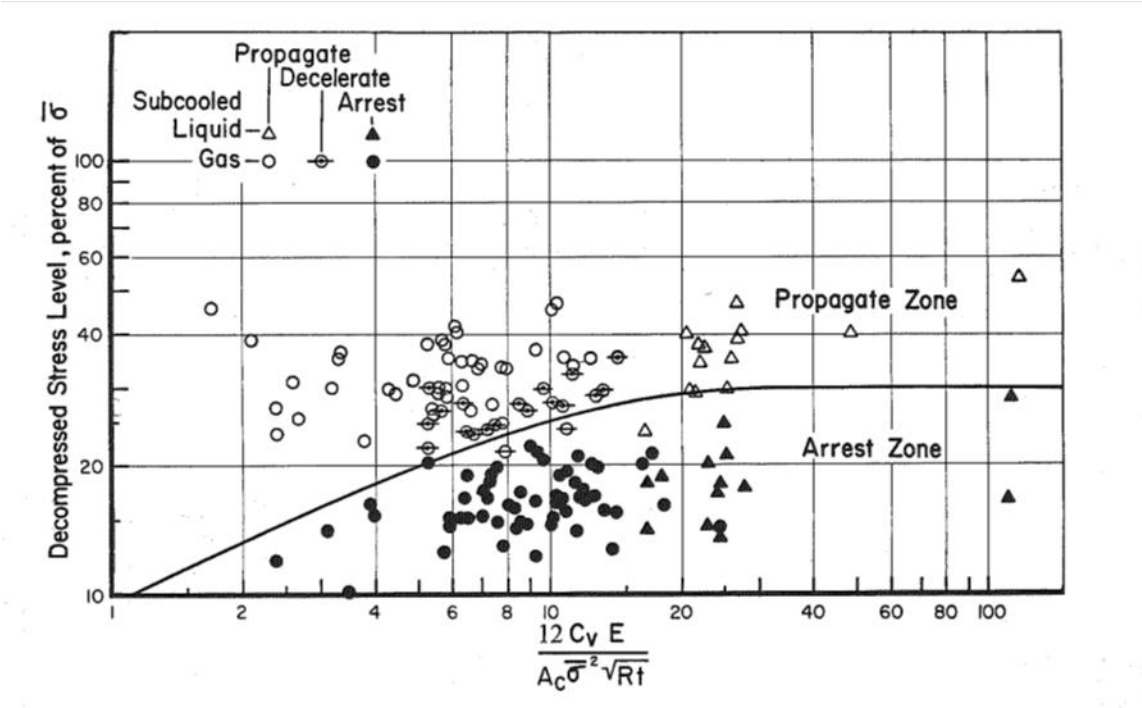

Figure 2. Arrest-Propagate Data Showing Maxey's Arrest Criterion [6]

If 6√Rt is substituted for L in Equation 2, one obtains M_T = 3.347. Then, using Equation3 with M_T = 3.347 one obtains the following.

$$\sigma_a = \frac{\bar{\sigma}}{3.347}\left(\frac{2}{\pi}\right)\arccos\left(e^{-\beta}\right) \qquad \text{Equation 5}$$

where

σ_a is the arrest stress level and

$$\boldsymbol{\beta = \frac{\pi}{24}\cdot\frac{12CVN}{A_c\bar{\sigma}^2\sqrt{Rt}}E} \qquad \text{Equation 6}$$

Equations 3 and 5 are identical and give the same boundary as Figure 2 for crack length of 6√Rt, at which the decompressed stress level is equal to the arrest stress level. Equation 5 gives the stress level at the tip of the propagating ductile fracture when the crack velocity has decreased to zero. A key assumption is that if propagation cannot continue, it can be inferred that crack initiation in the same material cannot take place. Hence, the arrest stress level defined by Equation 5 sets the boundary between a leak and a rupture. Moreover, as the fit of the data establishes a maximum effective defect length of 6√Rt, the Folias initiation model as well can be used to establish a leak/rupture boundary limited by this upper effective defect length.

Figure 3 gives the arrest stress levels for several typical line pipe materials as a function of toughness (in terms of Charpy energy) as predicted using Maxey's ductile fracture arrest stress model (Equation 5). The figure shows that not only the arrest stress depends on the toughness, but also it depends on the pipe yield strength and pipe geometry. The larger diameter and the higher the grade, the lower the arrest stress levels can be. Moreover, arrest levels, and thus rupture, can occur at levels as low as 15% depending on the combination of toughness, yield strength, and pipe geometry. This observation triggered the authors of the current INGAA study to conduct additional analysis to establish leak/rupture boundary conditions for various possible combinations of pipe toughness, yield strength, and geometry.

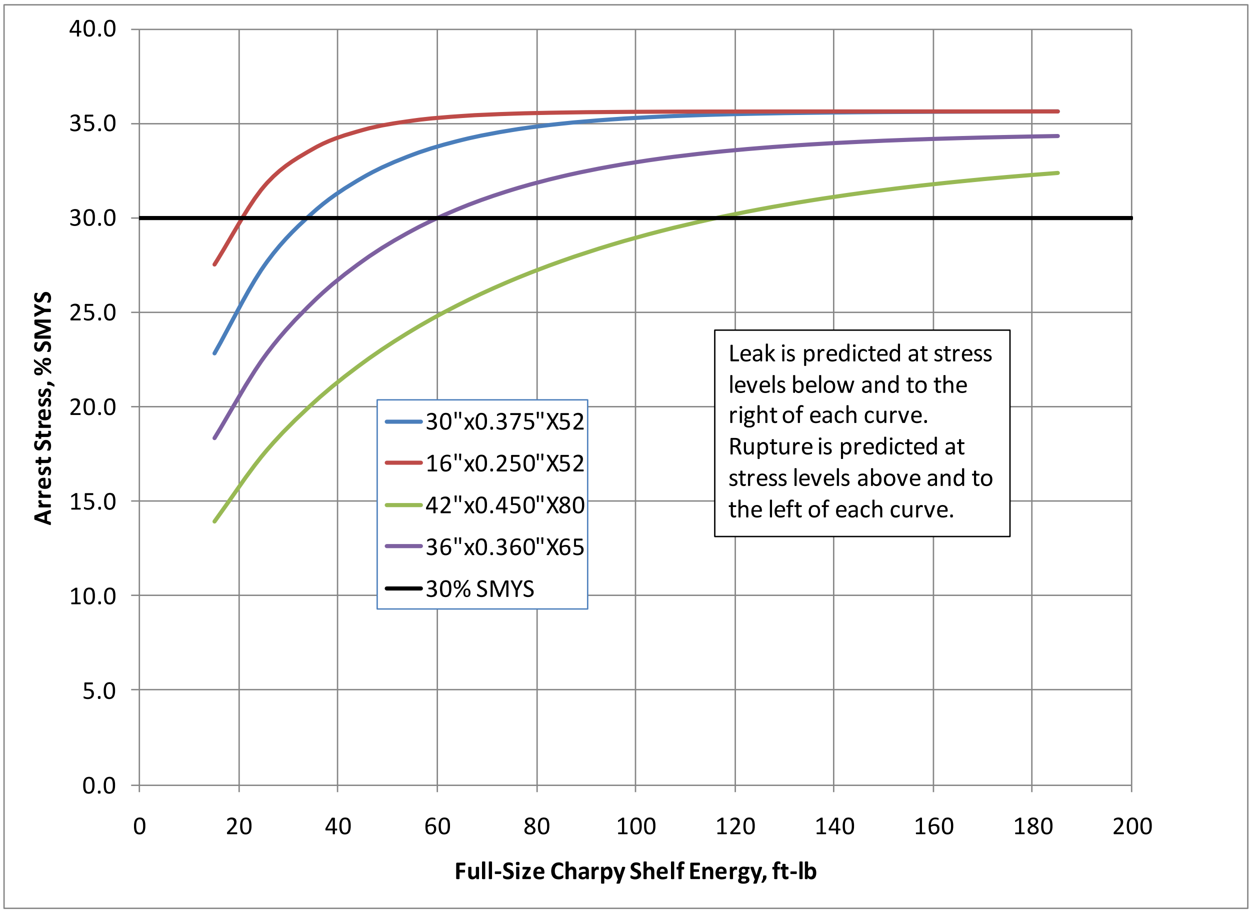

Figure 3. Arrest Stress Level as a Function of Pipe geometry, Strength, and Toughness (Maxey's Arrest Stress Model) [2]

New Analyses to Define Leak/Rupture Boundaries for Various Combinations of Pipe Toughness, Strength, and Geometry Based on Maxey's Crack Arrest Model

The leak/rupture boundary defined by Maxey's crack arrest model is strongly dependent on toughness. Two cases of moderate toughness, with values of 20 ft-lb, and high toughness, with a value of 50 ft-lb will be studied. Low toughness materials are not considered as they tend to give very low arrest stress levels and should be lumped with brittle materials. For the pipe grade, all material grades from B to X70 are considered. Finally, for the geometry, pipe sizes from NPS ½ to 36 inch OD are evaluated. The results are also dependent on the thickness as higher thickness gives lower arrest stress level. Several thicknesses based on operating pressure values of 500, 1000, 1500, and 2000 psig are presented. The thickness was calculated based on Barlow's equation and assuming a design factor of 0.4.

The results shown in Figure 4 through Figure 11 clearly show that the leak/rupture boundary, in terms of operating stress-to-yield strength ratio, decrease with decrease in pipe toughness, increase in pipe yield strength, and increase of pipe diameter. However, a minimum limit of 15% SMYS is observed for all cases, below which only leak can take place. Another interesting observation is that pipe NPS of 6 inches or less will always fail as leak for operating stress threshold of 30% SMYS or less. The figures can also be used to define the combination of pipe material and geometry properties that will only fail at leak at any operating stress threshold. Table 1 gives the combinations for operating stress thresholds of 15%, 20%, 25% and 30% SMYS.

Table 1. Pipe Material and Geometry Combinations for Different Leak/Rupture Stress Thresholds (MAOP is 2000 psig or less)

Stress threshold (%SMYS)	Toughness (CVN in ft-lb)	Pipe Grade	Pipe Diameter (inches)
15	20 or more	B-X70	½-36
20	20 to less than 50	B-X42	½-36
		X46-X70	½-16
	50 or more	B-X70	½-36
25	20 to less than 50	B-X42	½-20
		X46-X70	½-10
	50 or more	B-X52	½-36
		X56-X70	½-24
30	20 to less than 50	B-X42	½-6
		X46-X70	½-4
	50 or more	B-X52	½-22
		X56-70	½-12

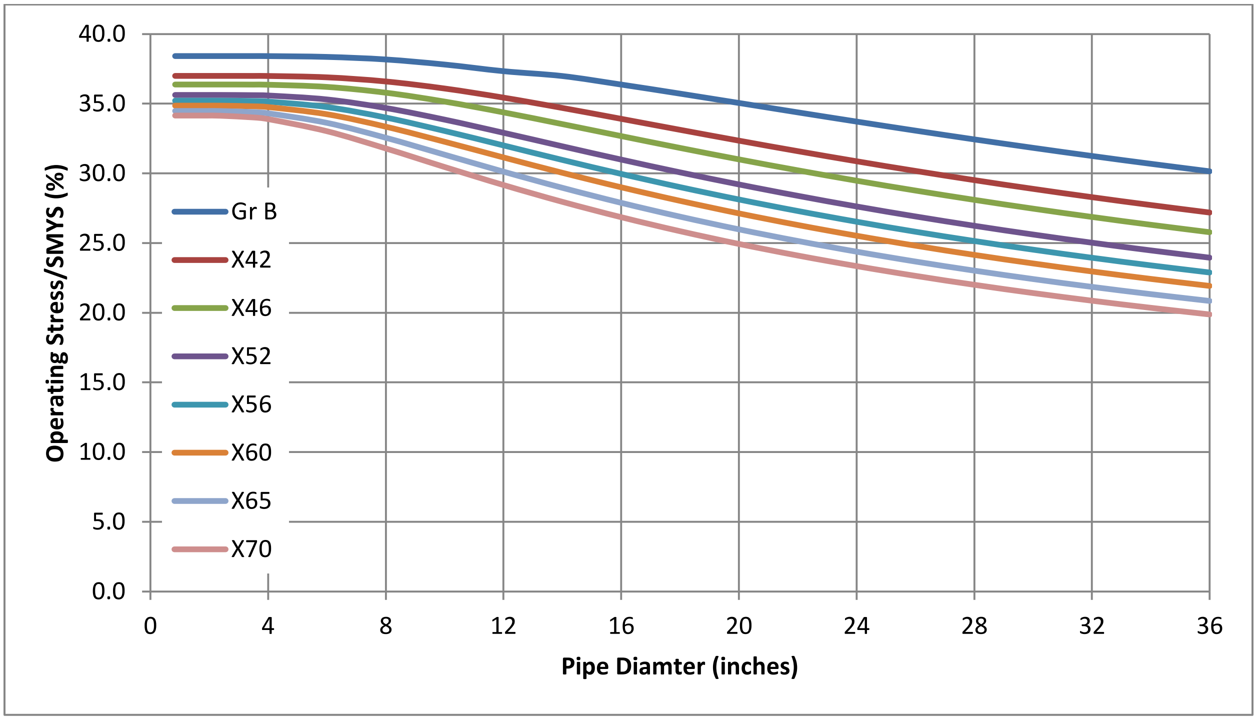

Figure 4. Leak/Rupture Boundaries for Moderate Toughness Pipe (CVN=20 ft-lb) Having MAOP of 500 psig or less

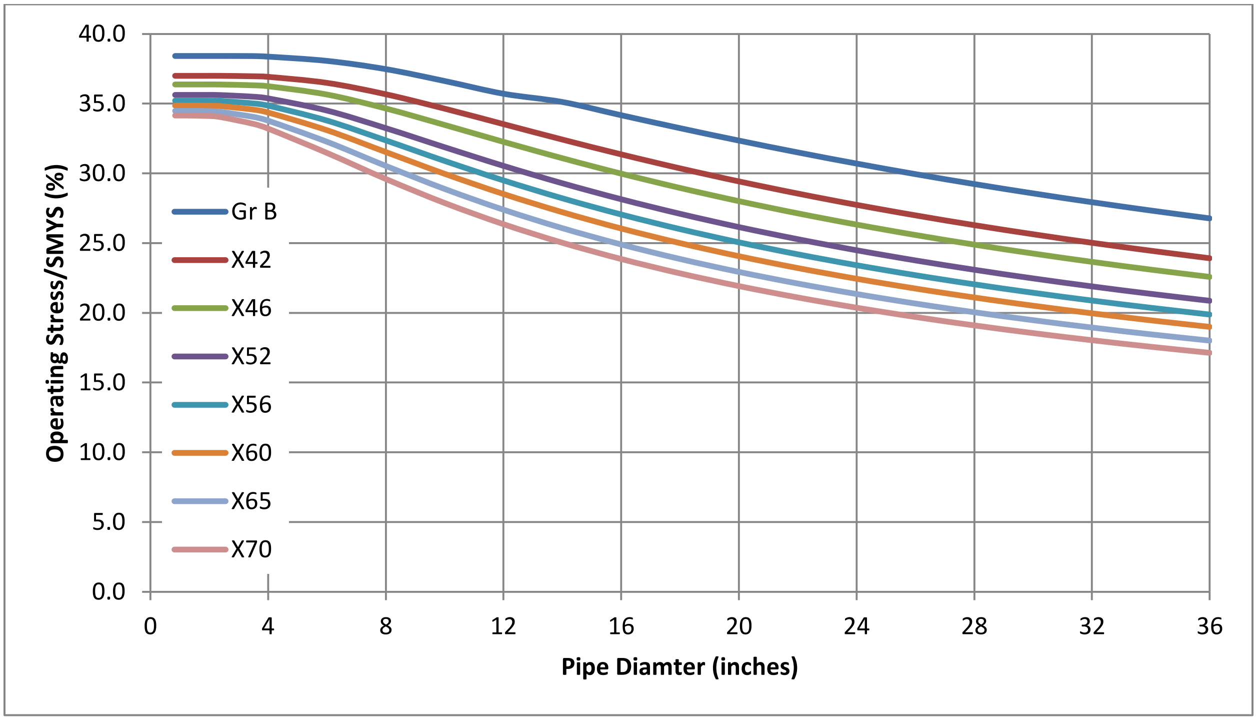

Figure 5. Leak/Rupture Boundaries for Moderate Toughness Pipe (CVN=20 ft-lb) Having MAOP of 1,000 psig or less

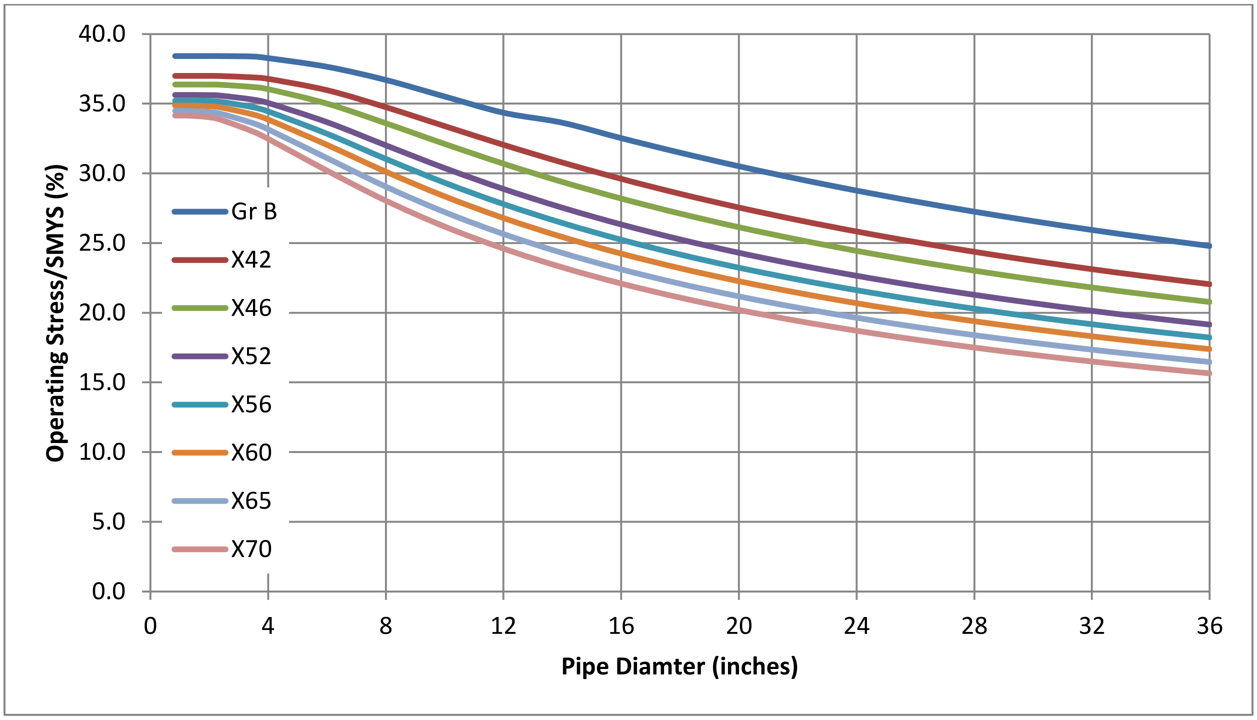

Figure 6. Leak/Rupture Boundaries for Moderate Toughness Pipe (CVN=20 ft-lb) Having MAOP of 1,500 psig or less

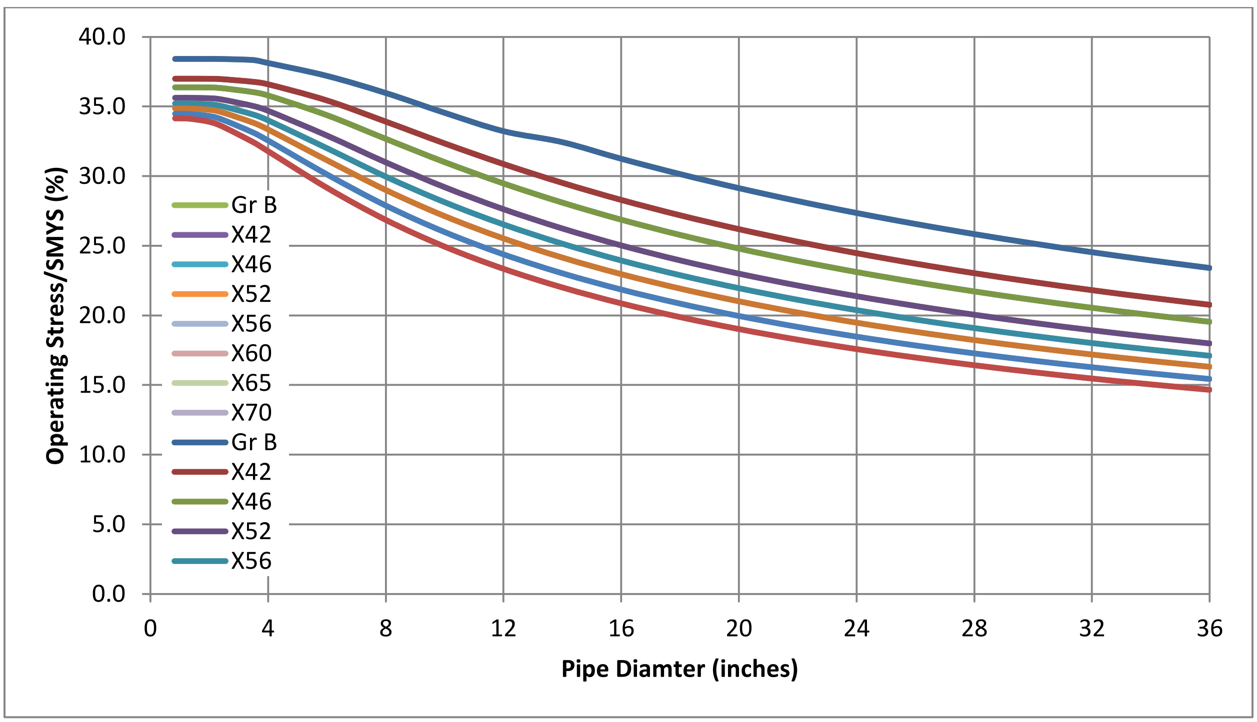

Figure 7. Leak/Rupture Boundaries for Moderate Toughness Pipe (CVN=20 ft-lb) Having MAOP MOP of 2,000 psig or less

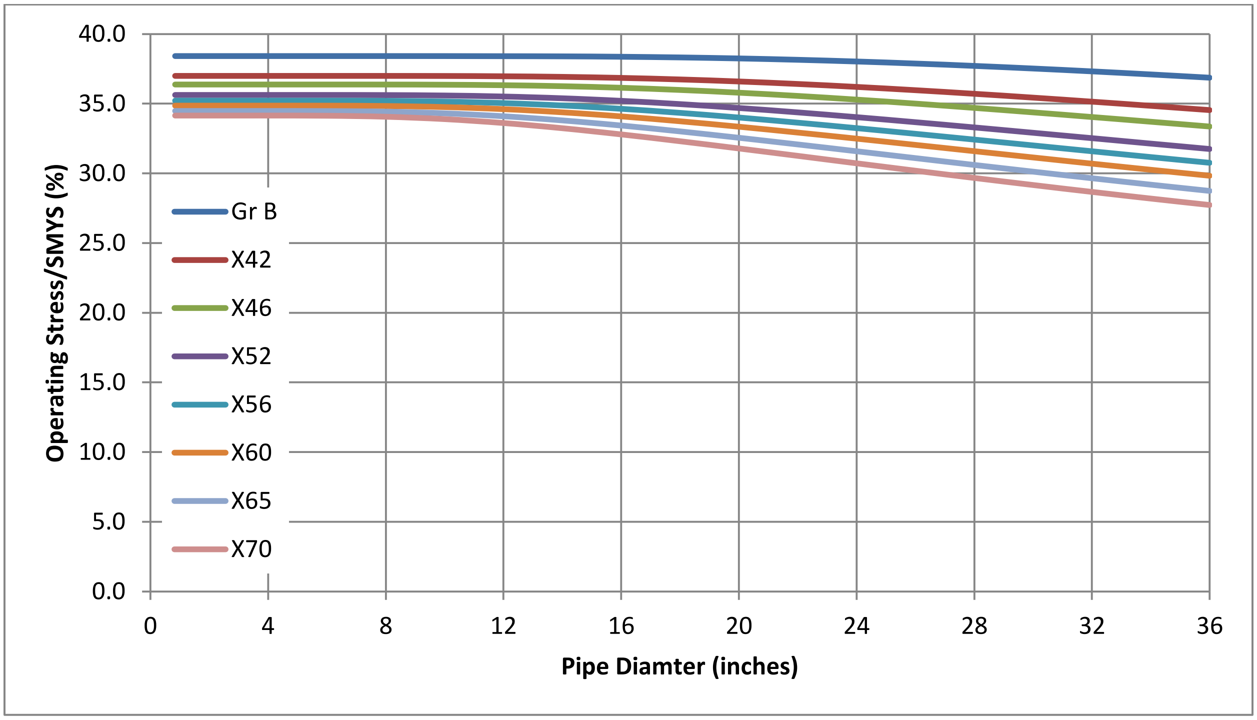

Figure 8. Leak/Rupture Boundaries for High Toughness Pipe (CVN=50 ft-lb) Having MAOP of 500 psig or less

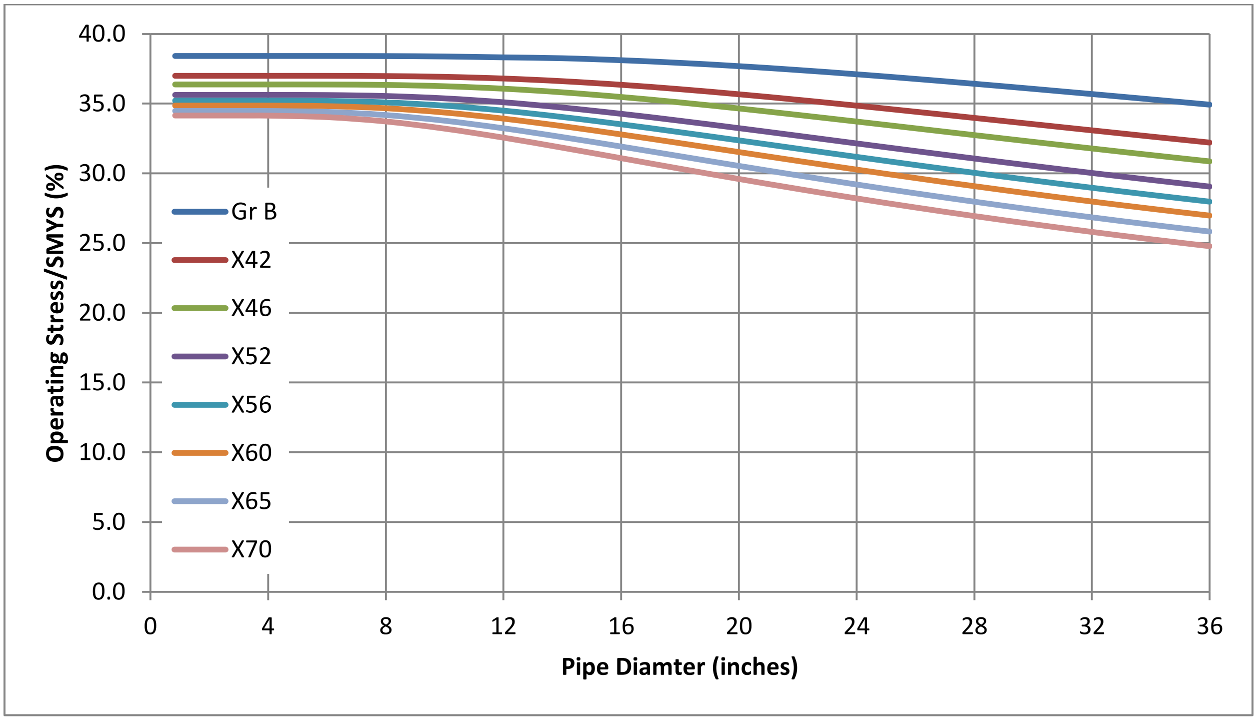

Figure 9. Leak/Rupture Boundaries for High Toughness Pipe (CVN=50 ft-lb) Having MAOP of 1,000 psig or less

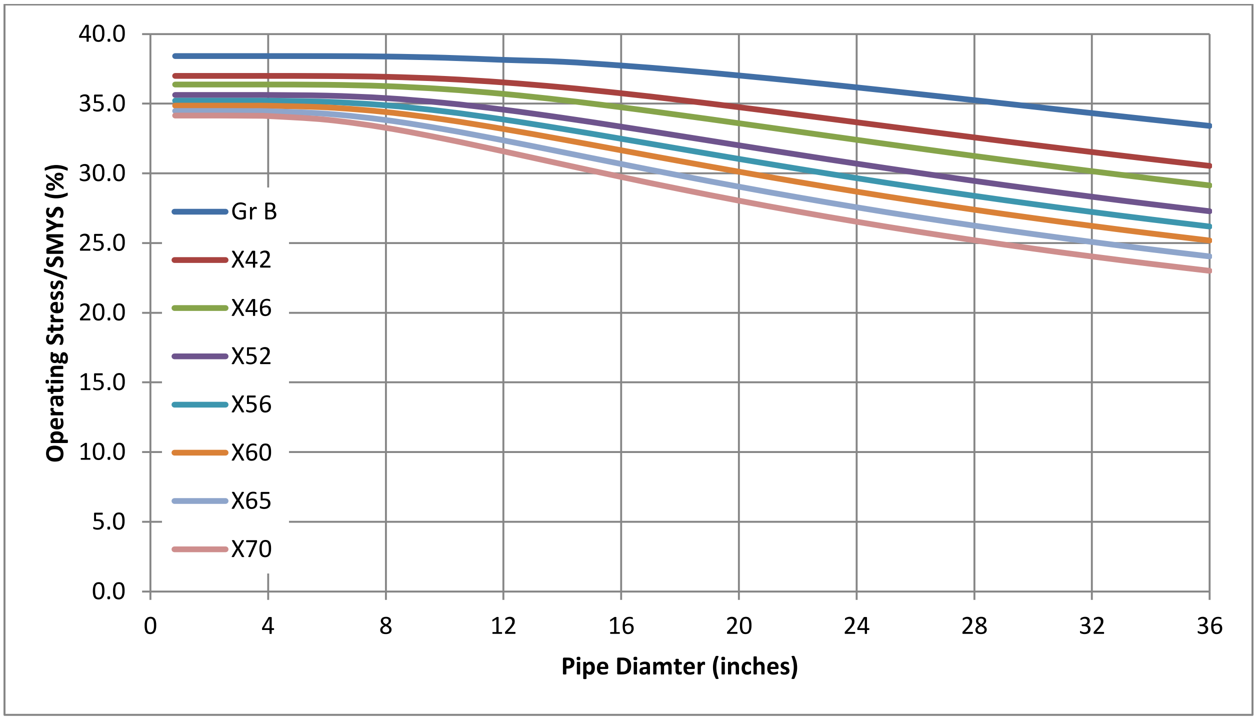

Figure 10. Leak/Rupture Boundaries for High Toughness Pipe (CVN=50 ft-lb) Having MAOP of 1,500 psig or less

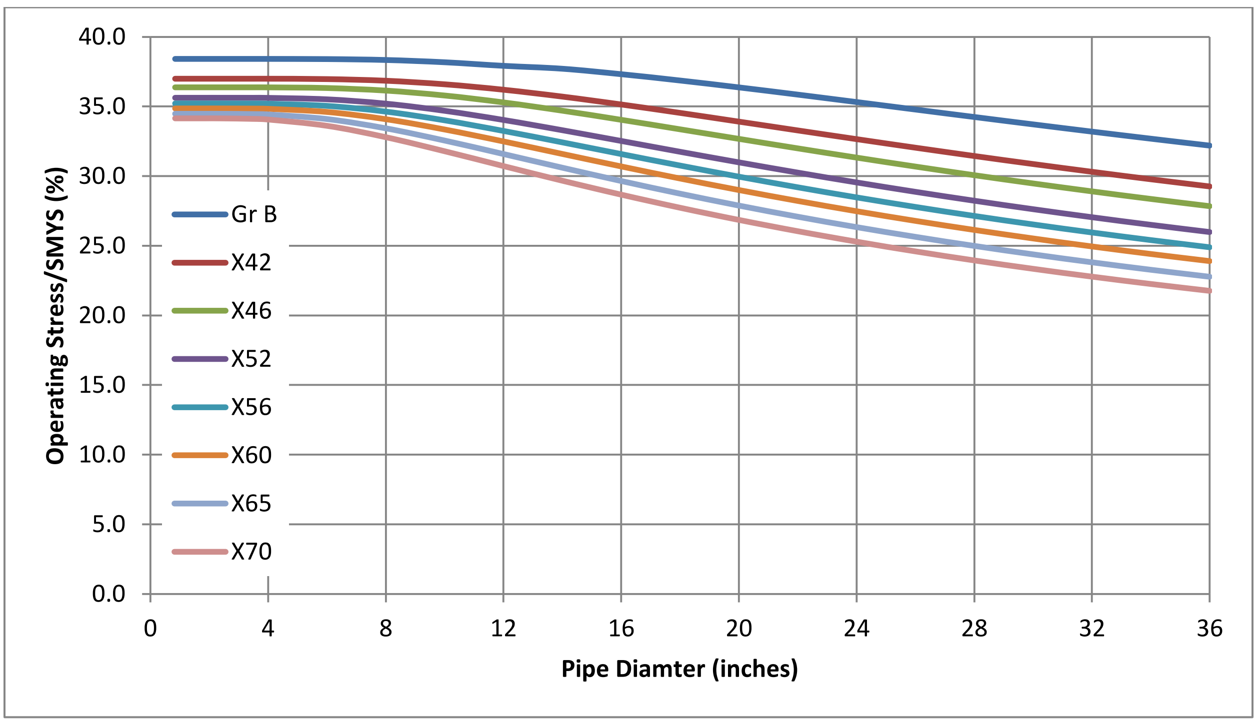

Figure 11. Leak/Rupture Boundaries for High Toughness Pipe (CVN=50 ft-lb) having MAOP MOP of 2,000 psig or less

Summary of the Reportable Incident Review (1985-2000)

The GTI report reviewed 1,381 U.S. reportable incident reports for the period from 1985 through 2000 [8] to determine which root causes of incidents are relevant to the leak/rupture propensity of pipelines operated at 30% of SMYS or less. Pipeline industry specialists and federal regulators have identified 22 root causes of pipeline failure. The discussion herein will be limited to manufacturing and construction defects to examine the role that hoop stress played in the incidents.

Some manufacturing and construction defects were judged to be not relevant to the leak/rupture boundary in terms of hoop stress thresholds, while some manufacturing and construction were judged to be possibly relevant. The GTI report also identified causes that were found to be clearly relevant to the leak/rupture boundary in terms of hoop stress thresholds.

The authors determined that a source of error inherent to the review of reported incidents is the possibly incorrect reporting of the failure as a leak or rupture by the pipeline operator. The personnel reporting the particulars of an incident may not be sufficiently informed to make an accurate distinction between the various modes of failure. The authors pointed out that it is likely that some large but stable leaks have been reported as ruptures, while some ruptures have been reported as leaks.

The GTI report found that 57 of the 1,318 incidents (5.7%) were attributed to defective fabrication welds (fillet welds around sleeves, weld-o-let welds, branch connections, etc.) and defective girth welds. Of these 57 incidents, 23 occurred as ruptures, but all at operating hoop stresses exceeding 30% of the SMYS. Nonetheless, since rupture was not driven by the hoop stress, the report classified these construction defects as not relevant to the leak/rupture boundary criteria in terms of hoop stress thresholds.

The GTI report classified pipe body defects and pipe seam defects, both manufacturing defects, as possibly relevant to the leak/rupture boundary criteria in terms of hoop stress thresholds. As such, they should be eliminated by either the manufacturer's quality control measures or the pre-service hydrostatic test of a pipeline especially for post 1941-API 5L which was subjected to mill hydrostatic tests of at least 60% SMYS. If the assumption of a mill test was known to be true for every piece of pipe installed in a pipeline being operated at a maximum hoop stress of 30% of SMYS or less, it would be possible to say that any such defects are non-injurious and are no threat to pipeline integrity (barring degradation or interaction with other failure mechanisms).

The review of the 1,318 incidents revealed that 43 incidents (3.3%) were caused by pipe defects and pipe seam defects. Rupture was reported in 20 incidents with pipe lines operating at hoop stresses as low as 16.5% SMYS. Some of these ruptures also occurred in pipelines that were not subject to a hydrostatic test prior to service. Instead the maximum allowable operating pressure (MAOP) has been "grandfathered" by 49 CFR (Code of Federal Regulations), Part 192. However, as only 3 of the 1,318 reportable incidents (0.2%) were reported as rupture and due to the possibility of misreporting, the GTI report conducted a careful analysis of these data which suggested that these pipe defects and pipe seam defects are not likely to affect pipelines operated at hoop stress levels of 30% of SMYS or less. The GTI report recommended that "If the operator's records show that the pipe material is an API line pipe material that had been subjected to the manufacturer's hydrostatic test to a minimum of 60% of SMYS, and the pipeline is operated at a hoop stress level not exceeding 30% of SMYS, then pipe defects and pipe seam defects need not be considered threats to pipeline integrity even if the pipeline has not been subjected to a hydrostatic test to at least 1.25 times its maximum operating stress level.". This conclusion is obviously valid for non API line pipes if Company Specifications and records indicate that the line pipe had a mill hydrostatic test of 60% SMYS or higher.

The only construction defect category that is clearly relevant to the leak/rupture boundary criteria in terms of hoop stress is "previously damaged pipe". Mechanical damage can happen during shipping and handling of the pipe or during installation, e.g. rock damage, prior to the line being in service. The GTI report highlighted that 43 of the 1,318 incidents (3.3%) were caused by previously damaged pipe, 30 of which were reported as ruptures. Five (5) ruptures occurred at hoop stresses below 30% of SMYS. Two of the ruptures were in the circumferential direction, and therefore, not driven by the hoop stress. The remaining three ruptures were of relatively short length indicating that the ruptures were limited to the original defect dimension and that they did not propagate.

AGA Study on Pressure Reversals in ERW Pipe

A "pressure reversal" is a phenomenon where a pipeline survives a hydrostatic proof test pressure only to fail in-service at a lower operating pressure, or where a pipeline fails during the pressure up to test pressure or soon after achieving test pressure, and then subsequently fails at a lower pressure during the next test attempt. The explanation is that crack growth to just near failure in the first proof test, depending on the unloading and the subsequent loading pressure failure can happen as low-cycle fatigue. The percentage difference between the proof pressure and the service pressure defines the magnitude of the pressure reversal. A definitive report of research funded by the AGA NG-18 line pipe committee, Report No. 111 [9], investigated this phenomenon based on published literature, reported incidents, and full-scale tests. Report No. 111 highlighted two trends based on the review of the case studies: that the reversal is more common on lines subject to repetitive proof tests, and that they are mostly associated with ERW manufacturing seam defects.

The AGA report pointed out that the maximum recorded service pressure reversal was 62 percent (on the fifth pressure test attempt), and was a rupture, in low toughness line pipe. The maximum pressure reversal in the AGA full-scale experiments was 25.2 percent in normal toughness line pipe which failed as a leak. Therefore, the AGA study recommends a minimum factor of 1.25 between the proof test pressure and the service pressure. As far as this current study is concerned, for lines that are manufactured post-1941, and therefore assumed to be subjected to a mill test pressure of 60% SMYS or more, and operating at stress levels of 40% of SMYS or less, 1.25 factor is met and failure due to pressure reversal should not be a concern.[2] The same holds for pipes that were manufactured prior to 1941 if reliable company records show that the installed pipe had received a mill hydrostatic test of 60% SMYS or higher.[3]

Ongoing Kiefner Analysis on Pressure Cycle Fatigue in Gas Pipelines

Kiefner have been performing numerous analyses of pressure cycle fatigue, mainly in liquid pipelines historically, but also natural gas pipelines more recently. The emphasis on liquid pipelines was due to failures from manufacturing defects that have been enlarged by pressure-cycle-induced fatigue having occurred on prior occasions in liquid-petroleum-products pipelines and crude-oil pipelines. No such failure had been confirmed in a gas pipeline until 2011 [10]. The incident involved a rupture in a 30-inch diameter 0.375-inch pipeline operating at hoop stress of around 48% SMYS since 1956 and resulted in fire, property damage, fatalities, and injuries. The rupture was caused by a fracture that originated in the partially welded longitudinal seam of a "pup". A zone of ductile tearing at the root of the unwelded portion of the seam enlarged due to pressure cycles. The fabrication of the pup would not have met generally accepted industry quality control and welding standards in effect.

The comparative absence of known pressure-cycle induced fatigue failures in natural gas pipelines relative to the experience of liquid pipelines can be attributed to the fact that gas pipelines are exposed to significantly less aggressive pressure cycling in service than liquid

[2] The mill test is discounted because its brief duration may not allow near-critical defects to fail. We discount it for the same reason that the recommended "spike" hydrostatic test is 10% above the long-term hold pressure. Tests in Reference 9 showed that tearing in pressure tested defects did not occur below 90% of the burst pressure for ruptures, but the threshold was closer to 85% for leaks. The target operating stress limit would then be 0.85x60%/1.25 = 40.8% SMYS which we rounded to 40% SMYS.
[3] We consider "reliable" to mean that it is reasonably possible to conclude what standard pipe actually present in the pipeline was manufactured to and when. Standards for documentary reliability may vary.

pipelines. While this “pup” piece is not representative of the majority of natural gas pipelines already installed, even older vintage ones, it made a case that should be addressed. A study by Kiefner [11] in 2004 found times to failure for the hypothetical seam defects that ranged from 170 years to more than 400 years when the defects that would have barely survived a hydrostatic test to 100 percent of SMYS were subjected to the typical gas-pipeline pressure histories. However, the fatigue life can be shorter if the ratio of the hydrostatic test level to the operating stress level is lower than 1.25. This was demonstrated in illustrative analyses in the 2007 report to DOT on stability of manufacturing and construction defects [12].

Ongoing Kiefner analysis of pressure cycle fatigue in gas pipelines based on actual pressure spectra is given in Figure 12. The figure suggests that pipelines operating at hoop stress of 25% of SMYS or less have a fatigue life of more than 100 years. As a matter of fact, all cases were reaching the 500 years limit of the program except for two cases where the pre-service hydrostatic test pressure to operating test pressure was around 1.6. (Lower operating stresses require larger test pressure ratios due to the fact that the size of flaw surviving a test is a function of the absolute test pressure, not test pressure ratio. Larger flaws grow more rapidly than small flaws subjected to the same operational cycles.) If the mill test pressure was used in the analysis, the life would be significantly longer. This is because, as highlighted previously, all API 5L line pipes manufactured after 1941 and operating at 30% of SMYS or less would have a mill test pressure to operating pressure ratio more than 2.

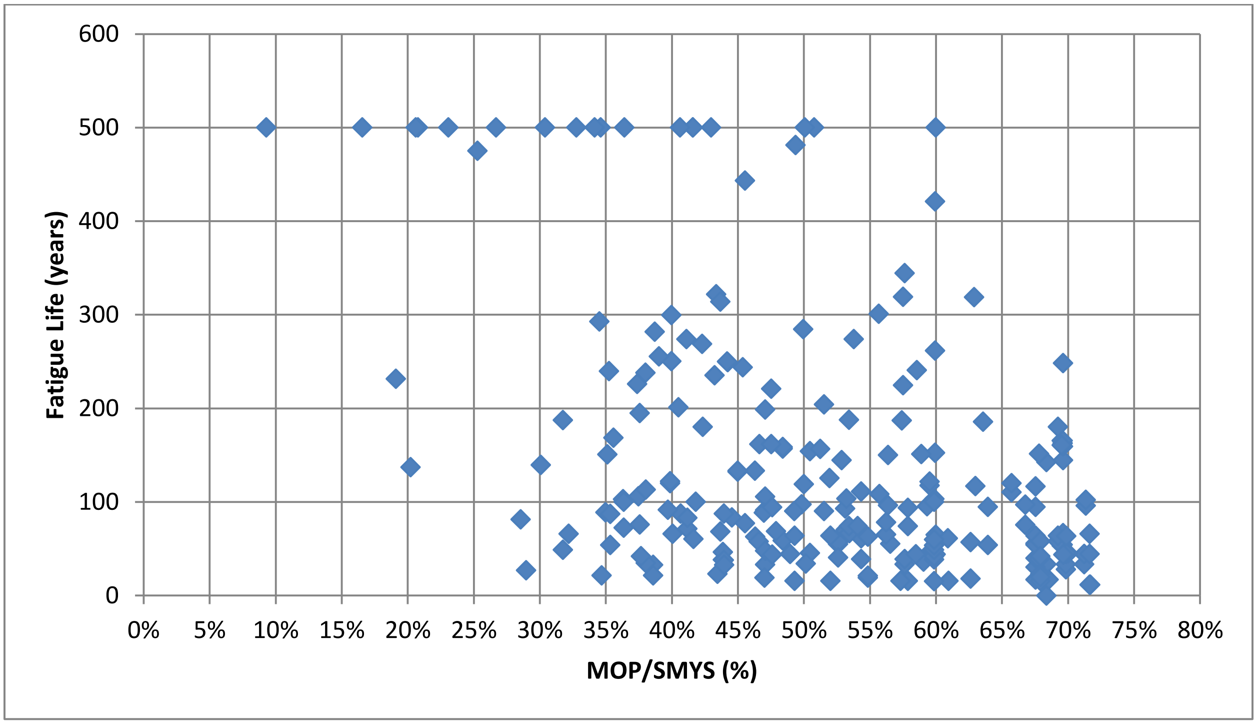

Figure 12. Fatigue Life Due to Pressure Cycles in Gas Pipelines Based on Ongoing Kiefner Analysis of Actual Pressure Spectrums

This fatigue life due to pressure cycles might be shortened if defects are enlarged or initiated after mill hydrostatic test before the line is put in service during transportation, in the phenomenon called transit fatigue. (It is sometimes referred to as rail-shipment fatigue but it can also affect pipe shipped by cargo vessel or by truck.) This was observed in a number of failures at field pre-service hydrostatic testing as well as in-service failures specifically with pipes having large diameter to wall thickness exceeding 70. However, API specifications controlling the method of shipment to reduce the possibility of this phenomenon, which adopted practices already used by major pipeline companies, have been in existence for many years [13]. In any case, and regardless of the original manufacturing defect being enlarged due to transportation loads or pressure loads, the final mode of failure whether a leak or rupture will be governed by the same criteria of the ductile fracture initiation and ductile fracture propagation discussed in the review of the GTI Study.

PHMSA Reportable Incident Database

Raw data of 4 PHMSA incident report databases for distribution and transmission pipelines for the period between 2004-present were analyzed [14-17] to investigate boundaries between leaks and ruptures for manufacturing and construction defects that failed due to pressure hoop stress. Elimination of failure types that are not clearly classified as either leak or rupture (i.e.

mechanical puncture, other, N/A, blanks) resulted in total of 591 leak incidents vs. 337 ruptures. The results are presented in Figure 13 through Figure 18.

Figure 13 presents the PHMSA leak vs. rupture cases in terms of operating stress ratio to SMYS for all causes of incidents. While the figure shows that there is no stress threshold below which rupture will not occur considering all causes, it is clear that ruptures trend with higher operating stress ratios than leaks. As this current study is concerned with manufacturing and construction defects that fail due to pressure hoop stress, it was necessary to filter the results. The filtration was at three levels: rupture orientation, failure details and failure causes. For the rupture orientation, all circumferential ruptures were filtered out as it was clearly not relevant to hoop stresses. For the failure details, any defect not related to manufacturing or construction was eliminated such as corrosion or environmental cracks. There was one incident that was reported to have initiated at an original manufacturing defect, but was thought to have been disturbed by an unspecified outside force, and therefore, it was also eliminated (*incident no. 20090066*).

The third filtration was for failure causes not relevant to this current study, namely degradation or events that occur later in service such as selective seam corrosion, third party excavation damage, impact from vehicles, outside natural forces, and the like. The most challenging to eliminate was the previously damaged pipe as it could have happened during construction/installation or during service. The cases where the narratives explicitly stated that the damage happened during construction/installation were kept in the analysis. The cases where the narratives explicitly stated that the damage happened during service were eliminated. There were cases where the narratives stated that failure investigation reports suggested that previous mechanical damage happened during service were also eliminated although no operation records of such occurrence existed (*incidents no. 20110231, 20110294, 20120073, 20120087, 20130021, and 20130067*).

Figure 14 for the filtered results showed that no rupture incident was reported because of manufacturing or construction defect failing at hoop stresses of 35% of SMYS or less. On the other hand, leaks have been observed in very low stresses approaching zero. This observation is independent of pipe material grade, pipe toughness, or pipe geometry. It is also in agreement with the theoretical analysis discussed in the GTI report that suggest a leak rupture boundary of 30% SMYS for most combination of pipe material and geometries.

Figure 15 and Figure 16 test for the leak/rupture boundary in the PHMSA database based on the pipe size. While Figure 15 shows no boundary exists considering all possible causes of incidents, Figure 16 suggests that pipelines of NPS 6 or smaller having manufacturing or construction defects will only fail as leaks rather than ruptures. This is in-line with the theoretical analysis presented in Table 1 which showed that pipe sizes from NPS ½ to NPS 6 will only fail as leaks.

Finally, the relationship of the leak/rupture boundary to diameter-to-wall thickness ratio is presented in Figure 17 and Figure 18. Again no distinction could be established for all causes of rupture, but for ruptures due to manufacturing defect failing by the action of hoop stress pipes with diameter-to-wall thickness ratio less than 40 will only fail as leaks. The figure also suggests an upper boundary on the ratio at 80, but no technical reasoning could be given.

Figure 13. PHMSA Reportable Leaks Vs. Ruptures in Terms of Operating Stress Percentage of SMYS for All Incident Causes

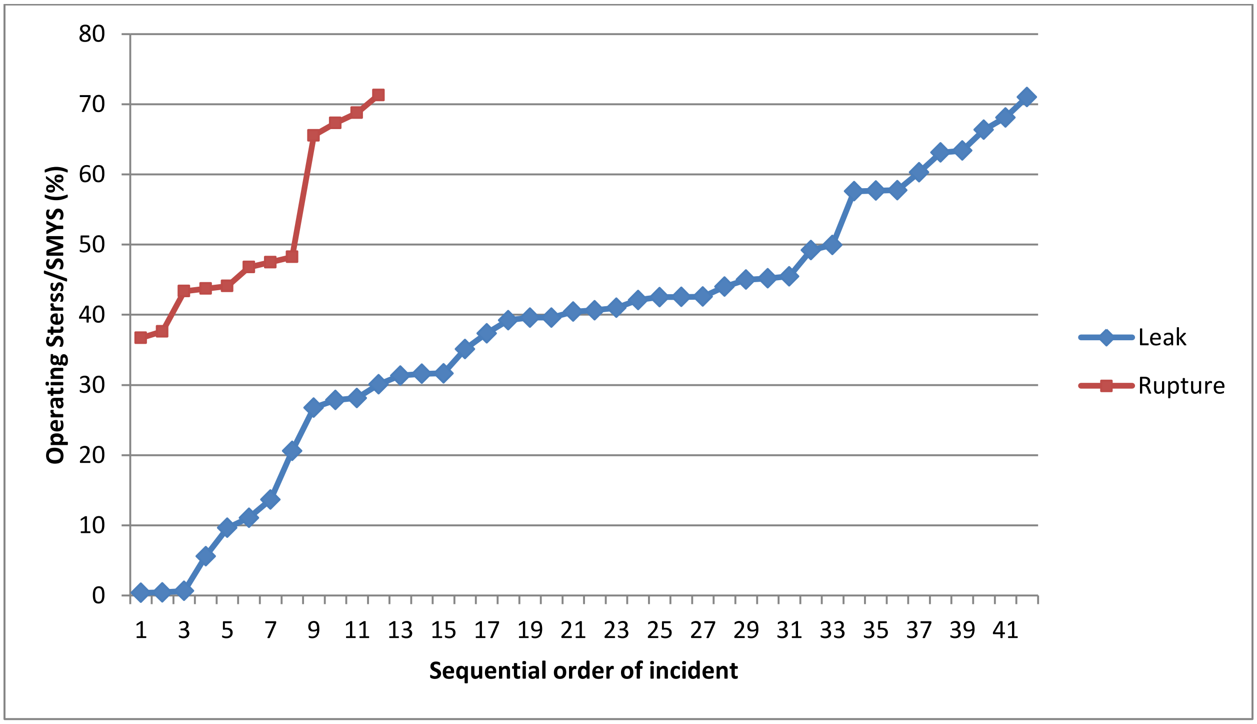

Figure 14. PHMSA Reportable Leaks Vs. Ruptures in Terms of Operating Stress Percentage of SMYS Filtered for Manufacturing Causes Relevant to Hoop Stress

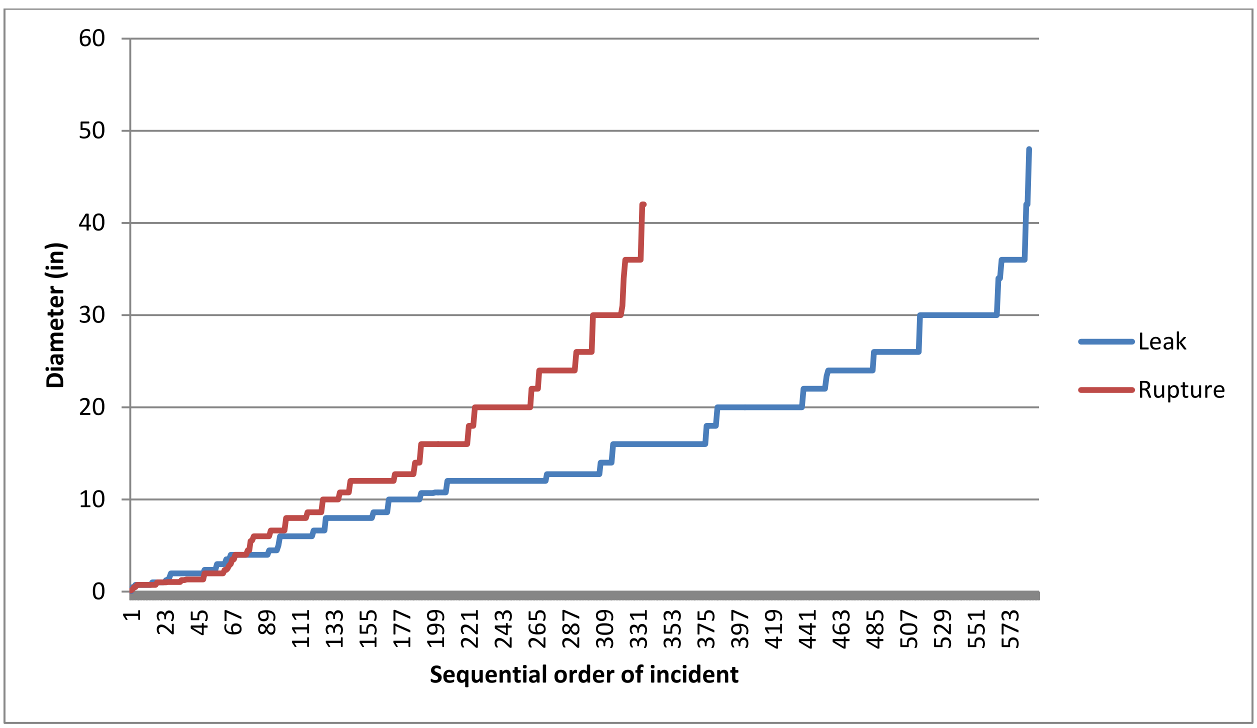

Figure 15. PHMSA Reportable Leaks Vs. Ruptures in Terms of Pipe Diameter for All Incident Causes

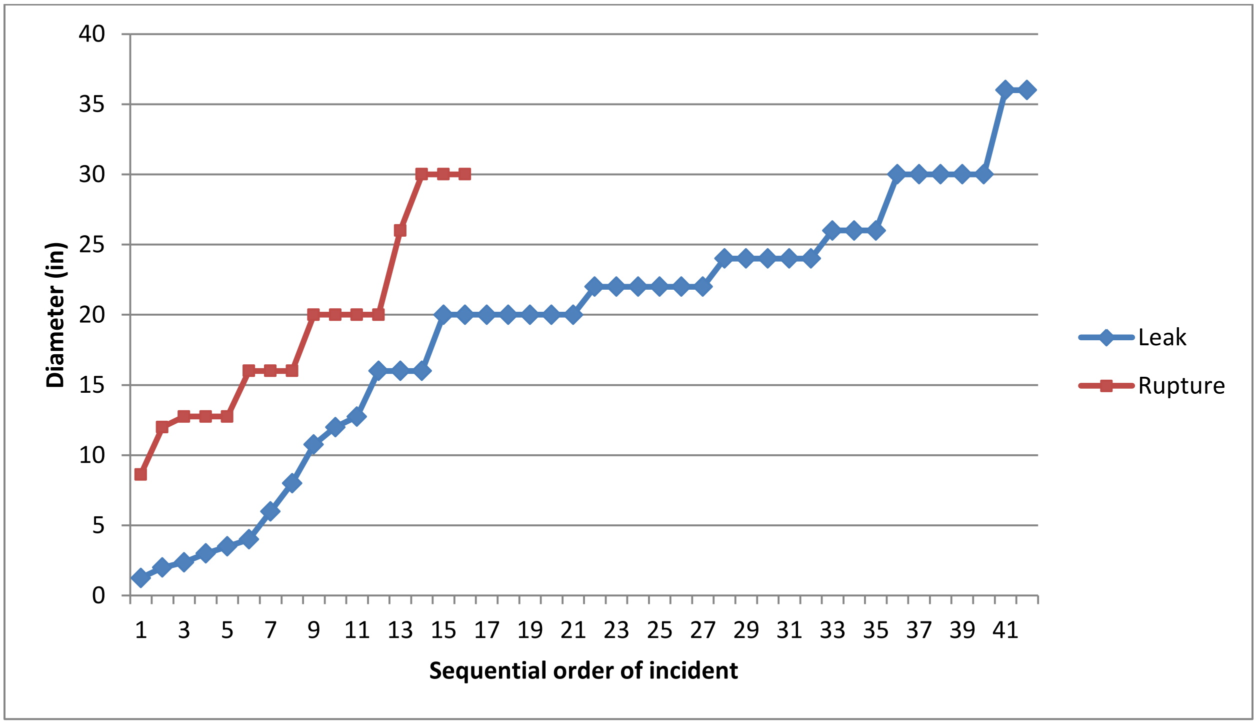

Figure 16. PHMSA Reportable Leaks Vs. Ruptures in Terms of Pipe Diameter Filtered for Manufacturing Causes Relevant to Hoop Stress

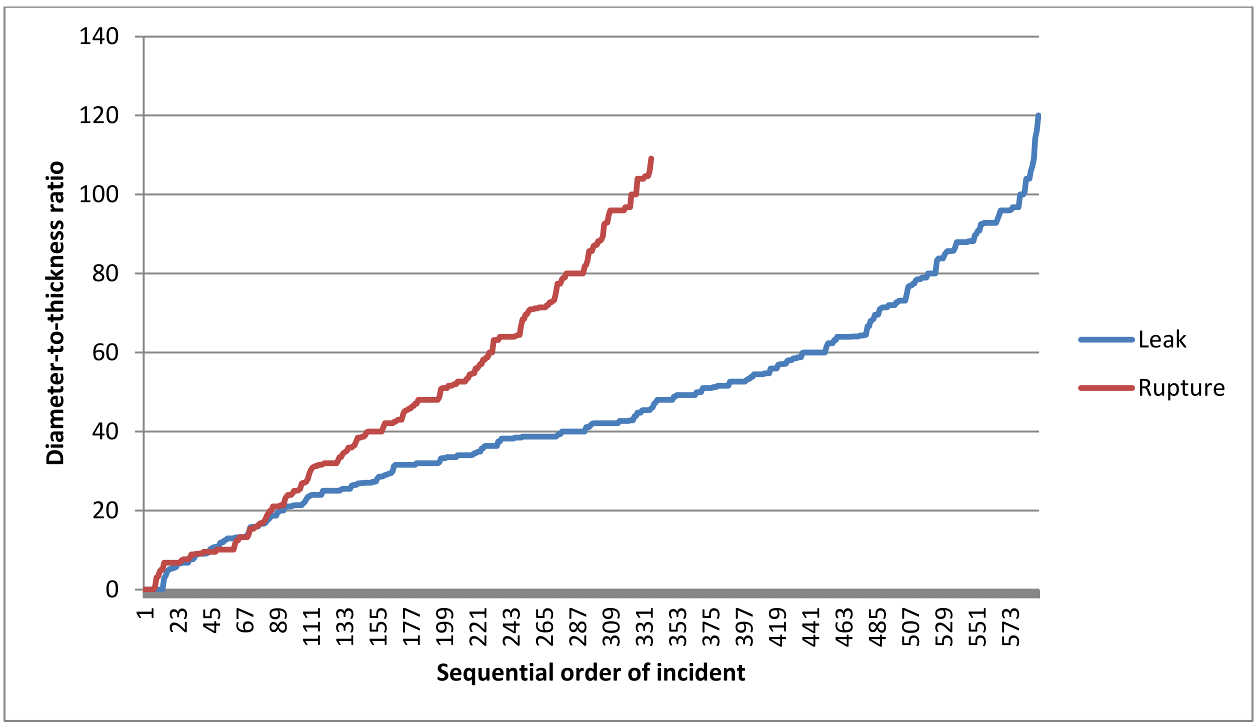

Figure 17. PHMSA Reportable Leaks Vs. Ruptures in Terms of Pipe Diameter-to-Thickness Ratio for All Incident Causes

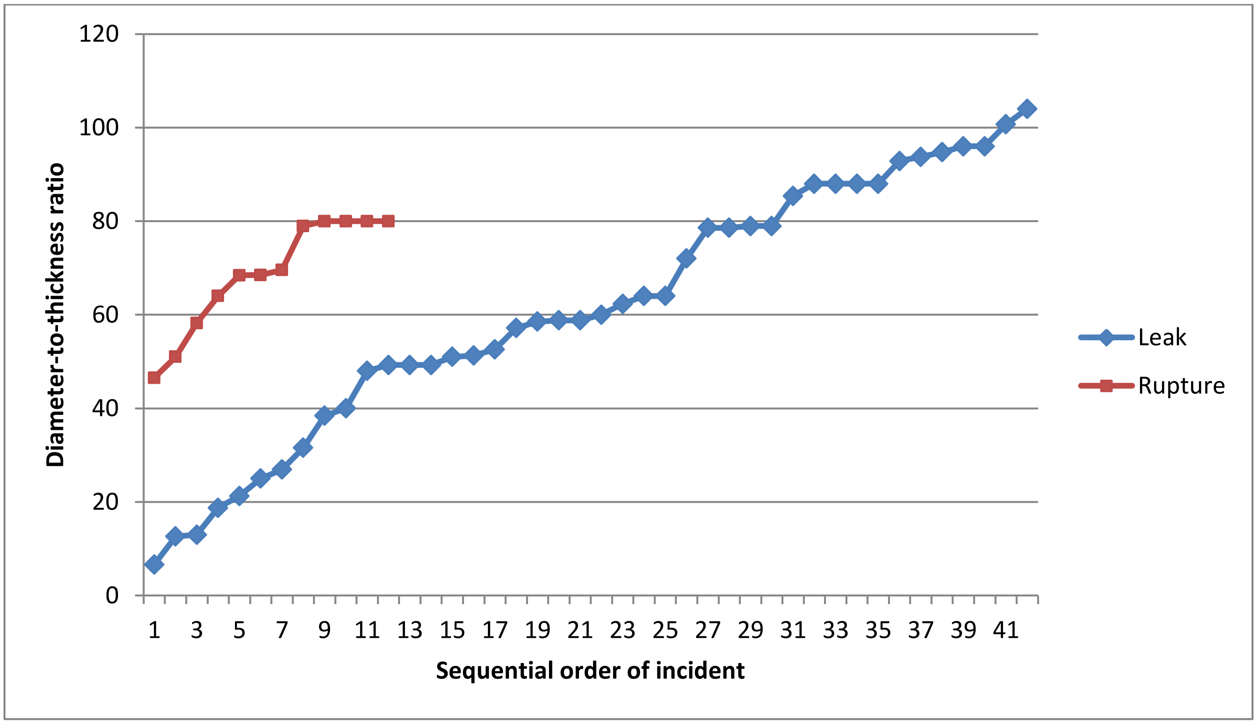

Figure 18. PHMSA Reportable Leaks Vs. Ruptures in Terms of Pipe Diameter-to-Thickness Ratio Filtered for Manufacturing Causes Relevant to Hoop Stress

Kiefner Failure Investigation Database

A total of 312 Kiefner failure investigation reports written between 1992 and 2013 were reviewed to investigate boundaries between leaks and ruptures for manufacturing and construction defects that failed due to pressure-induced hoop stress. A total of 312 failures were reviewed, out of which 141 were leaks while 171 were ruptures. Unlike the PHMSA database, the ruptures outnumber the leaks. One reason for this is that the Kiefner failure investigations included failures during hydrostatic tests which are not reportable to PHMSA. The results are presented in Figure 19 through Figure 24.

Figure 20 presents the Kiefner database leak vs. rupture cases in terms of operating stress ratio to SMYS for all causes of incidents. Similar to the PHMSA database, there is no stress threshold below which rupture will not occur considering all causes. Therefore, filtration to isolate failures at manufacturing or construction defects caused by hoop stresses was necessary and is presented in Figure 20. The filtered cases show that only one incident out of 94 failed as a rupture at a hoop stress less than 30% of SMYS, specifically at 27% SMYS, during hydrostatic testing. The cause of the failure was a manufacturing defect, specifically a cold weld in the seam. The pipe was NPS 10 x 0.250-inch wall thickness, grade B, low-frequency ERW seam pipe installed in 1956 (Kiefner Report No. 06-129). The detailed Kiefner investigation report stated that the pipe had limited ductility, but the CVN value was not given. CVN value of 5 ft-lb is calculated based on the Maxey's arrest formula to cause ductile rupture due to a hoop stress as low as 27% of SMYS for this specific pipe grade and geometry.

Figure 20 and Figure 21 investigate the leak/rupture boundary based on Kiefner database in terms of the pipe size. While Figure 15 shows that no boundary exists considering all possible causes of incidents, Figure 16 suggests that pipelines of NPS 6 or smaller having manufacturing or construction defects will only fail as leaks rather than ruptures except for three cases. Detailed review of these cases revealed they failed during hydrostatic testing at stress levels higher than 80% SMYS. This is in line with the theoretical analysis presented in Table 1 which showed that pipe sizes from NPS ½ to NPS 6 will only fail as leaks if operating at stress of 30% SMYS or less.

Finally, the relationship of the leak/rupture boundary to diameter-to-wall thickness ratio is presented in Figure 22 and Figure 23. Based on the Kiefner database, no leak/rupture boundary could be established based on the diameter-to-wall thickness ratio.

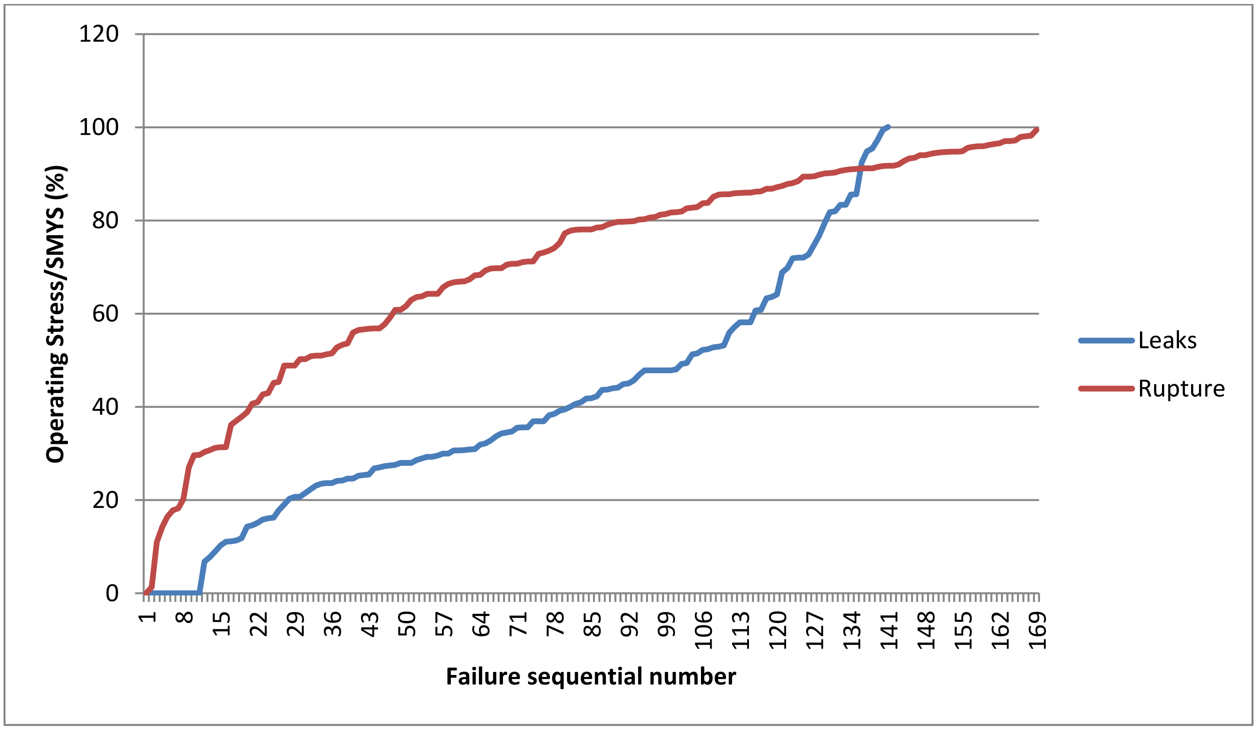

Figure 19. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Operating Stress Percentage of SMYS for All Incident Causes

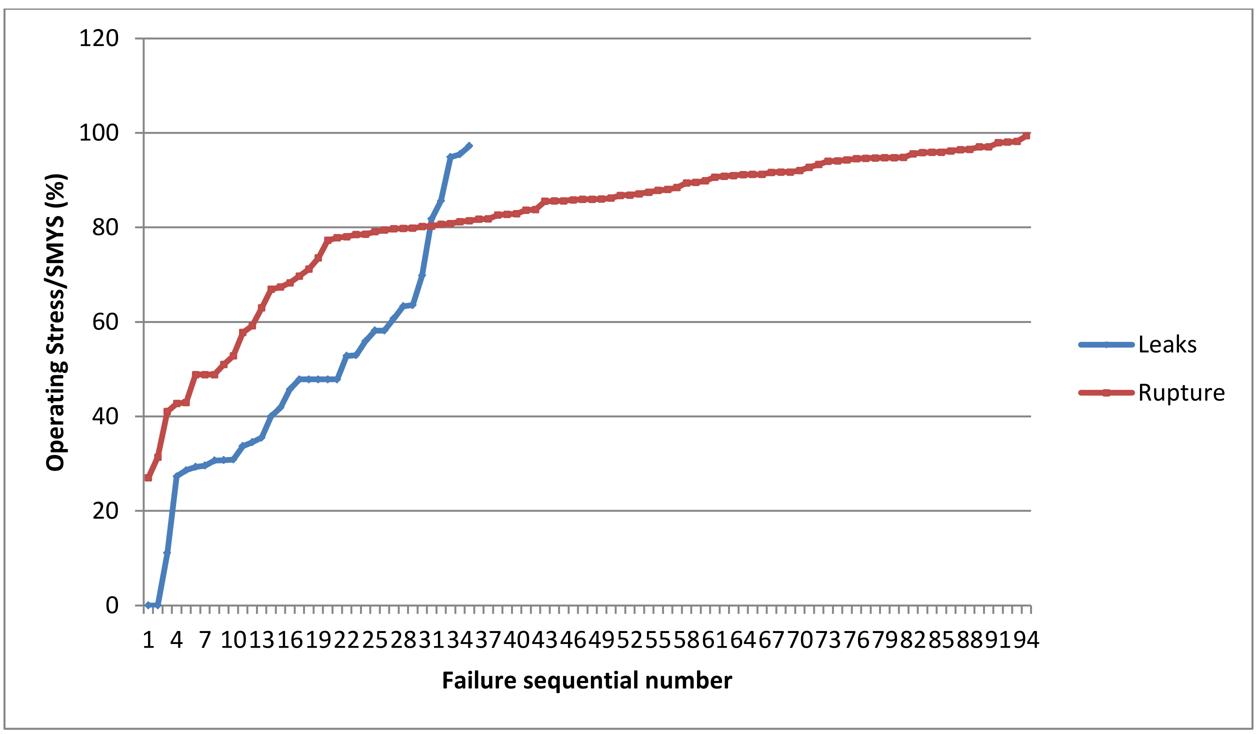

Figure 20. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Operating Stress Percentage of SMYS Filtered for Manufacturing Causes Relevant to Hoop Stress

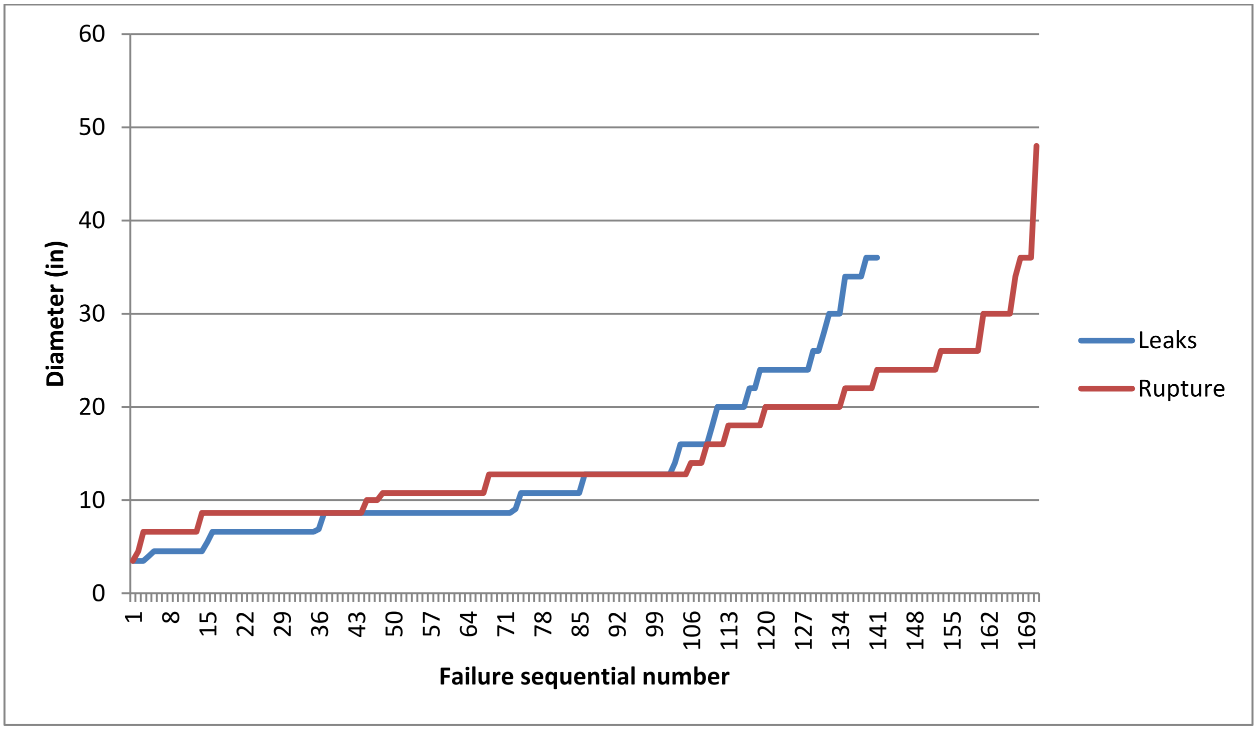

Figure 21. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Pipe Diameter for All Incident Causes

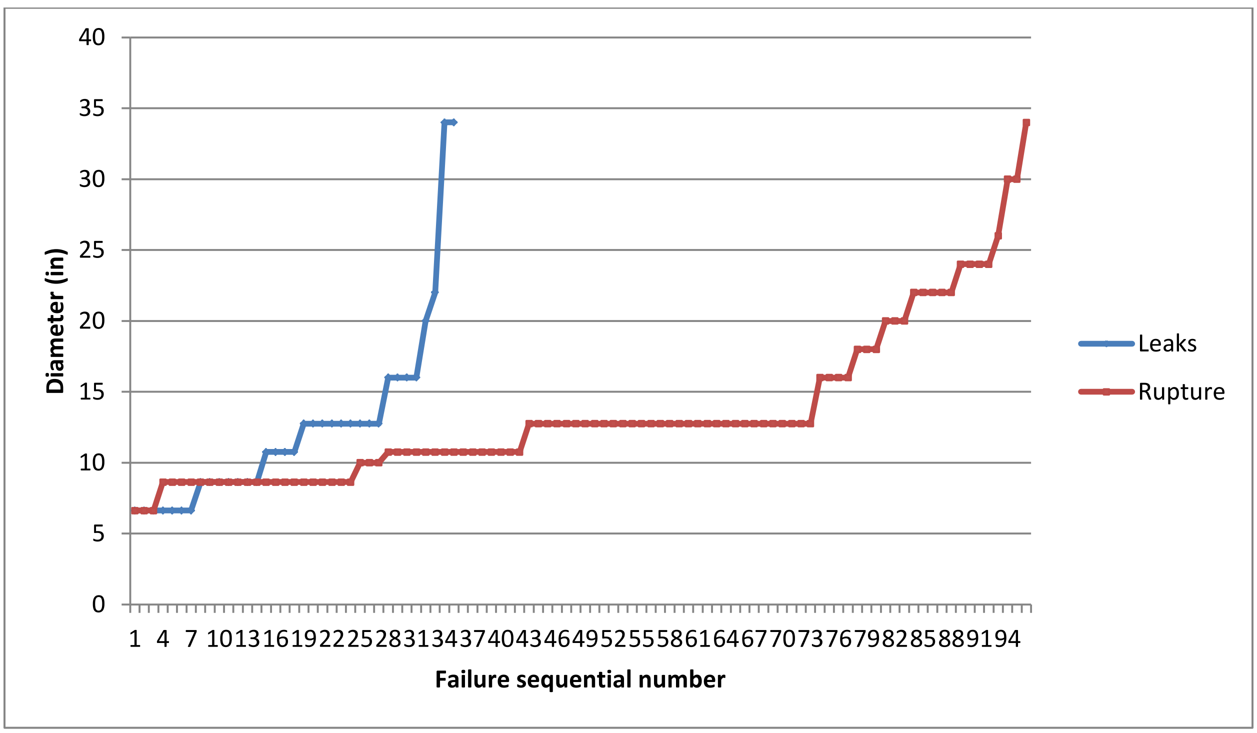

Figure 22. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Pipe Diameter Filtered for Manufacturing Causes Relevant to Hoop Stress

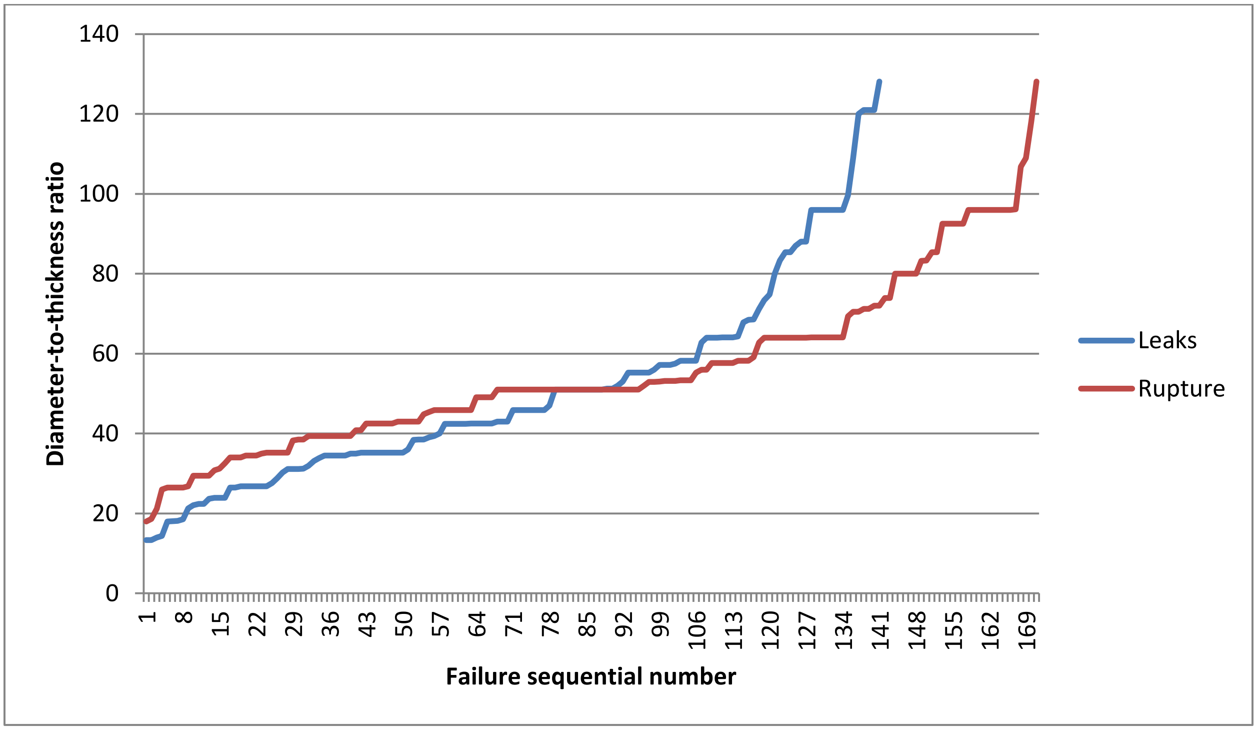

Figure 23. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Pipe Diameter-to-Thickness Ratio for All Incident Causes

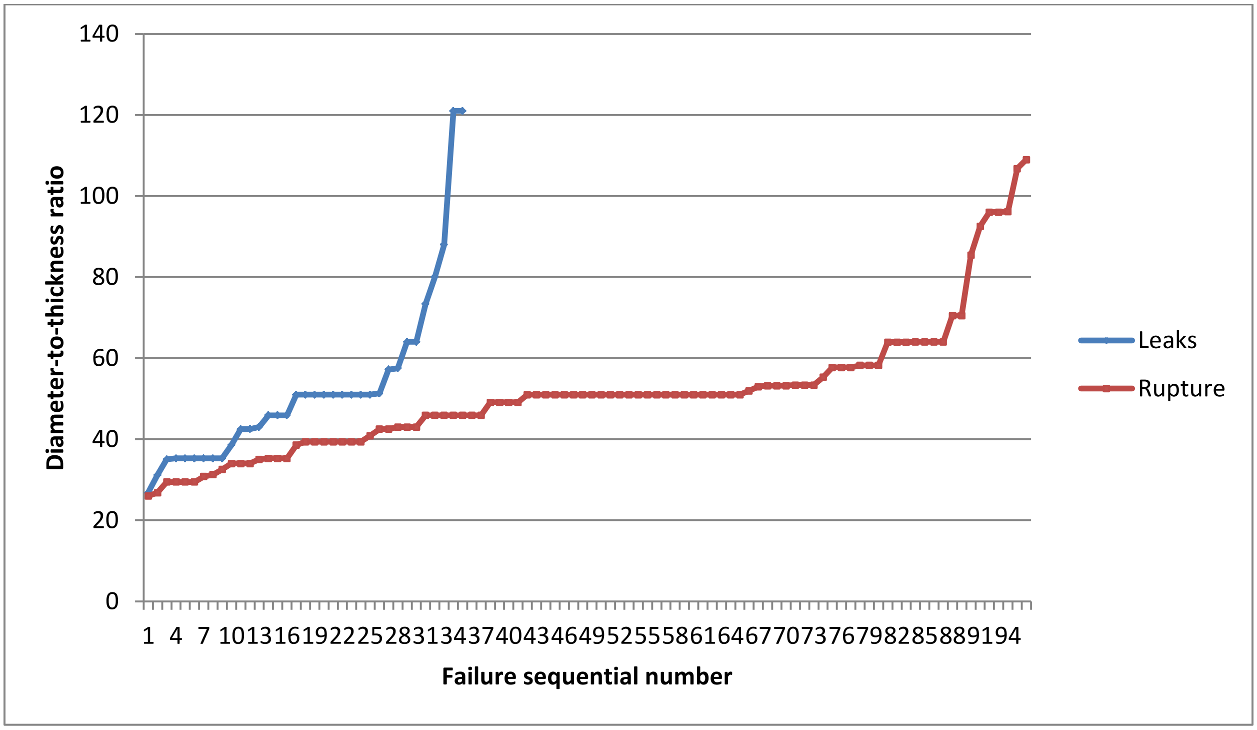

Figure 24. Kiefner Failure Database Leaks Vs. Ruptures in Terms of Pipe Diameter-to-Thickness Ratio Filtered for Manufacturing Causes Relevant to Hoop Stress

SUMMARY

The leak/rupture boundary models are limited to situations where ductile fracture behavior is assured. To avoid brittle fracture initiation, a pipeline must be operated at a minimum temperature at or above the fracture initiation transition temperature of the material. Theoretical models, that are validated by full-scale test and actual incidents, do exist which can be used to establish the leak/rupture boundary conditions in terms of operating hoop stress thresholds.

Thus study referred to a report prepared for the Gas Technology Institute (GTI) that evaluated theoretical fracture models and supporting test data in order to define a possible leak-rupture threshold stress level. The GTI report pointed out that "No evidence was found that a propagating ductile rupture could arise from an incident attributable to any one of these causes in a pipeline that is being operated at a hoop stress level of 30% of SMYS or less. However, data from full-scale pipe burst tests show that ductile ruptures can occur at hoop stress levels less than 30% of SMYS." In this current report, the theoretical model presented in the GTI report was used to identify combinations of pipe material and geometry properties that will always fail as leaks for operating stress thresholds of 20%, 25%, and 30%. Theoretically, lines of 36-inch diameter or smaller operating at 15% SMYS or less will only fail as leaks. Another observation is that pipe with NPS of 6 inches or smaller is predicted to only fail as a leak for operating stress threshold of 30% SMYS or less. These findings are predicated on an important restriction, which is that the material must be capable of initiating fracture in a ductile manner, which has particular relevance to older-vintage ERW pipe.

A major concern is failure due to prior mechanical damage where no reliable leak/rupture boundary could be established in terms of operating stress thresholds. Mechanical damage can occur during construction and installation activities prior to the line entering service. The GTI report highlighted five (5) ruptures of reportable incidents that occurred at hoop stress below 30% of SMYS. Two of the ruptures were in the circumferential direction, and therefore, not driven by the hoop stress. The remaining three ruptures were of relatively short length indicating that the ruptures were limited to the original defect dimensions and that they did not propagate.

Failure due to pressure reversal in ERW pipes, pipe that was manufactured post-1941 and therefore presumably subjected to a mill test pressure of 60% SMYS or more, and operating at stress levels of 40% of SMYS or less, should not be a concern. This is because the ratio of mill test pressure to operating pressure, even discounting the test level owing to the short duration of the test, exceeds the 1.25 margin recommended by the AGA pressure reversal study to avoid such failures. The same holds true for pipes that were manufactured prior to 1941 if company records show that the pipe had received a mill hydrostatic test of 60% SMYS or higher.

If severe pressure cycles are a concern, the hoop stress threshold equal to 25% SMYS or less should give a fatigue life greater than 100 years in natural gas service. This relies on the assumption that the line pipe was subject to the mill test of 60% SMYS or greater. This life might be shortened for pipelines with diameter-to-wall thickness ratio exceeding 70 if a defect that survived that hydrostatic test was enlarged before the line entered service as a result of a phenomenon called transit fatigue caused during transportation of the pipe. In any case, and regardless of the original manufacturing defect being enlarged, the final mode of failure whether a leak or rupture will be governed by the same criteria of the ductile fracture initiation and ductile fracture propagation discussed above.

Based on a review of PMHSA reportable incident data from 2002 to present, boundaries between leak and rupture can be found for manufacturing or construction defects that fail under the influence of the hoop stress. The reportable incident data is in very good agreement with the theoretical analysis. The PHMSA reportable incidents data listed no occurrences of pipe operating at a stress of 35% of SMYS or less failing as a rupture under the influence of hoop stress due to manufacturing and construction defects (excluding low-stress ruptures associated with interacting threats and degradation in service, such as selective corrosion). The mode of failure was as a leak in pipe sizes NPS ½ to NPS 6. The analysis of PHMSA reportable incident data also showed that the leak failure mode is expected where the pipe diameter to thickness ratio is less than 40.

A review of Kiefner & Associates, Inc. (Kiefner) failure investigation reports produced similar observations. All manufacturing related defects failing under the action of hoop stress alone failed as leaks if the hoop stress level was 30% SMYS or less except for one case out of 94 which failed at 27% of SMYS. The Kiefner database supported the conclusions from the theoretical models and was consistent with the PHMSA database regarding leakage as the mode of failure for NPS 6 and smaller and operating at a hoop stress of 30% of SMYS or less.

In view of the above findings, the authors believe that a hydrostatic pressure test to 1.25 times the MAOP is unnecessary to reasonably assure the stability of pipe manufacturing or construction related features for the following conditions:

- Ductile fracture initiation is assured by showing that the pipe has an operating temperature above the brittle fracture initiation temperature;
- Interaction with in-service degradation mechanisms such as selective seam corrosion or previous mechanical damage is absent;
- Hoop stress is 30% of SMYS or less;

- Mill pressure testing was conducted at 60% of SMYS or more, established by documented compliance to applicable pipe product specifications (e.g., API 5L) or company specifications;
- Pipe size is 6 NPS or smaller.

For pipes that are 8 NPS or larger but still meeting the first four conditions mentioned above, there might be merit to hydrostatic pressure testing to 1.25 the MAOP as theoretical analysis as well as full-scale laboratory tests show that failure as a rupture is possible for stress thresholds below 30% of SMYS. However, NPS 8 pipe may be prioritized lower than larger pipe because there were no reported incidents of service rupture in pipe that size where all other criteria were met.

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