Management of Pipeline External Stress Corrosion Cracking: A Time Story

By Daniel Sandana

With each passing day, not only do we pipeline engineers continue to age, but so do the assets that we are responsible for. The passage of time inevitably takes its toll on us, but, as pipeline engineers, we cannot ignore the impact that aging has on the integrity of our assets. The challenge for us is clear, to safely manage our energy infrastructures into the future. Corrosion, in all its forms, is one of the most significant time-dependent degradation mechanisms, compromising the integrity of our pipelines and potentially reducing their remaining life.

A friendly picture of corrosion is to look at it simply as a natural (physicochemical) process which drives material from an unstable (high energy) state to its more stable (low energy) state; rather as fatigue drives humans from a standing position to a sleeping position. In many applications, the influence of corrosion can actually be beneficial, such as passivation by oxidation of aluminum. However, in our industry, the processes by which corrosion occurs usually has undesired consequences, which affect the structural and containment properties of the facilities. These could result in unexpected asset failures, with consequences ranging from small leaks to major explosions, unless adequate corrosion control methods are incorporated at the design stage and reviewed regularly during the asset life cycle.

One of the most aggressive manifestations of corrosion is Stress-Corrosion Cracking (SCC). The generic definition and description of SCC can be a challenge without describing a specific mechanism. The most appropriate definition for SCC is probably to describe it as the fracture of a metallic material, essentially by cracking, which requires the synergistic action of a residual or applied tensile stress, together with an environment capable of causing corrosion of the material. SCC is frequently of a catastrophic nature as it generally occurs with little physical external evidence. This means that a failure from SCC could occur with little or no warning, unless specific non-destructive inspection techniques are used to detect it. SCC has been encountered both on external and internal pipeline surfaces. Currently, the integrity management of onshore buried steel pipelines susceptible to external SCC is one of the hottest topics in the pipeline integrity world.

The occurrence of external SCC on pipelines is not a recent phenomenon, having been first detected back in the 1960s. In the mid-1960s, operators in the USA began to suffer from in-service ruptures and leaks of onshore buried pipelines. This experience became the starting point for the pipeline industry to acknowledge the existence of external SCC. The earliest confirmation of external SCC was first reported in 1965 in Natchitoches, Louisiana. These initial forms of SCC were classed under what is now commonly referred to as "High-pH SCC". However, in the 1980s, a second form of cracking was experienced in Canada, which would now be classified as "Near-Neutral pH SCC". While these cases of SCC were originally believed to be limited to the US and Canada, SCC has since been reported around the world, in Australasia, the Middle-East, Europe and South America. Many occurrences of external SCC in steel pipelines will be a result of one of these two mechanisms, namely High-pH SCC or Near-Neutral pH SCC. It is important to remember that other SCC, or Environmentally-Assisted Cracking (EAC) mechanisms such as hydrogen embrittlement (possibly due to cathodic protection overprotection) or corrosion-fatigue, can also induce the presence of external cracks in pipeline steels. However, the presence of a crack does not necessarily mean it has resulted from an EAC process. A global view of the problem and the involvement of subject matter experts from technical areas such as materials, corrosion, welding, integrity, geotechnics, etc., are generally necessary to conduct an effective Root-Cause Analysis (RCA) that will establish the correct nature of the cracking mechanism, e.g. whether cracking originates from manufacturing, corrosion, welding, or some other cause. It should be emphasized that a flawed RCA diagnosis could have major implications in terms of effectiveness and costs on the future pipeline integrity management strategy and remaining life of a pipeline. On the other hand, a technically competent RCA diagnosis will support the operator in putting in place the most suitable management plans in order to achieve the desired operational asset life in a cost-effective manner.

There are a number of parameters which could affect the likelihood of initiation and propagation of external SCC (e.g. coating type, operating stress, temperature, pipeline diameter, downstream distance from compressors, etc.). The influence or weighted contribution of each of these parameters is largely dependent on the nature of the SCC mechanism [1]. At the same time, the most common features of parameter criticality relate to the presence of

***Figure 1**: Pipeline Coating showing signs of loss of adhesion (disbondment); Inside picture shows presence of an aqueous environment under disbonded coating where external SCC may initiate*

coating disbondment and pipeline/coating age. Time, once again, is usually very critical to allow for the coating to degrade (and disbond), and for a suitable cracking solution or environment to develop between the coating and the pipe surface interface, so that SCC colonies can initiate (and grow). Whether an initiated or established crack continues to grow or becomes dormant will be dependent on the presence of a micro-system at the crack tip. This micro-system is a function of the environment, material metallurgy, fissure morphology/geometry and mechanical stress characteristics at the crack tip. The Canadian experience of Near-Neutral pH SCC suggests that more than 90-95 % of initiated cracks enter the dormant state and stop growing. These cracks are generally found to be shallow and to feature blunt crack tips, but it should be noted that dormant cracks can be reactivated. A small fraction of SCC cracks will continue to grow and present a threat to pipeline integrity, which highlights the need to adequately manage the risk of pipeline external SCC.

So, what can we do to manage pipeline external SCC?

Following the first in-service failures in the mid 1960's, operators initially addressed the challenges of SCC by developing specific operational procedures. For example, one of the key parameters in the case of High-pH SCC is the fluid temperature. Elevated fluid temperatures are found downstream of compressor outlets, so pipelines that are in close proximity to a compressor station outlet are at a greater risk. Temperature is critical in this case, as it contributes to coating degradation (especially coal-tar) and increases High-pH SCC crack growth rates. Therefore, one of the mitigation measures has consisted of reducing compressor discharge temperatures. Another one has been to minimize operating pressure levels, although this is not the most favored option for obvious economical and commercial reasons.

From an early stage, hydrostatic tests have also been conducted to remove the more severe cracks before they could lead to inservice failure. Despite hydrotests having been effective at reducing inservice failures, hydrotests have some limitations. Apart from the need to shut down a pipeline, it is possible that subcritical cracks remain in the pipeline, which means that if such features are active they could grow further and possibly lead to a failure. This further underlines the requirement to conduct frequent hydrotests.

These hydrotests were generally supplemented by excavations conducted in a random or opportunistic fashion; the likely presence of SCC was, for example, investigated when pipe was uncovered for other operational reasons such as repair or corrosion. However, as the industry has become more aware of specific parameters influencing the susceptibility to SCC, methodologies and models have been developed to support a more systematic and consistent approach to the identification of cracking 'hot spot' locations [2]. Such practices have been translated into standards, e.g. ASME B31.8S [3], NACE SCC Direct Assessment (DA) SP0204 [4] and CEPA SCC Recommended Practice [5] [6]. Nevertheless, despite the establishment of a comprehensive knowledge base of external SCC mechanisms, there remains an inherent uncertainty in the susceptibility analysis, which impacts the effectiveness of the Direct Assessment method. This weakness has probably been associated with: (i) inaccuracy in data inputs (resulting from lack of knowledge of the specific system, or invalidity of measurement methods and/or procedures, etc.), (ii) potentially influential parameters are not considered in the models due to their general measurement complexity (e.g. soil/terrain, material hardness/toughness vs distance, etc.), (iii) lack of consideration specificity to actual operational pipeline/field. The framework of the DA method, reinforces the necessity of involving SMEs throughout the process, and the requirement of feeding back actual field data, observations and RCA findings into refining susceptibility algorithms on a field-by-field basis.

Today, SCC Integrity Management programs generally involve one or more of the following three methods: Hydrotest, Direct Assessment and/or in-line inspection (ILI). The development of increasingly more accurate and reliable crack-detection tools and technologies (e.g. EMAT) has made ILI an essential and important method on the SCC integrity management scene. ILIs allow the identification and sizing of cracks along pipelines, producing results which support pipeline integrity assessments and the identification and management of repairs. It must be recognized that all of the currently available and accepted industry methods have strengths and flaws. The biggest challenge currently for ILIs probably lies in the accuracy of the tool in sizing cracks, particularly crack depths. However, as the tool technologies evolve, they will undoubtedly become more accurate.

At ROSEN, we believe that the combination of using SCC susceptibility analysis assessments and ILI information (supported by field verifications) as part of SCC integrity management programs is a very powerful way forward in order to:

» prioritize direct inspections (ILI or excavations) as a function of susceptibility and risk,
» optimize further findings from ILIs by discriminating SCC features from other defects,
» prevent unnecessary costly field excavations,
» provide the most representative picture of the pipeline condition, in order to conduct appropriate integrity assessments and develop adequate repair and integrity management plans,
» calibrate and optimize SCC susceptibility tools on a field-by-field basis.

Our company has been closely involved with operators across the world throughout the SCC integrity management framework – from Root-Cause Analysis, SCC susceptibility/risk analysis, inspections, direct field measurements, through to integrity assessment and SCC integrity management plans. Our approach uses experts from key disciplines such as materials, corrosion, welding, risk, integrity, geotechnics, repairs, etc., to ensure the technical challenge of pipeline integrity management in relation to SCC is fully addressed.

In conclusion, as SCC is a time-dependent process, original construction practices and aging pipelines would suggest that the industry could see an increase in numbers of pipeline failures due to SCC. The good news is that any such increases and occurrences should be counter-balanced through the use of effective and available integrity management methods, and through future technology advances.

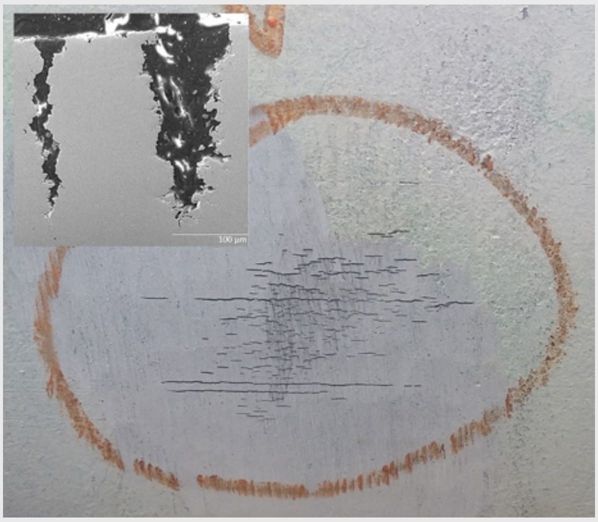

***Figure 2**: Pipeline external surface showing axial SCC cracks (revealed by MPI); inside picture shows Pipe cross section revealing active SCC cracks through pipe wall*

Yes, time challenges asset condition and integrity. But time also brings knowledge, wisdom, experience and technology. What we learn and develop from it will help us move forward towards a safer pipeline industry.

References

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