UKOPA

UK ONSHORE PIPELINE OPERATORS' ASSOCIATION - INDUSTRY GOOD PRACTICE GUIDE

Near Neutral pH and High pH Stress Corrosion Cracking

Guidance Issued by UKOPA:

The guidance in this document represents what is considered by UKOPA to represent current UK pipeline industry good practices within the defined scope of the guide. The document does not specify prescriptive requirements, should be considered guidance and should not be considered obligatory against the judgement of the Pipeline Owner/Operator. Where new and better techniques are developed and proved, they should be adopted without waiting for modification to the guidance in this document. The term 'shall' has been used to identify any requirement of UK law in Great Britain at the time of publication.

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CONTENTS

1 INTRODUCTION

A possible threat to the structural integrity of high pressure pipelines is external stress corrosion cracking (SCC). Although there is no documentary or anecdotal evidence of operators of pipelines in the UK having experienced this anomaly, the attributes (age, steel grades, coating types, soil types, operating conditions etc.) of the pipelines these operators are responsible for managing have some features in common with those where SCC has occurred elsewhere in the world.

Pipelines operated by UKOPA members have been in service for over 50 years, over 60% of which are protected with coat tar enamel (CTE) and asphalt (bitumen) coatings that have been associated with both high pH and near neutral pH forms of SCC. The product loss incidents reported by UKOPA [1] over the period 1962 – 2011, which represents 811,923 km yr of operation, include no incidents associated with external SCC. Despite this, UKOPA members acknowledge the fact that their assets are ageing and that they need to consider any threat that these ageing assets may become susceptible to with continued operation. It is pertinent to note that pipeline uprating, which has been undertaken on some operator's networks, may increase the risk of one of the factors that contribute to SCC occurring.

The guidance provided in this document should allow UKOPA members to understand:

- What is already known about SCC and what do we need to know?
- Where is SCC found?
- What are the frequency and consequence of SCC-related failures?
- How is SCC detected and characterised?
- What are the susceptibility parameters of SCC?
- What tools exist for detecting SCC and what is their reliability?

2 SCOPE AND APPLICATION

2.1 Scope

The guidance in this document is applicable to all buried steel pipelines operated by the UKOPA member companies. These pipelines can be categorised as:

- Natural gas transmission and distribution pipelines;
- Petrochemical liquids and gas pipelines;
- Oil and refined liquid pipelines.

For gas pipelines the guidance is generally applicable to steel pipelines with maximum operating pressures above 7 bar, however the principals of the document can be equally be applied to gas steel pipelines operating at lower pressures.

2.2 Application

The guidance in this document represents what is considered by UKOPA to represent current UK pipeline industry good practice within the defined scope of the document. All requirements should be considered to be guidance and should not be considered to be obligatory against the judgement of the Pipeline Owner/Operator. Where new and better techniques are developed and proved, they should be adopted without waiting for modifications to the guidance in this document.

3 Understanding Stress Corrosion Cracking

SCC in pipelines is characterized as ‘high pH SCC’ or ‘near-neutral pH SCC,’ with the ‘pH’ referring to the environment on the pipe surface at the crack location and not the soil pH. (pH is the measure of the relative acidity or alkalinity of water, the lower pH levels indicate an increasing acidity, while pH levels above 7 indicate increasingly alkalinity).

The most obvious identifying characteristic of SCC in pipelines, regardless of pH, is the appearance of patches or colonies of parallel cracks on the external surface of the pipe (Figure 1, Appendix D). There may be several of these colonies on a single pipe and many pipes may be involved. The cracks are closely spaced and of varying length and depth. These cracks may coalesce to form larger and longer cracks, which in some cases can lead to rupture (Figure 2, Appendix D). If the cracks are sparsely spaced, they might grow through the wall and leak, before they reach a length that is sufficient to cause a rupture.

In order for SCC to occur, three conditions need to be satisfied simultaneously:

1. A tensile stress must be present in the metal higher than the threshold stress, frequently including some dynamic or cyclic component to the stress.
2. The pipeline steel must be susceptible to SCC.
3. A potent cracking environment must be present at the metal’s surface. This generally develops under a disbonded coating.

In addition to these three conditions, the pipe potential must be in the narrow range of values under which high pH and near neutral pH SCC occur. For example, high pH SCC requires the pipe potential to be slightly cathodic of its free corrosion potential, whereas near neutral pH SCC occurs at the pipe’s free corrosion potential

In general, SCC has been found on onshore buried pipelines and is usually oriented longitudinally as shown in Figure 1 Appendix D, normal to the hoop stress of the pipeline, which is usually the dominant stress component resulting from the pipe’s internal pressure. However, SCC may also occur in the circumferential direction (C- SCC) when the predominant stress is an axial stress. Incidents resulting from C-SCC have been reported due to stresses induced by soil creep and localized bending from ground movements. Residual stresses at girth welds may also produce a resultant axial load within a pipeline and contribute to C-SCC.

3.1 High pH SCC

When pipeline steel is exposed to the surrounding environment due to some form of coating failure, it is vulnerable to corrosion. Because soil corrosion is an electrochemical process, cathodic protection (CP) is used to mitigate corrosion by passing an electrical current through the soil thus giving the pipeline a cathodic potential. A concentrated carbonate-bicarbonate (CO_3-HCO_3) solution has been identified as the most probable environment responsible for high pH SCC. This environment may develop as a result of the interaction between hydroxyl ions produced by the cathode reaction and carbon dioxide (CO_2) in the soil generated by the decay of organic matter. CP current causes the pH of the electrolyte beneath disbonded coatings to increase, and the carbon dioxide readily dissolves in the elevated pH electrolyte, resulting in the generation of the concentrated carbonate-bicarbonate electrolyte. The pH of this electrolyte depends on the relative concentration of carbonate and bicarbonate, and the cracking range within which the high pH form of SCC initiates lies between pH 8 and 11. High pH SCC has been predominantly observed under coal tar enamel (CTE), but has also been experienced under asphalt (bitumen) and tape coatings. Although failures typical occur within 15 – 20 years of commissioning a pipeline, they have taken place in time periods as short as 6 years and as long as 40 years.

The critical potential range for high pH SCC is generally more negative than the free corrosion potential of the steel and consequently high pH SCC and general corrosion do not occur simultaneously. Whilst, the critical potential required for high pH SCC is generally more negative than the free corrosion potential of the steel, it is usually less negative than that associated with a well maintained CP system. It follows that high pH SCC is possible in situations where a breach in the coating exits and the CP system is still working, but at reduced potential. However, a more likely situation is where the CP system is fully effective but coating damage has occurred in addition to cathodic disbonding. In this situation ground water can enter at the damage and become trapped under the disbonded coating. A metal surface potential under the disbonded coating, in the critical range, can become established due to two possible mechanisms. If the coating has become permeable, the ingress of water will reduce the electrical resistance of the coating sufficiently to allow some of the CP current to reach the metal surface. Alternatively, the CP current can pass along the crevice formed between the disbonded coating and the steel's surface, with a decay of potential as the current spreads over the metal surface under the disbonded coating. Analysis of the liquid trapped in the disbonded area or in the crack itself typically indicates a carbonate-bicarbonate solution with a pH of 8 to 9, where high pH SCC has been active.

Metallographic examination of a section across the crack shows the fracture path to be intergranular (around the grain boundaries), often with small branches, as shown in Figure 3, Appendix D. Laboratory simulation with small test specimens indicates that this form of SCC is temperature sensitive and occurs more frequently at higher temperature locations above approximately 35°C. This supports field reports that demonstrate a greater likelihood of high pH SCC immediately downstream of a compressor station where the operating temperature may reach temperatures of 65°C or higher.

There is almost universal agreement that crack initiation and growth in the high pH environment occur by selective dissolution of the grain boundaries, while a passive film forms on the remainder of the surface and on the crack sides to prevent corrosion at those locations. When an unstressed, polished surface of line-pipe steel is exposed to the high pH carbonate/bicarbonate environment at the appropriate potential for SCC, etching of the grain boundaries occurs with no noticeable corrosion of the grain faces [7]. A strong correlation has been found between the maximum rate of crack growth and the maximum corrosion rate that can be sustained in that environment [8]. The reason for preferential attack at the grain boundaries is thought to be related to some kind of chemical segregation or precipitation at the grain boundaries, but no direct evidence of either has been found.

3.1.1 Factors influencing the initiation and crack growth of high pH SCC

Pipe Steel: In principle all pipeline steels should be considered susceptible to high pH stress corrosion cracking but it is not possible to rank the risk of crack initiation and growth based on steel grade, structure, chemistry or age.

Stress: The threshold for high pH SCC ranges from 46 – 76% of SMYS dependent on the range of stress fluctuations; all but one failure due to high pH SCC has occurred at >60%. The bulk of evidence from field investigations in North America has shown higher levels of crack initiation, and growth, downstream from compressor stations where the mean operating stress and stress cycling was greatest. Much of this data was collected on pipelines operated with reciprocating compressors and the contribution of the pressure ripple associated with these machines is not fully defined.

In the absence of a sustained cyclic stress regime the threshold for crack initiation approaches yield [9]. Stress cycling is a critical factor in crack initiation and growth but the criteria for assessing variable loading regimes have not been fully defined.

Temperature: Temperature has an effect on the growth rate of high pH stress corrosion cracks and also affects the range of pipe-to-soil potentials in which cracks initiate and grow. High pH SCC has occurred at temperature between 10 – 60^{o}C with the majority occurring above 35^{o}C.

Crack growth rates increase by a factor of ~2 for each 10 ºC increase in temperature. Koch et al [10] reported an increase in crack growth rates from 1.7 X 10^{-8} mm/s at 50 ºC to 2.1 X 10^{-6} mm/s at 80 ºC. However, no change was observed in the threshold stress conditions for crack initiation with increasing temperature.

The effect of increasing temperature is to bring the potential range for cracking closer to the minimum polarisation limit of –850 mV (with respect to a Cu/CuSO4 electrode) that is normally accepted for effective cathodic protection on modern pipelines.

Environment: The generation of a carbonate – bicarbonate environment required for high pH SCC to occur is a function of the applied cathodic protection and the condition of the pipeline coating. The presence of a critical environment cannot be accurately predicted from ground conditions or soil type.

Pipe Potential: The range of pipe-to-soil potentials conducive to cracking appear to have been widespread on coal tar and asphalt coated pipelines in North America. This experience should not be extrapolated to coal tar enamel coated pipelines found elsewhere in the world because the lines in the USA may be different in a number of significant respects, including:

- The coatings in North America were field applied over a wire brushed surface, often still containing millscale, and this millscale served to stabilize potentials in the cracking range ;
- The coatings were thinner than applied to many pipelines in the UK;
- The coatings had been aged, and degraded, by high temperature operation;

- Operating temperatures were significantly higher on pipelines in North America than experienced in the UK and this shifted the potential range for cracking closer to the –850 mV (with respect to a Cu/CuSO4 electrode) criterion for cathodic protection. Temperature also increased the width of the pipe-to-soil potential band for cracking;
- The pipelines in North America were monitored at test posts using ‘on’ potential measurements so the actual potentials (free of IR drop through the soil) created by the cathodic protection were not known with any accuracy.

Coating: High pH SCC has been predominantly found under coal tar enamel, asphalt and tape coatings. No stress corrosion has been found under fusion bonded epoxy coatings, 2 or 3 layer extruded polyethylene (PE) systems, and liquid coatings including epoxy, epoxy urethane and polyurethane (PU). Many authorities accept that this may be a function of the age of the coating system rather than an indication of inherent immunity. However, fusion bonded epoxy, 2 layer PE and liquid epoxy, epoxy urethane and PU coated pipelines have been in service for more than 40 years, and 3 layer PE for more than 30 years, so pipeline age is not a satisfactory explanation. It is more probable that surface preparation, coating quality and operating conditions have contributed to this apparent immunity to stress corrosion.

Caution is required in extrapolating coating performance between pipeline systems and the differences between coal tar enamel coatings applied to pipelines in North America and the UK have already been discussed.

Soil: Studies of soil conditions on pipelines affected by high pH stress corrosion have not revealed any correlations to soil chemistry or composition [11]. Where some correlation has been established between stress corrosion and soil conditions they relate to soil position, texture and drainage and these are the properties of the soil that influence the distribution of the cathodic protection current on the pipeline.

The high pH stress corrosion cracking environment is generated by the applied cathodic protection and is separated from the soil by loose coating so no clear correlation would be expected with soil chemistry or composition. It is debatable whether a soil risk model based on soil position, drainage and texture can provide a better definition of risk.

3.1.2 Summary of findings

High pH SCC occurs under disbonded coal tar enamel, asphalt and tape coatings where the surface under the disbonded coating is still receiving CP current, which is encouraging a carbonate – bicarbonate environment to develop. The cracking mechanism typically occurs at stress levels >60% of SMYS, requires a cyclic component to the stress and is accelerated at elevated temperature.

There is no documented experience of high pH SCC occurring under FBE, 2 and 3 layer extruded PE and liquid coatings including epoxy, epoxy urethane and polyurethane (PU). In addition there is no documented experience of high pH SCC occurring on gas pipelines in the UK irrespective of the coating type and operating conditions.

3.2 Near Neutral pH SCC

3.2.1 Longitudinal Cracking

This form of SCC was not documented until the mid-1980s, and was first identified on buried pipelines in Canada, most commonly under tape coatings. It is acknowledged that near neutral pH SCC failures may have taken place before this time and incorrectly attributed to the high pH form of SCC. The solution trapped in wrinkles in the tape wrap under which near neutral pH SCC develops has a pH between 5.5 and 7.5. In the case of near-neutral pH SCC, the cracking environment appears to be a groundwater containing dissolved carbon dioxide. The source of the carbon dioxide is typically the decay of organic matter and geochemical reactions in the soil. This form of cracking occurs under conditions where there is little, if any, CP current reaching the pipe surface over a prolonged period, either because of the presence of a shielding coating, a highly resistive soil, or ineffective CP. Typically, the SCC colonies initiate at locations on the outside surface where there is already pitting or general corrosion, which is sometimes obvious to the unaided eye and at other times very difficult to observe.

Metallographic examination of near-neutral pH SCC reveals the cracks to be predominately transgranular (occur through the grain structure) and are wider (more open) than the high pH form, i.e. the crack sides have experienced metal loss from corrosion (see Figure 4 Appendix D).

Near neutral SCC cracks are more prone to initiation at sites that are subject to surface tensile residual stresses [12]. It follows that near-neutral SCC is more likely near to welds that have not been subjected to post weld heat treatment (Figure 5, Appendix D) and at sites of mechanical damage where work hardening has taken place in the surface of the pipeline wall. Conversely, it follows that initiation is less likely on pipeline surfaces that have been grit blasted as this process induces compressive stresses in the surface of the pipe's wall. Other potential sites of initiation include surface scratches and non-metallic inclusions.

A key feature of near-neutral SCC is that, because it occurs at the free corrosion potential, it is nearly always accompanied by pitting corrosion. In particular, near-neutral SCC cracks are seen to initiate at corrosion pits. It is thus likely that the incubation period is primarily determined by a period of development of pitting corrosion and in some cases the near neural pH cracks are found in broad, shallow corroded areas. More commonly, there is very little corrosion visible to the naked eye, but very small corrosion pits at each crack have been seen with microscopic examination. Thus, many researchers believe that a corrosion pit may act as a stress raiser to initiate the stress corrosion crack. Also, the environment at the bottom of a pit will become more acidic and encourage further pit growth.

3.2.2 Factors that influence the initiation and growth of near neutral pH SCC

Pipe Steel: In principle, all pipeline steels should be considered susceptible to near neutral pH stress corrosion cracking. Areas showing high residual stress, for example in the vicinity of seam welds, may show the greatest susceptibility. However, the risk of cracking in these areas will, in the first instance, be controlled by the propensity of the pipe coating to show preferential failure in this area of the pipe e.g. tenting on tape coatings (Figure 6). It is therefore not possible to rank the risk of near neutral pH stress corrosion crack initiation and growth on the basis of the pipeline steel.

Stress: The relationship between mean stress, stress cycling and crack growth rates is not fully understood. The literature suggest that a mean operating stress of ~70% SMYS and pressure cycling is required for crack initiation. However, the field data from North America clearly demonstrates that residual stress (for example from the manufacturing process) or externally applied loads due to ground movement etc. play a significant role in the practical development of near neutral pH stress corrosion in operational pipelines.

Temperature: Gas temperature is not a critical factor in the risk assessment of near neutral pH SCC.

Environment: Near neutral SCC has been found in all soil types (clay, silt, sand and bedrock) and there is no apparent difference in soil chemistry of SCC and non-SCC sites. SCC has been predominantly located in imperfectly to poorly drained soils in which anaerobic conditions were present.

Pipe Potential: Near neutral pH stress corrosion cracking occurs in areas where the action of the cathodic protection current is shielded and pipe-to-soil potentials are close to native (free corrosion) potentials.

Coating: The pipe coating can play a major role in the generation of an environment conducive to near neutral pH stress corrosion by preventing the flow of cathodic protection current to water filled crevices beneath the disbonded coating. Cathodic protection current cannot flow through polyethylene coatings because the electrical resistance of the coating is too high, but current can penetrate coal tar enamel, asphalt and fusion bonded epoxy (FBE) powder coatings. Again caution is required in extrapolating coating performance as 2 and 3 layer PE coatings are as shielding as tapes but SCC has never been experienced with these types of coating. This may be related to the depth of the crevice formed between the disbonded 2 and 3-layer PE coating and the steel substrate. The crevice formed between an extruded PE coating and the substrate is extremely tight and does not promote the renewal of ground water and hence active corrosion in
the crevice. In addition, PE coatings are applied over a grit blasted substrate; grit blasting induces compressive stresses into the steel surface which are claimed to mitigate SCC.
It is important to note that the risk of SCC is governed by the 'weakest' coating so if field joints on FBE coated pipe are protected with tapes, these joints may be at risk.

Soil: In North America, on tape coated pipeline sections, near neutral pH stress corrosion has been found in all soil and terrain types and there was no apparent difference in the soil chemistry between cracking sites and sites free of stress corrosion. However, most cracking sites were located in poorly drained soils with a high soil resistivity.

On the asphalt coated sections of the pipeline system, cracking was found most frequently in dry areas of sand, or sand and bedrock, where the local cathodic protection conditions were inadequate for full protection.

3.2.3 Circumferential Cracking

Circumferentially oriented SCC (C-SCC) is a subcategory of near neutral SCC. In the case of C-SCC the principle stress acting on the crack is a bending stress, due to:

i. Differential settlement of the backfill beneath the pipe;

ii. Slope movement;
iii. Forced alignment for welding at tie-in locations e.g. at stream crossings, or at locations of field bends.

The bending stress is a different stress than the normal circumferential hoop stress generated from the internal pipe pressure. The majority of C-SCC failures that have taken place to date have been leaks in which the cracks were either oriented circumferentially (perpendicular to the path of maximum axial stress) or followed the helical pattern of a disbonded tape (Figure 7, Appendix D).

There have been two known instances where C-SCC has resulted in a rupture. One of these ruptures occurred in 2001 on a liquid pipeline operated by Petrobras in Brazil [13], the other in 2005 on a gas pipeline in Northern Alberta [2].

To date, there have been 10 documented failures due to C-SCC [2, 13, 14], which have occurred in North and South America, Asia and Europe. Of these documented failures, 7 have occurred under tape, 2 under heat shrink sleeves and 1 under coal tar enamel. Failures have occurred on pipe diameters ranging from 168 – 914 mm and with pipe wall thicknesses ranging from 6 – 12.6 mm.

Industry experience indicates that C-SCC has much the same growth factors as longitudinal near neutral SCC, apart from the source of the principle stress. Therefore, as in the case of longitudinal SCC, a combination of known parameters related to susceptibility can be used to assess and prioritize pipeline segments. In the case of C-SCC, emphasis is given to those parameters that give rise to longitudinal loading or bending of the pipe.

The operating hoop stress may have a minimal impact on C-SCC as this may contribute only a small portion to the longitudinal stress. In most cases where failures have occurred due to C-SCC, the longitudinal stress has been above the SMYS of the linepipe. As with longitudinal near neutral SCC the crack growth is discontinuous
i.e. the cracks grow for some distance, become dormant for a considerable period of time, and then continue to grow.

Whereas longitudinal SCC can occur at any location along a pipeline, C-SCC failures will most commonly occur where a pipeline is laid in a high slope region subject to ground movement.

3.2.4 Summary of findings

Longitudinal near neutral pH SCC occurs under disbonded coal tar enamel, asphalt and tape coatings where the surface under the disbonded coating is being shielded from CP and shows active corrosion. The cracking mechanism typically occurs at stress levels around 70% of SMYS and is accelerated by cyclic loading; temperature is not implicated in the crack initiation or propagation of near neutral pH SCC.

Circumferential near neutral SCC has been experienced under tape, heat shrink sleeves and coal tar enamel and is the result of high axial stresses induced due to pipe settlement, ground movement or pipeline construction. In the majority of cases the stress has exceeded the SMYS of the linepipe.

There is no documented experience of near neutral pH SCC occurring under FBE, 2 and 3 layer extruded PE and liquid coatings including epoxy, epoxy urethane and PU. In addition there is no documented experience of near neutral pH SCC occurring on gas pipelines in the UK irrespective of the coating type and operating conditions.

3.3 Crack Characteristics

The high pH and near neutral forms of SCC bear many similarities, for example, they both occur as colonies of multiple parallel cracks that are generally perpendicular to the direction of the highest stress on the external pipe surface. The cracks can vary in length and depth and grow in two directions. As the cracks grow they tend to coalesce, or link together, to form longer cracks (Figure 2, Appendix D). At some point these cracks may reach a critical size at which a rupture may result. If a crack grows through the pipe wall before it reaches a critical length a leak rather than a rupture will result. It is important to note that critical size stress corrosion cracks do not need to fully penetrate the pipe wall for a rupture to occur, i.e., a shallow crack may reach a length that becomes critical. The strength and ductility of the remaining wall determines the critical size at which the crack behaviour changes from a slowly growing stress corrosion mechanism to an extremely rapid brittle or ductile stress overload. The most obvious differences between the two forms of SCC are the temperature sensitivity of high pH SCC, the fracture morphology, and the pH of the environment in contact with the pipe surface. The characteristics of high pH and near-neutral pH SCC are summarized in Table 1.

Factor	Near-neutral pH SCC	High pH SCC (Classical)
Location	• 65 percent occurred between the compressor station and the 1st downstream block valve (distances between valves are typically 16 to 30 km) • 12 percent occurred between the 1st and 2nd valves • percent occurred between the 2nd and 3rd valves • 18 percent occurred downstream of the 3rd valve • SCC associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings	• Typically within 20 km downstream of pump or compressor station • Number of failures falls markedly with increased distance from compressor/pump and lower pipe temperature • SCC associated with specific terrain conditions, often alternate wet-dry soils, and soils that tend to disbond or damage coatings
Temperature	• No apparent correlation with temperature of pipe • Appear to occur more frequently in the colder climates where CO2 concentration in groundwater is higher	• Growth rate increases exponentially with temperature increase
Associated Electrolyte	• Dilute bicarbonate solution with a neutral pH in the range of 5.5 to 7.5	• Concentrated carbonate-bicarbonate solution with an alkaline pH greater than 9.

Electrochemical Potential	• At free corrosion potential: –760 to –790 mV (Cu/CuSO4) • Cathodic protection does not reach pipe surface at SCC sites	• –600 to –750 mV (Cu/CuSO4) • Cathodic protection is effective to achieve these potentials
Crack Path and Morphology	• Primarily transgranular (across the steel grains) • Wide cracks with evidence of substantial corrosion of crack side wall	• Primarily intergranular (between the steel grains) • Narrow, tight cracks with almost no evidence of secondary corrosion of crack wall

Table 1: Characteristics of Axial High pH and Near-Neutral SCC in Pipelines

3.3.1 Crack Growth

Understanding the life cycle of SCC is useful in its management. An analysis of the life cycle illustrates differences in SCC growth rate and mechanism that assist in understanding SCC severity and in determining the timing of mitigation. The SCC life cycle is often described generically in terms of a "bathtub model" as depicted in Figure 8, Appendix D. The cycle of SCC crack growth is normally modelled as a four-stage process. The "bathtub model" suggests a period exists where conditions for SCC have not yet occurred (Stage 1). This period is often associated with the time necessary for the protective coating to fail and for electrolyte to reach the pipe surface and/or a suitable environment to be generated. As such, the length of this incubation period is often difficult to assess, as a coating may fail soon after pipeline construction if improperly applied, or years later when soil stresses, high temperatures or other forces act to cause coating failure.

When loss of coating adhesion takes place, groundwater is able to reach the pipe surface and SCC may initiate as a result of surface residual stresses, metallic imperfections, stress concentrations or a combination of these (Stage 2). Although the crack growth of the initiating cracks may be high, the crack growth rate tends to decrease rapidly after initiation is complete. SCC growth continues as a consequence of an environmental growth mechanism at a relatively low rate of growth and this 'Stage 3' period may extend for years or even decades with much of the SCC becoming blunted by corrosion and essentially dormant. A small percentage of SCC may continue to grow and an even smaller subset of this actively growing SCC will have sufficient alignment in the longitudinal and hoop direction to coalesce and form a much larger and injurious crack.

This continued growth and coalescence could result in an SCC feature that is of sufficient size that mechanical forces can begin to act synergistically with the environmental growth mechanism to accelerate the SCC growth rate. This increase in SCC growth velocity due to mechanical growth depends primarily on the pipeline's operating cyclic loading regime and the shape and size of the crack, especially the ratio of length to depth.

At the end of Stage 4 and during the final fracture, mechanical loading conditions become increasingly more important when compared to environmental growth.

3.3.2 Crack Categories

For pipeline management purposes it is appropriate to identify threshold lengths and depths at which cracks do not present any immediate threat to integrity. Cracks which exceed these thresholds are often referred to as 'Noteworthy'. *An SCC crack or colony is of Noteworthy size if the minimum crack depth is greater than 10% of the wall thickness and if the maximum interacting length is more than the critical length of a 50% through-wall crack at a stress level of 110% SMYS.*

For *'Noteworthy'* cracks, categories of crack severity can be based upon critical cracks at other stress levels, using the actual interacting length and maximum depth. For example, taking 125% and 110% of the maximum operating pressure (MOP) in addition to 110% of the specified minimum yield strength (SMYS) gives rise to a hierarchy of crack severities based on Predicted Failure Pressure (PFP) as follows:

Category 1; PFP is above 110% SMYS

Category 2; PFP is above 125% MAOP and below 110% SMYS

Category 3; PFP is above 110% MAOP and below 125% MAOP

Category 4; PFP is below 110% MAOP

Category Zero is used to describe cracks that are below the threshold for '*Noteworthy*' cracks; that is they present no threat to the integrity of the pipeline. Zero Category cracks fall into two groups:

- those that are shallow, i.e., less than 10% through-wall depth
- those that are so short that, even if they were 50% through-wall depth, they would not result in a hydrostatic test failure at 110% SMYS.

The formulation of these severity categories enables an estimate to be made of the minimum remaining life at the operating pressure for each severity category. Estimates are based upon the time taken for the crack to increase to the critical depth to cause failure at the operating pressure.

4 Detection of SCC

The techniques most commonly used to locate and monitor the development and hence the management of pipelines known to contain SCC include hydrostatic testing, direct assessment, and in-line inspection (ILI).

4.1 Hydrostatic Testing

Following longitudinal SCC failures of gas transmission pipelines in North America in the 1960s, hydrostatic testing was employed to confirm the integrity of the affected pipelines and prevent additional failures. *(It is important to note that hydrostatic retesting is not suitable for mitigating circumferential SCC as the axial component of the hoop stress may be insufficient to activate or remove critical defects [4])*. The pipelines were hydrostatically tested at pressures significantly higher than their operating pressure to facilitate the removal of cracks that were approaching a critical state. Because of its straightforward approach and interpretation, it became the mainstay of all regulatory codes in North America, and is still the most commonly utilized technique to ensure the integrity of the pipeline at the time of testing. However, pressure testing does not provide information about either the presence or severity of cracks that survive a test.

Hydrostatic testing failures take place when stress corrosion cracks reduce the load carrying capability of a pipeline sufficiently to allow either fracture toughness dependent or plastic collapse rupture, depending upon the toughness of the material. Near-critical features in relatively high toughness material are slower to respond to test pressures than the same feature in low toughness material. Hydrostatic testing methodologies, therefore, need to consider material toughness of both the pipe body and seam weld.

Hydrostatic testing has a number of limitations e.g. very few, if any, stress corrosion cracking flaws are removed, and the pipeline must be taken out of service for testing. In dry climates, obtaining adequate sources of water can be a challenge, while freezing of the water can be an issue in winter months or northern climates. For liquid petroleum pipelines, the water must be extensively treated prior to discharge back into the environment. There is also a finite probability of a phenomenon known as a pressure reversal occurring [18], where the failure pressure after a hydrostatic test is lower than the maximum test pressure, as a result of subcritical crack growth during the hydrostatic test.

4.2 In-field experience

Most pipeline operators use a short duration high-pressure spike (e.g., 100 to 110% of SMYS for up to 1 hour) to remove long flaws capable of producing a rupture, followed by a long duration low-pressure test (e.g., 90% of SMYS for up to 24 hours) to locate leaks in the pipeline [19]. The purpose of pressurizing to a high level for up to one hour is to remove potentially deleterious defects, while the purpose of holding at a reduced pressure for a long period is to avoid pressure reversals. PRCI studies [18] have shown that a rupture at MAOP/MOP, as a result of a pressure reversal, is highly unlikely (<1/10,000) when the test pressure is at least 1.25 times the MAOP/MOP. If MAOP/MOP equals 72% of SMYS, this implies a minimum test pressure of 90% of SMYS. Furthermore, experimental fracture mechanics studies of specimens from ERW API 5L X52 and X65 steel line pipe showed that the amount of ductile crack tearing (crack advance) at loads up to 110 percent of SMYS is less than 25 percent of the typical amount of SCC growth expected in one year. Thus, it is not considered likely that typical test procedures are likely to cause significant ductile crack tearing or pressure reversals [19].

Re-testing intervals for hydrostatic testing are constantly being re-visited. When the original re-testing programs were established in the 1970s, the intervals were based on engineering judgement and typically allowed the re-test interval to increase in steps from one year to 7-10 years if no further in-service or hydrostatic test failures occurred. Based on the collective experience over the ensuing 40 years, a new model [20] was developed taking into account the hydrostatic and operating pressures and the previous hydrostatic test history. Since the development of the Fessler Model some North American operators have adopted this for setting hydrostatic re-test intervals, while others have continued with their already-established re-testing schemes.

The experience with the use of hydrostatic testing and re-testing, for SCC threat management, continues to be very good. Following the establishment of 100-110% SMYS as the spike pressure, there has been only one occasion when a pipeline failed in service after having been hydrostatically tested; this instance was also the only occasion when a pipeline failed in a shorter time than the interval predicted by the Fessler Model.

The circumstances of this particular failure, which involved the time-dependent coalescence of two adjacent SCC defects have been reported [21]. This specific instance apart, only two other in-service failures had occurred during the five years 2006-2010, during which time around 80 near-critical cracks had been removed from pipelines in the US by hydrostatic testing.

4.3 SCC Direct Assessment

Because of the limitations in terms of hydrotesting, there has been a great deal of interest within the pipeline community in the development of alternative methods for managing pipelines containing SCC. One alternative is SCC Direct Assessment (SCCDA). The first recommended practice for SCCDA was issued in 2004 (NACE Standard RP0204-2004) [22]. SCCDA is a structured process intended to assist pipeline companies in assessing the extent of stress corrosion cracking on buried pipelines, thus contributing to their efforts to improve safety by reducing the impact of external stress corrosion cracking on pipeline integrity. The term is somewhat of a misnomer in that the process is much more extensive than simply examining the pipeline for evidence of stress corrosion cracking.

The first step in the process (pre-assessment) involves the collection of existing information on the pipeline that can be used to assess the likelihood that the pipeline is susceptible to stress corrosion cracking. The applied research described in this report has formed the basis for establishing the critical information that should be collected. In the case of high-pH stress corrosion cracking, the initial selection of the most susceptible segments is based on five factors; operating stress (>60% of the specified minimum yield strength), temperature (>38°C), distance from compressor station (< 32 km), pipeline age (>10 years) and coating type (other than fusion bonded epoxy (FBE)). In the case of near neutral pH SCC, all of the above factors excluding operating temperature, are employed. The topography along the route (slope gradient and propensity for land creep) along which the pipeline is laid may alert to the possibility of circumferential SCC.

Other types of information on the pipeline can be used for the selection of dig sites in the chosen segments. Again, much of this information is based on the applied research performed and includes factors such as topography, drainage, and soil type (near neutral pH SCC), the magnitude and frequency of cyclic pressure fluctuations, the specific coating type, including the girth weld coating, surface preparation prior to coating application, coating condition and prior history on the pipeline. A significant issue with SCCDA is that it is not capable of reliably identifying the location or locations of the most severe stress corrosion cracking on a pipeline segment. Accordingly, it is not necessarily a replacement for hydrostatic testing or in-line inspection in all instances. The pre-assessment phase of SCCDA may indicate that a particular pipeline segment is not likely to be susceptible to stress corrosion cracking and therefore, other threats are of a more immediate concern; an example would be a newer pipeline with an FBE coating. On the other hand, ILI, hydrostatic testing, or even pipe replacement may be warranted if extensive, severe stress corrosion cracking is found.

4.3.1 In-field experience

For a number of years, operators in North America have used excavations as a means of extending the scope of their SCC threat management strategies, particularly for those segments and lines that have not experienced in-service or hydrostatic test failures. Most operators currently require magnetic particle inspection (MPI) of regions of the pipe surface that are bare or have disbonded coating. Several thousand excavations have been completed, either as opportunistic excavations when the pipe has been exposed for other operational reasons, or as targeted excavations supported by soil/attribute/experience models. Most operators continue to use excavations on this basis.

Following the development of the NACE procedure for SCC Direct Assessment and its incorporation in ASME B31.8S [23], many North American operators have made use of SCCDA in their formalized Integrity Management Plans. Since 2004, many hundreds of SCCDA excavations have been conducted in North America, which have predominantly found cracks within Categories 0 – 1.

4.4 In-line Inspection

Pipeline operators have the option of using in-line inspection (ILI) technology to inspect operating pipelines for the presence of cracks. However, crack tool technology is not available for all pipeline sizes and generally has not been proven to the extent of Magnetic Flux Leakage (MFL) and ultrasonic metal-loss tools, especially in gas pipelines. Around the time the NACE SCCDA recommended practice was being developed, there was a growing consensus within the pipeline industry that the new generation of crack detection tools would eliminate the need for hydrostatic testing. Integrity management would then consist of four elements; find the cracks, size the cracks, assess the cracks and repair the cracks.

There are currently two main crack detection technologies available namely ultrasonics and EMAT (Electromagnetic Acoustic Transducer). Existing metal loss tools (MFL and ultrasonic) cannot directly detect longitudinal SCC cracks but the corrosion data reported offers insight into regions of the pipeline that may have damaged coating, cathodic protection (CP) shielding and local environments that correlate with areas of SCC. MFL tools are reported, however, to be capable of detecting circumferential SCC [13].

Currently, there are limitations to crack ILI technologies. Despite this, the crack ILI technology is developing well when compared to the historic life cycle development of MFL tools. For gas pipelines, the tool technologies are not as `mature' as MFL and ultrasonic metal-loss tools, therefore tool reliability and crack detection or discrimination capabilities are generally not as good as for metal loss. For liquid lines, ultrasonic crack tools are further along in their development, and are more widely accepted as a reliable alternative to hydrotesting.

Valuable information about the depth and length of detected features can be obtained from EMAT ILI data. The accuracy of depth and length measurements is very important when they are to be used in defect severity assessments. Both depth and length measurements can be difficult to interpret, particularly when depth measurements are expressed in ‘ranges’ (< 15-30% of wall thickness etc.), and length measurements do not take account of the threshold (1-2 mm) below which EMAT tools do not detect features. In addition, some operators have experienced a dead zone approximately 50mm either side of girth welds where no useful information is generated. These issues are being addressed by both the ILI vendors and the operators, but until a standardized approach to depth and length measurements has been adopted, it will be difficult to use EMAT ILI data for accurate severity assessment.

4.4.1 In-field experience –crack detection ILI

A general consensus amongst operators in North America is that crack detection ILI is not sufficiently reliable or accurate for general use as a primary tool for integrity management. However, considerable effort is being made by operators, working closely with ILI vendors, to develop and improve ILI crack detection methods and processes. Electromagnetic Acoustic Transducer (EMAT) technology, is receiving most attention and in excess of 45 inspection runs have been conducted in North America totalling nearly 500 km. During these inspections many crack-like features have been detected, and over 100 of the larger features have been confirmed by excavation to be SCC that would probably have failed a hydrostatic test.

A major use of the EMAT tool is to locate areas of coating disbonding. Although EMAT was unreliable at locating SCC in a pipeline known to have significant SCC at tape coated girth welds, it did prove successful at locating girth welds on which the tape coating had disbonded. This knowledge allowed the operator to target field joints for SCCDA.

ILI using ultrasonic inspection tools has proved successful in both Australia and Germany for both the location and sizing of SCC cracks, however, this involved filling the pipeline section being inspected with water, or alternatively running the tool in a slug of water.

4.4.2 Accuracy of crack sizing using EMAT technologies

The problem with the current generation of crack detection tools appears to be related to the accuracy of crack sizing. The tools are very good at finding crack-like features, and the length accuracy for these features is also typically fairly good. The problem is the depth accuracy. The feature calls are usually classified into depth ranges e.g. <15% of wall thickness, 15–30% of wall thickness, 30–45% of wall thickness and >45% of wall thickness. Currently, there does not appear to be sufficient accuracy in this process for integrity management purposes. The failure pressures in pipelines containing cracks are much more sensitive to depth than to length of the flaws. The problem could be related to the precision and accuracy of the tool, or the analytical process for analysing the tool data.

Because of these sizing issues, pipeline operators are sometimes required to perform a confirmatory hydrostatic test on portions of their system to demonstrate the performance of the crack detection tool. In some cases, pipeline operators may also be faced with a situation where a large number (thousands) of features are found on a segment of a pipeline. The elements of SCCDA can then be used, in conjunction with the standard crack sizing, to identify which features are most likely to be an integrity threat and should be excavated.

4.5 Future trends

The detection and sizing capabilities of the crack detection tools will undoubtedly improve, but there will always be a need for elements of SCCDA, developed through applied research, to prioritize pipeline segments for inspection. Depending on the pace of improvements in the precision and accuracy of these systems, there may continue to be a necessity, for the near future, to use elements of SCCDA to help identify which features are most likely to be SCC threats.

4.6 Detection of SCC - Summary of Findings

Hydrostatic testing has been and is likely to remain the predominant technique for monitoring the integrity of pipelines known or suspected of containing longitudinal SCC. ILI crack detection tools, which are designed to run in the gas phase, are not considered sufficiently sensitive to reliably locate and size SCC and have a dead zone adjacent to girth welds. Ultrasonic ILI tools, which operate in liquid lines or gas lines that are filled with water have been proven to have greater reliability and accuracy than EMAT tools in terms of crack detection and sizing.

5 SCC Prevention and Mitigation

This particular section reviews those documents that have been developed, mainly in North America, to address SCC and provide advice on SCC prevention and mitigation. These documents discuss the role of coatings and CP in allowing environments to develop that make a pipe conducive to SCC. The documents also provide guidance on the techniques that can employed to inspect for SCC and repair method for areas affected by SCC.

5.1 CEPA Stress Corrosion Cracking Recommended Practices

The CEPA recommended practices document [4] discusses the use of coatings, cathodic protection, hydrostatic retesting and repairs for prevention and mitigation of SCC.

5.1.1 Coatings

Inadequate coating performance is the main contributor to pipeline SCC susceptibility and the CEPA recommended practices emphasise the importance of developing coating procedures so that future coating failure susceptibility, especially disbondment, is minimised.

The most proven method of reducing SCC initiation on new pipelines is by the application of high performance coatings and effective CP. The effectiveness of preventing initiation of SCC in pipelines is primarily related to:

Preventing the environment/electrolyte that causes SCC from contacting the pipeline steel surface (i.e. resistance of a coating to disbonding).

The coating's ability to pass current through or under the disbonded coating thereby preventing the initiation of SCC.

Appropriate surface preparation, prior to coating application, to modify the steel's surface so as to render it less susceptible to SCC initiation.

Historically, coatings other than CTE, asphalt and tapes have shown no susceptibility to SCC. The CEPA document [4] advises operators to consider the use of coatings that have had extensive operational history but have shown no susceptibility to SCC; these include FBEs, liquid systems including epoxy and epoxy urethane, extruded PE and multi-layer coatings such as 3-layer PE. Although the extruded PE based systems will shield CP current, where disbonding occurs, there is no documented evidence of SCC ever having been experienced with these coatings despite being in service for over 40 years. It is imperative that girth welds, as well as the body of the pipe, is protected with coatings that have not experienced SCC.

5.1.2 Cathodic Protection

Near neutral pH SCC can only occur when there is an inadequate level of cathodic protection (CP) on the pipe surface. The minimum level of CP required to mitigate this type of SCC has not yet been established, however, the CEPA document states that it is generally accepted that this form of cracking will not occur where the generally accepted CP criterion (e.g. a polarized pipe-to-soil potential of -850mV with respect to a $Cu/CuSO_4$ electrode) is achieved and the coating does not promote shielding of CP current.

SCC is typically found in locations where CP is shielded from the pipe surface or is inadequate; CP survey techniques typically employed for pipeline monitoring will not indicate the pipe's potential under a disbonded coating.

5.1.3 Hydrostatic Testing

The CEPA document states that hydrostatic testing is one of the best ways to demonstrate the integrity of a pipeline. As previously stated in this report, hydrostatic retesting has been shown, through operating experience and research, to be a very effective means of safely removing near-critical axial defects, such as SCC, from both natural gas and liquid hydrocarbon pipelines. By removing those axial flaws that are approaching critical dimensions, a hydrostatic retest provides the operating company with a margin of safety against an in-service failure in that section of line for a definable period of time.

The CEPA document indicates that hydrostatic testing is not considered to be particularly useful for assessing pipeline integrity from the standpoint of circumferentially oriented defects such as circumferential SCC. Since pipeline integrity is much more likely to be affected by longitudinally oriented defects than by circumferentially oriented defects, the CEPA document states that hydrostatic testing is one of the best ways to demonstrate the integrity of a pipeline.

The CEPA document stresses the importance for an operator to examine their particular situation when developing a hydrostatic retest procedure and take the following factors into account:

Test appropriateness - If and when it is appropriate to hydrostatically test a pipeline, the test should be carried out at the highest possible stress level feasible. The challenge is to determine if and when it should be done, the appropriate test level, and the test section logistics that will maximize the effectiveness of the test.

Level of safety factor to establish in the pipeline segment - The level of safety factor achieved by a hydrostatic retest is based on the maximum operating pressure of the pipeline and the minimum test pressure used. The higher the test pressure, the higher the safety factor achieved by the retest from a potential SCC service failure.

Test pressure level - The highest feasible test pressure level should be used when hydrostatic retesting is conducted to revalidate the serviceability of a pipeline suspected to contain defects that are becoming larger with time, such as SCC. The higher the test pressure, the smaller the remaining SCC defects that can survive the test, resulting in a higher safety factor and/or longer re- test intervals.

Pressure reversal - With increasing pressure, defects in typical line-pipe material may begin to grow by ductile tearing prior to failure. If the defect is close enough to failure, the ductile tearing that occurs prior to failure will continue even if pressurisation is stopped and the pressure is held constant.

5.1.4 Pipeline Repairs

According to the Canadian Standards Association (CSA) criteria, pipe body surface cracks, including stress corrosion cracks, are considered to be defects unless determined by an engineering assessment to be acceptable. The CEPA document advises that SCC defects can be repaired using one or more of the acceptable repair methods given in Table 10.1 of CSA Z662 [24], which include:

- Grinding and buffing repair;

- Pressure containment sleeve;
- Pipe replacement;
- Steel reinforcement repair sleeve;
- Steel compression reinforcement repair sleeve;
- Fiberglass reinforcement repair sleeve;
- Hot tap;
- Direct deposition welding.

5.1.5 Re-assessment intervals

In order to comply with regulatory requirements, in North America, pipeline operators are obliged to prepare individual integrity management plans to minimise the risk of failures due to SCC. In this respect operators frequently call on the processes of integrity management outlined in ASME B31.8S [23], including re-assessment intervals.

In line with current guidance for SCC, in particular the Recommended Practices prepared by the Canadian Energy Pipeline Association (CEPA) [4], it is appropriate to identify within management plans threshold

lengths and depths at which cracks are not considered to present any immediate threat to integrity. Crack categorisation, in terms of the predicted failure pressure, has been discussed earlier and is reiterated below for Category 0 – 4 cracks.

Category 0; these cracks pose no threat to pipeline integrity

Category 1; PFP is above 110% SMYS

Category 2; PFP is above 125% MAOP and below 110%

SMYS Category 3; PFP is above 110% MAOP and below

125% MAOP Category 4; PFP is below 110% MAOP

The categorisation of cracks enables an estimate to be made of the minimum remaining life at the operating pressure for each severity category. Estimates are based upon the time taken for the crack to increase to the critical depth to cause failure at the operating pressure.

By assuming a crack growth rate, the type and timing of mitigating action can be determined, as well as the appropriate re-assessment intervals for smaller cracks that may remain after the first assessment. Some operators with experience of SCC are able to use a relevant, realistic crack growth rate, whilst others may be required to use an upper bound value of 0.3mm/year. Using this crack growth rate for a 30 inch (762 mm) diameter pipeline with 0.375 inch (9.52mm) wall thickness operating at 72% SMYS gives rise to the following minimum lives for each severity category [27].

Category Zero: failure life exceeds 15 – 25 years

Category 1; failure life exceeds 10 years

Category 2; failure life exceeds 5 years

Category 3; failure life exceeds 2 years

Category 4; failure may be imminent.

This approach allows an operator to mitigate against SCC by scheduling inspections that are intended to locate and remove cracks that are approaching a critical size, or may become so before the next inspection.

On-going mitigation action concerning a pipeline segment containing SCC, should constitute a measured response to the severity of the cracks discovered, reflecting the Predicted Failure Pressure and the estimated life at the operating pressure. For example,

Current US regulations recommend that on-going SCC condition monitoring be conducted on pipeline segments containing Category Zero cracks, and that the potential for Category Zero cracks growing be reassessed at intervals not exceeding 7 years.

Best practice dictates that pipeline segments containing Category 1 cracks should be monitored using occasional exploratory excavations or using information from 'opportunistic' excavations conducted for reasons other than SCC monitoring.

Best practice dictates that pipeline segments containing Category 2 cracks should be subjected to more extensive investigation using direct assessment or ILI at intervals of approximately every 3 years.

Pipelines containing category 3 cracks should be addressed by hydrostatic testing or immediate ILI to locate and remove cracks of this severity.

Pipelines containing Category 4 cracks would necessitate immediate pressure reduction and urgent hydrostatic testing or ILI to locate and remove cracks of this severity.

5.2 ASME B31.8S Repair and Mitigation Options

ASME B31.8S [23] (Table 4) presents acceptable repair methods for SCC. These methods are:

- Pressure reduction;
- Replacement;
- Grind repair/ECA (Engineering Critical Assessment); Type B, pressurized sleeve; and
- Type A, reinforcing sleeve.

If the grind repair/ECA method is utilized, the area is then evaluated in a similar manner to general metal- loss for which composite sleeves and epoxy filled sleeves may then be used to provide any required reinforcement after the stress corrosion cracks have been removed by grinding.

5.3 API Standard 1160

API Standard 1160 [25], 'Managing System Integrity for Hazardous Liquid Pipelines,' presents a summary of commonly used permanent pipeline repairs in Table 9-2 of the standard for various anomaly types and locations, and describes numerous repair strategies in Appendix B of the standard. However, note 9 to Table

9-2 states: "Other repair methods may be used provided they are based on sound engineering practice," and section 9.7 states: "The information in this standard should not be considered a complete summary of every type of repair, but an overview of some of the more frequently used techniques in the industry today." The standard goes on to state: "In the absence of detailed company procedures for pipe replacement or repair the PRCI 'Pipeline In-service Repair Manual' should be consulted."

6 Managing Pipelines with SCC

Pipe segments are susceptible to near neutral pH SCC if all of the three conditions listed below are met:

- The operating stress is >60% SMYS
- The pipeline is > 10 years old
- The coating is other than FBE or liquid epoxy
- Further criteria are included to identify segments that might be susceptible to high pH SCC, these are: Operating temperature >100^{o}F (38^{o}C)
- Distance from a compressor station within 20 miles (32 km)

As for near neutral pH SCC, unless all five conditions are satisfied a pipeline segment is not considered to be at risk from high pH SCC.

If the pipeline segment satisfies the criteria above Operators should consider a more detailed assessment for SCC risk and further guidance for assessing SCC risk and for the management of pipelines on which SCC has been identified is provided in the documents listed below. These documents provide state of the art information on the risk assessment and management of SCC and their content summarised in the following sections.

ASME B31.8S [23]

CEPA SCC Recommended Practices [4]

NACE SP0204 - SCC Direct Assessment (SCCDA) Methodology [34]

6.1 ASME B31.8S

The current 2012 edition of ASME B31.8S provides an integrity management plan to address the threat, and methods of integrity assessment and mitigation for stress corrosion cracking (SCC) of gas pipelines affected by near neutral pH and high pH SCC. The process involves the following:

1) Gathering, Reviewing, and Integrating Data
   a) age of pipe
   b) operating stress level (% SMYS)
   c) operating temperature
   d) distance of the segment downstream from a compressor station e.g. coating

2) Criteria and Risk Assessment

   a) Pipes are considered to be susceptible to near neutral pH SCC if :
      i) operating stress level >60% SMYS
      ii) age of pipe >10 yr
      iii) coatings is other than FBE

   b) Pipes are considered to be susceptible to high pH SCC if all of the above apply and
      i) operating temperature >100°F (38°C)
      ii) distance from compressor station ≤20 mi (32 km)

3) Integrity assessment
      i) Pipes considered to be at risk of SCC shall have a written inspection, examination and evaluation plan prepared
      ii) ASME B31.8 recommends the use of NACE SP0204 SCC direct assessment methodology for identifying appropriate sites for excavation and direct examination
      iii) Methods of examination include magnetic particle inspection, hydrotesting and ILI
      iv) The SCC crack severity criteria are provided in Table A-1 of ASME B31.8S and the response requirements in Table A-2.

4) Threat prevention and repair
      i) Pressure reduction
      ii) Replacement
      iii) Engineering analysis
      iv) Grinding
      v) Pressure containment

6.2 CEPA SCC Recommended Practices

Whereas ASME B31.8S provides detailed information for undertaking risk assessments and for managing gas pipelines at risk from SCC, there is no equivalent ASME document for liquid lines. However, the CEPA SCC Recommended Practices does provide detailed guidance on assessing the susceptibility and for managing gas and liquid pipelines at risk from near neutral pH SCC. Although the document acknowledges that some of the techniques discussed are similar to those used for the management of high pH SCC, it states that it does not specifically address this type of cracking. As with ASME B31.8S the CEPA SCC Recommended Practices details the SCC management programme that an operator must follow, the stages of which are identified below:

1) Pipe segment susceptibility assessment;

2) Investigate for the presence of SCC;
3) Determine the SCC susceptibility reassessment interval;
4) Classify the severity of the SCC;
5) Determine and implement a pipe segment safe operating pressure based on crack severity;
6) Plan and implement mitigation based on crack severity. (vii) Review and evaluate mitigation activities;
7) Document, learn and report;
8) Condition monitoring.

The CEPA SCC Recommended Practices is an extremely detailed and comprehensive standalone document which is well written and easy to understand by those who do not have a background in SCC. Although it is intended to apply to near neutral pH SCC the processes are equally applicable to high pH SCC.

6.3 NACE SP0204 Stress Corrosion Cracking (SCC) Direct Assessment Methodology

The NACE SP0204 SCC direct assessment (SCCDA) methodology is intended to be used in conjunction with ASME B31.8S and serves as a guide for applying the SCC direct assessment process. It is applicable to both types of SCC and to buried onshore gas and liquids pipelines. The SCCDA process is intended to identify areas where SCC has occurred, might be occurring or might occur in the future. The primary purpose is to reduce the threat of external SCC on pipeline integrity by means of condition monitoring, mitigation, documentation and reporting.

As indicated earlier in this document, the SCCDA process is a four stage process involving pre-assessment, indirect inspection, direct examination and post-assessment. Within the pre-assessment stage, the initial selection of pipeline segments for assessment of risk of SCC, is based on the criteria contained in ASME B31.8S e.g. proximity to compressor station, operating stress, pipe coating, operating temperature etc. NACE SP0204 does acknowledge the fact that B31.8S addresses gas pipelines but also acknowledges that the same factors and approach can be used for liquids petroleum pipelines.

SCCDA calls on the use of indirect inspection techniques e.g. DCVG, CIPS to aid in the prioritisation of segments for excavation and direct examination. The purpose of the direct examination stage is to assess the extent, type and severity of any SCC found. Within the post-assessment stage, decisions will be made whether mitigation is required, remedial actions will be prioritised, reassessment intervals defined and the effectiveness of the SCCDA process evaluated. NACE SP0204 does not provide guidance on SCC mitigation but indicates that this should be conducted in accordance with ASME B31.8S.

Unlike the CEPA SCC recommended practices, NACE SP0204 relies upon other documents, specifically ASME B31.8S, for the initial selection of pipeline segments that might be at risk from SCC and for guidance on SCC mitigation. The current version of NACE SP0204 provides no guidance on how frequently pipeline segments should be re-inspected.

7 Summary

7.1 Experience of SCC in the UK and Europe

One of the threats to the integrity of high pressure pipelines is SCC which can lead to ruptures as well as leaks. According to the data published by UKOPA [1], there have been no product loss incidents within the UK, due to external SCC; UKOPA monitor product loss incidents on over 22,000 km of pipelines, some dating back to 1952. The absence of SCC related incidents on these pipelines is despite the fact that many of these lines have features in common with pipelines on which SCC failures have occurred including, age, steel grade, coating type, operating conditions etc. The fact that UK operators have not experienced SCC has been attributed to a number of factors including:

- A degree of conservative engineering (pipe strength, wall thickness etc.), stringent construction practices, and pipeline route selection to avoid the introduction of axial stresses;
- High standards employed during coating application, in particular the level of surface preparation applied prior to coating application. A significant proportion of SCC failures in North America have occurred on pipe coated in the field over mechanically prepared surfaces;
- The requirement for regular coating condition assessment (Pearson and DCVG) to locate and repair coating damage;
- The requirement to cathodically protect pipe and confirm that pipe-to-soil potentials are within agreed limits;
- Operating pipelines to minimise pressure cycling and high pipe temperatures.

Although the majority of incidents due to SCC have occurred in North America, there have been incidents in Europe. According to the EGIG 2011 incident report, 8% of product loss incidents in the last 40 years, on pipes operating above 15bar (13 incidents) have been as a result of external SCC.

7.2 Stress Corrosion Cracking

Two forms of external stress corrosion cracking have been found to occur on high pressure pipelines and are referred to as high pH and near neutral pH SCC. Although they appear visually identical, metallurgical examination has confirmed that high pH SCC occurs intergranularly (around the grain boundaries) whereas near neutral pH SCC occurs transgranularly (through the grain structure) and is preceded by corrosion pitting.

Operator experience has indicated that the vast majority of longitudinal SCC has taken place in North America, typically within 30km of compressors stations where the highest cyclic stress fluctuations occur, and on pipelines operating at a stress level above 60% SMYS. Integrity management of pipelines containing SCC is not dictated by whether it is the high pH or near neutral SCC type, but by the crack attributes (crack length, depth and degree of coalescence) and therefore, a similar approach is taken to condition assessment, prevention and mitigation.

7.3 SCC Relation to Coating Type

Failures due to SCC have occurred under four main coating types, these are asphalt (bitumen), coal tar enamel, tapes and heat shrink sleeves. Although these coatings tended to be phased out in the UK in the late 1970s and early 1980s, up to 60% of steel pipelines operating in the ground in the UK are protected with one or more of these coating types.

It is important to note that SCC has not been experienced on pipelines coated with 2 or 3 layer PE, FBE or with liquid epoxy, epoxy urethane or polyurethane despite many of these coatings being in service for over

50 years: incidents of SCC on asphalt, coal tar enamel and tape coated pipelines started to occur in North America after 12 – 22 years. If epoxy coated lines are susceptible to SCC, the logic would suggest that cracking should have been identified by now.

Many of the FBE coatings applied in the 1960's had a tendency to loose adhesion early in their service lives hence reaching 'Stage 1' of the SCC life cycle (see Figure 7, Appendix D) relatively quickly. Stage 1 is the period required for loss of coating adhesion to take place and for electrolyte to reach the pipe surface and/or a suitable environment for SCC to be generated. ASME B31.8S and NACE SP204 acknowledge the fact that FBE coated pipelines are not susceptible to SCC and hence do not include them in the SCC risk assessment process. However, if field joints on FBE coated pipelines are protected with tapes or heat shrink sleeves then these areas will still be deemed to be susceptible.

7.4 Integrity Management

The significant information that has been generated on SCC over the past 40 years, related to basic research, operator experience, and pipeline integrity management (prevention, detection and mitigation), is as a direct result of SCC failures that have taken place in North America. The vast knowledge that has been generated on SCC is universally applicable and of direct benefit to UK operators, both in terms of identifying pipelines that might become susceptible to SCC but also in the integrity management of pipelines on which SCC may be subsequently found. Any operator, for which SCC is a new integrity threat, now has access to well established practices and procedures which have been developed by industry experts to manage this threat. The guidance provided in these documents will allow an operator, who is unfortunate enough to experience SCC, to quickly instigate the appropriate response; this may simply involve direct assessments to establish the scale of the problem for shallow cracking, or a pressure reduction and assessment by hydrostatic testing, ILI or 100% MPI if more severe cracking is confirmed.

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35. *Pipelines – Gas and Liquid Petroleum – Design and Construction*. Australian Standards International AS 2885.1, 2012.

36. *Pipelines – Gas and Liquid Petroleum – Operations and Maintenance*. Australian Standards International AS 2885.3, 2012.

37. *The Pressure Systems Safety Regulations*. Health and Safety Executive, 2000.

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Appendix A – Summary of Existing Reference Material

Significant information has been generated on SCC since the first high pH SCC failures were experienced in North America in the 1960s, these include:

- Basic research papers;
- Technical papers targeted at researchers and others wanting to understand the science of SCC;
- Comprehensive reviews of experimental programmes on specific aspects of SCC which focus on the mechanisms of SCC and conditions that make steel pipes conducive to SCC;
- Technical overviews that provide a useful comprehensive account of the understanding and management of SCC, targeted at operators, regulators, and other parties who are interested in developing a more general knowledge of SCC.

In preparing this position paper on SCC, many technical papers and reports have been reviewed. A number of these documents provide an excellent source of information for UKOPA members interested in furthering their knowledge of SCC, and for operators that may need advice on how to manage SCC; these are discussed briefly below.

National Energy Board Enquiry – 1996

The National Energy Board [2] document entitled 'Stress Corrosion Cracking on Canadian Oil and Gas Pipelines,' was published in 1996 following an enquiry into the near neutral pH SCC failures that first occurred in Canada in 1985. The information provided in the document was gathered from pipeline operators, industry associations, consultants, government agencies and researchers. The document is simply written and easily understood by those who do not have a background in SCC and includes information related to the two forms of SCC, prevention, detection and mitigation of SCC and SCC management.

CEPA SCC Recommended Practices 1st & 2nd Editions

The CEPA (Canadian Energy Pipeline Association) published a document in 1997 [3] entitled 'SCC Recommended Practices,' to support companies in the management of SCC. The content was compiled by pipeline integrity practitioners within the CEPA member companies. The practices constitute the sharing of SCC management experiences and practice for the purpose of assisting others with the development and implementation of SCC integrity management programs. The main focus of the document is SCC integrity management and specifically, field program developments, inspection, data collection, integrity assessment, prevention and mitigation and risk assessment.

A 2nd edition of this document was published in 2007 [4]. Although much of the revised document is similar in content and format to the 1st edition several major changes have been made including:

- A new SCC management flowchart that aligns more closely with current industry best practices;
- The introduction of a multi-level SCC severity assessment method to guide pipeline companies in determining the seriousness of any SCC discovered, as well as the mitigation required;
- The formal incorporation of circumferential SCC within the document;

- The addition of guidance during post SCC incident investigation and pipeline return to service;
- Less emphasis on the use of soils models as the primary SCC assessment and risk reduction tool.

Whereas the previous revision covered some aspects of high pH SCC, the 2nd revision of the recommended practices deals exclusively with near-neutral pH SCC and covers all aspects from detection, through to assessment, mitigation, and prevention. Section 5 of the recommended practice deals with SCC investigation programs and includes a detailed listing of the various factors that have been found to correlate with near-neutral pH SCC. These factors are categorized as coating type and coating conditions, pipeline attributes, operating conditions, environmental conditions, and pipeline maintenance data. The information provided in the CEPA recommended practices has been largely collected from the field.

Michael Baker Jnr - Stress Corrosion Cracking Study

In 2005, Michael Baker Jnr produced a very comprehensive report [5] entitled 'Stress Corrosion Cracking Studies,' funded by the Research and Special Programs Administration (RSPA) and the Office of Pipeline Safety (OPS) in the US. The scope of the project was to conduct an overall "umbrella" study of SCC issues relating to pipeline integrity for both gas and liquid lines, including the history of SCC, level of risk, indicators of potential for SCC, detection methods, mitigation measures, assessment procedures, and regulatory procedures for evaluation of industry assessments. The study is comprehensive in scope and involved coordination with major industry trade organizations, pipeline operators, pipeline regulators, and industry experts, both in the United States (US) and internationally. Known information on the subject of SCC has been assembled or identified in the report. The report also identifies gaps in the efforts to understand, identify, assess, manage, mitigate, and regulate enforcement of SCC concerns.

Frazer King - Development of Guidelines for Identification of SCC Sites and Estimation of Re-inspection Intervals for SCC Direct Assessment

In 2010, Frazer King (Integrity Corrosion Consultancy Inc.) was contracted by the US Department of Transportation (DOT), the Pipeline Hazards Safety Administration (PHSA) and the Pipeline Research Council Inc. (PRCI) to produce a report [6] entitled 'The Development of Guidelines for the Identification of SCC Sites and Estimation of Re-inspection Intervals for SCC Direct Assessment.' The report describes the development of a series of guidelines for the identification of SCC sites and the estimation of re-inspection intervals. The guidelines are designed to complement and supplement existing SCC Direct Assessment (DA) protocols by drawing on information from past R&D studies. Guidelines are presented for the various mechanistic stages of both high-pH and near-neutral pH SCC, namely; susceptibility, initiation, early-stage crack growth and dormancy, and late-stage crack growth.

The guidelines are designed to be broadly applicable, and include discussion of high-pH and near-neutral pH SCC, on gas and (hydrocarbon) liquid pipelines, existing and future pipelines, on local and regional scales in North America and internationally. The guidelines are designed to be of use to pipeline operators with prior experience of SCC and to those for whom this is a new or unknown integrity threat.

The report also describes how these guidelines can be implemented by operating companies and provides a list of the analyses that need to be performed, the necessary input data, and how the resultant information can be used to identify SCC sites and estimate re-inspection intervals.

Appendix B – History of SCC

Experience in North America

A large body of data from a recent joint industry project [15] involving a number of major natural gas transmission companies in North America is discussed below to reflect experience with both near neutral and high pH SCC in this region. The companies involved in the JIP represented most of the SCC experience on gas pipelines in North America over the past 40 years.

The data supplied was representative of 270,000km of pipeline and included:

- Pipelines attributes: age, diameter and wall thickness, grade, coating type, operating pressure;
- How and where SCC was discovered, date and means of discovery, location;
- Extent and nature of SCC: type of SCC; size, depth, and number of crack colonies and of individual cracks.

The JIP data set represented a large number of SCC occurrences, including:

- 59 in-service high-pH SCC leaks and ruptures;
- 26 in-service near-neutral pH SCC leaks and ruptures;
- 298 hydrostatic test high-pH SCC leaks and ruptures;
- 149 hydrostatic test near-neutral pH SCC leaks and ruptures.

FINDINGS REGARDING LONGITUDINAL HIGH-PH SCC [15]

- Around 90% of the in-service ruptures and leaks due to axially oriented SCC are within 20 miles of compressors;
- Around 95% of hydrostatic test failures are also within 20 miles downstream of compressors. The total is biased due to the high proportion of tests on first valve sections;
- Over 85% of in-service failures and over 95% of hydrostatic test failures have been in pipe designed to operate above 60% SMYS. Most of the exceptions are pipes less than 12 inches in diameter;
- In-service failures have continued to occur at a steady rate over the last 40 years, as pipeline age increases. Only two in-service failures, and no hydrostatic test failures, have been in pipes less than 10 years old. In more than 90% of the affected pipelines, SCC failures did not start to occur until after 20-30 years' service;
- Over 70% of the in-service failures have been on coal tar coated pipe, with the remainder being on tape-wrapped pipe. Elsewhere there have occasionally been reported instances on asphalt coated and wax coated pipe;
- Where SCC has been found on coal tar coated pipe, excavations have revealed anything from a few colonies to 200 or more. Colonies ranged from a few inches to 10 inches or more in axial and circumferential directions. Each colony contained from a few to 100 or more closely spaced individual cracks;
- In a dataset of 'opportunistic' excavations, less than 5% of the excavations revealed SCC, and estimates suggested that more than half of the colonies were less than 20% deep. In one developmental ILI run on a line with a history of high pH SCC, around half the pipe joints, contained cracks 15-30% deep but only one tenth of the cracks found were more than 30% deep;

- Failures have occurred on pipelines constructed between 1940 to 1969. No in-service failures have occurred in North America on pipelines constructed after 1969.

FINDINGS REGARDING LONGITUDINAL NEAR-NEUTRAL PH SCC [15]

- In-service ruptures and leaks due to longitudinally oriented SCC have occurred on asphalt and coal tar enamel coated pipe, tape wrapped pipe and one on wax-coated pipe;
- In-service failures on tape-wrapped pipes have mostly been within 20 miles downstream of compressor discharges, whereas those on asphalt-coated pipe have been experienced at distances that significantly exceed 20 miles;
- Hydrostatic test failures on tape-wrapped pipes have mostly been within 30 miles downstream of compressor discharges, whereas those on asphalt-coated pipe have been experienced at distances that significantly exceed 20 miles;
- All the in-service failures and all the hydrostatic test failures have been on lines designed to operate at above 70% SMYS;
- In-service failures first occurred in 1985 and have continued at an average rate of one per year since the early 1990s;
- For tape-wrapped pipes, the first in-service failures occurred 12 years after installation, whereas, for asphalt-coated pipes, the first failures occurred after 22 years (excepting a failure at mechanical damage after 13 years);
- In targeted excavation programs, between 5% and 80% of the excavations have revealed SCC;
- Excavations have revealed only limited cracking in pipes operated below 60% SMYS;
- Where SCC has been found on tape-wrapped pipe, excavations have revealed anything from a few colonies to 100 or more; each colony could be up to 15 inches or more in both axial and circumferential directions and could contain a large number of closely-spaced individual cracks. The tape overlap typically employed (10 – 20% or less) was significantly less than the 50% overlap specified in the UK;
- Where SCC has been found on asphalt-coated pipe, excavations have revealed typically around 10-30 colonies, while on coal tar coated pipe less than 5 colonies have generally been found;
- Around 10% of the colonies and cracks found by excavation were sufficiently deep (>10%) and long (>50mm) to be classified as ‘Noteworthy’;
- Vast majority of failures in North America occurred on pipelines constructed between 1950 and1980. No in-service failures have occurred on lines constructed after 1981.

FINDINGS REGARDING CIRCUMFERENTIAL NEAR-NEUTRAL PH SCC [4,13, 14]

- In-service failures have resulted where differential settlement of the backfill beneath the pipe has occurred, where geotechnical ground movement has taken place or where forced alignment for welding at tie-in locations e.g. at stream crossings, or at locations of field bends has occurred;
- In-service ruptures and leaks due to circumferentially oriented SCC have taken place on coal tar enamel coated pipe, tape-wrapped pipe and on pipe where HSS’s have been employed;
- In-service failures have taken place within as short a time as 8 years after pipe installation but more typically after 20 years’ service;

- An in-service failure has occurred on a pipeline constructed as late as 1998;
- The majority of in-service failures have resulted in a leak, however, two rupture have occurred to date;
- In-service failures have taken place within the body of the pipe and at girth welds;
- In-service failures have tended to occur at stress levels above or close to the pipe's SMYS.

Experience in Australia

In 1982 a rupture occurred on the 864 mm diameter Moomba to Sidney gas pipeline [16]. The 1299 km line was completed in 1976 and was externally protected with a coal tar enamel coating. The rupture occurred 4.2 km downstream of a compressor station and was attributed to high pH SCC. Following the rupture the following actions were taken:

- 28.4 km of pipe was replaced immediately downstream of the compressor;
- The maximum allowable operating pressure (MAOP) was reduced from 80 to 72% of SMYS;
- Gas coolers were installed at the compressor station;
- Pressure control was installed to minimise pressure fluctuations;
- CP operating parameters were revisited.

In 2000 and 2004 other SCC colonies were located during ILI with an ultrasonic inspection tool; the colonies were sufficiently deep to require repair with compression sleeves. It is unclear whether these colonies were found in the 28.4 km of pipe that was replaced or in the original pipe. The pipeline was constructed from pipe supplied by three different manufacturers. All three manufacturers' pipes were found to be susceptible to SCC, however, one manufacturer's pipe was found to be more susceptible than the others.

In 1982 and 1983 two SCC failures, presumed to be high pH SCC, occurred on gas gathering lines in the Cooper Basin on 323 and 456 mm diameter pipe [17]. The 456 mm pipe was reported to be of similar composition to sections of the Moomba to Sidney pipeline.

Experience in Russia

Russia has an extensive pipeline system carrying large volumes of gas over distances of many thousands of kilometres. The system has been built over many years, using steel from various sources in pipelines with diameter up to 1420 mm. Failures from SCC have been reported from the 1980s. Over 150 failures have been documented most of which are of the near neutral pH type. Cracking was predominantly found on tape- wrapped pipelines, typically located in a band 100 – 250 mm from the longitudinal seam weld. Control rolled steels were more susceptible to cracking and incubation periods for cracking tended to be shorter for the higher grade pipes. Failures occurred in various soils, including clay, rock and peat and were often reported to be in wet areas and often located at the bottom of the pipe.

Experience in Asia

The Grissik to Duri pipeline, owned and operated by PT Transportasi Gas Indonesia (TGI), failed at the girth weld due to a circumferential form of near neutral pH SCC [14]. The 711 mm (28") diameter 10.5 mm WT X65 pipeline was commission in 1998 and failed 12 years later. The pipeline was protected with a 3-layer PE mainline coating with heat shrink sleeves at the girth welds. The longitudinal stresses that had developed in the vicinity of the girth weld, due to the swampy nature of the ground and consolidation settlement of the swamp deposits, approached the ultimate tensile strength (UTS) of the parent pipe material.

Experience in Mainland Europe

The European Gas Pipeline Incident Data Group (EGIG) report issued in December 2011 entitled 'Pipeline Incidents - 8th Report of the European Gas Pipeline Incident Data Group' indicates that 8% of external corrosion incidents (13 incidents) that have taken place between 1970 and 2010 were due to SCC. Although the attributes (pipe steel, coating type, operating conditions) of many pipelines that are operating in the UK are similar to those on which SCC has occurred elsewhere in the World, there is no documentary or anecdotal evidence of SCC having been experienced in the UK.

Snam Rete Gas, an Italian operator, experienced one of the first incidents of circumferential near neutral pH SCC. The failure occurred on a pipeline in Southern Italy and involved axial stress in excess of the SMYS of the steel. The region in which this failure occurred was subject to land slip and the pipeline had been instrumented with strain gauges to monitor elongation prior to the failure occurring. Snam Rete Gas are known to have experienced other similar failures attributed to ground movement (landslides) and residual stress at the girth weld associated with poor construction practices. The failures occurred on circa 1965 – 1976 pipes under asphalt and tape coatings. This operator has not experienced pipeline failures due to the high pH form of SCC or the longitudinal form of near neutral pH SCC.

Circumferential near neutral pH SCC, resulting in a pipe failure, has been experienced in France on a CTE coated pipeline constructed in 1959; the failure was thought to have been due to ground movement.

The longitudinal form of near neutral pH SCC has been experienced on tape wrapped field joints on asphalt coated lines in Germany. On one 47 km section of one line 23% of field joints were affected. To date, there have been no leaks or ruptures reported. Cracking observed to date has been contained within the girth weld areas the worst of which have extended up to 50% of pipe wall thickness. ILI inspection using EMAT tools failed to locate cracking, however, the EMAT tool was effective at locating areas where loss of adhesion of the coating had taken place. Knowledge of where coating loss had occurred allowed the operator to target locations where direct examinations should be conducted. ILI to locate cracking was only effective when ultrasonic tools were run in a slug of water.

Appendix C – Regulatory Practices and Industry Standards

The majority of the codes and regulatory practices related to SCC have originated in North America due to the predominance of near neutral and high pH SCC experienced in this area of the world. A brief review of these North American codes and practices, and other international recommended guides and practices is presented below.

U.S.Regulations and Industry Standards

849CFR 192 and 49CFR195

49CFR 192 [28] and 195 [29] are the governing regulations for transportation of gas and hazardous liquids by pipeline in the US and present the minimum federal safety standards that must be met in design and operations of pipeline systems within the United States.

Minimum requirements for the protection of gas lines constructed of metallic line pipe from external, internal, and atmospheric corrosion are given in 49 CFR 192, Subpart I; this document makes no specific reference to SCC. Generally, Subpart I require pipelines to have an external protective coating and a cathodic protection system. Monitoring methods and intervals to verify the proper functioning of the cathodic protection system are also outlined. In addition, remedial measures are discussed for those instances when general or localized pitting corrosion is identified. 49 CFR 195 has similar requirements to 49 CFR 192 for protective coatings and cathodic protection systems as well as monitoring and mitigation measures. Although SCC is not explicitly discussed in 49 CFR 192 and 195, multiple requirements relating to design, construction, operation and maintenance of pipelines have a direct or indirect effect on preventing SCC.

ASME B31.4 and API 1160

The ASME standard B31.4 [30], 'Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids' is the current industry standard in the US for design and operations of liquid pipelines and is incorporated by reference in 49 CFR 195. B31.4 claims to provide only general statements rather than specific limits with regard to SCC. The Code comments on the requirement for adequate cathodic protection current levels, the importance of coatings type and surface preparation methods and the need to operate pipelines to minimise stress and temperature. The Code references the NACE RP0204 document as a source of useful information on SCC.

API Standard 1160 [25] 'Managing System Integrity for Hazardous Liquid Pipelines' addresses integrity management for hazardous liquid pipelines, but is not incorporated by reference in 49 CFR 195. API 1160 contains a brief description of both types of SCC and information relating to the use of ILI crack detection tools for detection of longitudinally oriented cracks and crack-like features, including SCC. The document also discusses the determination of inspection interval/frequency relating to SCC inspections.

ASME B31.8S

The ASME standard B31.8S-2010 [23] 'Managing System Integrity of Gas Pipelines' deals with the integrity management of gas pipelines. One of the threats considered within the document is SCC. Section A-3 provides an integrity management plan to address the threat of SCC, and methods of integrity assessment and mitigation for stress corrosion cracking (SCC) of gas pipelines; the plan is applicable to both high pH and near neutral SCC.

A list of criteria is provided for assessing the threat from SCC. Pipe segments are considered to be susceptible to SCC if:

The operating stress is >60% SMYS

The pipeline is > 10 years old

The coating is other than FBE or liquid epoxy

Further criteria are included to identify segments that might be susceptible to high pH SCC, these include:

operating temperature >100°F (38°C)

distance from a compressor station within 20 miles (32 km)

For this SCC threat, the risk assessment consists of comparing the data elements to the criteria. If the conditions of the criteria are met or if the segment has a previous SCC history (i.e. direct examination indicating SCC, hydrotest failures caused by SCC, in-service failures caused by SCC, or leaks caused by SCC), the pipe is considered to be at risk for the occurrence of SCC. Otherwise, if one of the conditions of the criteria is not met and if the segment does not have a history of SCC, no action is required.

The advice provided in ASME B31.8S is that a pipeline segment that has experienced an in-service leak or rupture attributable to SCC, should be subject to a hydrostatic test within 12 months of the failure. ASME B31.8S, includes the crack severity categories documented in the CEPA recommended practices, response requirements (depressurization, hydrostatic expansion test, ILI, SCCDA etc.) and response timings applicable to the five crack categories (see Table C.2).

Crack Severity	Response
No SCC or Category 0	Schedule SCCDA as appropriate. A single excavation for SCC is adequate.
Category 1	Conduct a minimum of two additional excavations. If the largest flaw is Category 1, conduct next assessment in 3 years. If the largest flaw is Category 2, 3 or 4, follow the response requirement applicable to this category.
Category 2	Consider temporary pressure reduction until hydrotest, ILI or MPI completed. Assess the segment using hydrotest, ILI or 100% MPI examination, or equivalent, within 2 years. The type and timing of further assessment(s) depend on the results of hydrotest, ILI or MPI.
Category 3	Immediate pressure reduction and assessment of the segment using one of the following: (i) hydrostatic test (ii) ILI (iii) 100% MPI, or equivalent, examination
Category 4	Immediate pressure reduction and assessment of the segment using one of the following: (i) hydrostatic test (ii) ILI (iii) 100% MPI, or equivalent, examination

Table C.2: Response to SCC indications found during direct assessment

The SCCDA process is discussed within ASME B31.8S as a means of selecting appropriate sites to conduct excavations the purposes of performing SCC integrity assessments, and hydrostatic testing for mitigation on pipe segments at risk from SCC. No specific guidance is offered in ASME B31.8S related to the use of ILI and the document states that until greater industry experience is established it is the responsibility of the operator to develop appropriate assessment and response plans when ILI is used for SCC investigation.

ASME B31G and RSTRENG

ASME B31G [31], 'Manual for Determining the Remaining Strength of Corroded Pipelines', is based on research completed by Battelle Memorial Institute in 1971. This work examined the fracture initiation behaviour of metal-loss defects caused by corrosion in line pipe to better understand failure mechanisms associated with these defects. ASME B31G, Section 1.2, *LIMITATIONS*, specifically notes: This manual applies only to defects in the body of line pipe which have relatively smooth contours and cause low stress concentrations (e.g. electrolytic or galvanic corrosion, loss of wall thickness due to erosion). However, these methods can be used to evaluate the remaining strength of a length of pipe from which stress corrosion cracks have been removed by grinding or buffing, leaving a smooth depression in the pipe wall.

API RP579

The API document RP579 'Recommended Practice for Fitness-for-Service,' [32] presents various assessment techniques for pressurized equipment in the refinery and chemical industries. The document covers a wide range of equipment and is not specifically directed towards hydrocarbon-containing pipelines.

The recommended practice describes assessment procedures for various defect types and processes, including: general metal loss, local metal loss, pitting corrosion, blisters and laminations, weld misalignment and shell distortion, crack-like flaws, and creep. Estimation of the crack growth rate is required for any component that is used in a service environment that supports SCC (or other types of cracking).

Because the recommended practice is not specifically directed towards pipeline operation, the example SCC crack growth rate expressions that are presented are not appropriate for predicting the rate of external cracking of underground pipelines. Appendix F of RP579 lists various fatigue and SCC crack growth expressions, but none of these are suitable for predicting the rates of high-pH or near-neutral pH SCC. Instead, when using the assessment procedures defined in API RP579, the rates of high-pH SCC should be estimated based on one of the following methods:

- empirical crack growth rates
- micro-mechanics based models
- slip-dissolution based models
- laboratory-based correlation of crack growth rate and strain rate

For near-neutral pH SCC, crack growth rates should be estimated based on:

- empirical crack growth rate data;
- corrosion-fatigue models, for deeper cracks and/or more-severe loading conditions;
- strain-rate based expressions.

NACE International

Publication 35103 - External Stress Corrosion Cracking of Underground Pipelines

Publication 35103 'External Stress Corrosion Cracking of Underground Pipelines' [33] provides an overview of the SCC phenomenon and how various factors (metallurgical, environmental and stress related) affect the initiation and growth of SCC on pipelines. It also briefly discusses prevention, detection and mitigation. However, as this document was a technical committee report, and not a recommended practice, recommendations and/or guidelines for use by pipeline operators in developing and maintaining an SCC integrity management plan was outside the focus of the report.

SP0204-2008 – Stress Corrosion Cracking Direct Assessment Methodology

This NACE standard practice SP0204 'Stress Corrosion Cracking Direct Assessment methodology' [34] covers the SCCDA process for buried steel pipeline systems and is the primary industry standard for identifying SCC sites using the four-step Direct Assessment methodology. It is intended to serve as a guide for applying the NACE SCCDA process on typical petroleum (natural gas, crude oil, and refined products) pipeline systems. The process is designed to be applied to both near-neutral-pH SCC and high-pH SCC and requires the integration of data from historical records, indirect surveys, field examinations, and pipe surface evaluations (i.e. direct examination) combined with the physical characteristics and operating history of the pipeline.

The document is intended as a flexible guideline for an operator to tailor the SCCDA process to specific pipeline situations and nothing in the standard is intended to preclude modifications that tailor the SCCDA process to specific pipeline situations and operators.

SCCDA is intended to be a continuous improvement process, through which successive applications should identify and address locations where SCC has occurred, is occurring, or might occur. SCCDA was developed as a process for improving pipeline safety. Its primary purpose is to reduce the threat of external SCC on pipeline integrity by means of condition monitoring, mitigation, documentation, and reporting. SCCDA is complementary with other inspection methods such as in-line inspection (ILI) or hydrostatic testing and is not necessarily an alternative or replacement for these methods in all instances. For example, ILI or hydrostatic testing might not be warranted if the initial SCCDA assessment indicates that significant and extensive cracking is not present on a pipeline system. However, SCCDA can be used to prioritize a pipeline system for ILI or hydrostatic testing if significant and extensive SCC is found.

The initial selection of pipeline segments for assessment of risk of high-pH and near neutral pH SCC on gas pipelines within the SCCDA is based on Part A3 of ASME B31.8S. Part A3 of ASME B31.8S considers the following factors: operating stress, operating temperature, distance from compressor station, age of pipeline, and coating type in identifying those segments of a pipeline that may be susceptible to SCC.

It is recognized that these screening factors will identify a substantial percentage of the susceptible locations, but not necessarily all of them.

The four step process employed in the SCCDA (Pre-Assessment, Indirect Inspections, Direct Examinations, and Post Assessment) has been described earlier in this document.

The current version of NACE SP0204 does provide some information related to mitigation of SCC but offers no guidance as to how frequently pipeline segments should be "re-inspected" using either the DA process or other techniques such as ILI or hydro-testing.

Canadian Standards Association

CSA Z662-03

The CSA Z662 document 'Oil and Gas Pipeline Systems' [24] sets out the technical requirements for the design, construction, operation and maintenance of oil and gas industry pipeline systems. The standard has been adopted by federal and provincial regulatory agencies that exercise jurisdiction over oil and gas pipelines in Canada. The standard treats SCC as any other cracking mechanism that poses a threat to the integrity of a pipeline. Some of the requirements in CSA Z662 that would be specifically applicable to SCC include:

the selection for both field-applied and plant applied coatings the

application of several types of plant-applied external coatings

the assessment and repair of cracks, including pipe body cracks and

the development and implementation of an integrity management program.

CEPA SCC Recommended Practices 2nd Edition

The second edition of the CEPA 'Recommended Practices on Stress Corrosion Cracking' [4], described earlier in this report, was published in 2007. Section 5 of the recommended practice deals with SCC investigation programs and includes a detailed listing of the various factors that have been found to correlate with near-neutral pH SCC. These factors are categorized as coating type and coating conditions, pipeline attributes, operating conditions, environmental conditions, and pipeline maintenance data. As with NACE SP204 and ASME B31.8S, these factors are largely based on field experience, but many are broadly consistent with the SCC guidelines developed from the R&D literature. On re-inspection intervals, Section 4.3.3 of the CEPA document provides no specific guidance, other than that the maximum reassessment interval should be 10 years. Section 5.6 of the document provides a more-detailed discussion that is largely based on monitoring changes in environmental and operating conditions.

Australian Regulations and Standards

Australian standards applicable to pipelines include:

AS 2885.1 Pipelines – Gas and Liquid Petroleum – Design and Construction

AS 2885.3 Pipelines – Gas and Liquid Petroleum – Operations and Maintenance

AS 2885.1 – 2012: Design and Construction

AS 2885.1 [35], Section 8 "Corrosion Mitigation" states that the potential for environmental related cracking shall be assessed, and if warranted, appropriate control measures shall be incorporated in the design and operation of the pipeline to prevent failure within its design life. Section 9.2 "MAOP upgrade Process" states that pipe defects that might affect the structural integrity of the pipe should be assessed, including SCC, and that limiting criteria for defects shall be established at the MAOP. Appendix P of this standard entitled "Environmental Related Cracking" gives a brief account of high pH and near neutral pH SCC and the factors that make a pipeline susceptible to these two forms of SCC. A reference is made to the CEPA SCC Recommended Practices document [3] as being relevant.

2885.3 – 2012: Operations and Maintenance

AS 2885.3 [36] in Chapter 6, Pipeline Structural Integrity," Section 6.3, "Pipeline Operation and Control", states four base conditions that the operating authority must ensure. It is noteworthy that the fourth condition is to ensure that operating conditions are such that the likelihood of stress corrosion cracking initiation or growth is minimised.

Section 9, "Anomaly Assessment and Defect Repair" in Clause 9.2 "Direct Assessment", states that procedures shall be established to assess anomalies and repair defects. Included in these procedures is the NACE SP0204 direct assessment methodology for SCC. Clause 9.4.2.6, "Environmentally Assisted Cracking", states that SCC shall be assessed as crack-like anomalies using fracture mechanics analysis and, if deemed to be appropriate, removed, replaced or otherwise repaired. Repair methods for SCC are identified in Table C1 of AS 2885.3.

UK Regulations and Practices

The Pressure Systems Safety Regulations – 2000

Pipeline operators in the UK must comply with 'The Pressure Systems Safety Requirements.' Although these regulations [37] do not specifically refer to SCC, multiple requirements relating to design, construction, operation and maintenance of pipelines have a direct or indirect effect on preventing SCC. For example, under Part II of 'The Pressure Systems Safety Regulations' it is stated that pressure systems shall be properly designed and constructed from suitable material so as to prevent danger. It also states that the way in which the pressure system is installed should not give rise to danger and that the pipeline is maintained in such a way as to prevent danger.

IGE TD1 – Edition 5

The Institute of Gas Engineers document IGE/TD/1 Edition 5 [38], is entitled 'Steel Pipelines for High Pressure Gas Transmission' and covers the design, construction, inspection, testing, operation and maintenance of steel pipelines and associated installations, for the transmission of dry Natural Gas, at a maximum operating pressure (MOP) exceeding 16 bar.

The document states in Section 3.4 (Pipeline Integrity Management) that pipeline integrity shall be managed and controlled at all stages of the pipeline life cycle. It goes on to state that the primary requirement of the pipeline integrity management process is the identification of potential threats, evaluation of risks associated with each threat, and the implementation of specific risk control measures; SCC is included as a potential threat.

IGE TD1, Section 5.7, deals with factory applied coatings and includes a note to indicate the potential for high pH SCC to take place, at elevated temperature, under a cathodically disbonded coating. A further reference to the potential for high pH SCC to occur, at elevated temperatures, is provided in Section 10.2.3. Reference to ILI tool capability and the possible requirement for crack detection tools is provided in Section 11.7.3, under 'Condition Monitoring' and the importance of the coating type (pipe and girth weld) stressed in terms of assessing the susceptibility of the pipe to SCC.

IGE TD1 Appendix 3 – 'Risk Assessment Techniques' includes SCC as a credible failure mode.

Appendix D – Figures

Figure 1: SCC colonies (Both high pH and near neutral pH SCC appear similar from a visual assessment)

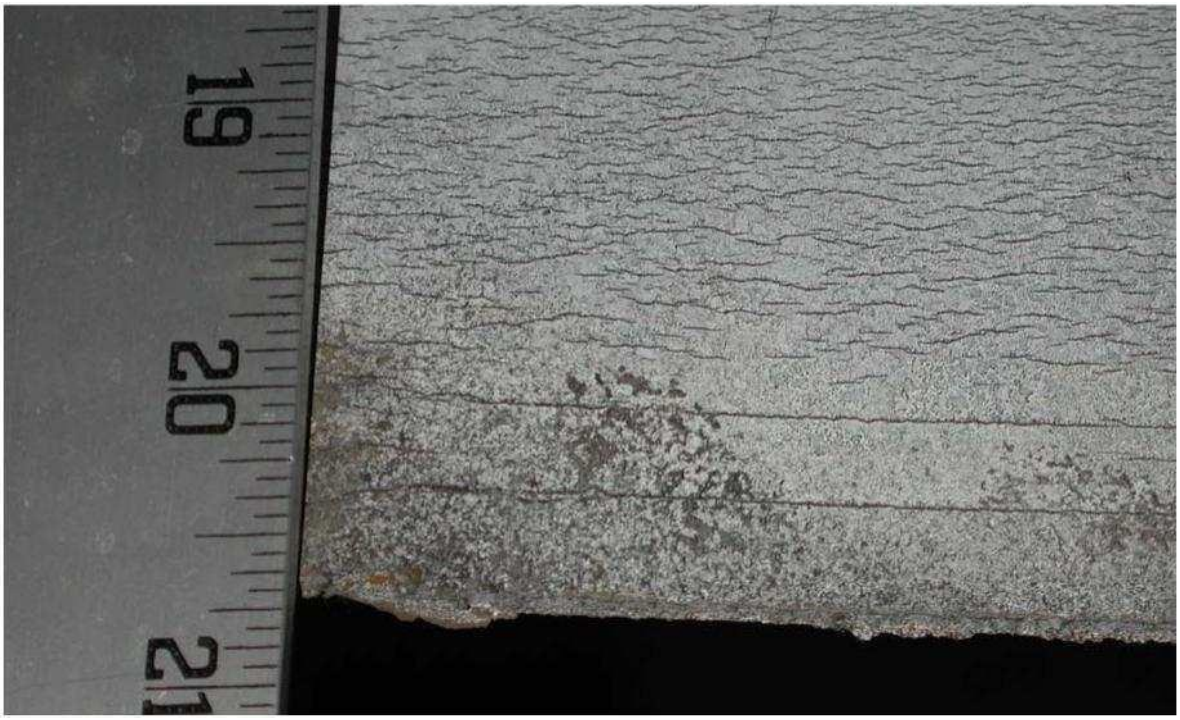

Figure 2: Crack growth and coalesence

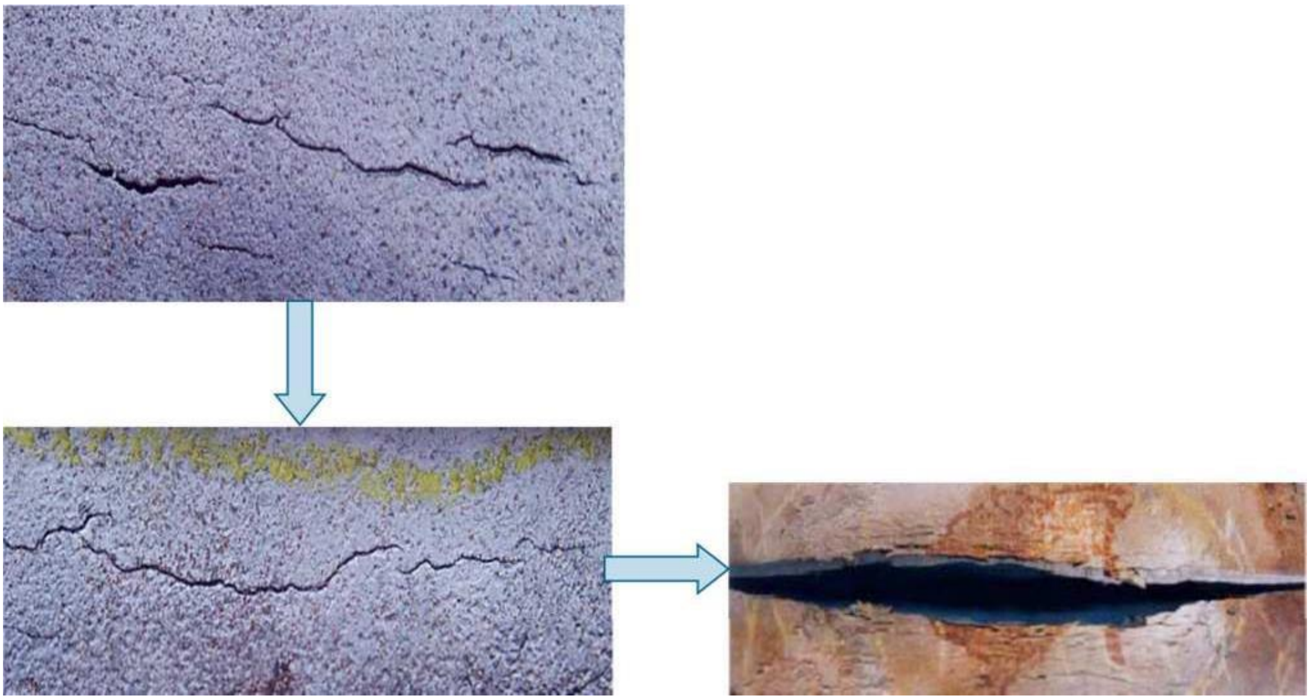

Figure 3: Intergranualr crack growth

Figure 4: Transgranualr near neutral pH crack initiating from a corrosion pit

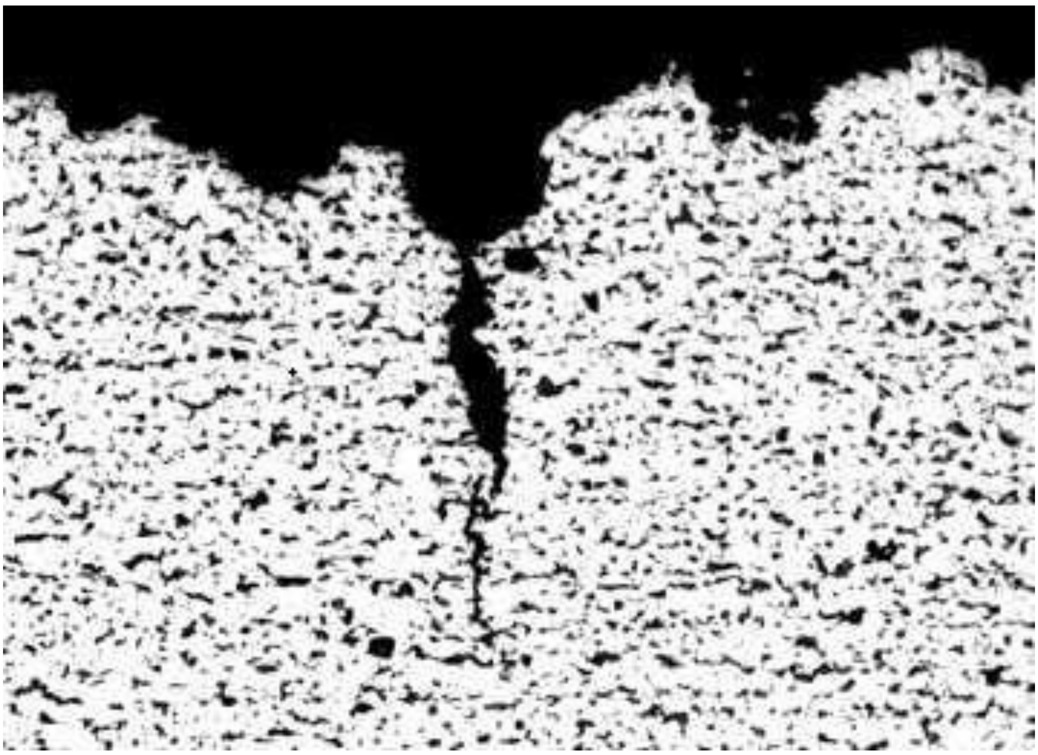

Figure 5: Near neutral pH SCC in vicinity of girth weld

Figure 6: Tape failure due to tenting at seam welds

Figure 7: Circumferential SCC failure

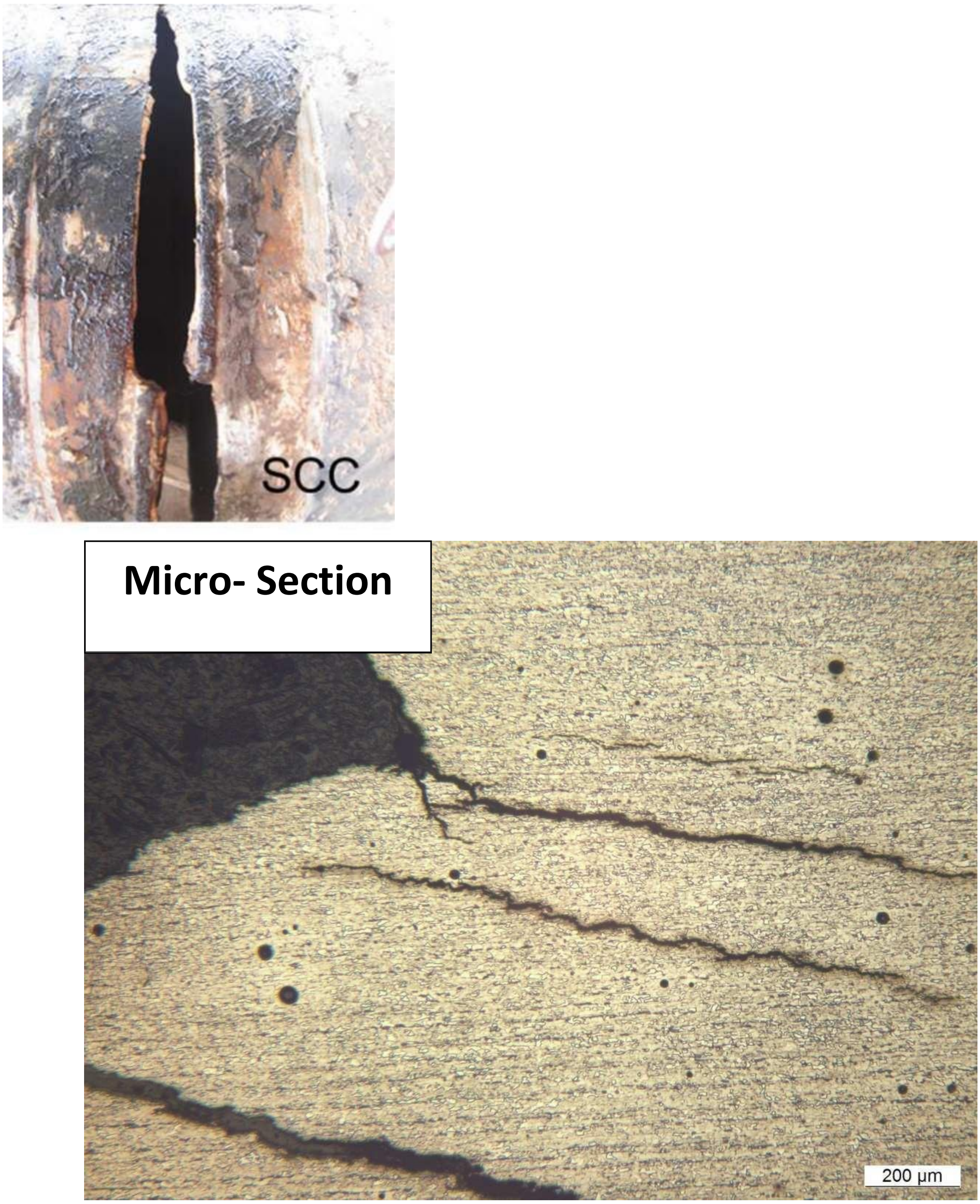

Figure 8: Bathtub Model Life Cycle of SCC growth in pipelines (Parkins, 1987)