Management of the Integrity of Underground Pipelines Containing Stress Corrosion Defects

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ABSTRACT

Two forms of external stress corrosion cracking (SCC) have been identified on underground pipelines. They are referred to as near-neutral pH SCC and high-pH SCC and develop under different field conditions. Both forms of cracking pose integrity concerns for pipeline operators. This paper presents an overview of the two forms of SCC and a methodology for the management of pipelines containing these types of defects.

INTRODUCTION

The first reported incident of stress corrosion cracking (SCC) on natural gas pipelines occurred in the mid 1960's(1) and there have been numerous service and hydrostatic test failures since that time. Most of the early failures were intergranular in nature, whereas, many of the recent failures that have occurred in Canada are transgranular.(2) It is now recognized that there are two forms of external SCC on underground pipelines. The intergranular form is referred to as high-pH or classical SCC while the transgranular form is referred to as low-pH, non-classical, or near-neutral-pH SCC. Near-neutral pH SCC is most commonly associated with shielding tape coating while high-pH SCC is associated with disbonded coal tar and asphalt coatings. Both forms of cracking pose integrity concerns for pipeline operators. This paper presents an overview of the two forms of SCC and a methodology for the management of pipelines containing these defects.

OVERVIEW OF SCC

Table 1 summarizes the characteristics of the two forms of SCC. These data show that both occur in colonies with hundreds to thousands of cracks on the pipe surface that are generally longitudinal in direction, and localized to a small area of pipe on a joint. A typical colony is shown in Figure 1. These cracks can over time link up to form long shallow flaws that can reach critical dimensions for either a leak or rupture. In both cases, the fracture faces are usually covered with black magnetite or iron carbonate films, as shown in Figure 2. However, there are a number of differences in the two forms of cracking. Near-neutral pH SCC is most commonly associated with shielding tape coating while high-pH SCC is associated with disbonded coal tar and asphalt coatings. Not a single incident has been recorded where either form of SCC has occurred on fusion bonded epoxy (FBE) coated pipelines. The cracks associated with near neutral pH SCC are generally wide and transgranular in nature with evidence of corrosion of the crack walls, as shown in Figure 3. High-pH stress corrosion cracks are generally intergranular and are usually sharp with little evidence of corrosion of the crack walls, see Figure 4. Near-neutral-pH cracking has been found to be associated with longitudinal DSAW and ERW weld seams, areas of general corrosion and/or mechanical damage and other locations on the pipe body where the coating has become disbonded. On the other hand, high-pH stress corrosion cracks are typically found in the body of the pipe. Pitting corrosion and CO_2 attack also are occasionally associated with near neutral pH SCC sites while high-pH stress corrosion cracks usually are not associated with any significant amount of corrosion.

CONTROLLING FACTORS

For SCC to occur on an engineering structure, three conditions must be met simultaneously; a specific crack-promoting environment must be present, the metallurgy of the material must be susceptible to SCC, and tensile stresses above some threshold value must be present. An intact coating that excludes the environment from the pipe surface will prevent both forms of SCC. Each of these factors is discussed below for high-pH and near-neutral-pH SCC of natural gas pipelines.

High-pH SCC

Environmental Factors.

In the early 1970's, an extensive field survey was performed on SCC of natural gas pipelines, which was presented in the Fifth Symposium on Line Pipe Research.[(1)] A majority of the failures were associated with coal-tar enamel coatings. At the time, the near-neutral pH form of cracking had not been identified but it is probable that the vast majority of these failures were the high-pH (classical) form of cracking. Of over 240 service and hydrostatic test failures, forty-six failures were associated with bare lines, five failures were associated with tape coatings, two failures were associated with asphalt coatings and the remained were associated with coal-tar enamel coatings. No failures were reported with thin-film or wax coatings. In this study, the distribution of failures among the various coating types was attributed to the relative number of miles for each coating type and the age of installation of the coatings. For example, a survey of pipeline companies indicated that asphalt coatings represented a significant percentage of the total miles of pipe only for pipe installed after 1955; whereas, the majority of failures reported in the paper (written in 1974) were associated with pipe installed prior to 1955.

In the study by Wenk[(1)] it was concluded that a concentrated carbonate-bicarbonate solution was responsible for intergranular (high-pH) SCC observed on pipelines and a plausible mechanism for the development of the environment was developed. Essentially, the cathodic protection (CP) system causes a pH increase at the pipe surface. Carbon dioxide, which is present in the soil, is rapidly absorbed by the high-pH solution to generate the concentrated carbonate-bicarbonate (CO_3–HCO_3) environment. This environment is simulated in the laboratory using a 1N $NaHCO_3$ – 1N Na_2CO_3 solution, which has a pH of about 9.3.

The concentrated carbonate-bicarbonate environment was readily accepted by the pipeline industry and the scientific community as the causative agent for SCC of natural gas pipelines. The characteristics of the SCC generated on line pipe samples in the laboratory in this environment were consistent with most of the field observations at that time. These include the intergranular mode of cracking, the temperature, potential, and stress dependence of cracking, the initiation of multiple cracks on pipeline samples, and the association of the cracking with a black magnetite film.

Stress corrosion cracking of pipeline steels in the high-pH environment occurs over a very limited potential range that is about 100 mV wide and is approximately centered around -722 mV CSE at 75°C[3,4]. The potential range narrows and moves in the positive (noble) direction with decreasing temperature, as shown in Figure 5. The rate of crack propagation also decreases with decreasing temperature. These processes combine to decrease the severity of high-pH cracking with increasing distance down stream from a compressor station.[5] Figure 6 shows that the incidence of SCC failures (service and hydrotest) decrease exponentially with distance from a compressor station. Stress corrosion cracking in the high-pH environment also occurs over a limited pH range, centered around about pH 9[6]. At pH values above ten, the solution is primarily composed of carbonate and the passive film characteristics and electrochemistry are not conducive to SCC. At pH values below eight, the solution is dominated by the bicarbonate ion and cracking does not occur unless cations such as NH_4^+ are present. The dominant soluble cation found in high-pH electrolytes is Na^+.

The limited temperature, potential, and pH ranges over which SCC occurs in the high-pH environment provides an explanation for the infrequent occurrence of high-pH SCC on most pipeline systems. These dependencies also suggest that seasonal fluctuations are important in the cracking process. In order for the concentrated high-pH environment to develop, significant current flow to the pipe is required to generate the elevated pH environment required to absorb the CO_2. However, if cathodic protection is applied continuously, the pH of the environment may exceed the susceptible range. The potential range for SCC also lies between the native potential of most pipelines, and adequate protection, -850 mV (CSE). This paradox can be resolved if one assumes that the environment and potential vary on a seasonal basis, with SCC occurring only during periods of the year where adequate CP is not achieved.

Metallurgical Factors

The survey by Wenk[1] attempted to correlate the occurrence of SCC with metallurgical, and mechanical parameters. SCC was found to occur on pipelines having a variety of diameters, wall thicknesses, pipe grades, chemical compositions, manufacturers, and joining techniques. The range of compositions in which SCC was found covered the range of almost all line pipe in use at the time.

Mechanical Factors

In order for stress corrosion cracks to propagate in a material, tensile stresses must be present at the crack tip. Tensile stresses also are required for SCC initiation, and cracking usually initiates at flaws on the surface where a stress concentration exists. Below some value of the tensile stress, referred to as the threshold stress (σ_{th}), crack initiation does not occur.

The tensile stresses can be applied or residual in nature. In the case of SCC of pipelines, both have been shown to play a role in cracking. Many cases of longitudinal SCC have occurred in the body of the pipe where the primary stress is the hoop stress generated by the internal pressure. This contention is supported by the fact that SCC occurs much less frequently on heavy wall pipe, where hoop stresses are lower.

The threshold stress parameter, σ_{th}, for the initiation of SCC on line pipe steels has been studied extensively in the laboratory in the high-pH cracking environment. It has been found that σ_{th} for machined surfaces approaches the yield stress of most materials but σ_{th} is significantly reduced for an actual pipe surface by the presence of mill scale and pits on the surface [7]. For mill scaled surfaces, σ_{th} values measured in the laboratory are typically between 60% and 70% of specified minimum yield strength (SMYS) in the high-pH environment.[8] There is a significant amount of scatter in the σ_{th} data for a given steel, which may be the result of variation in surface residual stresses, surface condition (pitting or mill scale distribution), or in the thermomechanical treatment during fabrication.

Cyclic stressing also affects SCC. Laboratory studies in the high-pH environment have shown that the small pressure fluctuations associated with operation of a natural gas pipeline tend to exacerbate SCC[9]. This effect has been attributed to the occurrence of cyclic creep at the crack tips, which facilitates rupture of the passive films.

Near-Neutral-pH SCC

Environmental Factors

In the mid 1980s, TransCanada Pipelines started experiencing transgranular (near-neutral pH) stress corrosion failures.[2] . These failures were generally associated with SCC colonies located in close proximity to the longitudinal weld seam. The stress corrosion cracks had a tendency to line up along the toe of the weld seam and as such sometimes produced long flaws that eventually led to rupture. The pipelines were installed between 1957 and the early 1970s; therefore, they had been in the ground more than fifteen years before SCC was first detected. In response to these failures, an extensive hydrostatic testing and field inspection program was initiated. Of the 251 excavations performed, between 1986 and 1989, on tape coated portions of the system, 69% contained crack colonies, with an average of 11 colonies per excavation in which cracks were discovered. Of the 189 excavations performed, between 1986 and 1989, on asphalt coated portions of the system, about 14% were found to contain SCC colonies, with an average of about 6 colonies in each excavation containing cracking.[10,11,12] The cracking at the tape coated sites also was generally deeper. Only 1% of all of the colonies detected had depths greater than 10% of the wall thickness and 96% had depths of less than 5% of the wall thickness. Thus, in spite of the large number of colonies detected, the vast majority were not an integrity concern.

The extensive field investigation program also demonstrated that the occurrence of SCC correlated with near-neutral-pH (pH <8) dilute CO_2 containing electrolytes and that cracking was not observed where high-pH electrolytes were detected.[11] The results of these studies indicate that the environment responsible for near-neutral-pH cracking is dilute groundwater containing dissolved CO_2. As is the case for high-pH SCC, the source of the CO_2 is decay of organic matter in the soil. However, in the case of near-neutral-pH SCC, cathodic protection current cannot flow to the pipe either because of shielding of the current by coatings such as tapes, high resistance soils, or a poor cathodic protection system design. As a result, a dilute carbonic acid solution develops.

In contrast with the strong temperature dependence exhibited by the high-pH form of SCC, the available field and laboratory data indicate that near-neutral pH SCC does not exhibit a measurable temperature dependence over the typical operating range for pipelines. In the TransCanada field studies [11] it was found that only 50% of the SCC failures (service or hydrotest) were located within 16 km (10 miles) downstream of the compressor stations while more than 20% were located more than 30 km downstream. Furthermore, there was no detectable effect of distance downstream of the compressor station or temperature on the depth or number of SCC colonies detected in the field dig program.

The association of cracking in the field investigation program [11, 12] with near-neutral pH environments indicates that cathodic protection is beneficial in mitigating this form of cracking. However, no correlation has been observed between the pipe-to-soil potentials measured on tape coated portions of the system and the occurrence of near-neutral pH SCC[13]. This behavior is the result of the shielding nature of tape coatings. The pipe at the holidays is protected and the potentials at the holidays meet cathodic protection criteria but the cracking occurs beneath disbonded coating, which cannot be sensed by ground-level measurements, and cathodic protection cannot reach. On asphalt coated pipelines, near-neutral pH SCC has occurred in regions of inadequate cathodic protection. Ground level electrical surveys can be used to help locate these regions.

Metallurgical Factors

Near neutral pH SCC has been observed on a number of pipelines having different grades and yield strengths [14]. They do all appear to be carbon-manganese steels with a ferrite/pearlite microstructure. Near neutral pH SCC failures with the newer micro-alloyed very low carbon steels have not been reported. This may simply reflect the fact that these are newer steels (have not been in service as long) and have better coatings (i.e. no tape). In any case, there are no laboratory or field data indicating that one particular microstructure or grade of steel is significantly more resistant to near-neutral-pH SCC.

Results of laboratory studies[15] on precracked compact type specimens have demonstrated that the coarse grain heat affected zone (CGHAZ) microstructure adjacent to the weld, in an X-65 steel, is significantly more susceptible to cracking than the base material in the near-neutral-pH environment. This may be a contributing factor in the service failures.

Mechanical Factors.

The mechanical conditions for near neutral pH SCC appear to be more restrictive than those for high-pH SCC. In SSR tests, cracking is generally only observed within the necked region of the specimen where plastic deformation and true stresses are very high, as previously described. In constant displacement rate testing [15], cracking was only observed where dynamic loading conditions were present

A threshold stress for crack initiation in the near-neutral-pH environment has not been established. A strong relationship has been established between the occurrence of SCC on one pipeline system and class location. On that system, SCC has led to about twenty failures in Class I locations, operating at 62% to 77% of SMYS, while only minor cracking and no failures have occurred on Class II or III locations, which operate at 64% and 53% of SMYS, respectively[14]. This relationship suggests that either the threshold stress for SCC initiation is above about 65% of SMYS or that crack growth rates at these stresses are too low to cause significant problems.

Development of an SCC Integrity Management Program

In order to systematically and cost effectively manage the various integrity threats present along a pipeline system, pipeline operators are beginning to develop risk-based Integrity Management Programs to address those threats which are specifically impacting their system. The general framework, for developing such programs, should be relatively similar irrespective of the integrity threat being addressed since each of the various programs typically share a common set of objectives. Listed below are the primary objectives of any Integrity Management Program:

- ensure the continued safety of the public and company personnel
- minimize the risk of damage to the environment and to public and private property
- maintain system reliability
- achieve the first three objectives in a prudent and cost effective manner

Provided in Figure 7, is an example of a generic framework that could be used in the development of an SCC Integrity Management Program. This type of framework is flexible enough to allow individual operating companies the ability to develop and implement an SCC Integrity Management Program that is specifically tailored to their own unique set of operating circumstances. The three primary components of this framework are:

- condition monitoring
- mitigation
- document and learn

The remainder of this paper will discuss how to develop an SCC Integrity Management Program using the framework illustrated in Figure 7 as a point of reference .

Condition Monitoring

The purpose of condition monitoring is to first assess whether or not there are any portions of a pipeline operator's system which are susceptible to SCC initiation and then secondly, to assess the severity of any SCC detected in the field in order to determine whether some form of mitigation is required.

There are many ways in which to define SCC severity. It is possible to define the severity of an SCC colony based upon its depth, length, estimated burst pressure or some combination thereof. Operating pipeline companies need to develop a definition for SCC severity that best suits their own particular situation. It is strongly recommended that any definition used to describe SCC severity be sufficiently conservative so as to allow the pipeline operator adequate time to develop and implement a proactive mitigation program to address the SCC of concern.

Condition monitoring consists of three key components; namely, initial susceptibility assessment, prioritizing and implementing field investigations and periodic monitoring. These three components will be briefly discussed below.

Initial Susceptibility Assessment

As described previously in this paper, there are specific parameters which are known to contribute to the initiation and propagation of SCC. Consequently, in order to effectively conduct an initial susceptibility assessment of a given pipeline system, it is essential that all relevant data pertaining to that system is collected and organized in a suitable manner for subsequent analysis. The types of relevant data that should be collected, if available, are listed below:

- the type of external coating used to protect the pipeline
- the terrain conditions (i.e. soil type, drainage and topography) present along the pipeline system
- data from cathodic protection surveys
- the maximum and typical operating stress levels of the pipeline system
- historical data relating to any previous incidents of SCC along the pipeline system
- the age of the pipeline system
- inline inspection data that indicates the presence of cracks, corrosion or mechanical damage
- the maximum and typical temperature of the pipeline (Note: this is important for high pH SCC but not as important for near-neutral pH SCC)
- the pipe manufacturer
- the pipe manufacturing process (i.e. seamless, longitudinally welded, spirally welded)
- the seam welding process (i.e. submerged arc welded, double submerged arc welded, electric resistance welded, flash butt welded, etc.)

Using the above data, the pipeline operator can then assess the relative susceptibility of their entire system to SCC. There has been a tremendous level of field activity undertaken, by some pipeline operators in Canada, in order to establish correlations between the susceptibility to near-neutral pH SCC and the various parameters discussed above [11,12,13,16,17]. Unfortunately, there has not been a similar effort undertaken, to date, to establish a correlation in the field between the above parameters and the susceptibility to high pH SCC. However, there does exist a considerable amount of laboratory data that can assist a pipeline operator in assessing the susceptibility of their pipeline system to high pH SCC[1,3,4,5,6,9,]. It is not within the scope of this paper, beyond what has been previously discussed, to go into more detail regarding correlations between SCC susceptibility and the above parameters.

Prioritization and Implementation of Field Investigations

Once the relative susceptibility to SCC of an entire pipeline system has been established, the next step in the process is to conduct a more thorough SCC assessment of the pipeline by undertaking an initial field excavation and investigation program. Depending upon the extent to which a pipeline system is assessed to be susceptible to SCC, it may be necessary to develop a multi-year field excavation program. The multi-year program would be developed through the prioritization of those discrete portions of the system deemed to be SCC susceptible.

Prioritization, if required, should be based upon the relative SCC susceptibility of those portions of the pipeline system deemed to be susceptible and their associated consequences if an incident were to occur. In establishing the consequences associated with any portion of their pipeline system, a pipeline operator should take into consideration individual and societal related consequences, environmental related consequences and business related consequences.

In establishing the appropriate scope of an initial field investigation program and the associated time frame for implementing that program, pipeline operators should consider several factors; namely, the total length of their system, the estimated length of potentially susceptible pipe within their system, the relative susceptibility of the pipe deemed to be susceptible and the consequences of an incident occurring within those discrete portions of the system deemed to be susceptible.

Periodic Monitoring

Periodic monitoring entails conducting, at an appropriate frequency, subsequent field investigation programs in discrete portions of the system which had been previously investigated. A pipeline operator should consider conducting a periodic monitoring program on those discrete portions of their system which meet the following criteria:

- SCC was detected during the initial field investigation program but its severity was within the acceptable limits as defined by the pipeline operator.

- SCC with a severity exceeding the acceptable limits, as defined by the pipeline operator, was detected but it was subsequently determined that the extent of such SCC was limited.

In determining the appropriate number of additional field investigations to be undertaken in a given discrete portion of the system and the frequency at which those investigations are to be conducted, pipeline operators should take into consideration several factors; namely, the extent and severity of the SCC detected during the initial field investigation program, the total length of their pipeline system or the estimated length of potentially susceptible pipe within their system and the consequences of an incident occurring within those discrete portions of the system deemed to be susceptible.

Mitigation

A pipeline operator should develop and implement a mitigation program whenever they detect SCC having a severity which exceeds their acceptable limits. By undertaking such a program the operator will ensure the continued integrity and safety of their system.

Mitigation consists of two key components; namely, selecting the appropriate method of mitigation and then prioritizing and implementing the mitigation program. These two components will be briefly discussed below.

Method of Mitigation

Anytime SCC, of an unacceptable severity, has been detected in a portion of their system, a pipeline operator should assess the probability of there being additional SCC of similar severity elsewhere in that particular portion of the system.

If a pipeline operator is able to determine that there is a very low probability of additional SCC, of an unacceptable nature, being present in a given portion of their system they should select a “discrete” form of mitigation. “Discrete” mitigation is aimed at addressing only those particular joints of pipe in which SCC, of an unacceptable severity, was detected. This form of mitigation is generally used to address isolated locations which are typically less than 100 m in length. The various forms of “discrete” mitigation are: grinding repairs, selective pipe replacements and recoating.

Whereas, if a pipeline operator determines that there is a high probability of there being widespread SCC, of an unacceptable nature, present in a given portion of the system they should select a “general” form of mitigation. “General” mitigation is aimed at addressing not only those joints of pipe which were found to contain SCC of an unacceptable severity but also joints of pipe that have been assessed to be potentially susceptible to such SCC. This form of mitigation is generally used to address longer sections of pipeline which are typically more than 10 km in length. The various forms of “general” mitigation are: hydrostatic retesting, inline inspection, large scale pipe replacements and large scale recoating.

Prioritization and Implementation of Mitigation Program

Anytime unacceptable SCC is detected during the course of a field investigation program the pipeline operator should, whenever possible, immediately undertake some form of "discrete" mitigation to address the specific SCC of concern. However, depending upon the extent of "general" mitigation required, it may become necessary to develop a multi-year "general" mitigation program through the prioritization of the affected portions of the system.

Prioritization, if required, should be based upon the number of unacceptable SCC colonies detected in a given portion of the pipeline system, the estimated burst pressure of the unacceptable SCC detected, the estimated remaining life of the unacceptable SCC and the associated consequences if an incident were to occur in that portion of the system. As previously mentioned, a pipeline operator should take into consideration individual and societal related consequences, environmental related consequences and business related consequences when determining the overall consequences associated with a particular portion of their system.

Following the successful implementation of an initial "general" mitigation program the pipeline operator will need to assess whether such a program will be required on a regular basis. This assessment should take into consideration the following factors:

- whether the type of "general" mitigation previously implemented permanently addressed the SCC of concern (i.e. such as large scale pipe replacements or recoating)
- results of the initial "general" mitigation program (i.e. were there any hydrostatic test ruptures or near-critical SCC colonies detected)
- additional information from subsequent field investigation programs (i.e. is the amount of unacceptable SCC actually as widespread as it was initially perceived to be).

Should the pipeline operator determine that a regular "general" mitigation program is required for a specific portion(s) of their system, it will then be necessary for them to establish a safe and prudent frequency with which to undertake subsequent programs. In identifying a prudent frequency with which to undertake subsequent "general" mitigation programs, the pipeline operator should take into consideration the maximum size of an SCC flaw that could have been left in their pipeline following the initial "general" mitigation program, the critical dimensions of an SCC flaw at the maximum allowable operating pressure (MAOP) of their pipeline and any available information as to observed SCC growth rates in either their pipeline system or other operator's systems exposed to similar operating and environmental conditions.

Document and Learn

The effectiveness of a pipeline operator's SCC Integrity Management Program is ultimately governed by their ability to continuously learn not only from their own previous experiences but the experiences of others. Consequently, it is strongly recommended that pipeline operators keep concise and accurate documentation pertaining to the methodology used in the development and implementation of their SCC Integrity Management Programs. It is also suggested that pipeline operators develop a protocol for the collection of data which should be obtained during any field investigation program undertaken on their system.

Pipeline operators should also, when possible, take advantage of opportunities to mutually share not only their SCC related information but general pipeline integrity related information with others in the industry through, industry organizations and associations, one on one information exchanges with other operating companies and attending pipeline related conferences and seminars.

Summary

Presented within this paper was an overview of the two recognized forms of SCC currently affecting the pipeline industry worldwide and a methodology for the prudent and proactive management of pipelines containing such defects.

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Table 1. Comparison of High-pH and Near-Neutral-pH SCC.

CHARACTERISTIC	NEAR-NEUTRAL-pH SCC	HIGH-pH SCC
Electrolyte pH	6.5 to 7.5	9 to 10
Fracture Mode	Transgranular	Intergranular
Cracking Orientation	Longitudinal	Longitudinal
Numerous Surface Cracks	Yes	Yes
Linking of Crack	Yes	Yes
Patches of Cracks	Yes	Yes
Corrosion of Crack Faces	Yes	No
Corrosion of Pipe	Sometimes	Usually Not
Association with Iron Carbonate and Magnetite Films	Yes	Yes
P/S Potential, CCS	Native Potential	!722 mV
Width of Potential Range	Probably > 100 mV	Narrow (< 100 mV)
Temperature Dependence	Not Established	Arrhenius Behavior

Figure 1. Optical photograph of near-neutral pH SCC colony following MPI inspection.

Figure 2. Optical photograph of pipe sample following breaking in liquid nitrogen, showing interlinked stress corrosion cracks.

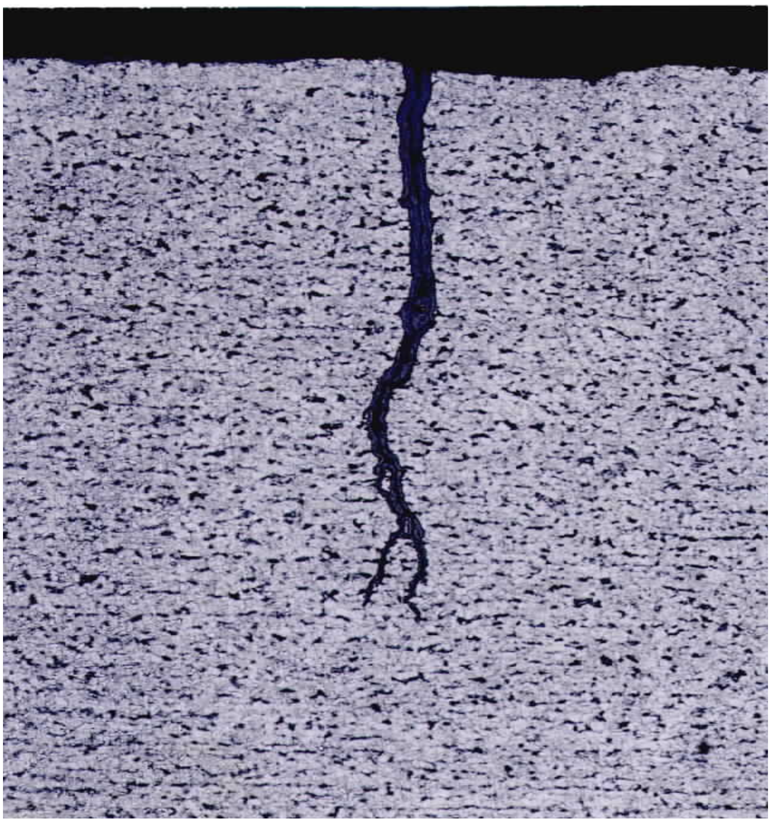

Figure 3. Typical near neutral pH stress corrosion crack from a field cut-out of pipe containing an SCC colony. (100X Magnification)

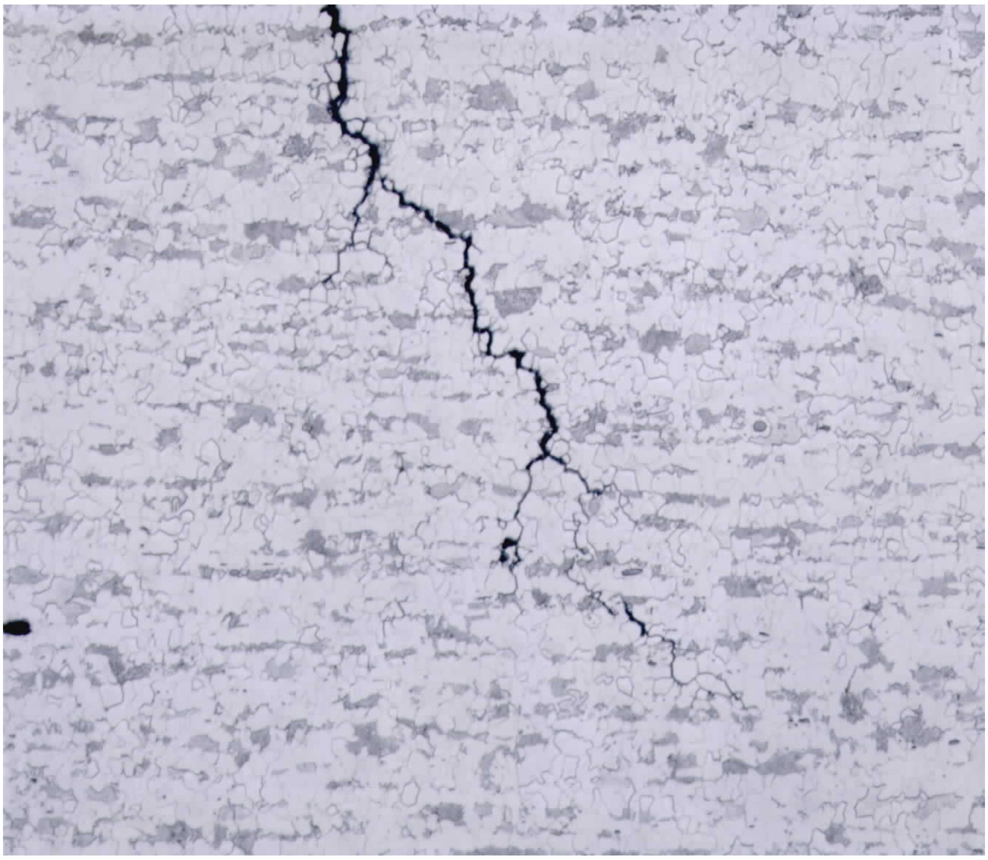

Figure 4. Typical high-pH stress corrosion crack from a field cut-out of pipe containing an SCC colony. (200 X Magnification)

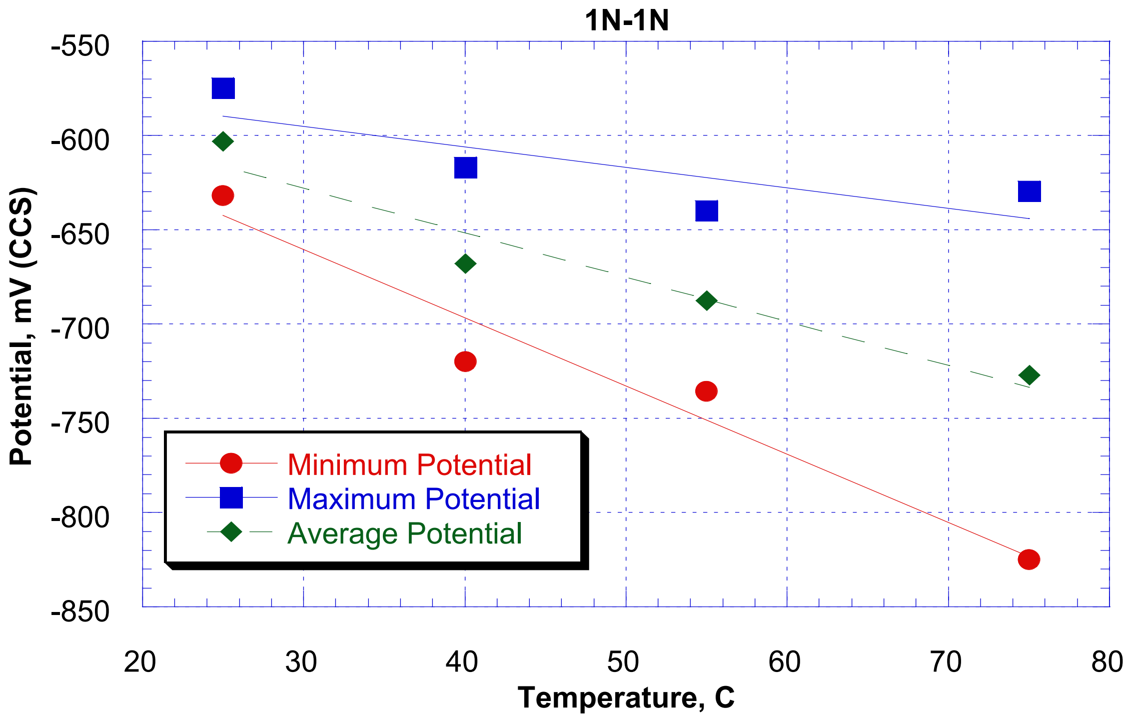

Figure 5. Potential range for cracking as a function of temperature for SSR tests performed in 1N Na_2CO_3 – 1N $NaHCO_3$. (Reference 4)

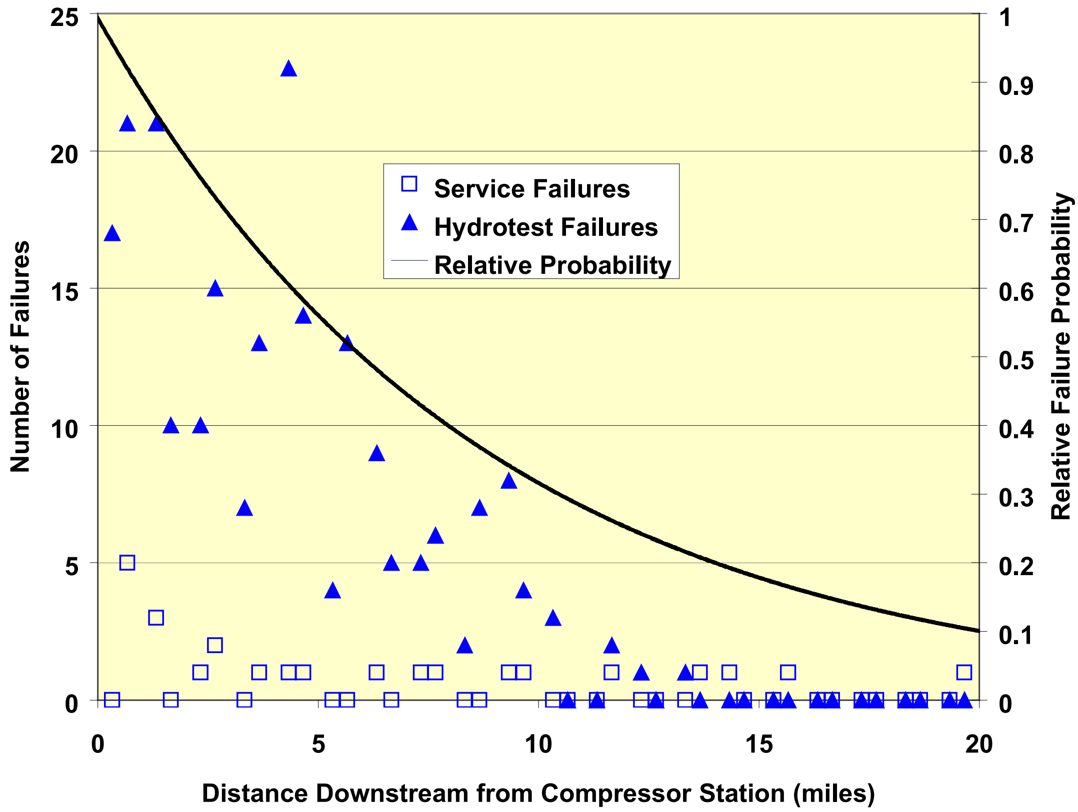

Figure 6. Failure history and calculated failure probability (based on temperature) as a function of distance down stream from compressor station: activation energy = 10,000 cal./mole, discharge temperature = 54.4^{o}C, ground temperature = 15.5^{o}C, temperature constant = 0.045/mile. (After Reference 5)

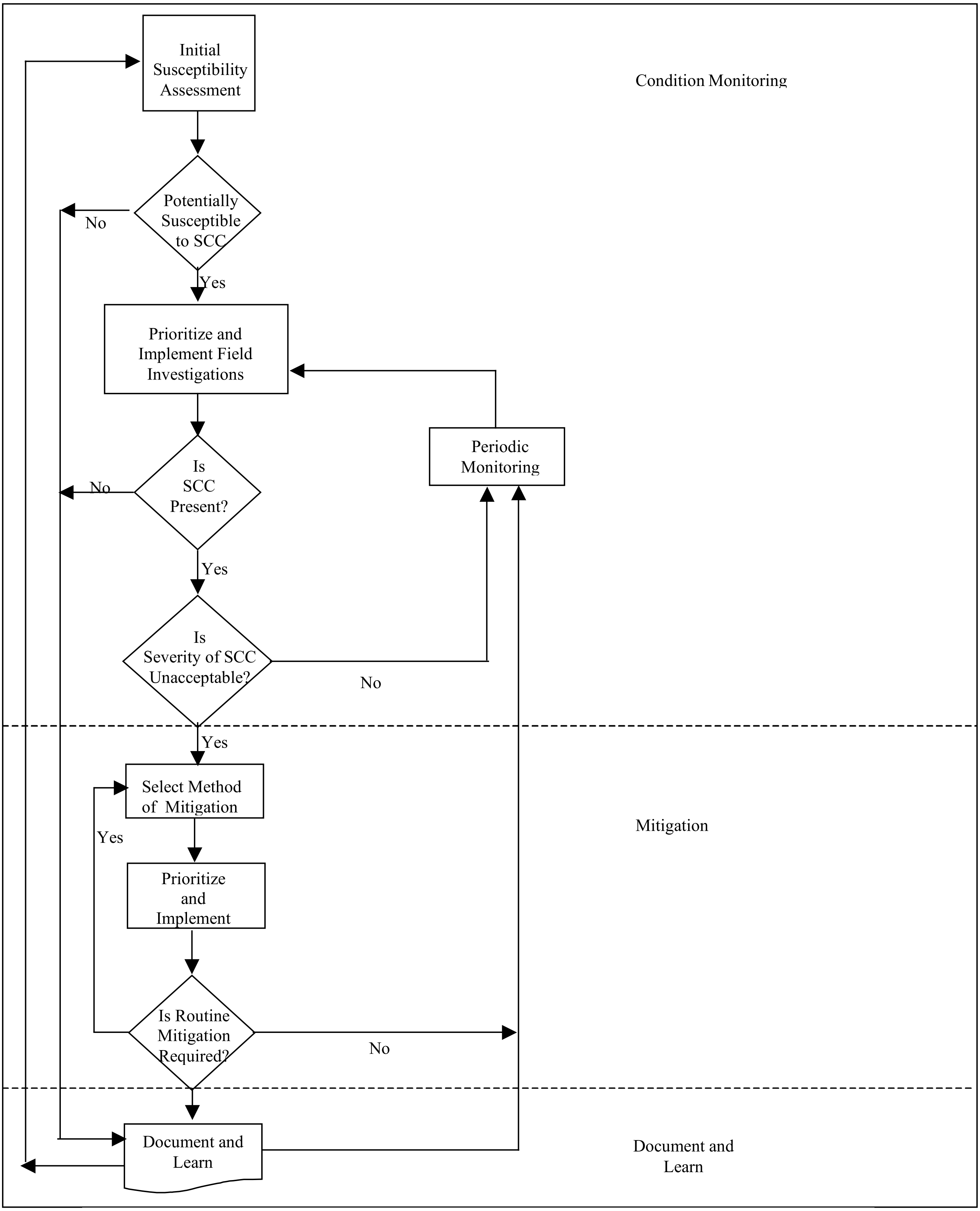

Figure 7 – Example of an SCC Integrity Management Program