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Spike Hydrostatic Test Evaluation

FINAL REPORT

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This report is intended to serve as a technical resource for OPS and State pipeline safety inspectors evaluating operators' integrity management (IM) programs. Inspectors consider information from a number of sources in determining the adequacy of each IM program. Development of this report was funded via a Congressional appropriation specifically designated for implementation of IM oversight. This and other similar reports are separate and distinct from the work products associated with and funded via OPS's R&D Program.

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Executive Summary

This report documents an evaluation of the concept of using a spike hydrostatic test (SHT) as applied to the hydrostatic retesting of existing oil and gas pipelines. A SHT is a test in which the test-pressure-to-operating-pressure ratio significantly exceeds the minimum value of 1.25 required by federal regulations and the duration of which is considerably shorter than the minimum time of 8 hours also required by federal regulations.

Test pressures that result in hoop stress levels between 100 percent and 110 percent of the specified minimum yield strength (SMYS) of the pipe, or in terms of Maximum Operating Pressure (MOP), 1.39 and 1.53, respectively, have typically been used for SHT. These values are all based on the assumption that the pipeline is designed to operate at a hoop stress level equal to 72 percent of SMYS. For cases where operating stress levels are less than 72 percent of SMYS, the concept of SHT is still valid even test stress levels below 100 percent of SMYS are used. However, simply requiring the test pressure to be between 1.39 and 1.53 of the operating pressure does not necessarily result in the best assessment of pipeline integrity.

Two guideline formulae for calculating the appropriate test pressure are given, one if the main concern is pressure-cycle-induced fatigue, and the other for when stress-corrosion cracking (SCC) or selective seam corrosion is suspected. Engineering judgment should be applied before using these formulae when considering a pipeline containing segments of low-frequency electric-resistance welded (LF-ERW) pipe, since testing such lines to 100 percent of SMYS may result in excessive numbers of failures, and therefore careful consideration of the actual desired operating pressure should be made.

The hold time at maximum pressure is also a consideration for SHT. Various hold times are found in the literature, with the most common being between ½- and 1-hour. And while a ½-hour hold time is recommended in this report, discussion provided in this report indicates that the length of hold time has no discernible impact on the effectiveness of a hydrostatic test in establishing an adequate safety margin. The most important consideration is attaining the highest possible test pressure even if for only a few minutes. This philosophy is apparent in ASME B31.8S, *Managing System Integrity of Gas Pipelines*, (ASME B31.8S), which specifies a 10-minute hold time when testing for SCC.

The reassessment interval is another important consideration of SHT. Developing a universal reassessment interval is not possible due to the failure mechanisms and the way degradation of the structural integrity occur. However, methodologies for determining appropriate reassessment intervals for pressure-cycle fatigue and SCC or selective seam corrosion are described.

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1 Introduction

This report was prepared in accordance with the Statement of Work and proposal submitted in response to RFP for Technical Task Order Number 6 (TTO 6) entitled *"Spike Hydrostatic Test Evaluation"*.

This scope entails assessing the concept of using a spike hydrostatic test (SHT) as applied to the hydrostatic retesting of existing oil and gas pipelines. In this context, a SHT means a test in which the test-pressure-to-operating-pressure ratio significantly exceeds the minimum value of 1.25 required by federal regulations and the duration of which is considerably shorter than the minimum time of 8 hours also required by federal regulations. The purpose of conducting a SHT as opposed to, or in addition to a standard regulatory minimum test is to optimize the level of pipeline integrity demonstrated by the test while minimizing the exposure to unnecessary test breaks. An additional subsequent constant-pressure test conducted at a pressure level significantly below the SHT level may be necessary to accomplish an appropriate test for leak tightness. It is generally understood that the short-duration SHT, more effectively than the lower minimum required test, either removes or proves the absence of defects that could affect the serviceability of a pipeline. Following a SHT, a lower pressure leak test of appropriate duration can prove leak tightness of the pipeline without the concern for additional test breaks occurring because of continuing defect growth. The purpose of this report is to establish what ranges of SHT parameters (test-pressure-to-operating-pressure ratios and test durations) are adequate for demonstrating pipeline integrity and serviceability.

The Office of Pipeline Safety (OPS) noted during initial comprehensive integrity management inspections of large liquid pipeline operators that SHT were being conducted utilizing a variety of procedures or formats. Hydrostatic testing has been included in OPS regulations for many years, and therefore the purpose and process for conducting hydrostatic testing are well documented. However, a SHT is not addressed by current regulations nor is there an industry standard for conducting such a test.

This report begins with a background section that describes why the SHT concept meets the "common sense" test. The next section discusses current SHT practices. The brief length of this section highlights the fact that there is limited "standardization" of SHT practices. There are a variety of rational options available to pipeline operators. Selecting a SHT procedure for a specific application involves a compromise between selecting higher test pressures and less-frequent tests versus lower test pressures and more-frequent tests. The appropriate choice is usually a matter of assessing the circumstances and planning a test scenario that best fits.

The original scope of work alludes to discussing SHT concepts for two categories of pipelines. One category envisioned was low-frequency electric-resistance welded (LF-ERW) pipelines. The other original category included pipelines affected by stress-corrosion cracking (SCC) and pressure-cycle induced fatigue. As organization of this report progressed, two slightly different categories were identified as being more appropriate and efficient. Consequently, Section 4 of this report addresses pipelines affected by pressure-cycle induced fatigue, irrespective of the type of line pipe. Section 5 addresses pipelines affected by SCC, irrespective of the type of line pipe, along with LF-ERW that has suffered selective seam corrosion. These categories were selected based upon the type of analysis required in each case. Each of these sections has recommendations for determining the appropriate pressure ratio of test pressure to maximum operating pressure for SHT.

A brief study was performed to show how changing various parameters (pipe diameter, wall thickness, specified minimum yield strength (SMYS) and Charpy V-notch (CVN) toughness values) affect the analysis results.

Finally, the report briefly discusses considerations for pre-1970 LF-ERW pipe and the differences between SHT for liquid and gas pipelines, and also presents a list of references.

2 Background

SHT is hydrostatic testing in which the maximum test pressure is greater than that normally used for compliance with the Code of Federal Regulations (CFR) for commissioning new pipelines or replacement segments, while the duration of the SHT may be significantly less. Hydrostatic tests conducted for compliance with 49 CFR 192 and 195 are normally conducted at a pressure equal to 1.25 times the Maximum Operating Pressure (MOP) of the line being tested for a period of at least four hours. In the case of a pipeline that is not visually inspected for leakage during the test, the pressure test must continue for an additional 4 hours at a pressure of at least 1.10 times the MOP.

The pressure used during SHT is typically equal to 1.39 times the MOP of the line. This value is based on the ratio of 100 percent of SMYS to 72 percent of SMYS (maximum hoop stress). The upper limit is normally set at SMYS due to concerns that higher pressures may result in permanent expansion of the pipe. However, the Canadian Energy Pipeline Association (CEPA) has stated that significant permanent expansion of the pipe would not result from pressurizing up to 110 percent of SMYS, a fact that was established by industry-sponsored research (Duffy, 1968). This is further reinforced by the finding in the American Gas Association (AGA) Topical Report NG-18 No. 194 (Leis, 1992) that a maximum pressure level between 100 and 110 percent of SMYS appears to provide a good balance between removing large flaws that might cause failure in service and producing growth only in a relatively few near-critical flaws. Thus, the pressure for SHT may be as high as 1.53 times the MOP for lines that are designed to operate at the upper limit allowed by 49 CFR.

As for duration of SHT, the AGA Topical Report NG-18 No. 194 found that a maximum pressure hold time of one-hour is a reasonable upper limit, as it causes a very high percentage of the near-critical flaws to fail, while still minimizing the growth of the remaining flaw population. CEPA recommends a one-hour high pressure test between 100 and 110 percent of SMYS, followed by a leak test at no more than 90 percent of the peak test pressure. More recently, ASME B31.8S recommends a SHT hold time of 10 minutes.

Hydrostatic testing has been proven effective in removing defects oriented longitudinally; however, hydrostatic testing has not proven as effective for removing circumferential defects. The difference in effectiveness in removing the two types of defects is related to the magnitude of the stresses that hydrostatic testing imposes on these defects. Longitudinal defects are subjected to circumferential stresses due to internal pressure (hoop stress), while defects oriented in the circumferential direction are subjected to longitudinal or axial stresses. Since the longitudinal component of hoop stress is one-third to one-half the circumferential stress, the stress imposed upon a circumferential defect is only a valid demonstration that the pipeline can withstand the longitudinal stress due to the service pressure and is of little or no value for demonstrating the ability of the pipeline to withstand other externally imposed longitudinal stresses.

2.1 Test-Pressure-to-Operating-Pressure Ratios

Practical experience (Bergman, 1974) and early pipeline-industry-supported research on hydrostatic testing at Battelle (Duffy, 1968) demonstrated unequivocally the role of hydrostatic testing in preventing pipeline service failures. The empirical evidence provided by industry experience and by the pressure tests conducted at Battelle showed that the effectiveness of a hydrostatic test arises from a basic physical principle. That principle is that there is a unique relationship between the stress applied to a structure and the size of defect that will cause the structure to fail at that stress level. The higher the stress level, the smaller the flaw required to cause the structure to fail. From this principle, it follows that the higher the hydrostatic test pressure (HTP) to maximum operating pressure (MOP) ratio (HTP/MOP) the more effective the test is as a demonstration of fitness for service at the MOP.

Figure 2.1, Figure 2.2 and Figure 2.3 illustrate the principle. Each of these figures is based on the same failure-pressure-versus-defect-size relationship for 30-inch outside diameter, 0.375-inch wall, API 5L X52 pipe. The MOP of this pipe at 72 percent of SMYS is 936 psig. Figure 2.1 depicts a hydrostatic test at a maximum pressure of 1,170 psig (corresponding to 90 percent of SMYS), and it represents an HTP/MOP of 1.25, the minimum required test under federal regulations. The shaded band in Figure 2.1 represents the size range of defects that will either be removed by such a test or that did not exist prior to the test. After such a test, only defects with sizes lying above the shaded band can exist. Similarly, Figure 2.2 and Figure 2.3 reveal shaded bands representing higher test pressure levels of 1,300 psi (corresponding to 100 percent of SMYS and HTP/MOP = 1.39) and 1,430 psig (corresponding to 110 percent of SMYS and HTP/MOP = 1.53), respectively. These figures reveal that the representative sizes of defects that survive each of these tests decrease with increasing HTP/MOP.

For example, the “0.5” curve in Figure 2.1 representing the failure pressures of various defects length rises above the shaded band at a defect length of approximately 5 inches. By comparison, the “0.5” curve in Figure 2.2 rises above the shaded band at a defect length of 3 inches, and in Figure 2.3 at a defect length of 1.5 inches. Comparison of the depth/thickness ratios (*a/t* Ratio) at the tops of the three bands for a fixed defect length of 5 inches also illustrates the benefits of the higher HTP/MOP ratios. In Figure 2.1, *a/t* is approximately 0.47. In Figure 2.2, *a/t* is aprroximately 0.34. In Figure 2.3, *a/t* is approximately 0.2. Clearly, the higher the test pressure level, the smaller are the remaining (surviving) defects. The inescapable conclusion is that the higher the HTP/MOP ratio, the more effective a hydrostatic test is as a demonstration of fitness for service.

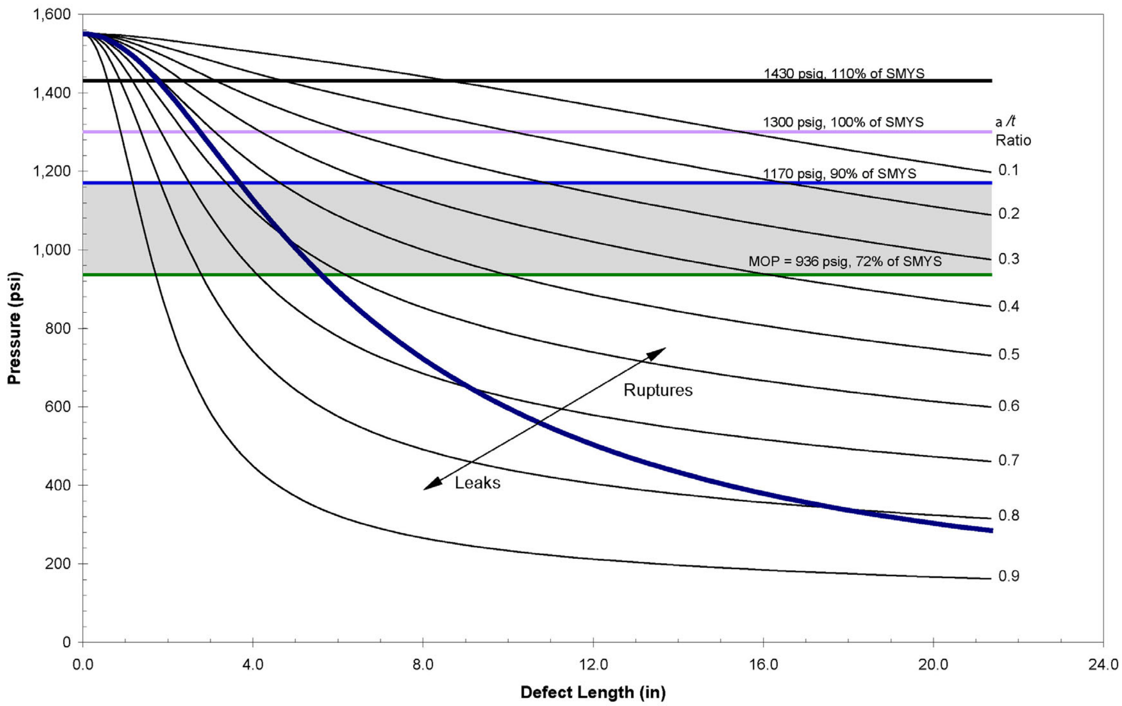


Figure 2.1 Failure Pressure vs. Defect Size Relationship—HTP/MOP = 90/72

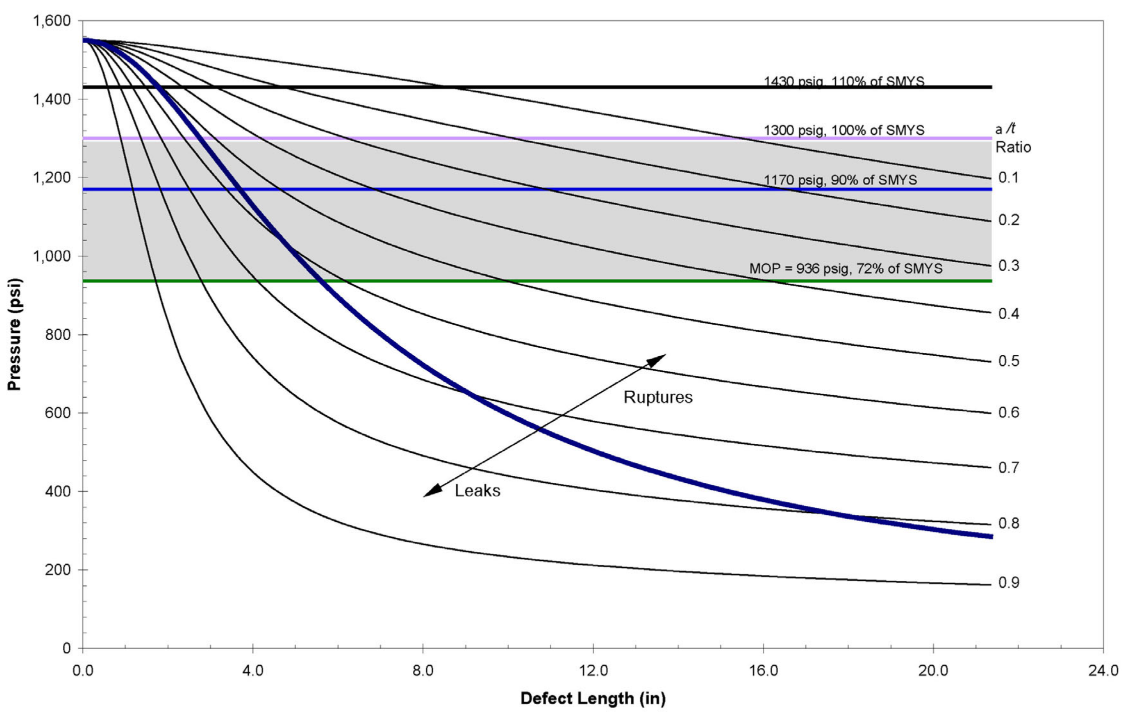


Figure 2.2 Failure Pressure vs. Defect Size Relationship—HTP/MOP = 100/72

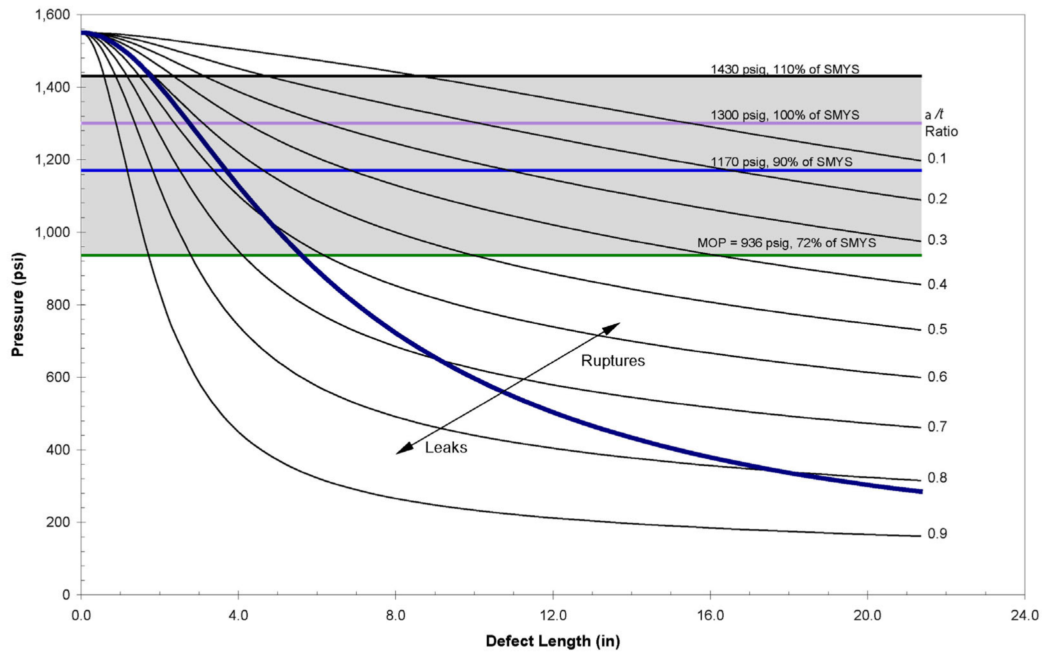


Figure 2.3 Failure Pressure vs. Defect Size Relationship—HTP/MOP = 110/72

2.2 Duration of Hold Time

The residence time at the maximum pressure of a hydrostatic test is characterized as the hold time. The effect of hold time on what is accomplished by a hydrostatic test is highly dependent on the population (number and characteristics) of defects that are present in a section of pipe being tested. Research conducted at Battelle under the sponsorship of the pipeline industry (Kiefner, 1980 and Leis, 1992) demonstrated that the duration of the hold time at a given test pressure level does not contribute to the effectiveness of the test as a demonstration of fitness for service.

As the work described by Leis, et al. (Leis, 1992) and Kiefner, et al. (Kiefner, 1980) showed, a longitudinally oriented, part-through-the-wall defect changes in measurable ways as the test pressure approaches the "failure" pressure of the defect. Strain levels in the material surrounding the defect increase at increasingly rapid rates as the failure pressure is approached. The defective region will bulge radially outward and the defect will begin to tear through the remaining ligament of wall thickness. These changes are irreversible and constitute potential damage with respect to future pressurizations if the pressure is reduced prior to failure of the defect. Once these changes reach a certain level with increasing pressure, they may continue even if the test pressure is held constant. The resulting "creep-like" behavior can be measured using "crack opening displacement" (COD) as the pressure within the pipe containing the defect is held at a constant level.

The implications of this creep-like behavior are illustrated by the hypothetical example presented in Figure 2.4. Hypothetical COD-versus-time relationships for four defects each having slightly different failure pressures are presented in Figure 2.4. The failure pressure of Defect 1 is the lowest such that as the "hold time" begins at "1" on the logarithmic time axis, it is almost ready to fail. In fact, as Figure 2.4 shows, Defect 1 grows to failure in slightly more than 10 minutes after the hold time at constant pressure begins. Defect 2, if held for slightly more than 2 hours, will fail as well. Defects 3 and 4, which are smaller than Defects 1 and 2, will not grow to failure unless held for several thousand minutes (more than 24 hours).

The 10-minute hold time was included in Figure 2.4 since this is the hold time recommended by ASME B31.8S for addressing stress corrosion cracking. Other hold times of up to 24 hours have also been employed by the pipeline industry for hydrostatic testing.

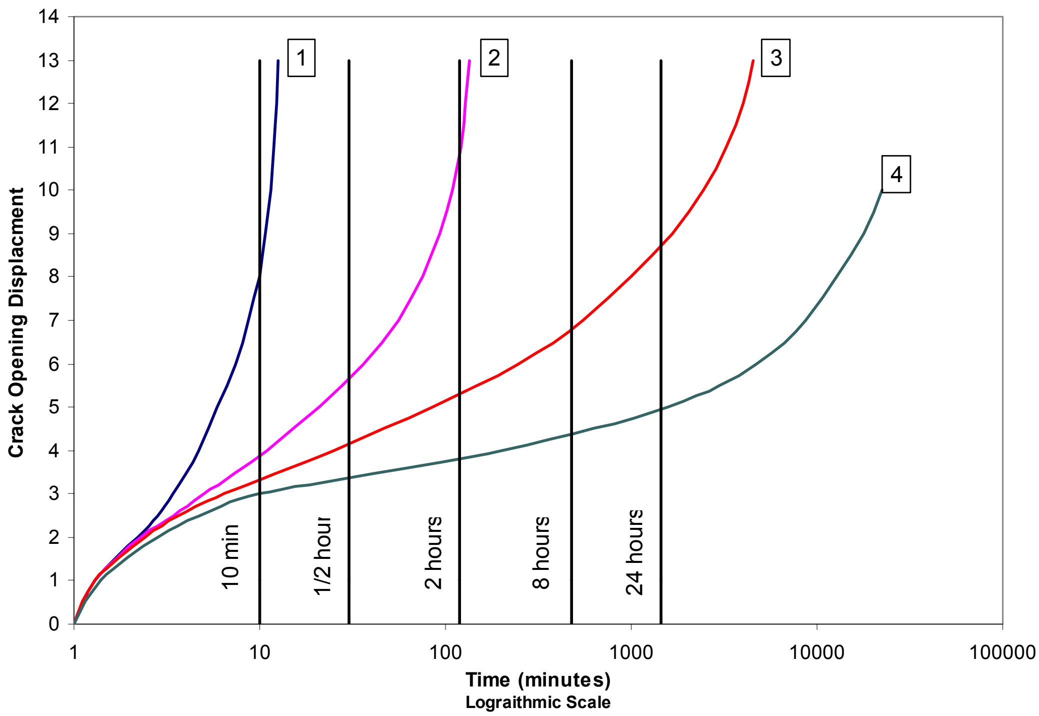


Figure 2.4 COD versus Time

(Note: Information presented is purely hypothetical for illustration only.)

The hypothetical information in Figure 2.4 illustrates why hold time cannot be counted upon to contribute to the effectiveness of a pressure test of a pipeline segment containing a population of defects similar to Defect 1, 2, 3 and 4. The outcome of a ½-hour hold would be that Defect 1 would fail, but Defects 2, 3, and 4 would not. Instead, Defects 2, 3 and 4 would survive the ½-hour test having been strained, and perhaps, though not necessarily, they might not survive another test to the same pressure level.

The outcome of a test with a 2-hour hold time would also be that Defect 1 fails, while Defects 2, 3, and 4 survive. But, the three nonfailing defects have been caused to grow more by the 2-hour hold than they would have been by the ½-hour hold. The growth of Defects 2, 3 and 4 caused by the additional 1-½ hour hold time would likely have a negative effect on the integrity of a pipeline segment with respect to a future pressurization.

The outcome of a test with an 8-hour hold time would be that Defects 1 and 2 would grow to failure. Some may opine that an 8-hour hold time is better than a 2-hour hold time because the longer hold time would remove Defect 2. However, Defects 3 and 4 have grown more than they would have with a 2-hour hold time and significantly more than with a ½-hour hold time. Finally, Figure 2.4 illistrates that a 24-hour hold causes additional growth of Defects 3 and 4 without the benefit of removing additional defects.

These examples from Figure 2.4 illustrate that the best hold time for integrity purposes depends on factors that cannot be known prior to a pressure test, namely, the numbers and sizes of defects that will be affected by the maximum test pressure. Irrespective of the selected hold time one cannot know the status of surviving defects. Therefore, the potential benefit of one hold time over another cannot be assessed.

Hold time at a constant pressure does have value from the standpoint of leak detection. However, as the above example illustrates, holding at the maximum test pressure may or may not be beneficial. It is better to conduct a leak test at a slightly reduced pressure after a satisfactory integrity test has been achieved. The integrity test itself need not be held longer than a few minutes to an hour. One could opine that a ½-hour hold is sufficient for an integrity test. Experiments described by Duffy, et al. (Duffy, 1968) showed that no additional growth of surviving defects would occur after an integrity test level is attained if the pressure level is reduced from the "spike" level by at least five percent.

2.3 Pressure Reversals

From the earliest field experiences with hydrostatic testing, pipeline operators were aware of a phenomenon referred to as a "pressure reversal" (Brooks, 1968). A pressure reversal describes a situation in which a segment of pipe being pressurized fails at a pressure level lower than a level that it has survived on a recent prior pressurization. Research by Battelle (Kiefner, 1980) demonstrated that a pressure reversal occurs because the defect that fails was extended nearly to failure on a prior pressurization, but the pressure was reduced or relieved before the defect had a chance to grow to failure. The phenomenon arises precisely because of the creep-like behavior of near-failure pressure levels illustrated in Figure 2.4. A pressure reversal is schematically illustrated in Figure 2.5. The magnitude of a given pressure reversal is usually expressed as the difference between the highest prior pressure that the defect survived and the pressure at which it eventually fails divided by the previous highest pressure. The pressure reversal phenomenon is associated with one to a very few cycles of pressurization, so that the mode of crack propagation is ductile tearing rather than fatigue crack growth of the type that can occur with hundreds to thousands of pressure cycles typical of pressure fluctuations that occur in pipeline service. Duffy, et al. (Duffy, 1968) showed that pressure reversals of one to a few percent were not that uncommon in hydrostatic tests where tens of dozens of test failures take place. They also showed that the size of pressure reversal is inversely related to its probability of occurrence. Given that a 20 percent pressure reversal would be needed to cause a defect that survived a 90-percent-of-SMYS test to fail at 72 percent of SMYS upon being subjected to service pressure, they concluded that the chance of a pressure reversal causing a service failure was an extremely improbably event. Calculations based on typical pressure-reversal data indicate the probability to be less than one in ten million. Therefore, pressure reversals are not considered to be a significant threat to pipeline integrity.

ChallengeUs.

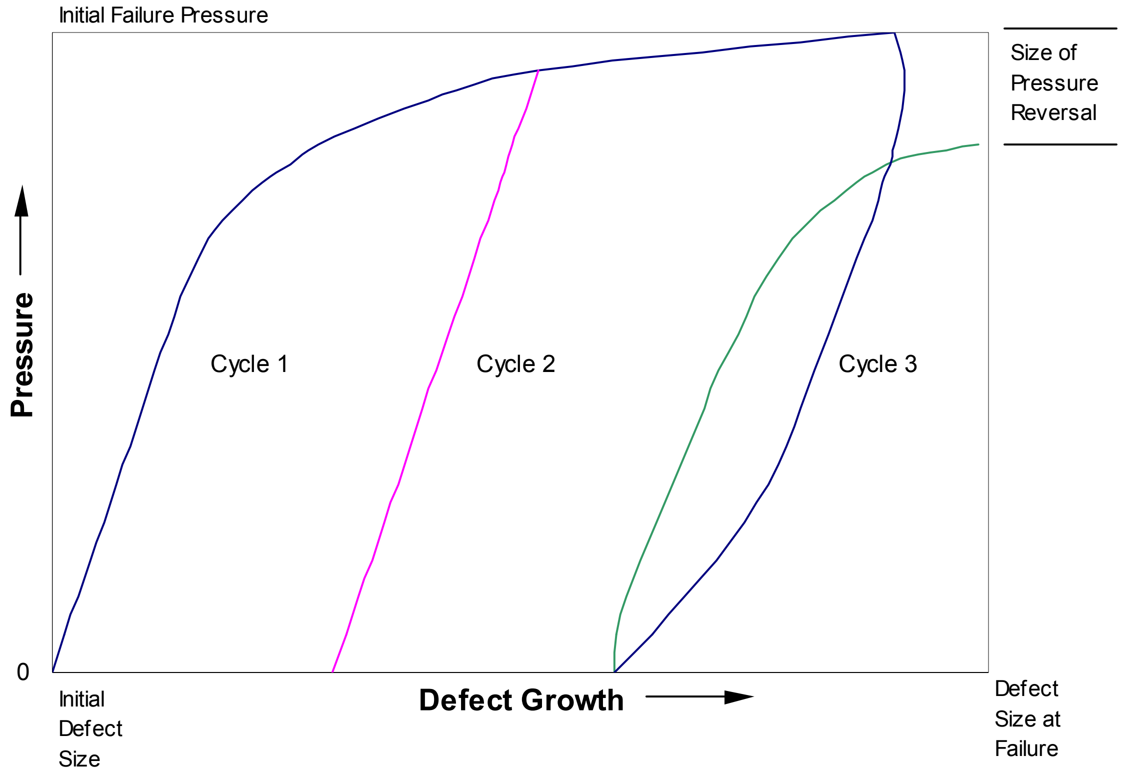
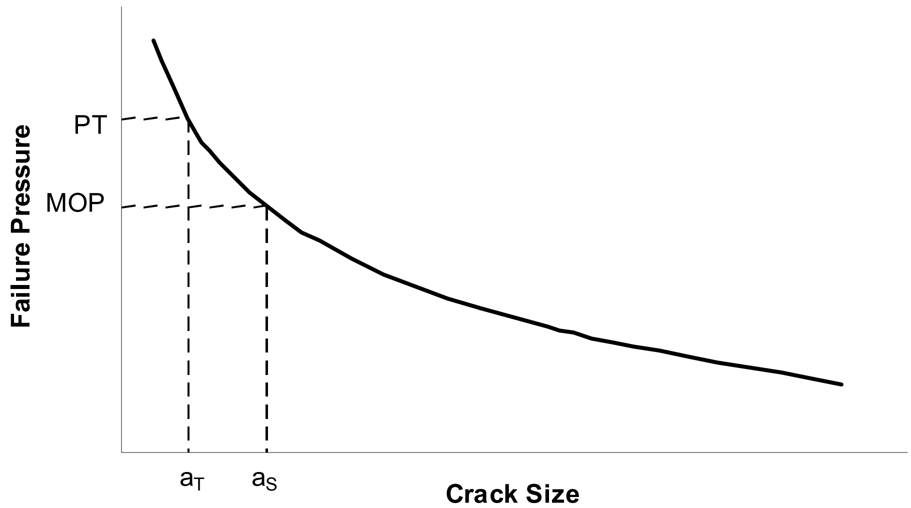


Figure 2.5 Defect Growth and Pressure-Reversal Phenomenon

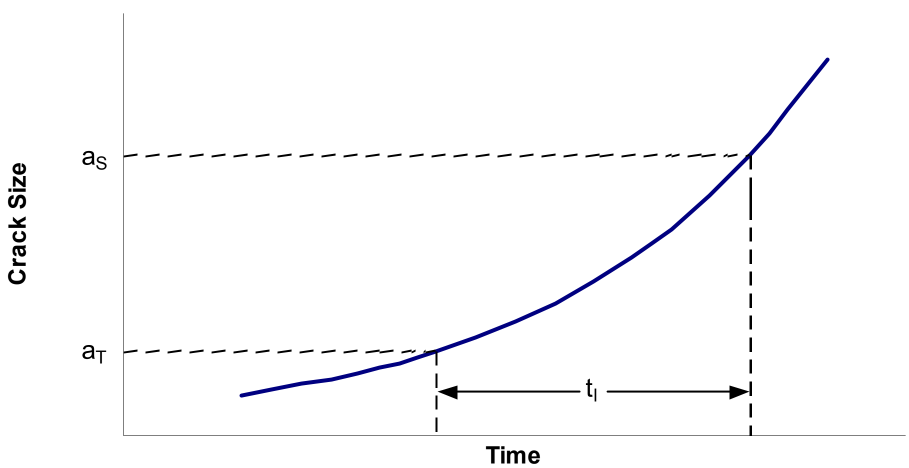
2.4 Test Pressure Level and Retest Interval

The relationship between test-pressure-to-operating-pressure ratio (HTP/MOP) and the frequency of retesting is illustrated in Figure 2.6 (a and b). The fracture mechanics principle discussed previously, namely, the higher the applied stress level, the smaller is the defect that can remain in a structure is illustrated in Figure 2.6. Thus, if an operator conducts a test at the pressure level, PT, the largest remaining flaw can have a crack depth no greater than a_T. At the MOP, no flaw smaller than a_S can cause a failure. Hence, the test assures a safety margin based on the difference between a_T and a_S or between PT and MOP (the same thing as HTP/MOP).

When a mechanism for flaw growth exists (such as SCC, pressure-cycle induced fatigue, or corrosion), then the size of flaws will increase with the passage of time. When the size of the largest flaw reaches a_S, a failure is likely to occur. Timely intervention on the part of the operator (for example the conducting of a hydrostatic retest to the level of the initial test, PT) can eliminate the growing defects and reestablish the maximum surviving crack size as a_T. It is apparent that the larger the HTP/MOP ratio, the longer the interval between retests can be.



a. Failure presure as a function of crack size



b. Crack growth with time

Figure 2.6 Effect of Crack Growth on Pipeline Integrity

3 Review of Current SHT Practices

3.1 Subtask 01 – Scope

This chapter addresses Subtask 01 of the Work Scope that states:

> **Overview:** Review current SHT practices employed by pipeline operators, both generally and specifically for pre-70 LF-ERW pipe seam integrity assessment and for identifying areas of SCC or fatigue related issues.
>
> **Activities:**
>
> a) Research and collate information regarding current SHT general practices.
>
> b) Research and collate information regarding current SHT practices specific to evaluation of pre-1970 LF-ERW pipe.
>
> c) Research and collate information regarding current SHT practices specific to identification of areas of SCC and fatigue.
>
> **Deliverables:**
>
> a) Narrative of general SHT practices
>
> b) Narrative of SHT techniques specific to pre-1970 LF-ERW pipe
>
> c) Narrative of SHT methods specific to SCC and fatigue issues
>
> d) Narrative discussing differences between specific practices

3.2 General SHT Practices

As early as 1979, one of the leading experts on SCC in pipelines at the time, Ray Fessler, was advocating a form of spike testing. The following is a quote from his 1979 paper "Detection and Removal of Stress-Corrosion Cracks from a Pipeline" (Fessler, 1979).

> "From the standpoint of removing other defects, a relatively high pressure—in the vicinity of 100 to 110 percent of SMYS—impressed for a short period of time followed by a hold period at a pressure level 15 to 20 percent lower for a longer time is expected to be optimum for maximizing the safety of the line and minimizing adverse effects to the line".

Fessler's advice is consistent with the principles discussed in Section 2. It is believed that numerous gas pipeline operators adopted this practice following the presentation of the paper if they had not already done so. It is necessary to note that Fessler's advice was predicated on the assumption that the pipelines at issue were being operated at stress levels of 72 percent of SMYS or more. Thus, he stressed the use of spike test pressures in the range of 100 to 110 percent of SMYS. As will become apparent, it is unrealistic to expect that operators of older pipelines containing low-frequency-welded or dc-welded ERW materials to test those pipelines to such levels. Nevertheless, the spike-test principle can be applied to lower test stress levels with significantly beneficial effects.

The Canadian pipeline industry has adopted a recommended SHT procedure consisting of "a 1-hour high-pressure test between 100 and 110 percent of SMYS, followed by a leak test at no more than 90 percent of the peak test pressure" (Canadian Energy Pipeline Association, 1997 and National Energy Board, 1996).

While the above practices allude to the use of an SHT for SCC, pipeline operators have used SHT as parts of return-to-service plans in response to Corrective Action Orders from the OPS on several occasions. In some of these instances, the SHT consisted of a HTP/MOP ratio of 1.39.

At least one pipeline operator has prepared a draft standard for conducting a 1-hour maximum duration SHT that embodies an HTP/MOP ratio of 1.39 at the high-elevation point in each test section. The maximum pressure is limited to 100 percent of SMYS at the low elevation, so that this procedure involves a maximum stress level of less than 100 percent of SMYS for the vast majority of the pipe in each test section. This procedure is designed to be applied to older ERW pipelines among other pipelines within a system, so it is not surprising to see the imposed stress limit. Nevertheless, the SHT concept has merit for reasons discussed in Section 2. For liquid pipelines, the effective margin of test-pressure-to-operating pressure ratio at many locations is actually much greater than the HTP/MOP ratio because a large part of most liquid pipelines are never exposed to pressure levels approaching the MOP owing to the hydraulic gradient.

4 SHT to Assess Pipelines Affected by Pressure-Cycle-Induced Fatigue

4.1 Subtask 03 – Scope

This chapter addresses Subtask 03 of the Work Scope which states:

> **Overview**: Develop practicable SHT criteria for application to identifying areas of SCC and fatigue, including minimum test pressure, as a function of Specified Minimum Yield
>
> Strength (SMYS), and duration for a minimum of three categories of operating pressure. These categories, based on the hoop stress as a function of SMYS are: 72 percent or higher, 50 to 72 percent, and less than 50 percent. Based on the criteria developed and an assumed pressure cycling of one cycle per month, determine a minimum re-test interval for each category.
>
> **Activities**:
>
> a) Evaluate effects of test pressure and duration on critical flaws for each category of operating pressure.
>
> b) Develop SHT procedures for each category of operating pressure.
>
> c) Evaluate effects of postulated pressure cycling on critical flaws for each category.
>
> d) Determine minimum re-test interval based on postulated pressure cycling for each category.
>
> **Deliverables**:
>
> a) Narrative discussing effects of test pressure and duration on critical flaws.
>
> b) SHT procedures.
>
> c) Narrative discussing effects of pressure cycling on critical flaws.
>
> d) Narrative presenting the recommended minimum re-test interval and the process used to determine this interval.

4.2 Discussion

The SHT concept is applicable for the retesting of existing pipelines affected by pressure-cycle-induced fatigue, though the level of hoop stress achievable may not always be as high as 100 to 110 percent of SMYS. This section of the report addresses the impact of both the HTP/MOP ratio and the absolute hoop stress levels (test and operating) on the effectiveness of a SHT from the standpoint of mitigating pressure-cycle-induced fatigue. The approach consists of looking at seven cases of SHT applied to one particular liquid petroleum pipeline. The need for retesting this pipeline arises from the presumption that its operational pressure cycles could produce a service failure as the result of fatigue crack growth of the worst-case hypothetical defects that could survive an initial baseline hydrostatic test. The times to failure are computed using standard linear-elastic fatigue-crack-growth-modeling techniques. The analysis can be easily extended to a gas pipeline where the intensity of pressure cycling would be much lower.

The parameters for the "model" pipeline are presented in Table 4.1, while the HTP/MOP ratios, as well as the corresponding pressures both in psig and percent of SMYS for each case discussed are given in Table 4.2.

Table 4.1 Model Pipeline Parameters

Outside diameter	12.75 inches
Wall thickness	0.250 inch
Grade	X46
SMYS	46,000 psi
Material toughness (full-size Charpy equivalent energy)	25 ft-lb
C (for ΔK in psi $\sqrt{in}$ units)	8.6E – 19
n	3
Pressure cycles	One per day zero to MOP and back to zero

Table 4.2 HTP/MOP Ratios for Pressure-Cycle Fatigue Cases Analyzed

Case	HTP/MOP	HTP		MOP	
		psig	% SMYS	psig	% SMYS
1	1.39	1,804	100	1,299	72
2	1.25	1,624	90	1,299	72
3	1.50	1,353	75	902	50
4	1.39	1,254	69.5	902	50
5	1.25	1,128	62.5	902	50
6	1.625	1,173	65	722	40
7	1.25	902	50	722	40

The first step of the analysis is to determine the critical crack length for a given crack depth that will just survive the stipulated test pressure. This can be done using the NG-18 "ln-secant" equation:

$$\frac{C_V \pi E}{4 A_C L_e \sigma_f^2} = \ln\left[\sec\left(\frac{\pi M_S \sigma_H}{2\sigma_f}\right)\right]$$

where:

E is the elastic modulus,

L_e is an effective flaw length equal to the total flaw length multiplied by π/4 for a semi-elliptical flaw shape common in fatigue,

σ_f is the flow stress typically taken as the yield strength plus 10 ksi or else as the average of yield and ultimate tensile strengths,

σ_H is nominal hoop stress due to internal pressure,

C_V is the upper shelf Charpy V-Notched impact toughness,

A_c is the cross-sectional area of the Charpy impact specimen. (Note that a constant for compatibility of units between C_V and A_c may be necessary.)

The term M_S is a stress magnification factor for a surface-breaking axial flaw, calculated as

$$M_S = \frac{1-(a/t)(M_T)^{-1}}{1-a/t}$$

where

a is flaw depth, and

t is the pipe wall thickness.

The term M_T is Folias' original bulging factor for a through-wall axial flaw, written as

$$M_T = \sqrt{1+1.255\left(\frac{L_e^2}{2Dt}\right)-0.0135\left(\frac{L_e^4}{4D^2t^2}\right)}\text{, for }\left(\frac{L_e^2}{Dt}\right)\leq 50$$

or

$$M_T = 0.032\left(\frac{L_e^2}{Dt}\right)+3.3\text{, for }\left(\frac{L_e^2}{Dt}\right)> 50$$

The results from this step for each case analyzed are presented in Table 4.3 for various crack depth-to-wall thickness ratios.

Table 4.3 Summary of Initial Crack Size Parameters

Case	Initial Crack Lengths in Inches for Various Depth/Thickness Ratios								
	0.9	**0.8**	**0.7**	**0.6**	**0.5**	**0.4**	**0.3**	**0.2**	**0.1**
1	0.65	0.99	1.34	1.75	2.29	3.16	4.92	8.47	13.07
2	0.83	1.30	1.79	2.43	3.39	5.23	8.79	13.67	19.16
3	1.13	1.83	2.68	4.00	6.58	11.26	17.44	24.29	32.00
4	1.26	2.07	3.13	4.960	8.67	14.59	21.70	29.61	38.69
5	1.44	2.44	3.91	6.820	12.39	19.98	28.49	38.34	49.79
6	1.37	2.30	3.59	6.050	10.90	17.92	25.84	34.91	45.42
7	1.86	3.46	6.63	13.48	23.21	34.44	47.93	63.90	76.86

Crack growth is then evaluated using Paris' Law:

$$da/dN = C(\Delta K)^n$$

where:

da/dN is the increment of crack extension per load cycle,

ΔK is the magnitude of stress intensity range for a given load cycle, and

C and n are material properties.

Raju and Newman (Raju, Unknown) give an expression for crack-tip stress intensity for a semi-elliptical surface flaw as:

$$K = \sigma_H \cdot F \cdot \sqrt{\pi \cdot \frac{a}{Q}}$$

where:

$$Q = 1 + 4.595\left(\frac{a}{L_e}\right)^{1.65}, \frac{a}{L_e} \leq 0.5,$$

$$F = M_1 + M_2\left(\frac{a}{t}\right)^2 + M_3\left(\frac{a}{t}\right)^4,$$

$$M_1 = 1.13 - 0.18\left(\frac{a}{L_e}\right),$$

$$M_2 = \frac{0.445}{0.1 + \frac{a}{L_e}} - 0.54, \text{ and}$$

$$M_3 = 0.5 - \frac{0.5}{0.325 + \frac{a}{L_e}} + 14\left(0.5 - 2\left(\frac{a}{L_e}\right)\right)^{24}$$

In this example, since the pressure cycles from zero to MOP and back to zero, ΔK is equal to K at MOP. Note that values for a and L_e change during each pressure cycle and thus values for Q, F, M_1, M_2, and M_3 must be reevaluated after each cycle. The resulting crack dimensions must also be evaluated after each cycle using the "ln-secant" equation to determine whether the crack has grown to critical size.

"Years to Failure" and "Cycles to Failure" for Various Depth/Thickness Ratios are presented in Table 4.4, while final flaw depths and lengths calculated are presented in Table 4.5.

Table 4.4 Summary of Years/Cycles to Failure

Case		Depth to Thickness Ratio								
		0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1
1	Years to Failure	2.21	2.00	1.98	2.14	2.49	3.23	5.33	12.53	39.36
	Cycles to Failure	808	731	723	781	909	1179	1946	4573	14366
2	Years to Failure	0.97	0.90	0.95	1.03	1.23	1.80	3.84	10.94	36.68
	Cycles to Failure	355	327	346	376	448	656	1402	3993	13389
3	Years to Failure	2.06	2.00	1.95	1.85	2.18	4.21	11.73	36.44	123.13
	Cycles to Failure	752	731	711	677	795	1537	4283	13302	44944
4	Years to Failure	1.41	1.39	1.28	1.19	1.58	3.64	11.01	35.18	120.43
	Cycles to Failure	513	509	468	434	577	1330	4018	12840	43956
5	Years to Failure	0.78	0.76	0.64	0.61	1.05	2.95	9.68	32.01	112.15
	Cycles to Failure	284	278	233	223	383	1078	3534	11683	40933
6	Years to Failure	2.99	2.85	2.39	2.05	2.92	7.26	22.46	72.03	245.58
	Cycles to Failure	1090	1039	872	747	1065	2649	8197	26292	89635
7	Years to Failure	0.89	0.70	0.46	0.58	1.54	5.21	18.32	62.26	227.68
	Cycles to Failure	324	255	168	213	562	1903	6685	22725	83103

Table 4.5 Summary of Final Crack Size Parameters

Case		Final Depth to Thickness Ratio and Crack Lengths								
1	Ratio	0.961	0.922	0.876	0.823	0.759	0.679	0.581	0.482	0.399
	Length (in)	0.697	1.032	1.372	1.771	2.303	3.166	4.922	8.470	13.07
2	Ratio	0.944	0.884	0.819	0.745	0.663	0.569	0.475	0.389	0.307
	Length (in)	0.853	1.318	1.803	2.437	3.394	5.231	8.790	13.67	19.16
3	Ratio	0.953	0.901	0.842	0.775	0.701	0.627	0.558	0.490	0.420
	Length (in)	1.148	1.844	2.689	4.004	6.582	11.26	17.44	24.29	32.00
4	Ratio	0.944	0.883	0.816	0.742	0.664	0.588	0.515	0.441	0.366
	Length (in)	1.272	2.079	3.135	4.962	8.671	14.59	21.70	29.61	38.69
5	Ratio	0.931	0.858	0.779	0.696	0.613	0.532	0.451	0.369	0.288
	Length (in)	1.447	2.45	3.912	6.821	12.39	19.98	28.49	38.34	49.79
6	Ratio	0.954	0.903	0.845	0.780	0.713	0.650	0.587	0.523	0.458
	Length (in)	1.384	2.310	3.596	6.053	10.90	17.92	25.84	34.91	45.42
7	Ratio	0.927	0.850	0.770	0.678	0.607	0.526	0.444	0.363	0.307
	Length (in)	1.864	3.462	6.631	13.48	23.21	34.44	47.93	63.90	76.50

Perhaps the easiest way to get at the meaning of the results is to consider Cases 2, 5, and 7 in Table 4.4. Each of these represents a standard pressure test per 49 CFR 192 or 195 (i.e. test pressure of 1.25 times MOP). In Case 2, the pipeline is operated at an MOP corresponding to 72 percent of SMYS. In Case 5, the pipeline is operated at an MOP corresponding to 50 percent of SMYS, and in Case 7, the pipeline is operated at an MOP corresponding to 40 percent of SMYS. Note that the times to failure are not the same for these three cases even thought they were subjected to the same HTP/MOP-ratio test, namely 1.25. The pipeline operated at 72 percent of SMYS (Case 2) has the longest minimum time to failure of the three (0.90 years or 327 cycles) for the 1.3-inch-long 80-percent-through-wall defect. The pipeline operated at 50 percent of SMYS (Case 5) has the second longest time to failure (0.61 years or 223 cycles) for the 6.82-inch-long 60-percent through- wall defect. The pipeline operated at 40 percent of SMYS (Case 7) has the shortest time to failure (0.46

years or 168 cycles) for the 6.63-inch-long 70-percent-through-wall defect. The point of comparing these three cases is to show that the effectiveness of the HTP/MOP ratio is dependent on the absolute test and operating stress levels. The lower the absolute levels, the less effective is a given HTP/MOP ratio.

Next, consider Cases 1 and 2. In both cases, the pipeline is operated at an MOP corresponding to 72 percent of SMYS. As indicated in Table 4.4, the use of an HTP/MOP ratio of 1.39 (Case 1) assures a minimum time to failure of 1.98 years (*a/t* ratio of 0.7) whereas the use of an HTP/MOP ratio of 1.25 (Case 2) assures a minimum time to failure of 0.90 years (*a/t* ratio of 0.8). Thus, an SHT with an HTP/MOP ratio of 1.39 is slightly more than twice as effective as a standard "Subpart E" test with an HTP/MOP ratio of 1.25.

Next, consider Cases 1 and 4. The HTP/MOP ratios are the same (1.39), but the times to failure are not. The minimum times to failure for Case 4, where the pipeline is operated at an MOP corresponding to 50 percent of SMYS, is only 1.19 years (*a/t* of 0.6) whereas that of Case 1 is 1.98 years (*a/t* of 0.7). As in the comparisons of Cases 2, 5, and 7 discussed above, the Case 1/Case 4 comparison shows that the effectiveness of a given HTP/MOP ratio decreases with decreasing absolute stress level.

The final comparison to consider is that of Cases 1, 3, and 6. These three cases reveal the appropriate HTP/MOP ratios to use to achieve about equal times to failure, that is, about equal test effectiveness for the pipeline being operated at maximum hoop stress levels corresponding to 72, 50, and 40 percent of SMYS, respectively. For Case 1, the HTP/MOP ratio of 1.39 yields a minimum time to failure of 1.98 years (*a/t* of 0.7). For Case 3, the HTP/MOP ratio of 1.50 yields a minimum time to failure of 1.85 years (*a/t* of 0.6). For Case 6, the HTP/MOP ratio of 1.625 yields a minimum time to failure of 2.05 years (*a/t* of 0.6).

The results provide useful guidance for operators that may need to perform seam integrity assessments on older ERW pipelines. It is unlikely that an operator would choose to test such a pipeline to a hoop stress level in excess of 100 percent of SMYS. Therefore, a reasonable upper bound or HTP/MOP for a pipeline operated at 72 percent of SMYS would seem to be 1.39. It will be recognized from these results, however, that higher HTP/MOP ratios would be needed to achieve equivalent effectiveness in terms of times to failure for pipelines operated at maximum hoop stress levels below 72 percent of SMYS.

It should be noted that the times to failure presented in Table 4.4 and in the foregoing discussion are illustrative only. They are not meant to imply that a specific test margin is good for only 1 or 2 years, or any other specific time frame. The actual time to failure is dependent on actual pipeline system operation as well as on pipe material crack-growth properties.

4.3 Relative Aggressiveness of Pressure Cycles

An important element in evaluating the effects of pressure cycling on pipeline integrity is the relative aggressiveness of the pressure cycles. One may evaluate relative aggressiveness by comparing the fatigue lives associated with the spectra provided by the operator to those associated with the pressure cycles listed on a benchmarking scale given in *Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe with Respect to HCA-Related Integrity Assessments*

(Kiefner, 2002). The benchmarking list is shown in Table 4.6. It is based on actual pressure patterns observed for pipelines in which fatigue failures have occurred. These four spectra are used with other parameters of the actual segment of interest (i.e., diameter, wall thickness, grade, toughness, etc.) to calculate times to failure. One assumes that the pipeline has been tested to 100 percent of SMYS[1] and that it is operated at a MOP corresponding to 72 percent of SMYS[2]. These assumptions establish initial and final flaw sizes and key the ranges of pressure cycles to the segment being analyzed. Note that the aggressiveness comparisons are independent of the crack-growth-rate constants, because the same constants are used for time-to-failure calculations involving both the actual and the benchmark cycles.

The values in the left-hand column of Table 4.6 indicate fluctuations in hoop stress in terms of SMYS (e.g., 72% means a cycle from 72 percent of SMYS to zero and back to 72 percent of SMYS, 65% means a cycle from 72 percent of SMYS to 7 percent of SMYS and back to 72 percent of SMYS, 55% means a cycle from 72 percent of SMYS to 17 percent of SMYS and back to 72 percent of SMYS, and so on). The cycles are top-down instead of bottom-up because some crack growth models consider the often-real effect of mean stress on fatigue life. In some situations, the higher the mean stress, the shorter the time to failure.

Direct comparison of the actual cycles for a given pipeline to the cycles in the four benchmark categories is very difficult. A more practical approach is to employ a crack growth model and perform a series of five evaluations on a set of initial defects using the same pipe attributes including a set of crack growth rate constants (*C* and *n* values). One run is based on the actual pressure cycles for the pipeline; the other four runs employ each of the four benchmark sets. In the run based on the actual cycles the real hydrostatic test pressure is used to establish initial flaw sizes. In the runs based on the benchmark cycles the hydrostatic test pressure corresponds to 100 percent of SMYS for the pipe. For the sake of consistency in initial flaw sizes, 25 ft-lb Charpy energy is used to represent the toughness. The user then compares the times to failure with the actual cycles to those associated with each of the four benchmark aggressiveness categories.

An example set of resulting times to failure for the four benchmark cases is shown in Table 4.7. Note that this example is based on different pipeline parameters than those described in Table 4.1. A comparison set of resulting times to failure for an actual segment is presented in Table 4.8. As seen in Table 4.7, the very aggressive benchmark cycles produce a life less than 2 years and the aggressive cycles produce a minimum time to failure around 7 years. Since the pressure cycles for the actual segment, as shown in Table 4.8, result in minimum predicted times to failure for the deeper defects around 5 years, the actual cycles are considered aggressive for the case in which the starting defect size was established by a hydrostatic test to 1.25 times MOP. The predictions for times to failure based on the flaws that would survive a test to 1.39 times MOP show that the pressure cycles in this case lie in the moderate-to-aggressive range.

[1] Whether or not it actually has been tested to this level does not matter. The purpose of the calculation is to assess the aggressiveness of the actual cycles relative to the benchmark cycles.
[2] The benchmark cycles have a maximum stress range of 72 percent of SMYS, so the benchmark cycles are keyed to a maximum of 72 percent of SMYS for the segment being examined.

Table 4.6 Benchmark Cycle Counts—Annual

Percent SMYS	Very Aggressive	Aggressive	Moderate	Light
72%	20	4	1	0
65%	40	8	2	0
55%	100	25	10	0
45%	500	125	50	25
35%	1000	250	100	50
25%	2000	500	200	100
Total	**3660**	**912**	**363**	**175**

Table 4.7 Remaining Life Based on Categorized Aggressiveness

Pressure Cycle Category	Years to Failure for Various Defect Depth-to-Thickness Ratios			
	90%	**70%**	**50%**	**30%**
Very Aggressive	1.88	1.88	2.38	5.38
Aggressive	7.12	7.37	9.62	21.67
Moderate	18.12	19.12	25.12	56.12
Light	55.63	56.89	71.38	144.89

Table 4.8 Time to Failure Based on Test Scenarios of 1.25 x MOP and 1.39 x MOP

Test Stress Level	Years to Failure for Various Defect Depth to Thickness Ratios			
	90%	**70%**	**50%**	**30%**
1.25 x MOP	5.00	5.47	7.52	24.10
1.39 x MOP	10.32*	10.62	13.79	31.08
*Minimum value of 10.06 occurred for 80-percent-through defect.				

4.4 Effects of Variations in Pressure-Cycle Aggressiveness and Material Constants on Flaw Growth

Consider a 22-inch OD x 0.344-inch WT X46 pipeline being evaluated for susceptibility to fatigue from a hook crack. Hook cracks are manufacturing defects in the longitudinal weld of the pipe, caused by inclusions at the plate edge that are turned out of the plane of the steel during the welding process. The CVN upper shelf absorbed energy is 18 ft-lb equivalent from a full-size specimen. The pipeline maximum operating pressure (MOP) is 1,035 psig, corresponding to a hoop stress equal to 72 percent of SMYS.

The assumed fatigue crack length is $L=2(Dt)^{1/2}=5.5$ inches. The "ln-secant" equation results in the relationships between flaw size and failure pressure shown in Figure 4.1. At a flaw length of 5.5 inches, a defect would become critical at the MOP at a depth of 64.5 percent of the wall thickness, or 0.222 inches. If the pipe were hydrostatically tested to a pressure level of 90 percent of SMYS, a flaw of this length would be critical at a depth of 47.1 percent of SMYS or 0.162 inch; if the pipe were hydrostatically tested to a pressure level of 100 percent of SMYS, a flaw of this length would be critical at a depth of 34.1 percent of SMYS or 0.117 inches.

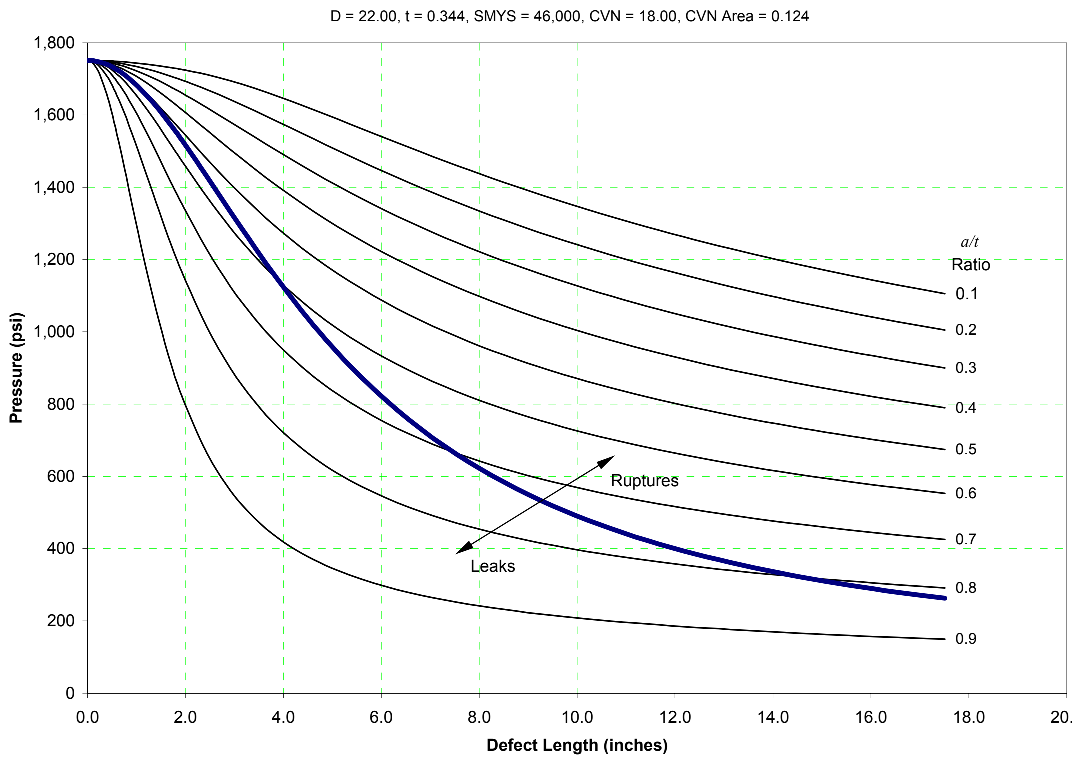


Figure 4.1 Example Relationship Between Failure Stress and Flaw Size

The best means for selecting *C* and *n* values is to benchmark the values against a known incident where the initial flaw size, the final flaw size, a detailed operating pressure spectrum, and the hydrostatic test history are all known. Even so, there is no one combination of *C* and *n* that uniquely defines the crack growth curve between initial and final flaw sizes for any given operating spectrum, unless another hydrostatic pressure test or reliable crack-detection in-line inspection (ILI) occurred some time later in service. The later test or ILI puts an upper bound on how large the flaw could have been at a given point in time. The test may also have left an arrest mark on the fracture surface giving an indication of the flaw size at that time, although it is usually difficult to make such correlations. If only an initial and final flaw size are known with no intermediate test or ILI, then it is not possible to define a unique *C* and *n* combination, other than by selecting a reasonable *n* value, perhaps based on analyses of other pipe of the same type, and changing *C* to match the known conditions. Considerable judgment is involved in making these choices.

Consider that for the example pipe, it was already established that $C=5.56\text{x}10^{-18}$ (for ΔK in psi $\sqrt{in}$ units) and $n=2.77$ based on prior studies. Figure 4.2 shows the crack growth over time under the influence of a particular operating pressure spectrum that happens to be moderate in terms of cycle aggressiveness. The curve shows failure at the MOP at a flaw depth of 0.222 inches, potentially as early as 9 years after a hydrostatic test to 85 percent of SMYS, or 21 years after a hydrostatic test to 90 percent of SMYS, or 61 years after a hydrostatic test to 100 percent of SMYS if the flaws had the maximum survivable depth at the time of the test.

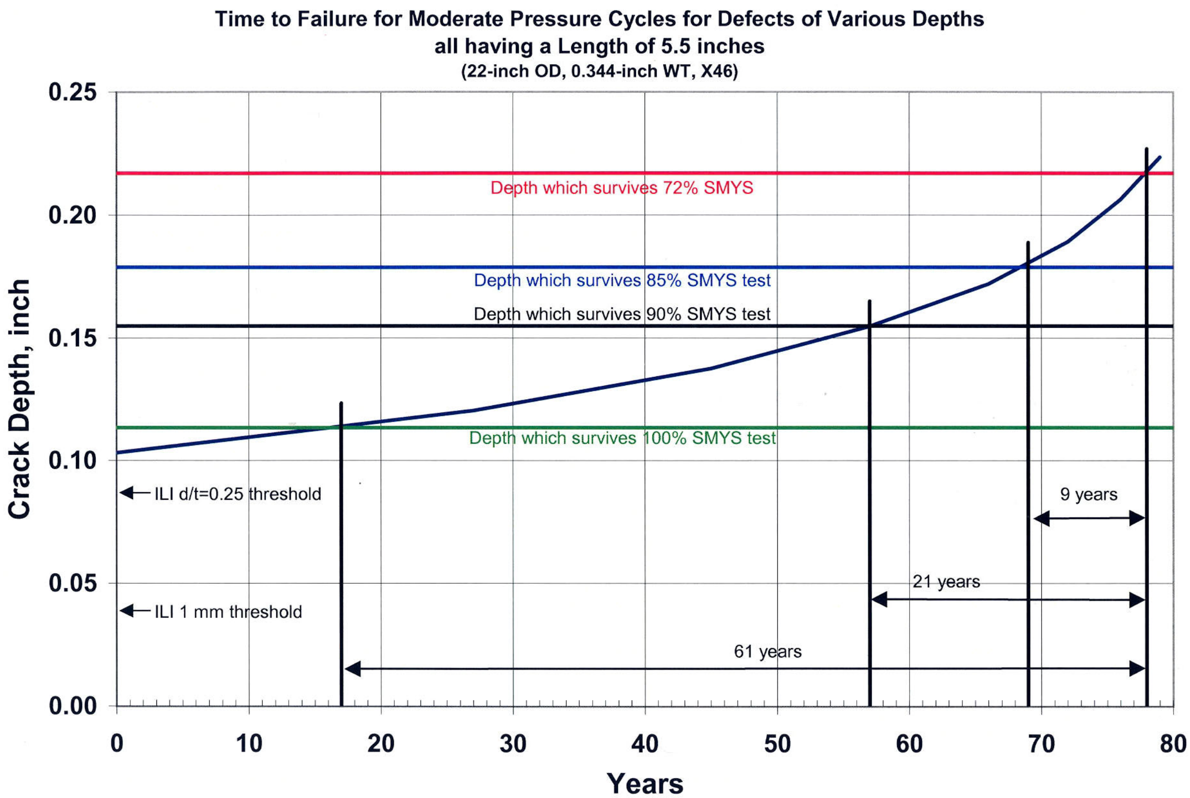


Figure 4.2 Example Crack Growth in Service

Figure 4.3 shows the effect on crack growth over time, for this particular case, of more aggressive and less aggressive operating conditions. Figure 4.4 and Figure 4.5 show the effects of greater or lesser values for *C* with the same *n* value, and greater or lesser values for *n* with the same *C* value, respectively. Note that by pure coincidence, the curve shown for lower *C* and the same *n* is almost identical to the curve for the same *C* and lower *n*. This result might not necessarily occur with a different operating spectrum, however.

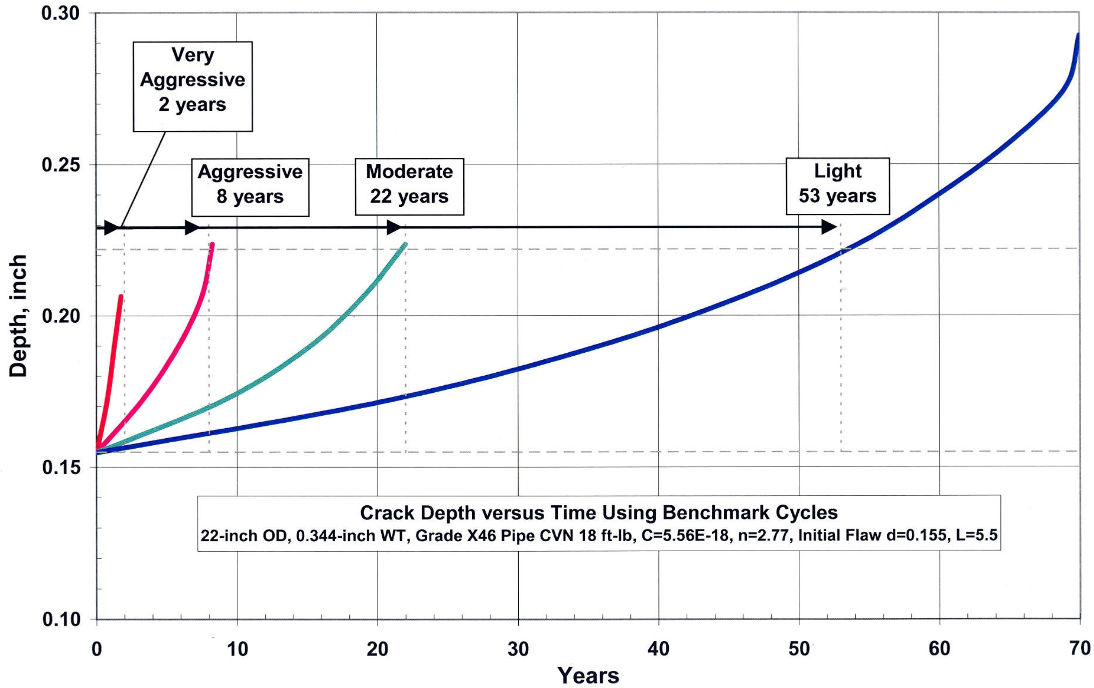


Figure 4.3 Example of the Effect of Operating Pressure Spectrum

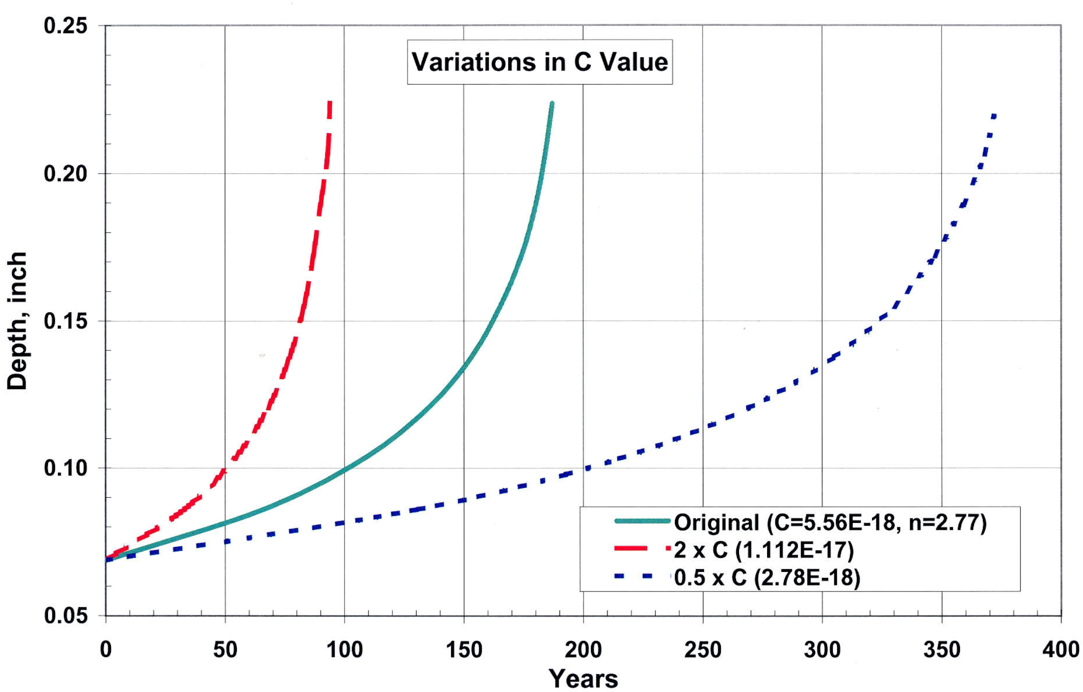


Figure 4.4 Illustration of the Effect of Variations in *C*

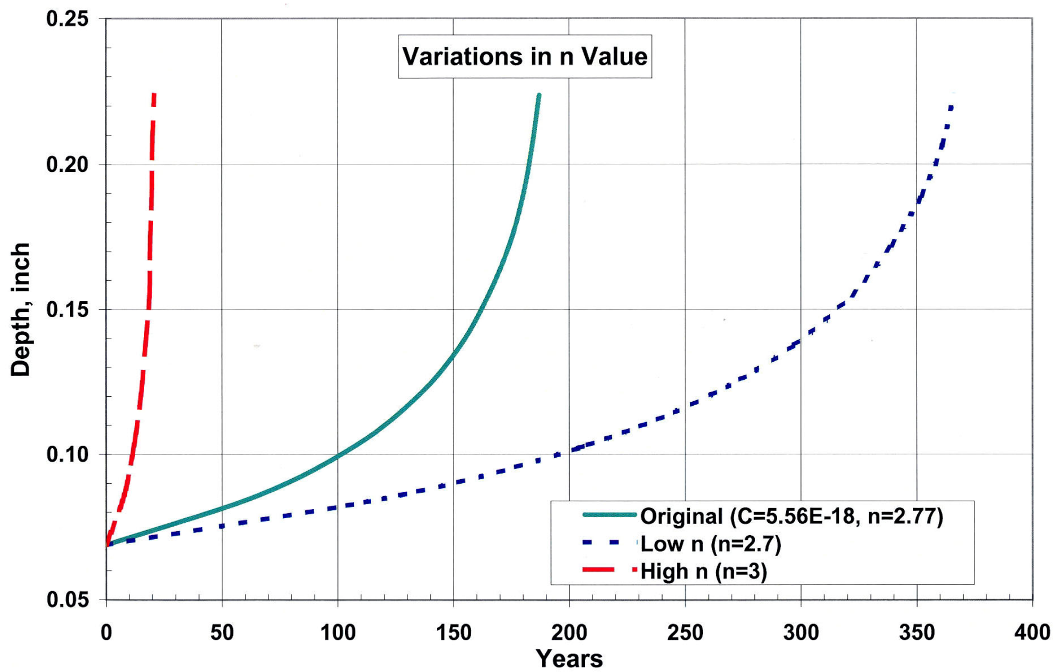


Figure 4.5 Illustration of the Effect of Variations in *n*

4.5 Recommended SHT Procedures

It is recommended that SHT be used whenever practical to enhance the integrity assessment effectiveness of a hydrostatic test of a pipeline. A guideline for choosing an appropriate test-pressure-to-operating-pressure ratio (HTP/MOP) to achieve approximately equal levels of effectiveness for cases where MOP is less than or equal to 72 percent of SMYS is given by the linear equation:

HTP/MOP = -0.00736 (% SMYS at MOP) + 1.919

For example, if a pipeline is operating at a maximum pressure that produces hoop stress equivalent to 72 percent of SMYS, then the HTP/MOP ratio is equal to –0.00736(72) + 1.919, or 1.39. This ratio results in a test pressure that would produce a hoop stress equivalent to 100 percent of SMYS. HTP/MOP ratios and resulting stresses in terms of %SMYS for several levels of MOP in terms of %SMYS are presented in Table 4.9.

Table 4.9 HTP/MOP Ratios and Resultant Stresses in Terms of %SMYS

MOP as % SMYS	Fatigue	
	HTP/MOP	%SMYS
20	1.77	35
30	1.70	51
40	1.62	65
50	1.55	77
60	1.48	88
72	1.39	100

It is unrealistic to expect an operator to employ this equation to justify pressurizing a pipeline containing older ERW pipe to a pressure level exceeding the equivalent of 100 percent of SMYS. Furthermore, there is a trade-off between the HTP/MOP ratio and the retest interval. A relatively low HTP/MOP used in conjunction with an appropriately short retest interval can be as effective as a higher HTP/MOP used in conjunction with a long retest interval.

As discussed in Section 2.2, ½ hour, with an upper limit of 1-hour, is the recommended hold time for a SHT.

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5 SHT to Assess Pipelines Affected by SCC or Selective Seam Corrosion

5.1 Subtask 03 – Scope

This chapter addresses Subtask 03 of the Work Scope which states:

> **Overview**: Develop practicable SHT criteria for application to identifying areas of SCC and fatigue, including minimum test pressure, as a function of Specified Minimum Yield Strength (SMYS), and duration for a minimum of three categories of operating pressure. These categories, based on the hoop stress as a function of SMYS are: 72 percent or higher, 50 to 72 percent, and less than 50 percent. Based on the criteria developed and an assumed pressure cycling of one cycle per month, determine a minimum re-test interval for each category.
>
> **Activities**:
>
> a) Evaluate effects of test pressure and duration on critical flaws for each category of operating pressure.
>
> b) Develop SHT procedures for each category of operating pressure.
>
> c) Evaluate effects of postulated pressure cycling on critical flaws for each category.
>
> d) Determine minimum re-test interval based on postulated pressure cycling for each category.
>
> **Deliverables**:
>
> a) Narrative discussing effects of test pressure and duration on critical flaws.
>
> b) SHT procedures.
>
> c) Narrative discussing effects of pressure cycling on critical flaws.
>
> d) Narrative presenting the recommended minimum re-test interval and the process used to determine this interval.

5.2 Discussion

Historically, the SHT concept was first applied to hydrostatically retesting pipelines affected by SCC (Fessler, 1979). The early uses of SHT for SCC involved arbitrarily selected retest intervals because the rate of growth for SCC in any given situation was difficult if not impossible to estimate. The normal practice was to select an initial interval of 1 to 3 years. If no service failures from SCC occurred between tests, the interval was gradually lengthened. Multiple companies continued this approach. A study of the effectiveness of this approach is not within the scope of this report. It is still clear, however, that a successful retest program depends on either knowing or conservatively estimating the rate of SCC growth.

Researchers have developed laboratory data on SCC growth rates that show rates ranging from 0.03 mm/yr (1 mil/yr.) to 30 mm/yr (1,180 mils/yr) (National Energy Board, 1996). It is also known that SCC can become a dormant process. The Canadian National Energy Board states that safe retest intervals can be calculated using a time-averaged value of 0.6 mm/yr. (24 mils/yr) (National Energy Board, 1996). This rate is used in the following analyses to show the effects of various SHT pressure ratios (that is, HTP/MOP ratios) on times to failure after the test. It is noted that the same analytical approach applies to selective seam corrosion of ERW seams. In the case of the latter, however, the rate of corrosion penetration is likely to be site-specific. Therefore, the following discussion is intended to show only the relative effects of HTP/MOP ratios; it is not meant to be a guide for selecting actual retest intervals for a particular pipeline.

The approach to setting appropriate HTP/MOP ratios for retests of pipelines affected by SCC or selective seam corrosion is based on the same model pipeline that was used to discuss HTP/MOP ratios for pipelines affected by fatigue (see Table 4.1 for pipeline parameters).

In the examination of appropriate HTP/MOP ratios for SCC and selective seam corrosion, the cases presented in Table 5.1 will be considered.

Table 5.1 HTP/MOP Ratios for SCC Cases Analyzed

Case	HTP/MOP	HTP		MOP	
		psig	% SMYS	psig	% SMYS
8	1.53	1,984	110	1,299	72
9	1.39	1,804	100	1,299	72
10	2.0	1,804	100	902	50
11	1.8	1,624	90	902	50
12	1.53	1,380	76.5	902	50

Unlike the analysis for fatigue, the analysis for SCC and selective seam corrosion is based on the assumption that cracks or grooves that survive a hydrostatic test will grow at a linear rate with time. Therefore, the analysis can be based on the failure-pressure-versus-defect-size relationships shown in Figure 5.1 and Figure 5.2. On these figures, a pressure level (test or operating) can be represented as a horizontal line. Along each such line lie the families of defects that can barely survive that pressure level or, alternatively, fail at that pressure level. Hence, defects that survive a test pressure level will fail in service at a lower pressure level if they grow over a long enough period of time.

Figure 5.1 represents Cases 8 and 9 where the test pressure levels are 1,984 psig (110 percent of SMYS) and 1,804 psig (100 percent of SMYS). The MOP for both cases is 1,299 (72 percent of SMYS), so the HTP/MOP ratios are 1.53 and 1.39, respectively. Arrows on the figure represent hypothetical crack-growth scenarios for four different lengths of cracks (2, 4, 6, and 8 inches).

Figure 5.2 represents Cases 10, 11, and 12 where the test pressure levels are 1,804 (100 percent of SMYS), 1,624 (90 percent of SMYS), and 1,380 psig (77 percent of SMYS). The MOP for all three cases is 902 psig (50 percent of SMYS), so the HTP/MOP ratios are 2, 1.8, and 1.53, respectively. As in Figure 5.1, the arrows on Figure 5.2 at total lengths of 2, 4, 6, and 8 inches represent hypothetical crack-growth scenarios.

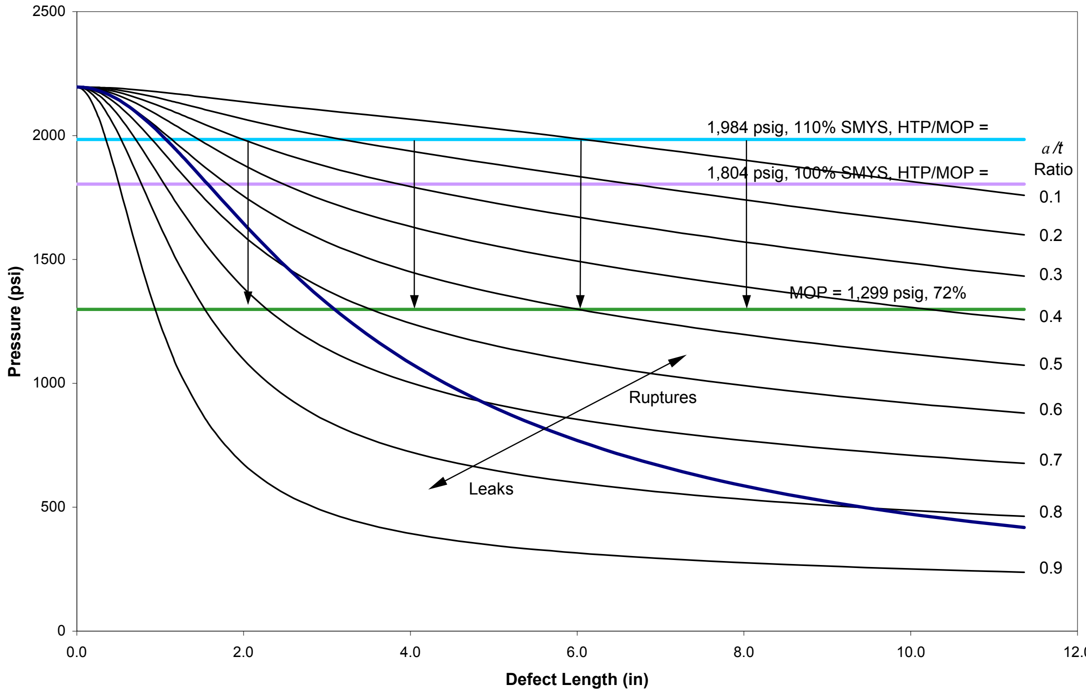

Figure 5.1 Failure Pressure vs. Defect Size Relationship – MOP Equal to 72% SMYS

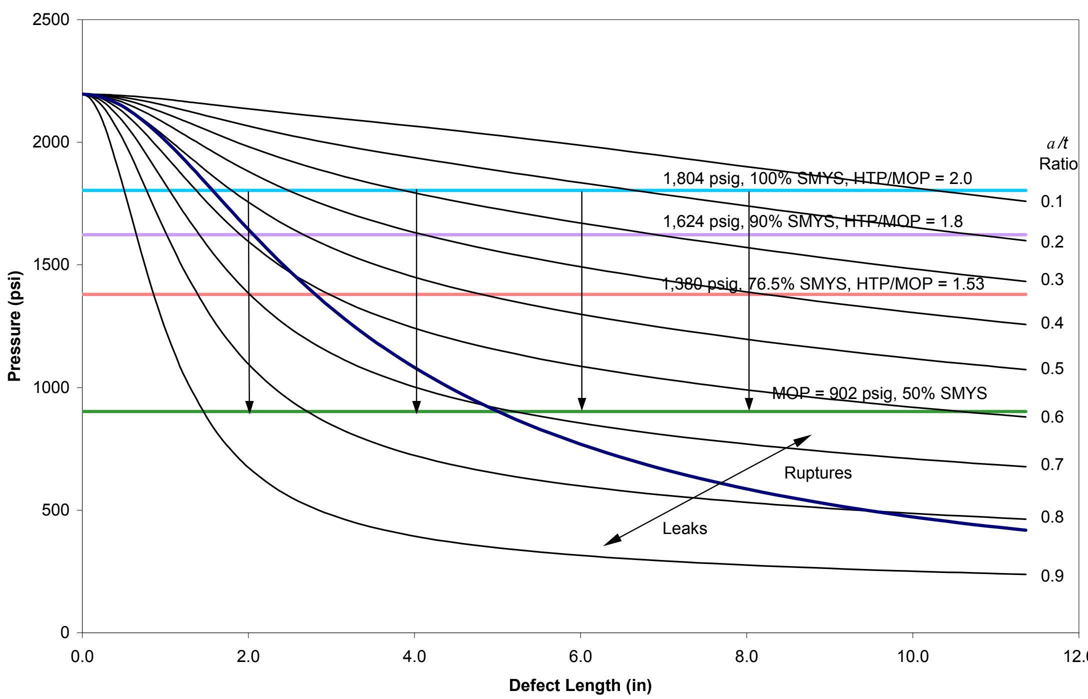

Figure 5.2 Failure Pressure vs. Defect Size Relationship – MOP Equal to 50 % SMYS

To analyze the crack-growth scenarios represented by the arrows in Figure 5.1 and Figure 5.2, one needs to consider the *a/t* value corresponding to the intersection of the arrow's shaft with a horizontal pressure line. For example, in Figure 5.1, the shaft of the arrow at a total length of 2 inches intersects the 1,984-psig level at an *a/t* of 0.30, the 1,804-psig level at an *a/t* of approximately 0.47, and the MOP level of 1,299 psig at an *a/t* of approximately 0.73. This means that a 2-inch-long crack that barely survives a test pressure of 1,984 psig will be no more than 30 percent through the wall. Yet in order to fail in service, it must grow to a depth that is 73 percent through the wall. This growth of 43 percent of the 0.250-inch wall thickness will take place in 4.5 years at a growth rate of 24 mils per year (the time-averaged rate suggested by the NEB (NEB, 1996)). By the same reasoning, if a 2-inch-long defect had barely survived a test pressure of 1,804 psig, it would have grown to failure in only 2.7 years. This is because one must assume its initial depth after the test was 47 percent of the wall thickness. If it then grows through 26 percent of the wall thickness (65 mils) at a rate of 24 mils per year, it will reach a depth of 73 percent of the wall thickness in 2.7 years and it will fail at the MOP of 1,299 psig.

Table 5.2 presents a summary of the analysis of Cases 8 through 12 based on Figure 5.1 and Figure 5.2 and the thought process described above. In much the same manner as revealed for fatigue crack growth, the effectiveness of a given HTP/MOP ratio for SCC is dependent on the operating stress level. As one can see by comparing Cases 8 and 10, an HTP/MOP ratio of 1.53 for a pipeline that is operated at 72 percent of SMYS has about the same effectiveness as an HTP/MOP ratio of 2.00 for a pipeline that is operated at 50 percent of SMYS.

Table 5.2 Times to Failure of SCC Defects for Various HTP/MOP Ratios

Case	*a/t* at HTP				*a/t* at MOP				Years to Failure			
	L=2 in	L=4 in	L=6 in	L=8 in	L=2 in	L=4 in	L=6 in	L=8 in	L=2 in	L=4 in	L=6 in	L=8 in
8	0.30	0.17	0.10	0.07	0.73	0.58	0.50	0.45	4.5	4.3	4.2	4.0
9	0.47	0.30	0.22	0.16	0.73	0.58	0.50	0.45	2.7	2.9	2.9	3.0
10	0.47	0.30	0.22	0.16	0.85	0.73	0.68	0.63	4.0	4.5	4.8	4.9
11	0.59	0.41	0.33	0.28	0.85	0.73	0.68	0.63	2.7	3.3	3.6	3.6
12	0.70	0.53	0.46	0.40	0.85	0.73	0.68	0.63	1.6	2.1	2.3	2.4

5.3 Recommended SHT Procedures

It is recommended that SHT be used whenever practical to enhance the integrity assessment effectiveness of a hydrostatic test of a pipeline. A guideline for choosing an appropriate test-pressure-to-operating-pressure ratio (HTP/MOP) to achieve approximately equal levels of effectiveness for addressing SCC or selective seam corrosion is given by the equation:

$$(HTP/MOP) = -0.02136\ (MOP\ in\ \%\ SMYS) + 3.068.$$

For example, if a pipeline is operating at a maximum pressure that produces hoop stress equivalent to 72 percent of SMYS, then the HTP/MOP ratio is equal to –0.02136(72) + 3.068, or 1.53. This ratio results in a test pressure that would produce a hoop stress equivalent to 110 percent of SMYS. HTP/MOP ratios and resulting stresses in terms of %SMYS for several levels of MOP in terms of %SMYS are presented in Table 5.3.

Table 5.3 HTP/MOP Ratios and Resultant Stresses in Terms of %SMYS

MOP as % SMYS	SCC	
	HTP/MOP	%SMYS
20	2.64	53
30	2.43	73
40	2.21	89
50	2.00	100
60	1.79	107
72	1.53	110

In using this equation it should be remembered that it is unrealistic to expect an operator to pressurize a pipeline comprised of older ERW pipe to a pressure level exceeding the equivalent of 100 percent of SMYS even if the pipeline is operated at 72 percent of SMYS. Also, it is well to remember that there is a trade-off between the HTP/MOP ratio and the retest interval. A relatively low HTP/MOP used in conjunction with an appropriately short retest interval can be as effective as a higher HTP/MOP used in conjunction with a long retest interval.

As discussed in Section 2.2, the recommended hold time for SHT is 1/2 –hour, with an upper limit of 1-hour.

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6 Sensitivity to Pipe Parameters

The relationship between failure pressure and defect size is dependent upon a few key pipe parameters: diameter, wall thickness, SMYS and fracture toughness (Charpy V-Notch energy measurements) of the pipe material. The relationship also depends on the Young's Modulus value for the material, though variations in this value typically have a minor impact on the results when analyzing steel pipe.

6.1 Changes in Diameter

Series of analyses were conducted to show the effect changing the diameter of the pipe has on the failure-pressure-versus-defect-size relationship. Analyses were conducted for 12-, 16-, 20-, 24- and 36-inch nominal diameter pipe. All other variables were held constant; wall thickness was 0.312-inch, yield strength was 52,000 psi, and CVN value was 15 ft-lb. The results are presented in Figure 6.1, Figure 6.2, Figure 6.3, Figure 6.4 and Figure 6.5. A direct comparison of the failure-pressure-versus-defect-size relationship for all diameters analyzed assuming a constant *a/t* ratio of 0.5 is shown in Figure 6.6.

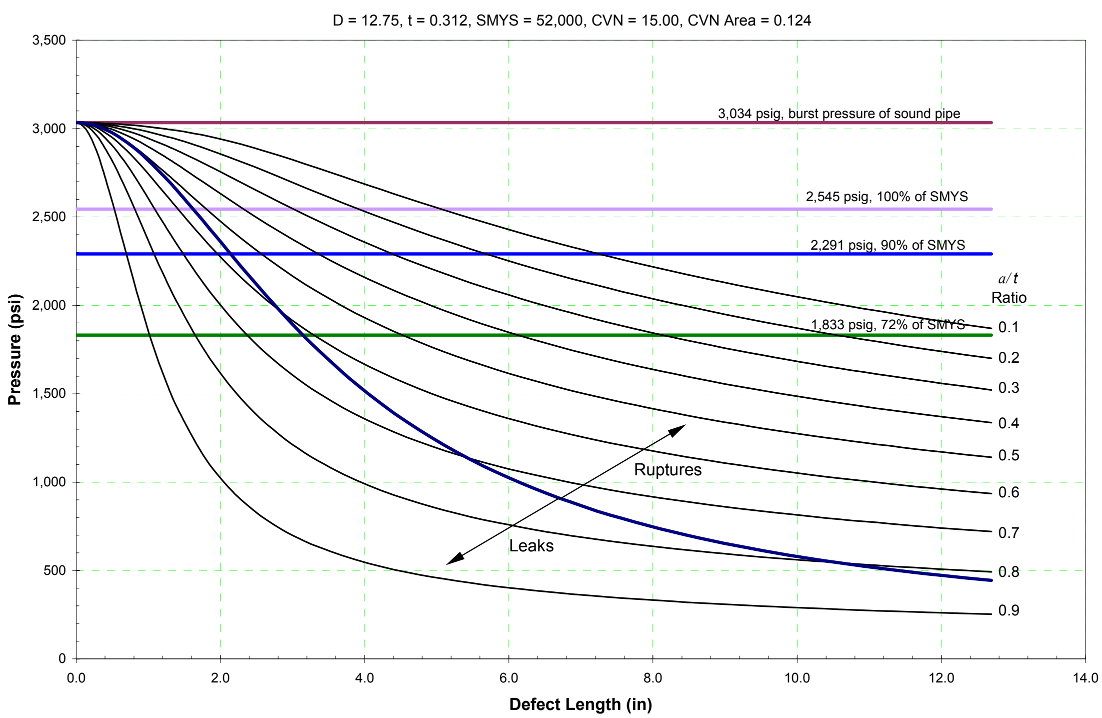

Figure 6.1 Failure Pressure vs. Defect Size—12-inch Nominal Diameter

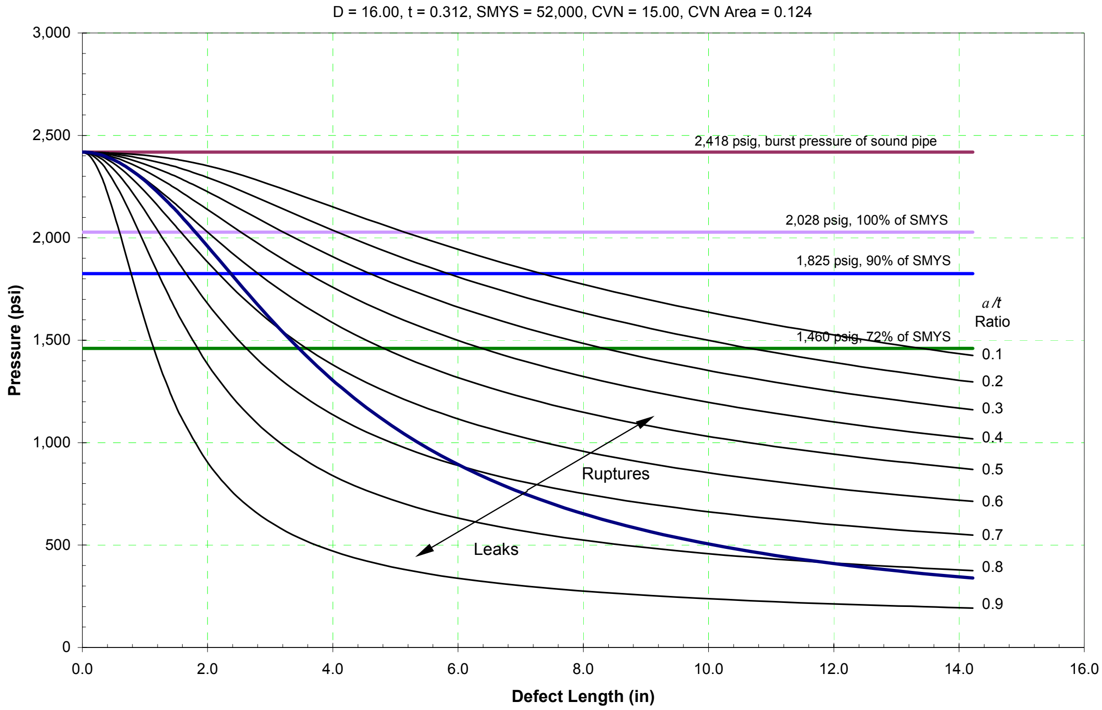

Figure 6.2 Failure Pressure vs. Defect Size—16-inch Nominal Diameter

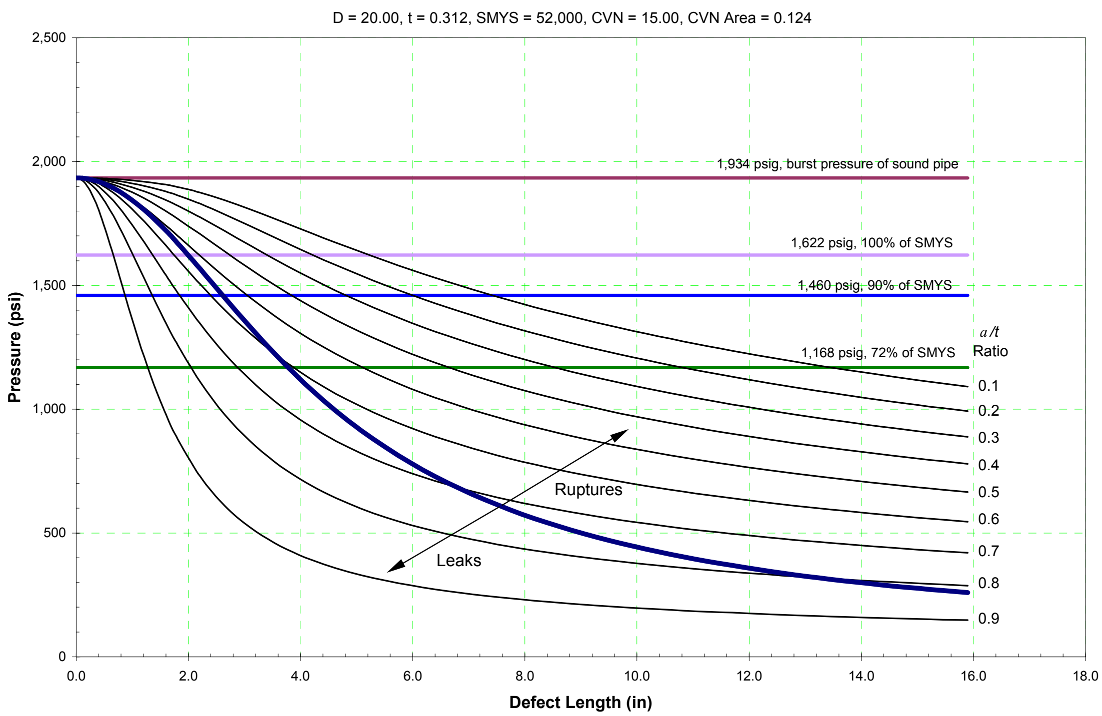

Figure 6.3 Failure Pressure vs. Defect Size—20-inch Nominal Diameter

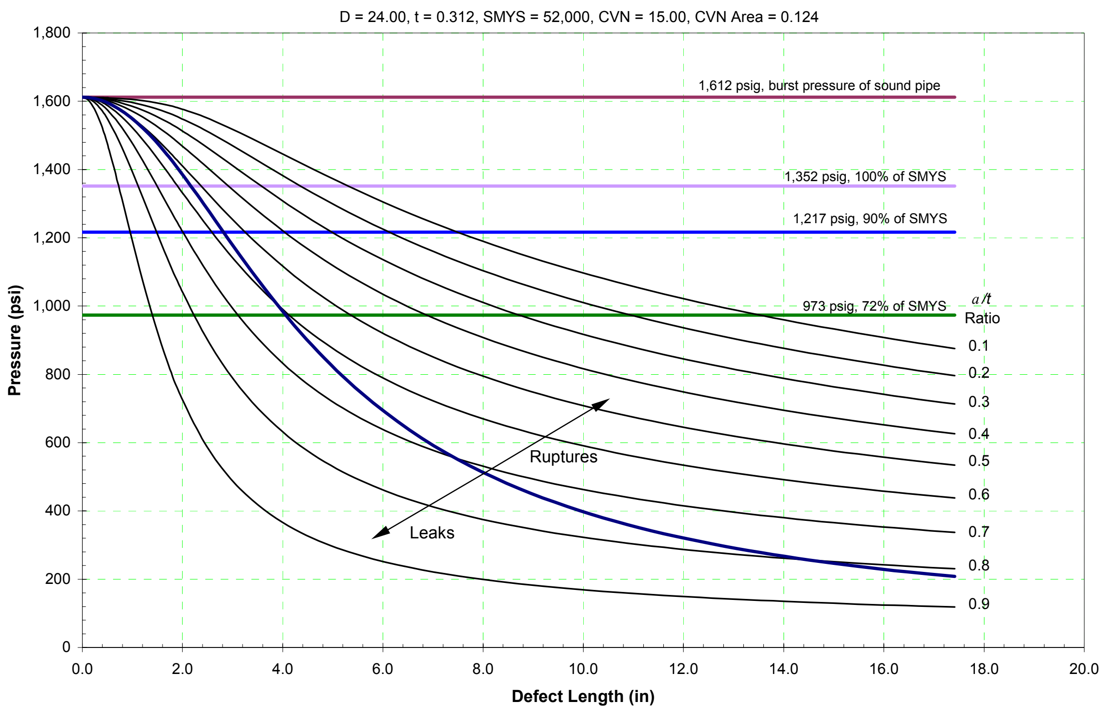

Figure 6.4 Failure Pressure vs. Defect Size—24-inch Nominal Diameter

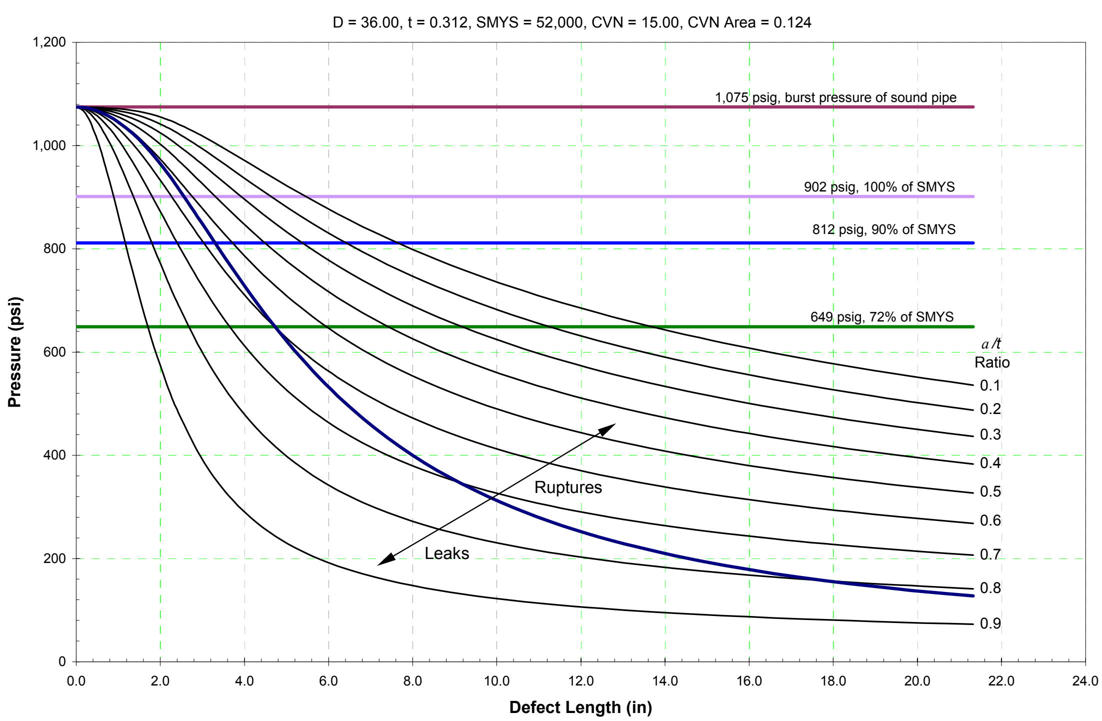

Figure 6.5 Failure Pressure vs. Defect Size—36-inch Nominal Diameter

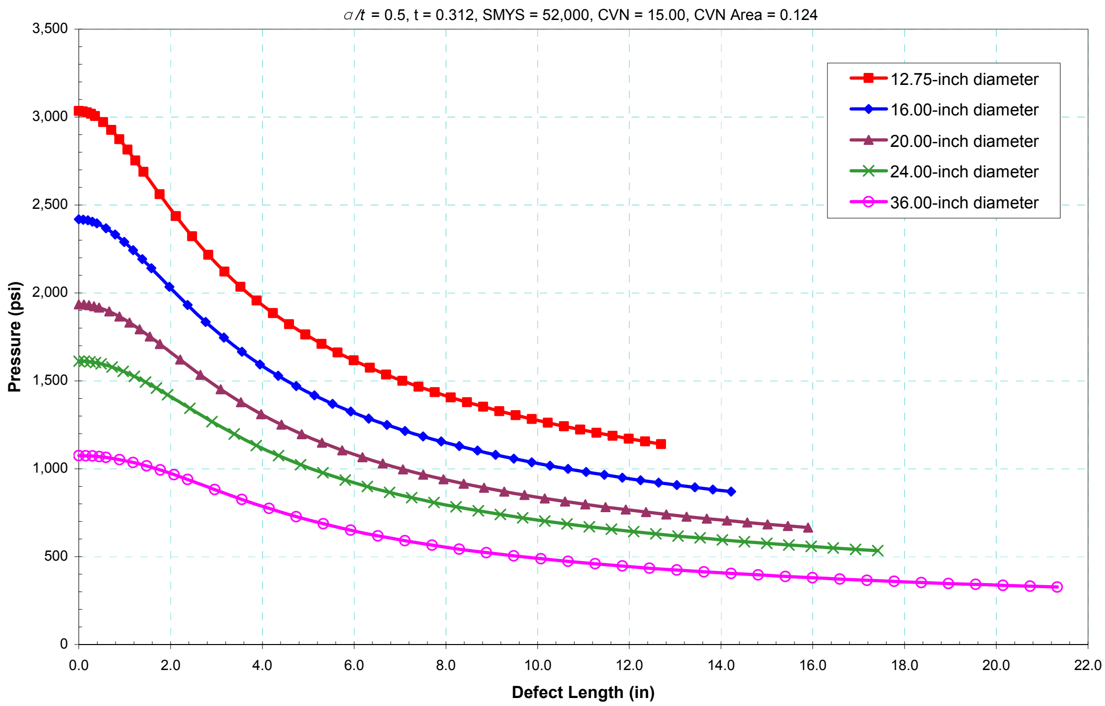

Figure 6.6 Comparison of Failure Pressure vs. Defect Size for Different Pipe Diameters

Another series of analyses were conducted to show the effect changing the diameter of the pipe has on the time-to-failure-versus-defect-size relationship. These analyses assumed the same pipe parameters and assumed a HTP equivalent to 100 percent of SMYS and an MOP equivalent to 72 percent of SMYS. The analyses followed the procedure described in Section 5 for SCC with an average corrosion rate of 24 mils per year. The results are presented in Figure 6.7.

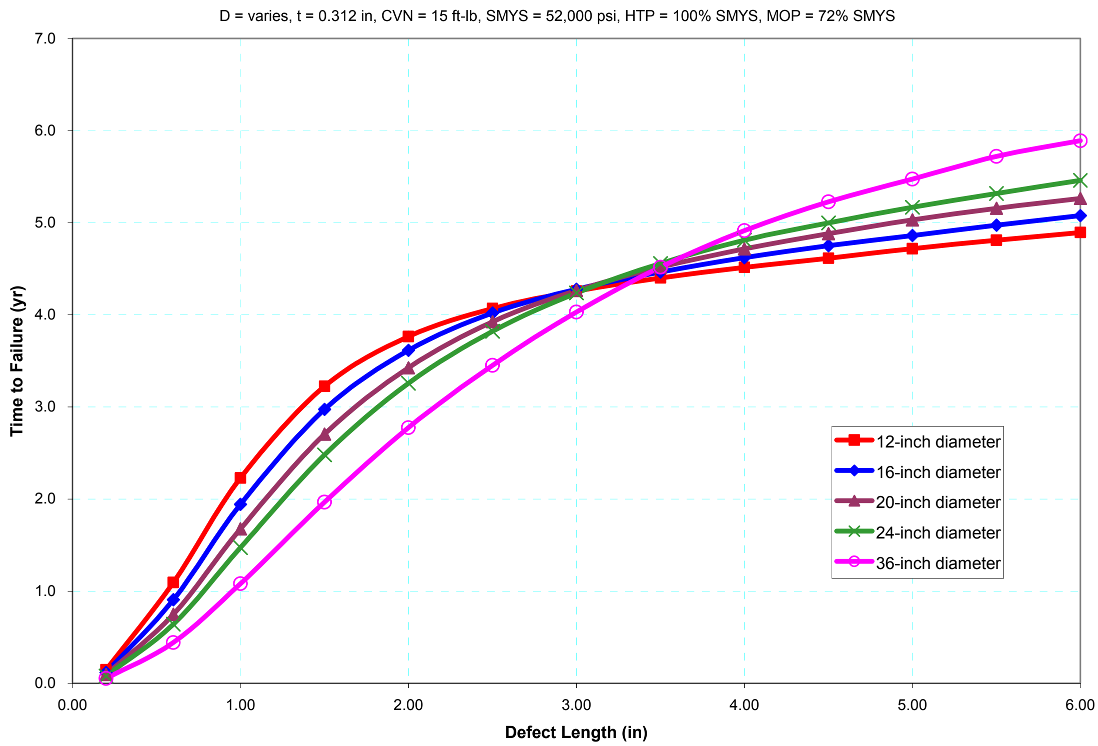

Figure 6.7 Comparison of Time to Failure vs. Defect Size for Different Pipe Diameters

6.2 Changes in Wall Thickness

Similarly, additional analyses were conducted to show the effect changing the wall thickness of the pipe has on the failure-pressure-versus-defect-size relationship. These analyses were conducted for a 20-inch diameter pipe with wall thicknesses of 0.250 and 0.375 inches. All other variables were held constant; yield strength was 52,000 psi, and CVN value was 15 ft-lb. The results are presented in Figure 6.8 and Figure 6.10. The results for a wall thickness of 0.312 inches were presented in Figure 6.3 and are repeated in Figure 6.9 for completeness and ease in comparison with the results for the other wall thicknesses analyzed. A direct comparison of the failure-pressure-versus-defect-size relationship for all wall thicknesses analyzed assuming a constant *a/t* ratio of 0.5 is shown in Figure 6.11.

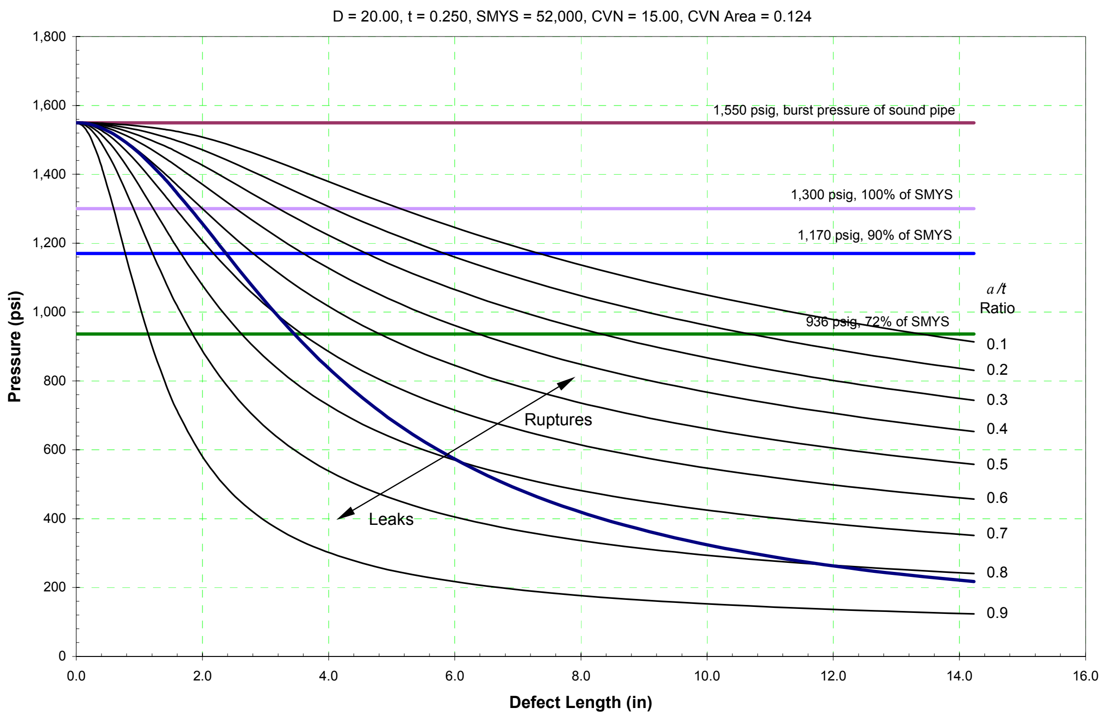

Figure 6.8 Failure Pressure vs. Defect Size—0.250-inch Wall Thickness

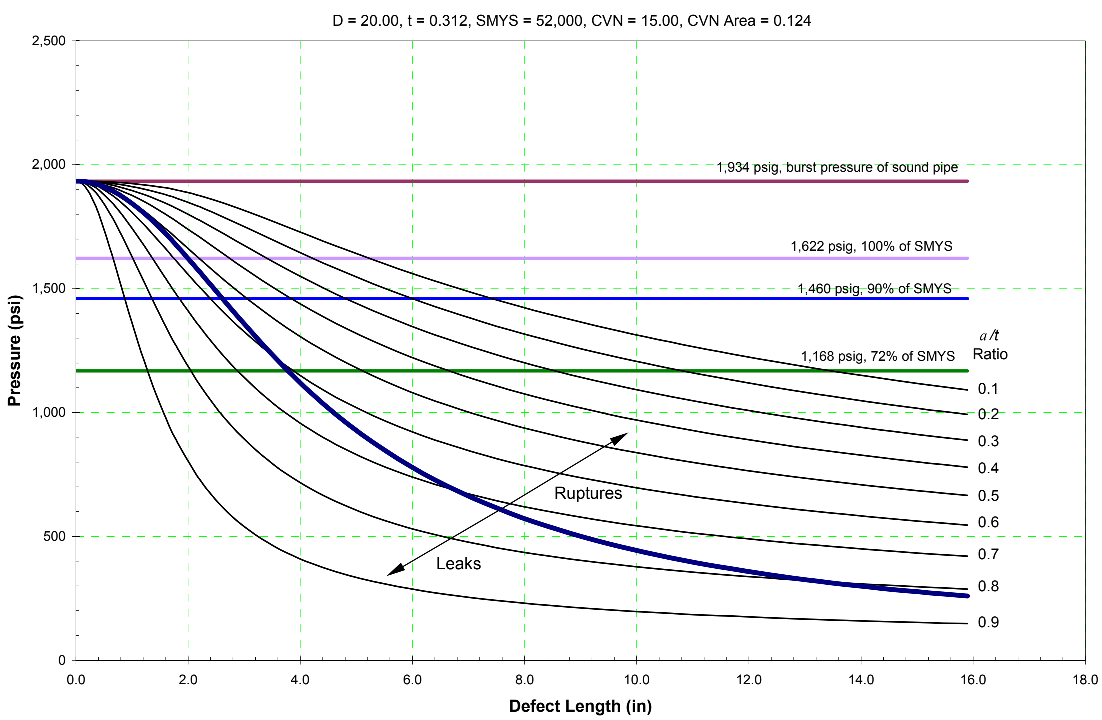

Figure 6.9 Failure Pressure vs. Defect Size—0.312-inch Wall Thickness

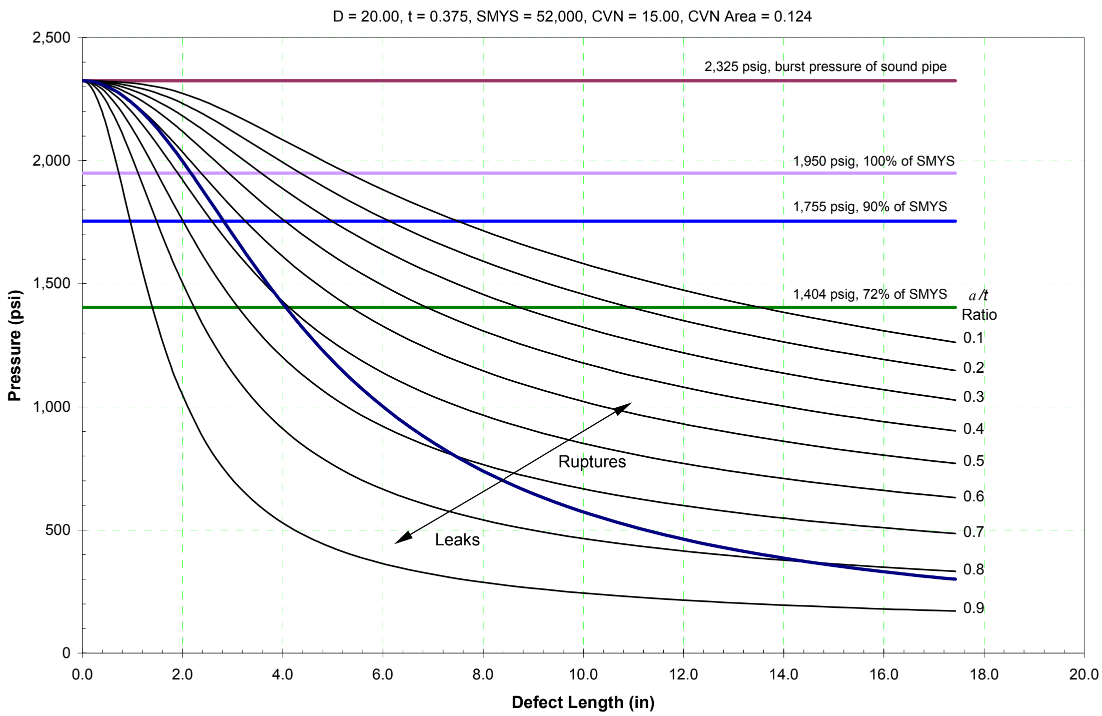

Figure 6.10 Failure Pressure vs. Defect Size—0.375-inch Wall Thickness

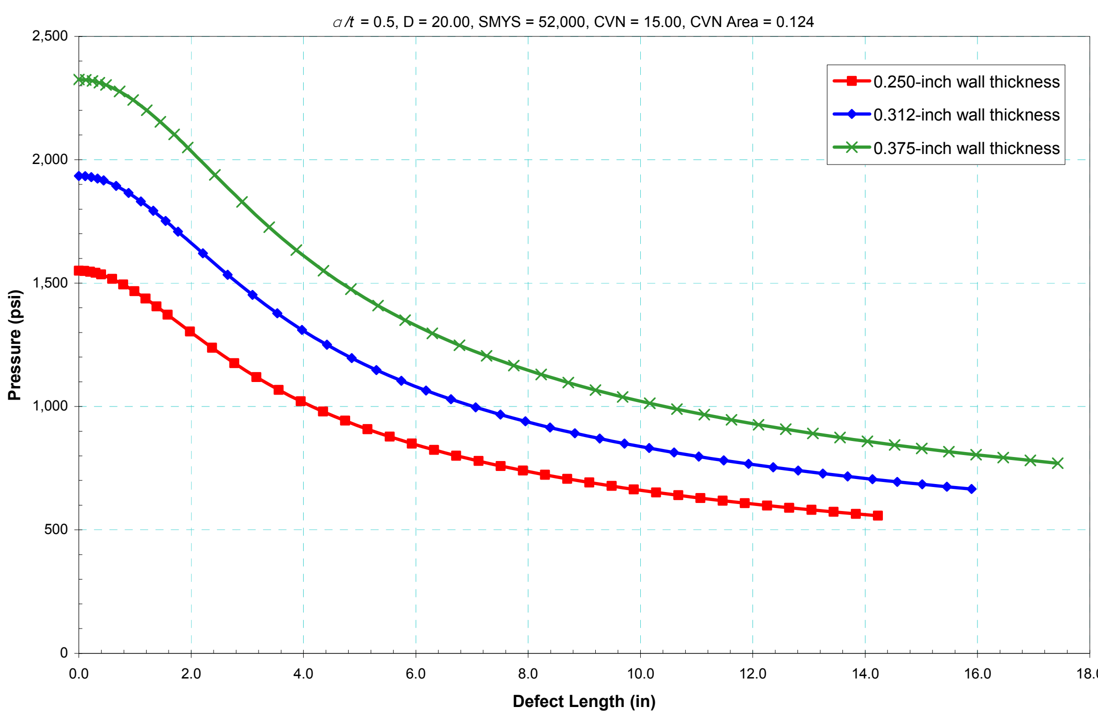

Figure 6.11 Comparison of Failure Pressure vs. Defect Size for Different Wall Thicknesses

Once again, a series of analyses were conducted to show the effect changing the wall thickness of the pipe has on the time-to-failure-versus-defect-size relationship. These analyses assumed the same pipe parameters and assumed a HTP equivalent to 100 percent of SMYS and an MOP equivalent to 72 percent of SMYS. The analyses followed the procedure described in Section 5 for SCC with an average corrosion rate of 24 mils per year. The results are presented in Figure 6.12.

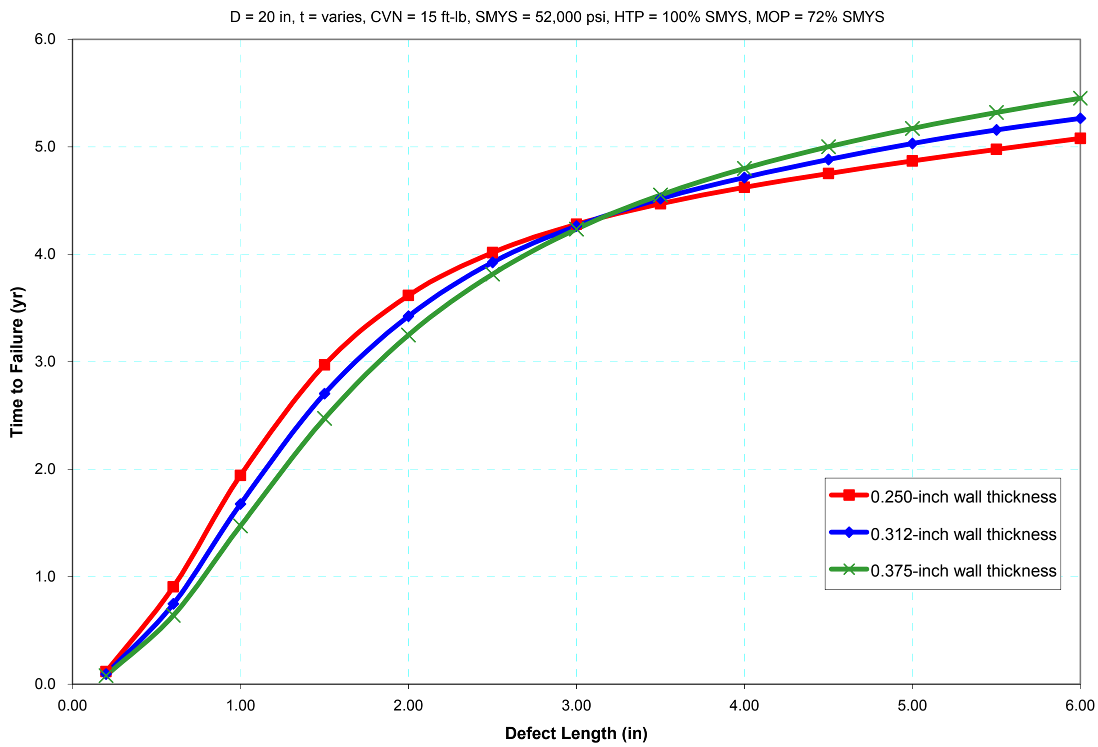

Figure 6.12 Comparison of Time to Failure vs. Defect Size for Different Wall Thicknesses

6.3 Changes in Yield Strength

Similarly, additional analyses were conducted to show the effect changing the yield strength of the pipe material has on the failure-pressure-versus-defect-size relationship. These analyses were conducted for yield strengths of 42,000 and 60,000 psi assuming a 20-inch diameter pipe with a wall thickness of 0.312 inches. A CVN value of 15 ft-lb was also used for the analyses. The results are presented in Figure 6.13 and Figure 6.15. The results for a yield strength of 52,000 psi were presented in Figure 6.3 and are repeated in Figure 6.14 for completeness and ease in comparison with the results for the other yield strengths analyzed. A direct comparison of the failure-pressure-versus-defect-size relationship for all yield strengths analyzed assuming a constant *a/t* ratio of 0.5 is shown in Figure 6.16.

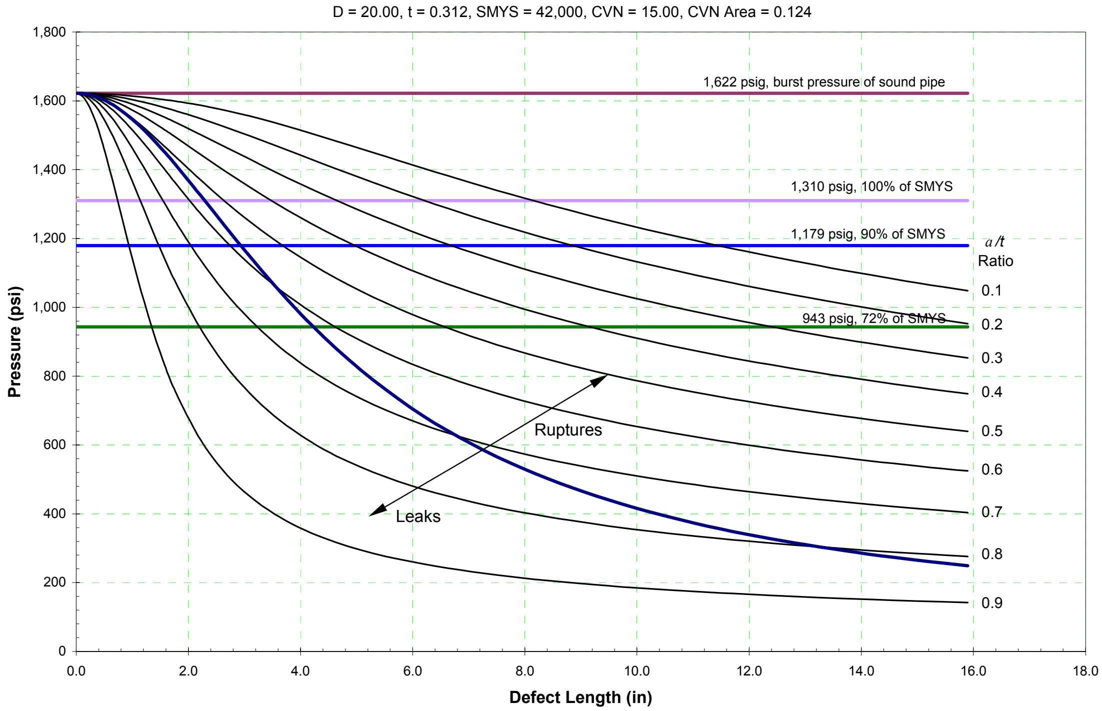

Figure 6.13 Failure Pressure vs. Defect Size—API 5L X-42 Steel

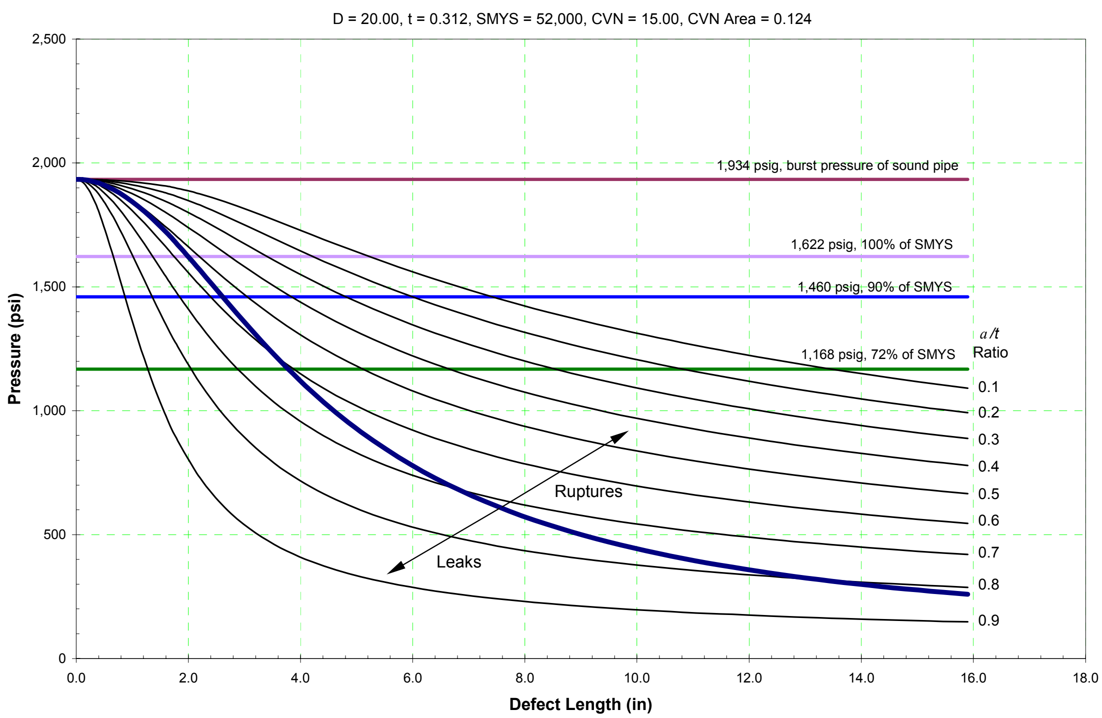

Figure 6.14 Failure Pressure vs. Defect Size—API 5L X52 Steel

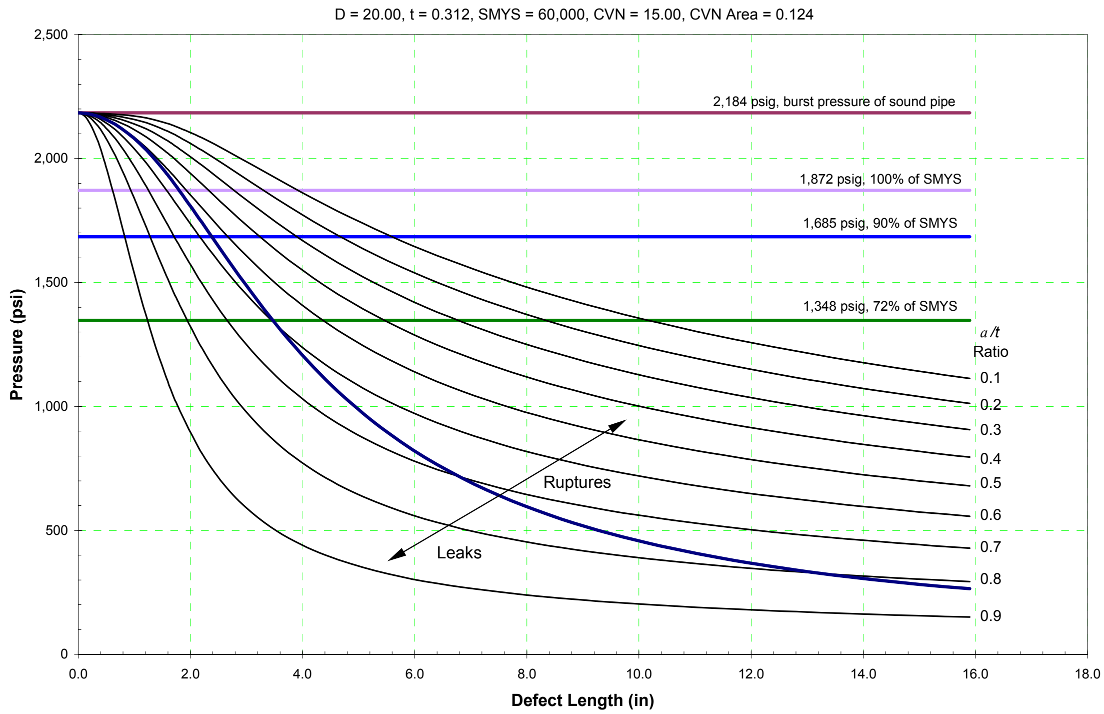

Figure 6.15 Failure Pressure vs. Defect Size—API 5L X60 Steel

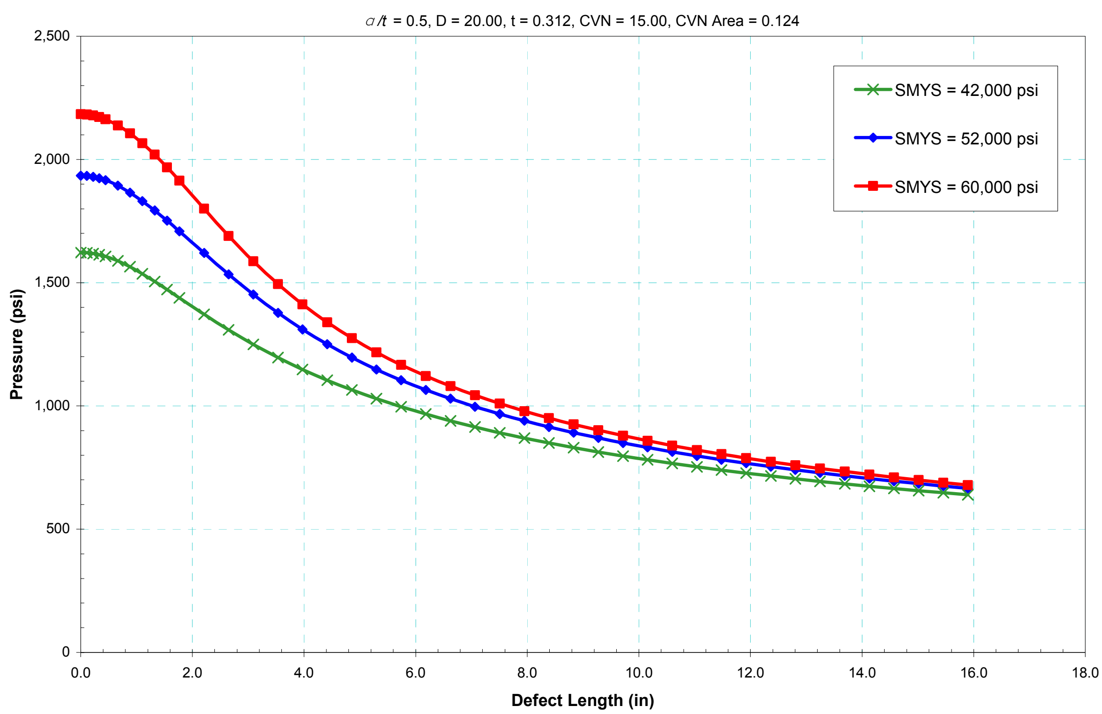

Figure 6.16 Comparison of Failure Pressure vs. Defect Size for Different API Steel Grades

Another series of analyses were conducted to show the effect changing the yield strength of the pipe material has on the time-to-failure-versus-defect-size relationship. These analyses assumed the same pipe parameters and assumed a HTP equivalent to 100 percent of SMYS and an MOP equivalent to 72 percent of SMYS. The analyses followed the procedure described in Section 5 for SCC with an average corrosion rate of 24 mils per year. The results are presented in Figure 6.17.

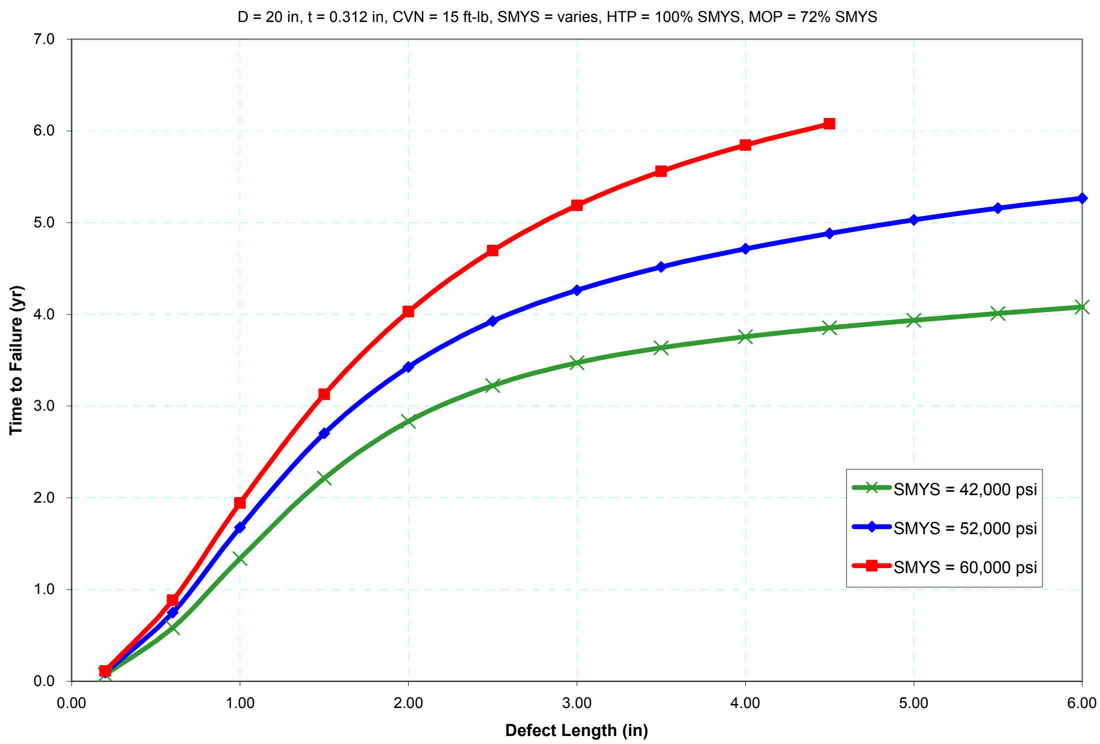

Figure 6.17 Comparison of Time to Failure vs. Defect Size for Different API Steel Grades

6.4 Changes in Fracture Toughness

A series of analyses were conducted to show the effect changing the fracture toughness of the pipe material has on the failure-pressure-versus-defect-size relationship. These analyses were conducted for CVN values of 5, 25, 35 and 40 ft-lb assuming a 20-inch diameter pipe with a wall thickness of 0.312 inches. A yield strength of 52,000 psi was used for the analyses. The results are presented in Figure 6.18, Figure 6.20, Figure 6.21 and Figure 6.23. The results for a CVN value of 15 ft-lb were presented in Figure 6.3 and are repeated in Figure 6.19for completeness and ease in comparison with the results for the other yield strengths analyzed. A direct comparison of the failure-pressure-versus-defect-size relationship for all yield strengths analyzed assuming a constant *a/t* ratio of 0.5 is shown in Figure 6.23.

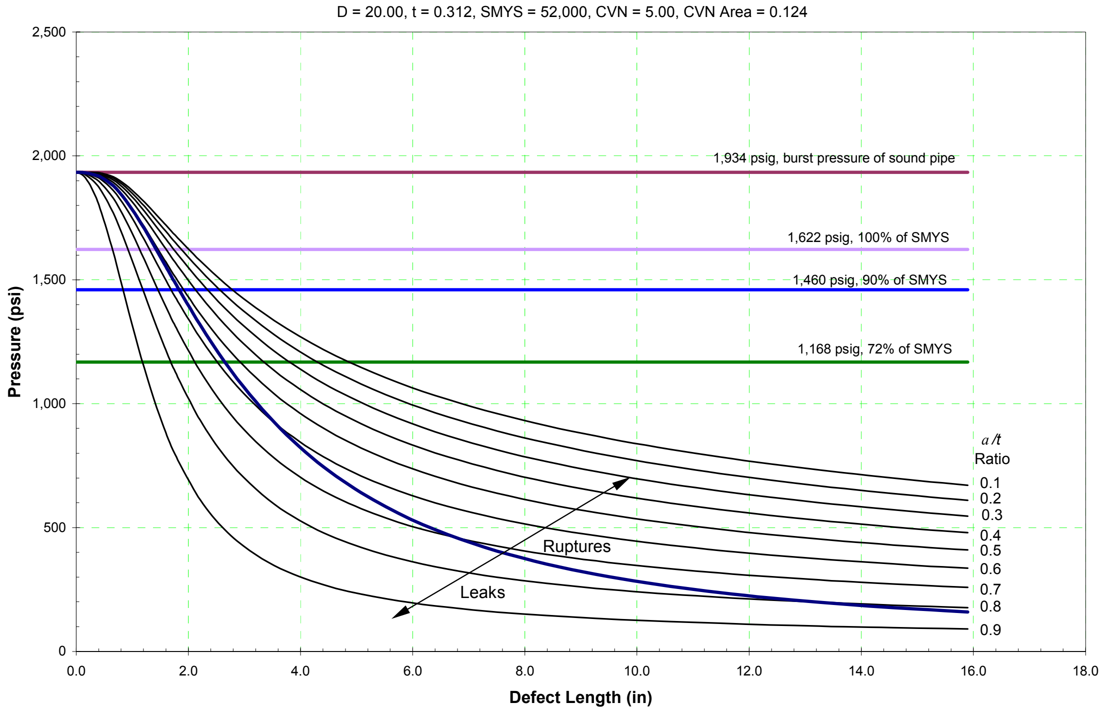

Figure 6.18 Failure Pressure vs. Defect Size—CVN Value Equal to 5 ft-lb

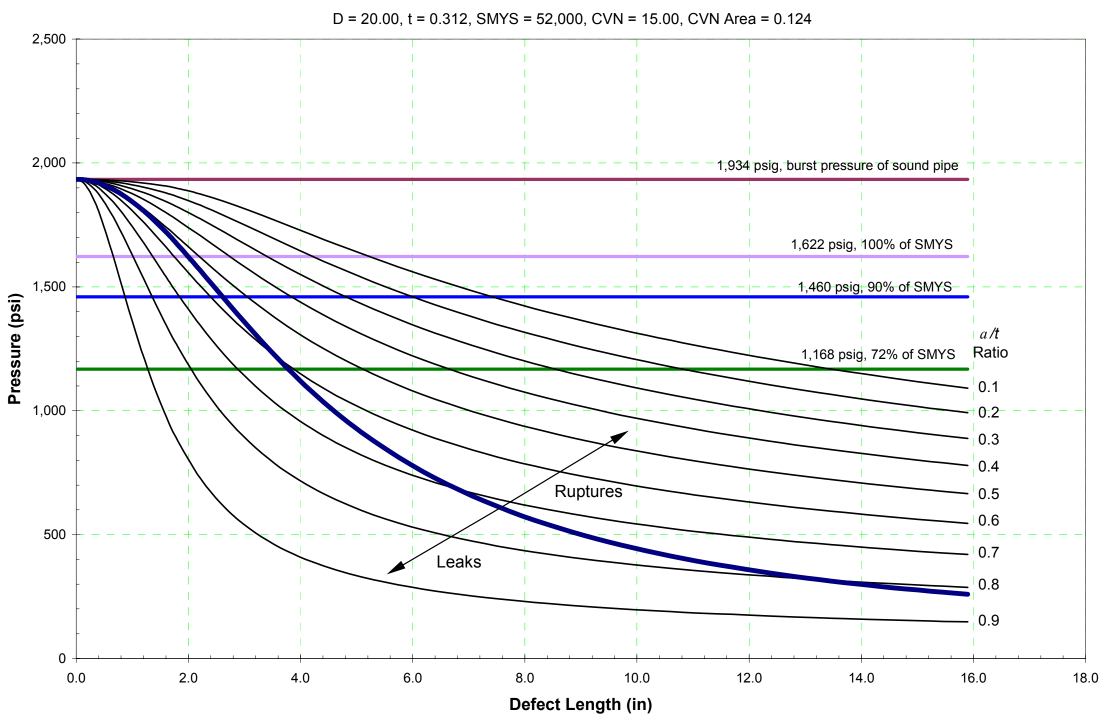

Figure 6.19 Failure Pressure vs. Defect Size—CVN Value Equal to 15 ft-lb

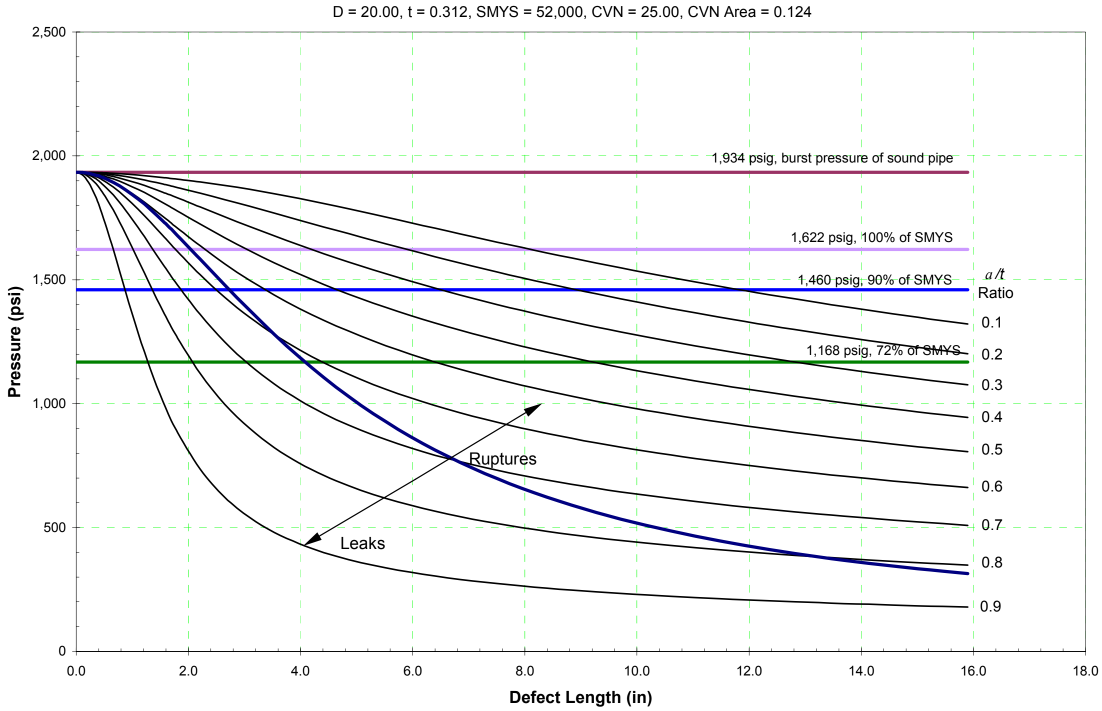

Figure 6.20 Failure Pressure vs. Defect Size—CVN Value Equal to 25 ft-lb

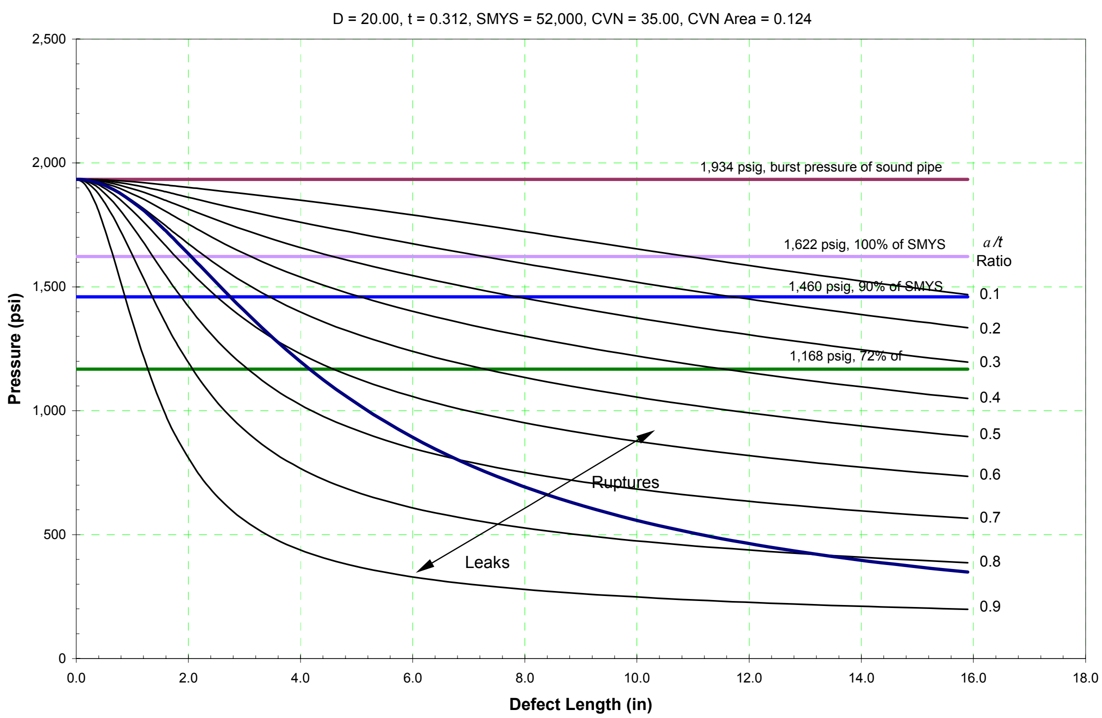

Figure 6.21 Failure Pressure vs. Defect Size—CVN Value Equal to 35 ft-lb

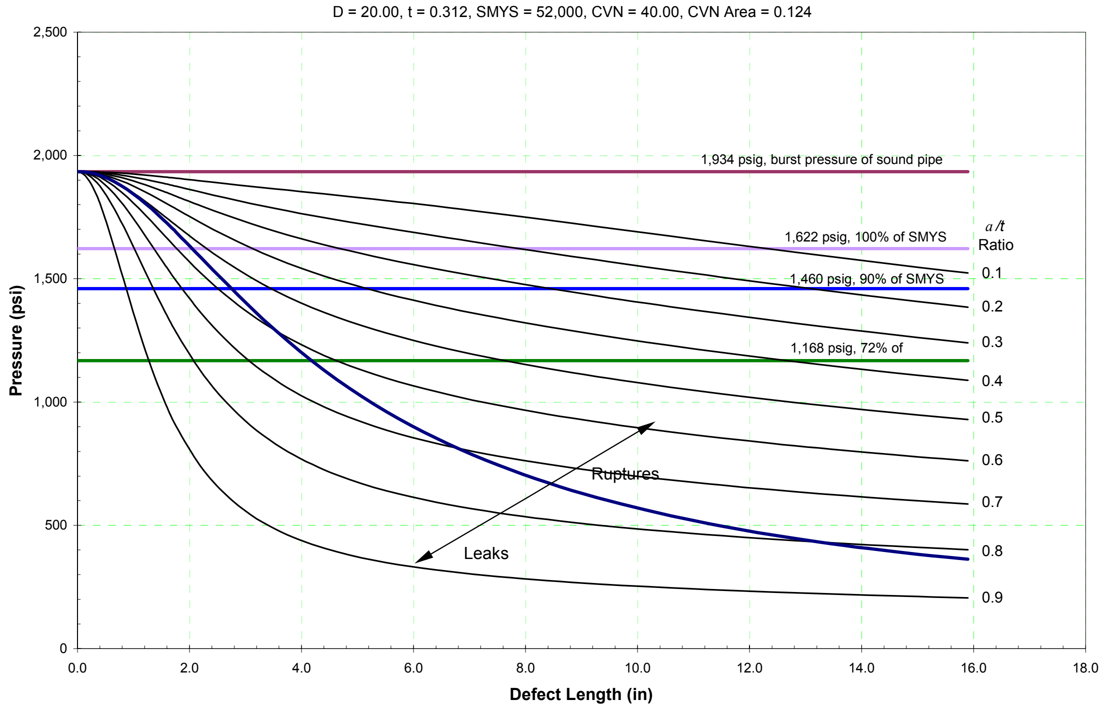

Figure 6.22 Failure Pressure vs. Defect Size—CVN Value Equal to 40 ft-lb

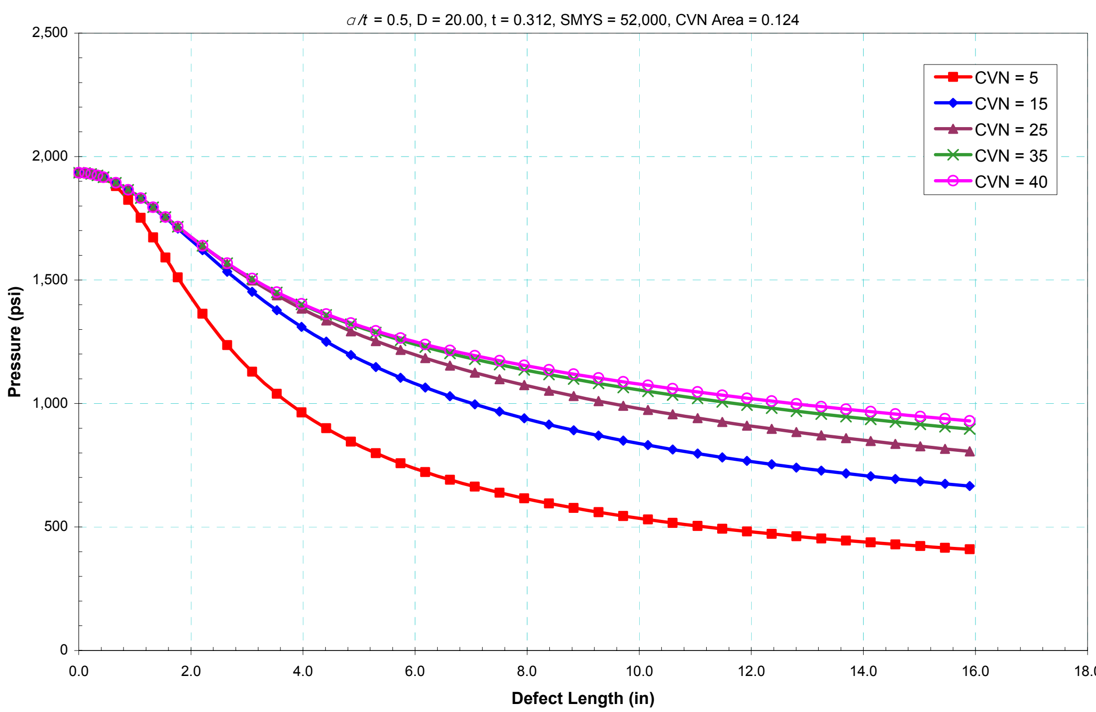

Figure 6.23 Comparison of Failure Pressure vs. Defect Size for Different CVN Values

A series of analyses were conducted to show the effect changing the fracture toughness of the pipe material has on the time-to-failure-versus-defect-size relationship. These analyses assumed the same pipe parameters and assumed a HTP equivalent to 100 percent of SMYS and an MOP equivalent to 72 percent of SMYS. The analyses followed the procedure described in Section 5 for SCC with an average corrosion rate of 24 mils per year. An analysis for a CVN of 500 ft-lb was also conducted to show the effect of an "ultimate" toughness. The results are presented in Figure 6.24.

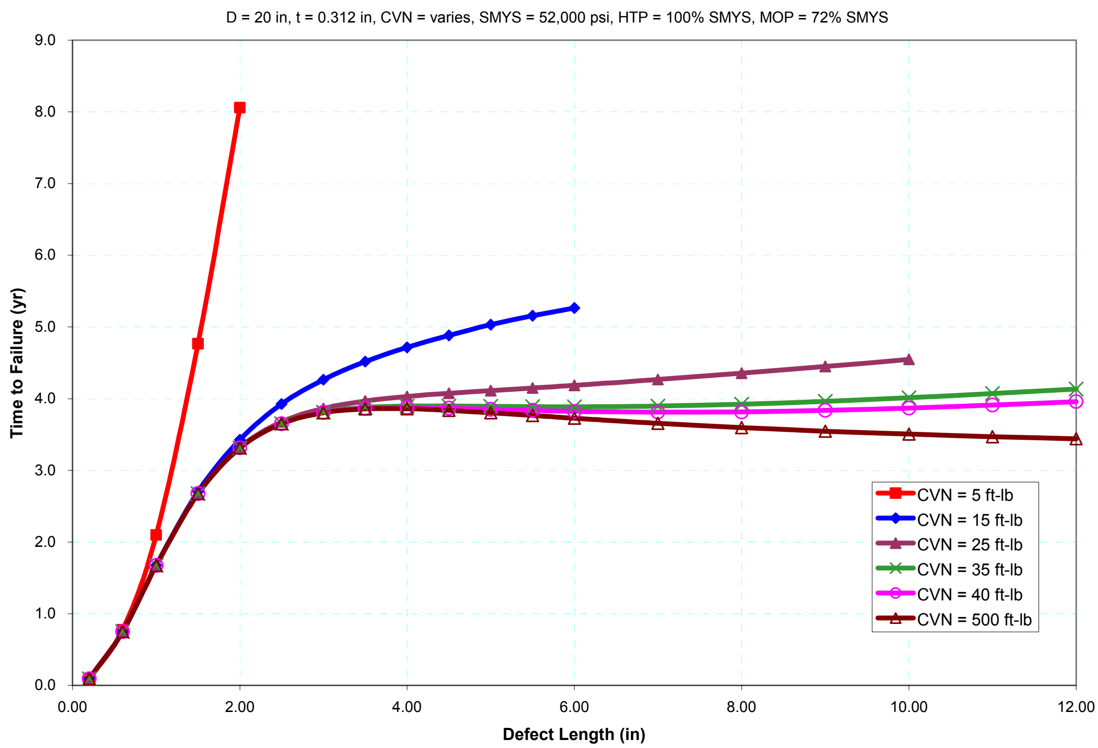

Figure 6.24 Comparison of Time to Failure vs. Defect Size for Different CVN Values

6.5 Changes in HTP and MOP

Finally, a number of analyses were conducted to determine the effect changing the HTP and MOP has on the time-to-failure-versus-defect-size relationship. The pipe parameters used were 20-inch diameter, 0.312-inch wall thickness, SMYS of 52,000 psi, and a CVN of 15 ft-lb. The HTP values examined were equivalent to 110 percent, 100 percent and 90 percent of SMYS, while the values of MOP were equivalent to 72 percent, 60 percent and 50 percent of SMYS. The results are presented in Figure 6.25, Figure 6.26, and Figure 6.27, for MOP of 72 percent, 60 percent and 50 percent of SMYS, respectively. The analyses followed the procedure described in Section 5 for SCC, where two different defect *a/t* ratios are calculated for a given length and the difference between the two is first multiplied by the wall thickness then divided by the assumed average corrosion rate (24 mils per year in these examples).

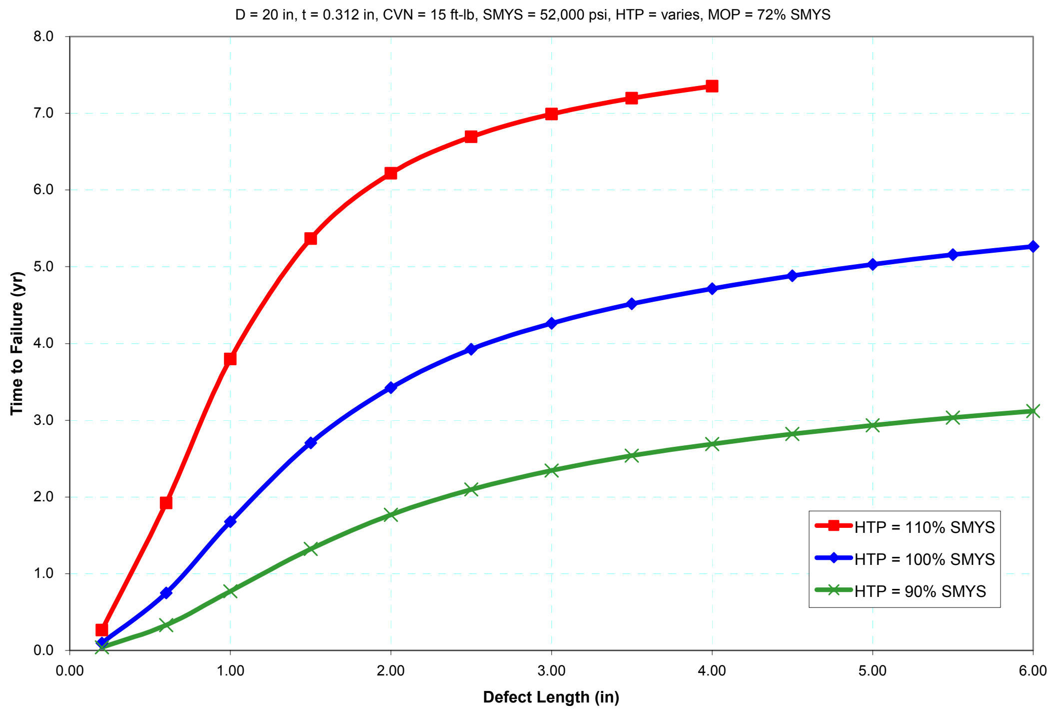

Figure 6.25 Comparison of Time to Failure vs. Defect Size for Different HTP Levels with an MOP of 72% SMYS

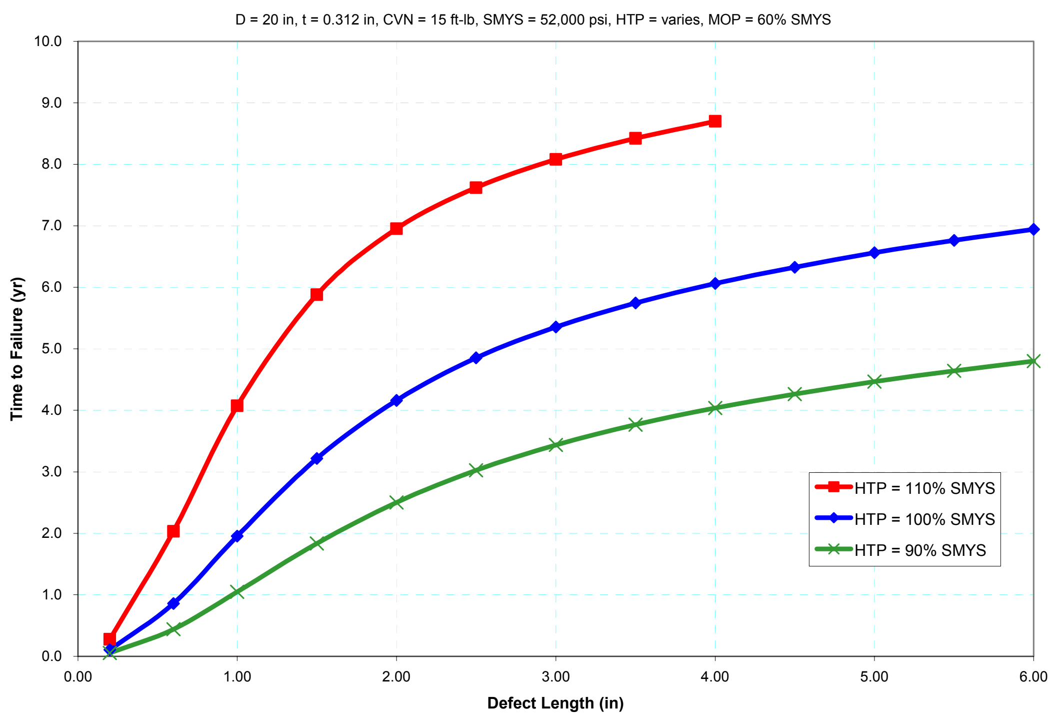

Figure 6.26 Comparison of Time to Failure vs. Defect Size for Different HTP Levels with an MOP of 60% SMYS

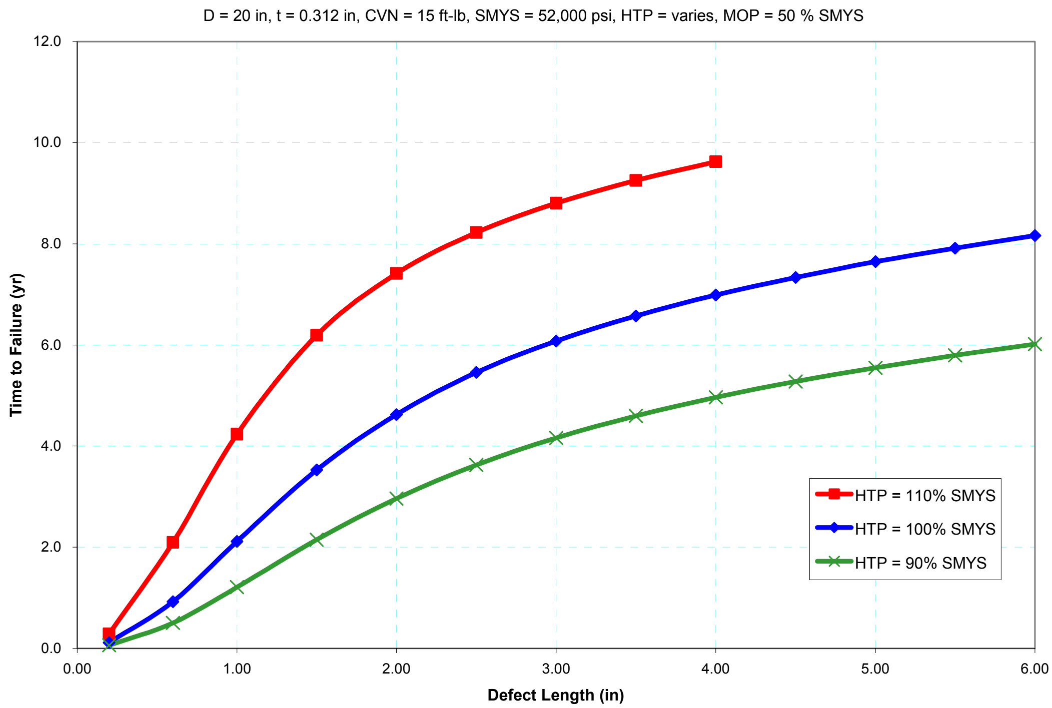

Figure 6.27 Comparison of Time to Failure vs. Defect Size for Different HTP Levels with an MOP of 50% SMYS

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7 Considerations for Pre-1970 LF-ERW Pipe

7.1 Subtask 04 – Scope

This chapter addresses Subtask 03 of the Work Scope that states:

> **Overview**: Develop practicable SHT criteria for application to pre-1970 LF-ERW pipe, including minimum test pressure, as a function of Specified Minimum Yield Strength (SMYS), and duration for a minimum of three categories of operating pressure. These categories, based on the hoop stress as a function of SMYS are: 72 percent or higher, 50 to 72 percent, and less than 50 percent. Based on the criteria developed and an assumed pressure cycling of one cycle per month, determine a minimum re-test interval for each category.
>
> **Activities**:
>
> a) Evaluate effects of test pressure and duration on critical flaws for each category of operating pressure.
>
> b) Develop SHT procedures for each category of operating pressure.
>
> c) Evaluate effects of postulated pressure cycling on critical flaws for each category.
>
> d) Determine minimum re-test interval based on postulated pressure cycling for each category.
>
> **Deliverables**:
>
> a) Narrative discussing effects of test pressure and duration on critical flaws.
>
> b) SHT procedures.
>
> c) Narrative discussing effects of pressure cycling on critical flaws.
>
> d) Narrative presenting the recommended minimum re-test interval and the process used to determine this interval.

7.2 Discussion

Longitudinal seam failures on pre-1970 LF-ERW pipe due to defects generic to the seam-welding process have raised concerns related to determining operational integrity of pipelines containing this type of pipe. The typical causes of these seam failures are pressure-cycle-induced fatigue and selective (grooving) corrosion of the bondline region of the seam.

The most common manufacturing-related defects in LF-ERW pipe are lack of fusion (welds that are intermittently fused), mismatched edges, and hook cracks (Kiefner, 2002). Hook cracks are caused by inclusions at the plate edge that are turned out of the plane of the steel during the welding process. It is the turning out of the metal at the weld that gives the characteristic "hook" or "J" shape to the crack. Seam manufacturing defects that passed the manufacturer's initial hydrostatic test possibly can fail later due to pressure-cycle-induced fatigue.

Selective seam corrosion is affected primarily by the degree of exposure to corrosive conditions (i.e., poor or absent coating and ineffective cathodic protection) and by the nature of non-metallic inclusions in the bondline region. Since most of older ERW materials have these types of non-metallic inclusions, they should be considered susceptible to selective seam corrosion.

Based on this information, the discussions in both Sections 4 and 5 have some applicability when evaluating pipelines containing LF-ERW pipe. However, as stated at the end of each of these sections, the recommended SHT procedures may need to modified somewhat for application to lines containing LF-ERW pipe to avoid stress levels in excess of 100 percent of SMYS.

8 Comparison of SHT Methods for Gas versus Liquid Lines

8.1 Subtask 04 – Scope

This chapter addresses Subtask 04 of the Work Scope that states:

> **Overview:** Compare SHT methods for assessing integrity issues on gas lines to those recommended for liquid lines.
>
> **Activities**:
>
> a) Evaluate differences in SHT criteria for use in gas versus liquid lines.
>
> **Deliverables**:
>
> a) Narrative presenting differences and considerations for using SHT on gas versus liquid lines.

8.2 Discussion

SHT are applicable to both liquid and gas pipelines. The problems for which SHT may be needed may differ, however, depending on whether the pipeline transports gas or liquid. For example, the threat of failure from pressure-cycle-induced fatigue is more likely to affect a liquid pipeline than a gas pipeline. In the analysis on HTP/MOP ratios for fatigue presented in Section 4, it was assumed that the pipeline was subjected to 365 cycles per year with the pressure ranging from zero to MOP and back to zero once each day. The resulting times to failure were on the order of 1 to 2 years. A gas pipeline would seldom experience pressure cycling more intense than the equivalent of one of these cycles per year. That being the case, the comparable times to failure for the gas pipeline cycled once per year from zero to MOP and back to zero would range from 365 to 730 years. Even if the cyclic frequency were as intense as one cycle every 30 days, the times to failure would lie in the range of 12 to 24 years. Therefore, it is much more likely that SHT will be used on liquid pipelines to assess integrity from the standpoint of fatigue than on gas pipelines.

From the standpoint of SCC or selective seam corrosion, the susceptibilities of liquid and gas pipelines should be considered equal. In reality, the rates of SCC for liquid lines could be different from those of gas pipelines; there is simply not enough published information to know. For the time being, however, it seems reasonable to treat them the same.

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9 Recommendations

Application of SHT whenever practical, is likely to improve the integrity assessment of a pipeline. Determining the appropriate test pressure is somewhat dependent upon the desired MOP for the pipeline and the anticipated failure mechanism: pressure-cycle-induced fatigue, or corrosion (SCC or selective seam corrosion). Two values of test pressure commonly used are 1.39 times MOP and 1.53 times MOP, these correspond to 100 percent of SMYS and 110 percent of SMYS for lines with an MOP equaling 72 percent of SMYS. However, for lines with an MOP other than that equating to 72 percent of SMYS, the basic recommended SHT pressures are different and can be determined from the following equations:

$$HTP/MOP = -0.00736\ (\%\ SMYS\ at\ MOP) + 1.919$$

when pressure-cycle-induced fatigue is anticipated, and

$$(HTP/MOP) = -0.02136\ (\%\ SMYS\ at\ MOP) + 3.068$$

when SCC or selective seam corrosion are anticipated.

These formulae are only guidelines and there may be justifiable reasons for using different pressures. In either case, the duration of hold-time is of less import than assuring that the test pressure is as high as possible. A hold-time of only a few minutes is sufficient to prove integrity of a pipeline. The recommended hold time is ½-hour, with an upper limit of 1-hour. Reassessment interval on the other hand is not as easily determined, in fact, it is not possible to develop a universal recommendation since there are multiple pipeline specific variables affecting this determination. In addition to the basic pipe parameters (diameter, wall thickness, SMYS), the pressure of the last hydrostatic test, the MOP, as well as, an estimate of the material toughness are necessary in order to determine the maximum size of flaws that may have still existed in the line after testing and to determine the maximum size of flaws that will not cause a leak or rupture under normal operating conditions.

In pipelines subject to pressure cycling, the pressure cycle history or projection are also required in order to calculate the number of cycles, or time, required to grow the flaws that remained after testing to the critical size that would result in a leak or rupture under normal operating conditions.

For pipelines where either SCC or selective seam corrosion is the issue, the determination of reassessment interval is somewhat more straightforward since it only depends on the estimated rate of corrosion, the basic pipe parameters, MOP, and last test pressure.

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10 References

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