Hydrostatic Testing for Pipelines with SCC Threats

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Abstract

Hydrostatic testing or pressure testing has been an accepted industry method for the verification of the integrity of pipelines. Integrity assessment methods can be used for either Maximum Allowable Operating Pressure (MAOP) or other threats such as stress corrosion cracking (SCC). However, this paper will focus on pipelines that have been in-service for a long period of time concerning time dependent threats such as SCC and static type threats. In addition, integrity intervals will be discussed, calculating the length of sections needed, predicted failure pressure with metal loss as determined by ASME B31.G, RSTRENG and reassessment intervals.

Introduction

This paper will focus primarily on Stress Corrosion Cracking (SCC) type threats. In addition, it includes threats that the pressure test was not designed. If a failure occurs due to an unintended type of threat, this information is important regarding other threats and the test section(s) being evaluated for risk issues. Pressure tests use water as the medium which we know as hydrostatic tests. It should be noted that the hydrostatic pressure test shows that no defect should fail below the test pressure.

Pressure tests have been used over the years to prove the integrity of the pipeline. Therefore, they must show that no defects would fail during normal operating conditions by exposing the line to pressures that are higher than the predicted maximum operating pressure. This means that the pipeline can manage the higher pressure even when the operating pressure of the line is not always known with this type of test. Cracks and crack like defects must be used to determine failure pressure/stress pressure and crack growth using proven fracture mechanics modeling. This data is required for analysis of predicted or assumed anomalies/cracks.

Therefore, a hydrostatic test is performed 10 to 25 percent greater than the established maximum operating pressure. This results in defects that would fail above this test pressure could remain after this test. Then how does one test for SCC or another crack-like defect? Again, the number of defects must be determined or predicted after any test. There may be defects that exist that are smaller than those that did not fail at the time of the test. Therefore, the challenges are that defects can exhibit growth over time due to the normal or abnormal stresses encountered during operations and could fail near or even below test pressure later. Remaining life calculations must be re-evaluated at the MAOP.

Keywords: Pressure or Hydrostatic tests, MAOP, Stress Corrosion Cracking, RSTRENG, and Reassessment Intervals

Background

The first documented incident(s) of stress corrosion cracking (SCC) occurred on natural gas pipelines in the mid 1960's. Transco and Tennessee Gas were the first to experience these types of failures that were found to have SCC. This type was determined to be a high-pH type known as classical SCC. High-pH SCC is intergranular and there is little, or no external corrosion associated with this type of cracking. Whereas near-neutral pH SCC is the second type that is found in mixed mode in some cases. Carbonate-bicarbonate solution is typically the environment that forms with this type of cracking and is associated with external corrosion. The characteristic of SCC exhibits the presence of multiple colonies. These are longitudinal surface cracks that form in the body of the pipe. Then they link up to form long shallow flaws.

Pressure Testing

From operating experience, hydrostatic testing has shown to be an effective tool to remove SCC that approaches critical size of axial defects on natural gas and hazardous liquid pipelines. A hydrostatic test addresses these axial flaws that approach critical flaw size while meeting the safety/integrity required over time. Using crack growth modeling can determine retest intervals and repairs. Hydrostatic testing provides the following:

- Validates integrity of the pipeline section(s)
- Determines maximum operating pressure(s)
- Qualifies pipeline section(s) for upgrades

It should be noted that hydrostatic testing finds these issues with longitudinal stresses due to the internal pressure and is limited when it comes to girth welds and circumferentially orientated SCC defects. However, the likelihood of these type defects is unlikely to fail or leak. Another consideration is large elevation changes in gas lines. There could be issues at low elevation areas due to overstressing in pipelines.

The challenge is to remove SCC defects in the pipeline while minimizing the growth of the other remaining defects. One way is to use a two-step process using a high-pressure test to remove the near critical SCC defects. This is followed up by a lower pressure test to determine if any previous SCC defects have not failed but could result in a leak situation.

Consideration should be given to the following factors:

- Test pressure – Higher the pressure, the smaller remaining defects

- If pressure reversals occur after successive hydrostatic pressure tests, spike testing is recommended
- Stress level – Highest test level feasible
- SMYS – Testing at 100% yield strength can result in the plastic range
- Original mill defects – Mill defects could rupture
- Safety – Higher the pressure additional safety is gained

There are a variety of pressures and hold times that have been developed by research and experience. However, it is up to the pipeline operator to develop and implement a pressure testing program that meets his requirements.

High Pressure SCC Integrity Test

Below is Table 1 that is currently being used by the oil and gas pipeline industry[1]. However, this paper will focus on classical SCC and the experiences using a two (2) hour high pressure test with a six (6) hour pressure test with a Max 110% Specified Minimum Yield Strength (SMYS) for high and a Max for 100% SMYS.

Table 1

Hydrostatic Testing Pressures and Hold Times

Procedure	"High" Pressure Intensity Phase		"Low" Pressure Phase	
	Min	Max	Min	Max
Battelle Test Pressures	100% SMYS (Min.)	110% SMYS (Max.)	90% SMYS (Min.)	100% SMYS (Max.)
Battelle Hold Times	1 hour		2 hours assuming pressure stabilization achieved	
CSA-Z662 Test Pressures	125% MOP (Min.)	110% SMYS (Max.)	110% MOP (Min.)	125% MOP (Max.)
CSA-Z662 Hold Times	4 hours		4 hours assuming pressure stabilization achieved	
Kiefner & Associates, Inc.	Spike Test as high as possible. (5 minutes)		Conduct CSA 8 hour test at a level at least 5% below spike test level.	

It is important to achieve the required stress levels for the entire test section especially with large elevation changes. This is needed to maintain the minimum hoop stress and test pressure throughout the segment; therefore, it requires breaking up it into many test sections. Today there is software to assist the operator with this kind of planning. Figures 1 and 2 show GIS mapping, data input and results[2]. In the early 1970's these were manually calculated.

[1] Canadian Energy Pipeline Association (CEPA), 1860 205 5th Ave. SW Calgary, Alberta, Canada
[2] Technical Toolboxes, 3801 Kirby Ave, Houston, TX 77098

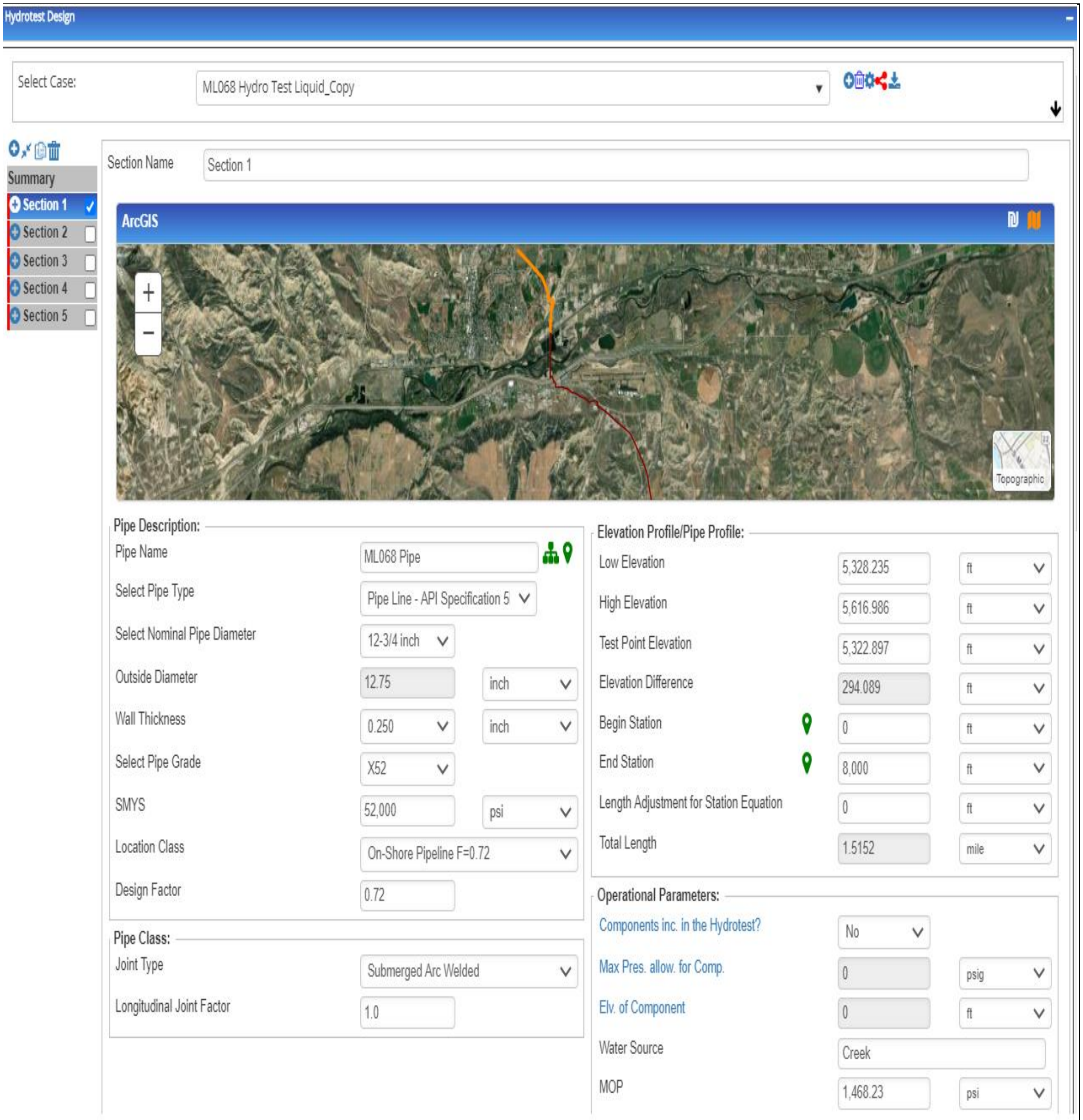

Figure 1 – GIS Map with Section 1 of 5 – Typical data input required for the Hydrostatic Test program to run which includes pipe description, pipe class, elevation profile and operational parameters.

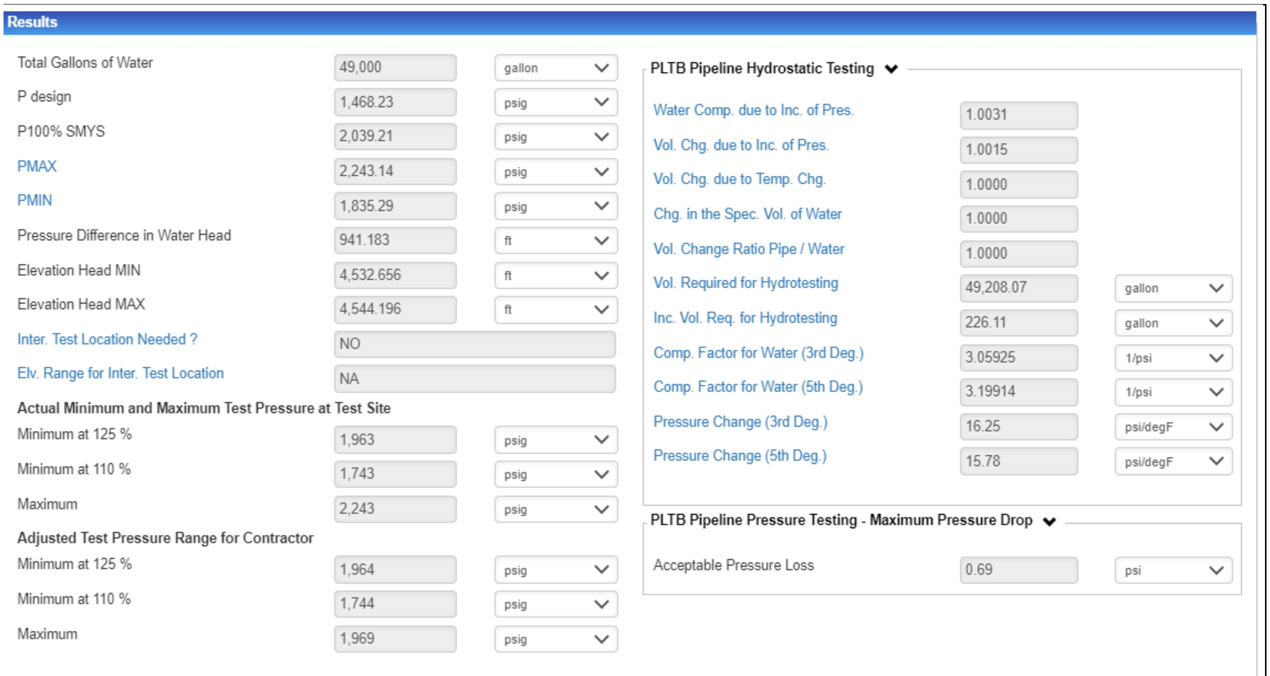

Figure 2 – Result of calculation – Typical results show water required, test pressures, hydro static testing and maximum pressure drop.

In lieu of a 2-hour high pressure test, spike pressure tests have become the norm to remove SCC. These tests should be run from a minimum of 15 minutes up to 30 minutes. The spike test determines the ratio of test pressure to operating pressure. Then operators will run the full 8-hour test at a minimum of five (5) % below the spike test, but a reduction of 10 percent is preferred to prevent subcritical crack growth during the remainder of the prescribed test period[3]. The high-pressure test is used to validate the integrity of the pipeline; whereas the low pressure allows the time to determines leaks in the pipeline.

Low Pressure SCC Integrity Test

The pipeline operator should use low pressure type leak tests for a hoop stress between 90% and 100% SMYS as shown in Table 1. One of the big differences between the low and high-pressure tests is the temperature variations that can impact the results. In the low pressure evaluate any pressure changes need to be addressed by comparing it to the temperature fluctuations to ensure that there are no small leaks. Figure 3 is a pictorial of a typical hydrostatic test data setup that shows temperature indicators are set a minimum of 500 feet from exposed pipe[4].

[3] Interstate Natural Gas Association of America (INGAA), 20 F Street, NW Suite 450, Washington, DC, 20001

[4] Willbors Group, Inc., 4400 Post Oak Parkway, Suite 1000, Houston, TX 77027

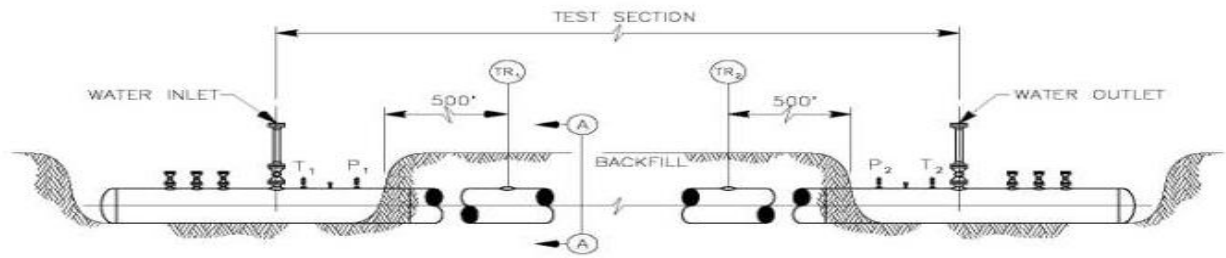

Figure 3 – Pictorial of hydrostatic test data setup shows the layout of the piping and temperature bulbs.

Investigative Digs/Mitigation/Repairs

During the late 60's natural gas pipelines were experiencing many high pH SCC leaks and failures. The primary cause was operating with hot discharge temperatures from natural gas compressors to keep up the customer natural gas demand during peak winter seasons. This was a result in discharge temperatures that were well over 65.66 C (150 F) that caused the external coal tar enamel coatings to cold flow on the bottom half of the pipeline and thus shield the cathodic protection from the pipe surface. This resulted in high pH or classical SCC primarily in the first two (2) valve sections which were approximately 18 miles apart.

During pre-investigative digs and direct examinations of classical SCC, it was common to see the SCC defects wink at you during these pipeline operations. My first experience on a SCC investigation took me back to see how these cracks would open and close during the pumping operations. These dig sites were typically within a couple of miles on the downstream side of a natural gas compressor station.

Equipment to measure the crack depths was not fully accurate due to tightness of these type of SCC cracks and the only way to estimate the depth was using grinding now called buffing techniques to remove them. Most cracks were surface cracks; however, when these cracks begin to link and grow longer, then the problems begin which required hydrostatic techniques to locate and remove them. At that time, it was trial and error period before the two-component type hydrostatic techniques became common and refined.

Common repairs included the following:

- Grinding or buffing
- Type B Steel Sleeve (Pressure Containment)
- Type A Steel Sleeve (Reinforcement – After SCC Removal)
- Replace a cylinder of pipe
- Hot tap

Reassessment Intervals

Pipe replacement evaluation is one of the biggest decisions a pipeline operator must make which is based on the location and other factors. These factors include the future susceptibility (risk) to future SCC. Next comes the decisions on when to retest a segment and or sections of the pipeline. Factors to be considered are as follows:

- Did the previous pressure test determine the maximum flaw size that survived the test?
- Will the MOP or established MAOP cause the pipe to fail?
- What is the crack growth rate that will determine the next pressure test?

The most difficult criterion is to determine the next reassessment interval for a specific segment and or segment of pipeline. Because SCC can grow and link up, consideration must be given for future growth and replacement. Therefore, crack growth must be a factor that is considered as shown in the failure as in figure 4.

Figure 4 shows the result of a SCC crack growth failure.

Conclusions

SCC failure pressure for a pipe segment or section can be assessed by the high-pressure test. Since the first documented incident(s) of stress corrosion cracking (SCC) occurred on natural gas pipelines in the mid 1960's, the industry is now faced with other forms of low pH SCC. It was from the early operating experience by pipeline operators, hydrostatic testing has shown to be an effective tool to remove SCC (for near critical axial defects) from both natural gas and hazardous liquid pipelines. Using good hydrostatic test procedures with experience removed axial flaws that approach these critical types of defects while meeting the safety/integrity required over time. Crack growth modeling can be used to determine reassessment intervals and types of repairs.

References

1. CEPA, Stress Corrosion Cracking Recommend Practices. 2nd Edition
2. Technical Toolboxes Hydrostatic Test Program

3. INGAA, Report 2013.03
4. Willbros, Hydrostatic Testing Practices