Nondestructive Testing Technologies and Applications for Detecting, Sizing and Monitoring Corrosion/Erosion Damage in Oil & Gas Assets

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ABSTRACT

Mechanical Integrity is the focal point of a multi-disciplined operational philosophy in which knowledge of equipment-damage mechanisms and judicious application of Nondestructive testing (NDT) can allow safe and reliable plant operation under normal and aberrant conditions. When incorporated into an evergreen Risk Based Inspection (RBI) program, these tools can provide valuable material data and condition assessment information that allow operators to make informed decisions as to run/replace or continued operation of pressure equipment and piping. This paper will highlight some specific damage mechanisms and NDT methodologies used to detect, size and/or monitor that specific damage, both on-line and during shutdowns to assess and prioritize the conditions of plant equipment. An overview of specific Damage Mechanisms will be presented along with results of actual plant experience employing this methodology for non-invasive corrosion assessment of critical components.

Key words: Damage mechanism, Mechanical Integrity, Nondestructive Testing, Nondestructive Examination, Ultrasonic Testing, Phased Array, Digital Radiography, Eddy Current, Electro-magnetic, Remote Visual Inspection, Risk Based Inspection, RBI, Fitness for Service, FFS, PIMS.

INTRODUCTION

Nondestructive testing (NDT) technologies including ultrasound, radiography, electro-magnetic and remote visual have evolved significantly over the past few years by a fundamental, demand-driven need within industry for improved test data. All four of these inspection disciplines are able to leverage significantly larger investments being made in the healthcare and consumer market segments. Advances in micro-electronics and optics, imaging, data and digital-signal processing (DSP) and software have all been adapted to a next generation of field-deployable NDT equipment capable of enhanced inspection productivity at refineries, chemical plants, pipelines and offshore production sites.

Detecting, sizing and monitoring for metal loss due to corrosion and erosion continues to be an important maintenance and operational challenge at large industrial facilities within the Oil & Gas community. In the United States, The Department of Labor, Occupational Safety and Health Administrations' (OSHA) Process Safety Management (PSM) Standard 29 CFR 1910.119[1] adopted into law in the 1990's, requires that hazardous materials processing be performed in accordance with public and worker safety as a primary objective. Since then, organizations such as the American Petroleum Institute (API) have provided very specific guidelines and recommended practices for asset owner to use to better manage risks associated with equipment failure due to metal loss, material degradation, etc. and provide input for Risk Based Inspection (RBI) and Fitness for Service (FFS) methodologies as found in API 580[2], 581[3] and 579[4].

The authors present six specific examples of how asset owners and NDT service suppliers are deploying newer NDT techniques for the improved detection, sizing or monitoring of metal loss. Improvements are seen via better image clarity yielding increased productivity and probability of detection (POD) with these tests. Furthermore, the costs and risks associated with deploying inspection personnel into difficult or harsh field environments can be better optimized.

1. Corrosion Under Insulation (CUI) Sizing with Digital Radiography (DR)
2. Compressor Blade Pitting Sizing with Phase Measurement and Remote Visual Inspection (RVI)
3. Pipe Wall Pitting characterization with Phased Array Ultrasonic Testing (PAUT) Dual Transducer
4. High-Temperature, Real-Time Monitoring Of Wall Thickness with UT Permanently Installed Monitoring System (PIMS)
5. Electromagnetic Inspection Of Heat Exchanger Tubing For Damage and Wall Loss
6. High-Temperature Hydrogen Attack (HTHA)

1. CORROSION UNDER INSULLATION (CUI) SIZING WITH DIGITAL RADIOGRAPHY (DR)

Corrosion under Insulation (CUI) is corrosion of piping, pressure vessels and structural components resulting from water trapped under insulation or fireproofing. As described in API 571[5], the typical materials affected by CUI are Carbon steel, low-alloy steels, 300 Series SS, and duplex stainless steels. It affects externally-insulated vessels and those that are in intermittent service or operate between:

1) 10°F (–12°C) and 350°F (175°C) for carbon and low-alloy steels,
2) 140°F (60°C) and 400°F (205°C) for austenitic stainless steels and duplex stainless steels

Corrosion rates increase with increasing metal temperatures up to the point where the water evaporates quickly. For insulated components, corrosion becomes more severe at metal temperatures between the boiling point 212°F (100°C) and 350°F (121°C), where water is less likely to vaporize and insulation stays wet longer. Cyclic thermal operation or intermittent service can increase corrosion. Equipment that operates below the water dew point tends to condense water on the metal surface thus providing a wet environment and increasing the risk of corrosion. Plants located in areas with high annual rainfall or warmer marine locations are more prone to CUI than plants located in cooler, drier, mid-continent locations. Environments that provide airborne contaminants such as chlorides (marine environments, cooling tower drift) or SO_2 (stack emissions) can accelerate corrosion.

An inspection plan for corrosion under insulation should be a structured and systematic approach starting with prediction/analysis, then looking at the more invasive procedures. The inspection plan should consider operating temperature; type and age/condition of coating; and type and age/condition of insulation material. Although external insulation may appear to be in good condition, CUI damage may still be occurring. CUI inspection may require removal of some or all insulation. If external coverings are in good condition and there is no reason to suspect damage behind them, it may not be necessary to remove them for inspection of the vessel.

Portable, digital radiography has had a profound impact on the work of inspection companies in a variety of field applications. This technique was discovered to be an effective solution to the challenge of CUI detection in harsh climates and on aged assets. Portable DR used with an electro-mechanical crawler provides the inspector with the ability to perform 100% inspection, for extensive sections of horizontal pipeline, detecting and sizing both ID and OD metal loss.

This type of inspection is enabled by formless, flat panel detectors. Light is converted and emitted by the absorption of x-ray photons by the cesium iodide scintillator. A low-noise photodiode array, where each photodiode represents a pixel, absorbs the light and subsequently translates it into an electronic charge. Finally, low-noise digital electronics read out the charge at each pixel.

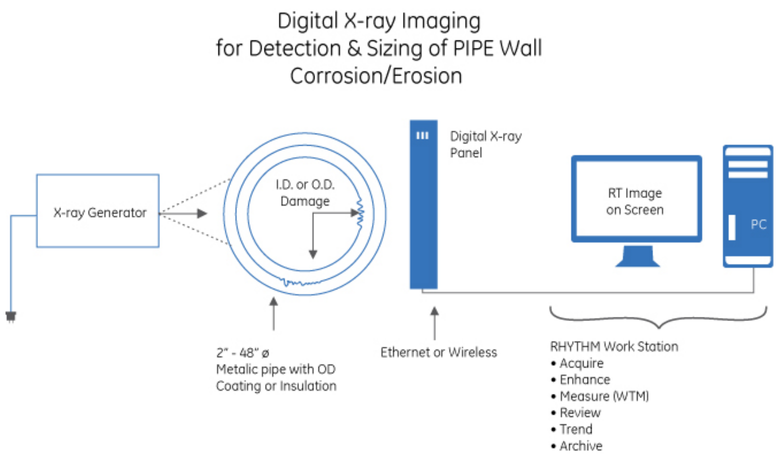


Figure 1: Illustration of digital x-ray functionality.

Figure 2: Field deployment of digital x-ray (DXR) imaging system for insulated pipe inspection.

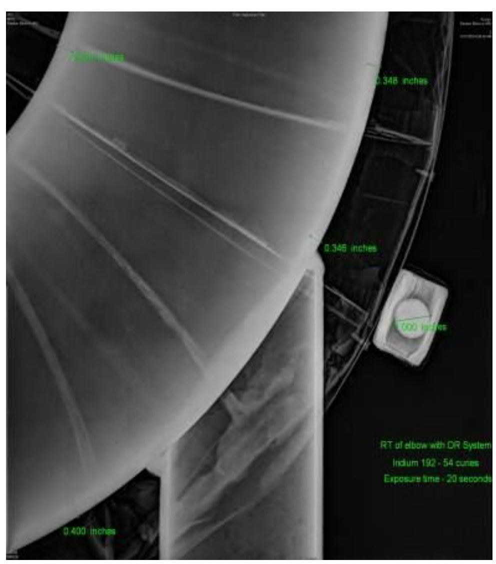


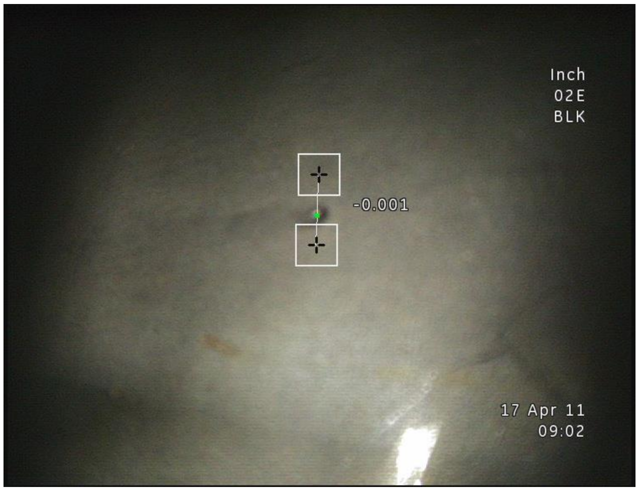
Figure 3: Typical DR image of insulated pipe elbow showing metal loss along with a digital thickness measurement.

The advantages of this technology are several. DR has been field proven to significantly reduce inspection times by > 95% by shortening radiation exposure time, eliminating film chemical processing and minimizing the safety-affected work area. DR also reduces overall image noise levels yielding improved image quality while further image enhancement highlights ID and OD edges better so that very accurate wall thickness measurements can be with the software tools. These combined factors improve the Detective Quantum Efficiency (DQE) metric, a widely-accepted metric for full-field digital detectors.

2. COMPRESSOR BLADE PITTING SIZING WITH PHASE MEASUREMENT AND REMOTE VISUAL INSPECTION (RVI)

Compressor blades may suffer damage and pitting on the surface of the blades from corrosion. When left unmonitored, compressor blade pitting can lead to lower efficiency, cracking, blade failure and additional compressor damage.[6]

3D Phase Measurement provides accurate 3 dimensional surface scans allowing measurement of all aspects of surface indications. Inspectors can view and measure a defect using a single probe tip, eliminating the extra steps required to back out, change the tip and then relocate the defect. 3D Phase Measurement provides accurate measurement "on-demand", while simplifying the inspection process. This technique was developed to perform visual inspection and detection, and performs the measurement of detected flaws, such as pits. This technique has the capability to measure much smaller features than before, like leading-edge pitting as small as 0.004” (0.1mm) diameter and 0.001” (0.025 mm) in depth.



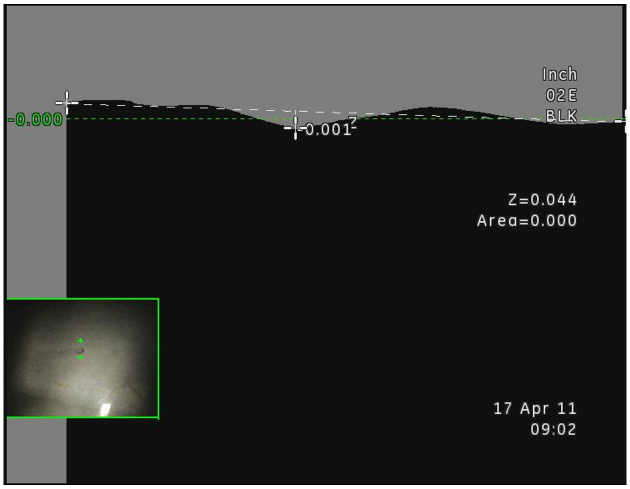


Figure 4 (left): Small, isolated pit on a compressor blade face.
Figure 5 (right): Phased measurement analysis of the isolated pit.

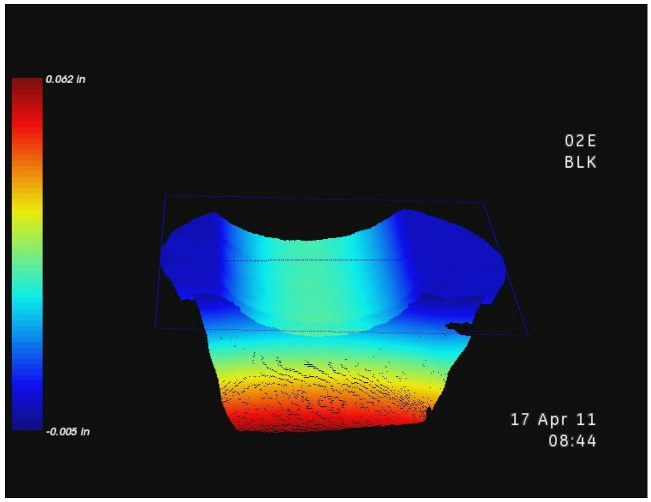


Figure 6: High-resolution color graphic of the compressor blade pit.

3. PIPE WALL PITTING CHARACTERIZATION WITH PHASED-ARRAY ULTRASONIC TESTING (PAUT) WITH DUAL TRANSDUCER

Pitting corrosion is a form of highly localized metal loss that can be elusive for detection and detailed characterization. Pitting can occur on piping, vessels, tank bottoms, sometimes close to the side wall, in stagnant zones, or under deposits. These areas have traditionally been difficult to inspect and size with any accuracy with conventional UT transducers, due to limited inspection area.

The phased-array dual transducer ultrasound technology was recently developed in response to these challenges. The system has the ability to transmit a signal that can penetrate the piping wall or tank bottom, reflect, and be picked up by multiple receiver elements. The v-path created by the phased-array dual transducer makes it possible to identify the size and dimensions of the pit much more precisely than conventional transducers.

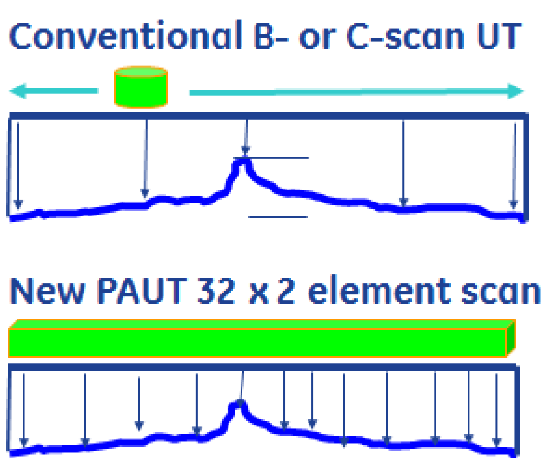


Figure 7 (upper-left): Conventional UT transducer inspection requires more scanning and limits the area covered during flaw-pit detection and sizing.
Figure 8 (lower-left and right): PAUT system electronically profiles the defect, allowing for faster inspections, increased area coverage and improved pit sizing.

4. REAL-TIME MONITORING OF WALL THICKNESS WITH PERMANENTLY-INSTALLED MONITORING SENSORS (PIMS)

It is common in the oil production, refining, and transportation industries to have equipment in difficult and inaccessible locations; for instance unmanned, offshore platform installations or crude unit overhead lines. These assets may require frequent or periodic scheduled wall thickness measuring: either for inspection planning or regulatory compliance in an effort to assess corrosion. High corrosion/erosion rates can be experienced at places in the process where the flow increases dramatically or process conditions change from established parameters. The integrity of these assets is critical since a failure could lead to catastrophic events and loss of production. For these unmanned and/or remote locations, a system configuration allowing for real-time, automated readings and transmission of such data on remaining pipeline wall thickness has numerous advantages.

One such PIMS commercial offering is Rightrax™, a system that can measure wall thickness continuously by using permanently-installed UT transducers, is rated intrinsically safe and has been successfully field deployed for over 6 years. Ultrasonic wall thickness measurement is direct, absolute and well proven. The area-array transducer system can be used in temperatures up to 248°F (120°C), above which the functionality of the transducers will be compromised.

Further, with additional complexities like high-temperature service, the value of this technology which can handle such environments is even greater. A high-temperature PIMS system can be used for multiple single-point measurement up to 932°F (500°C) for real-time wall thickness monitoring.

Performing ultrasonic tests in high temperature environments has the additional challenge of accurate calibration. Calibration changes as the material's temperature increases due to lowering of the acoustic velocity. Instruments that have been calibrated under normal temperatures will generate different measurements when being used to test the same material at a higher temperature. Traditionally, technicians have had to make a manual adjustment to the readings. Newer PIMS contain functionality that automatically compensates for the temperature difference to within +/- 2°F (1°C) accuracy.

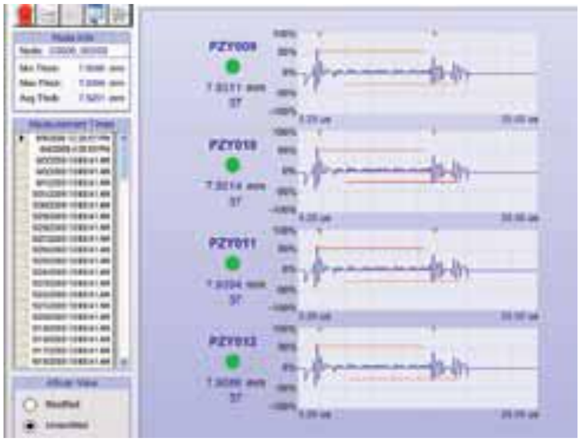


Figure 9 (left): Multi-sensor readout of wall thickness, with minimum threshold alarm gates.
Figure 10 (right): Installed high-temperature transducer and clamp on refinery process pipe.

Figure 11: Installed transducer pads on critical elbows at an offshore production platform.

Use of permanently installed sensors facilitates better planning and forecasting around maintenance. Shut downs can be avoided, or planned alongside other required maintenance, since consistent, traceable data is available for analysis. Thus, permanently-installed sensors prevent catastrophic failures enabling reduced downtime.

Downloading and analyzing the data can be done manually or via remote monitoring with wireless technology and informed decisions can be made on each specific location. The technology allows for precise corrosion rates to be determined, highlighting exactly when and where problems exist.

5. ELECTROMAGNETIC INSPECTION OF HEAT EXCHANGER TUBING FOR DAMAGE AND WALL LOSS

Electromagnetic methods, namely eddy current, have been developed for the nuclear steam generator industry into a next-generation technique to perform NDT on installed heat exchanger tubing from the tube inside diameter (ID). Eddy current technology (ECT) safeguards against failure during service, by detecting small discontinuities. This next generation technology has been applied in both ferromagnetic and non-ferromagnetic materials efficiently and precisely.

Eddy current signals can characterize outside diameter (OD) or inside diameter (ID) forms of corrosion via an alternating frequency-energized probe inserted through the length of the tube. Impedance depends upon numerous factors such as conductivity, metallurgy, mechanical work, dimensions, and location. As signals are received, they are processed and displayed for evaluation. The results are compared to signals obtained during the calibration process, in which the calibration tube used is of the same material as the tube being inspected.

Prior to the development of remote field eddy current testing (RFT) the only existing methodology for ferromagnetic material was Ultrasonic - Internal Rotary Inspection System (IRIS). While IRIS is used in numerous situations for its high level of precision, it is known to be a much slower, less efficient process. Important uses for IRIS as a complementary inspection with electromagnetic methods include detection for first-time testing signals, or for verifying RFT measurements.

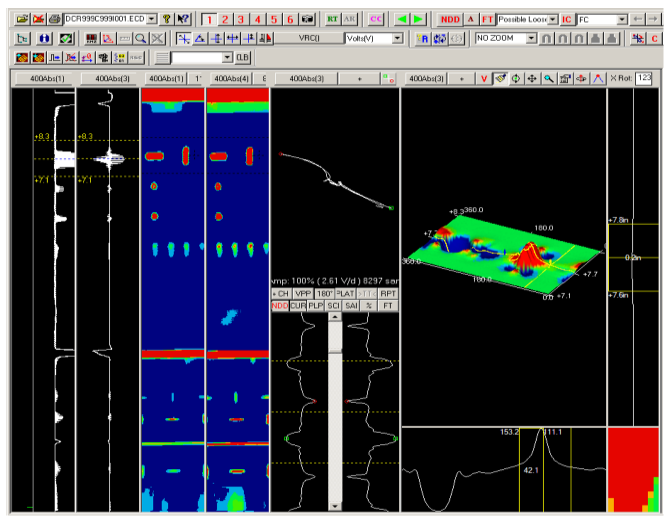


Figure 12 (left): Field inspection of specialized heat exchanger tubes at a chemical plant using eddy current technology.

Figure 13 (right): Eddy current graphic of a Terrain Plot of data demonstrating detected wall thinning, pitting, erosion, and cracking.

Figure 14: New-to-market detachable ECT tube ID probes which enable lower-cost HX tube inspections.

The benefits of electromagnetic methods are extensive. The primary benefit is the speed at which testing can occur. Eddy current assessments are completed significantly faster than the alternative IRIS method. Additional benefits of eddy current RFT include equipment portability and flexibility, paired with reliable and reasonably-precise flaw detection, allow operators to perform testing quickly and effectively. Use of the RFT application is particularly ideal in the detection and sizing of large volume defects. As the market and technology continue to mature, electromagnetic instrumentation are designed for longer life and improved signal-to-noise ratios.
There are limitations to all of the aforementioned NDT methodologies. While RFT can detect both ID/OD discontinuities, it cannot distinguish between the two types of flaws. In addition, in certain materials, the flaw detectability is less precise than alternatives.[7]

A variety of probes exist for eddy current testing. For heat exchanger corrosion detection, there are several benefits to using motorized rotating pancake coil and/or array probes. Advantages include circumferential crack detection, improved ID-initiated crack sizing, detection of either single or multiple cracking in the same plane/axis and improved volumetric damage sensitivity. In addition, Near Field Testing (NFT) is primarily used for the inspection of carbon steel tubes with aluminum fins. NFT allows for the detection and sizing of ID pitting and erosion defects.

A distinct challenge facing the RFT market is the lack of qualified operators to perform the tests and analyze the results. This is particularly due to the complexity of evaluating material magnetism, and the degree of changes in magnetism. For the same material, changes in magnetism can occur based on test location (i.e. field test permeability varies from lab permeability, sometimes due to magnetic scale deposits), adding to the degree of testing difficulty, and requiring highly-specialized field technicians.

Recent ECT advances in electronics come from newer digital signal processing (DSP) circuits which aid in instrument stability, repeatability and defect probability of detection (POD). In addition to enhancements in the areas of life cycle management and signal-to-noise ratios, future technological and design improvements will continue to occur especially with multi-channel, multi-frequency array probes which will enable both 2D and 3D ECT imaging.

6. High Temperature Hydrogen Attack

High Temperature Hydrogen Attack (HTHA) is a longstanding problem in the Oil Refining Industry. This phenomenon has been usually defined by empirical operational experience from API 941 (The Nelson Curves) [8]. The temperature-pressure limits below which no attack occurs for long exposures are given in a chart devised by G.A. Nelson. The Nelson curves provides a go/no-go basis of selecting steels for hydrogen service; however, they give no quantitative indication of the time required to produce attack and corresponding degradation of mechanical properties when the temperature-pressure limits are exceeded.

Hydrogen attack can be described as a loss of strength and ductility that can occur in steel exposed to hydrogen at high pressure and elevated temperature. This damage is attributed to the diffusion of atomic hydrogen into the steel. The reaction between the hydrogen and the iron-carbide in the steel, forms methane internally, at grain boundaries. The overall process of attack may be expressed by the equation:

$$\mathbf{Fe_3\,C + 2H_2\ (gas) = 3Fe + CH_4\ (gas)}$$

Since methane is a larger molecule than hydrogen it cannot diffuse out of the metal. The methane accumulates at the boundaries and may develop pressure to cause cracking along the boundaries.

Steel which is exposed to hydrogen attack conditions will pass through an incubation period before actual attack is initiated. During the incubation period, steel which has absorbed hydrogen may suffer a loss in ductility which can be restored by a relatively low temperature heat treatment. While undergoing this incubation exposure, no changes in structure, composition, or physical properties can be detected. After incubation, hydrogen attack is characterized by decarburization and formation of methane as shown in Figures 14 and 15. Further attack produces more decarburization, fissuring at grain boundaries and eventual crack formation in the structure.

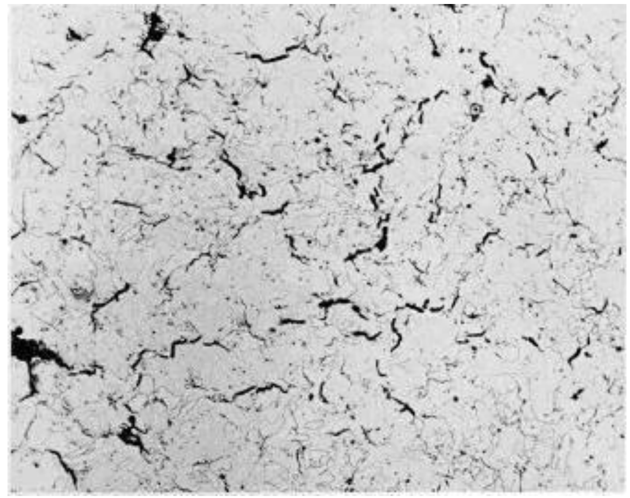
 

Figure 15 (left): A pipe ID surface exhibiting complete decarburization of the original structure, magnified at 200X.
Figure 16 (right): High magnification photomicrograph showing linkup of microfissures to form continuous cracks and damage is accompanied by a significant amount of decarburization.

These API 941 curves have served as an industry reliable guideline but have had occasional been significantly revised. In the late 1970’s, operational experience with C-1/2 Mo had led industry to consider “lowering” or removing the C-1/2 Mo curve from API 941.

Since its development in the early 1970’s, these ultrasonic methods have been considered the primary non-intrusive inspection techniques for the detection of hydrogen attack. The major challenge is that it is difficult to obtain consistent and interpretable results from one inspection period to the next, or from a different methodology/vendor at the same inspection. There have been three primary techniques commonly evaluated for detection and characterization:

1. Ultrasonic Backscatter
2. Ultrasonic Velocity Ratio
3. Ultrasonic Attenuation

Throughout the 1980’s, many owner-users struggled with NDE assessments of C-1/2 Mo equipment assessment. After many inspections employing different techniques, many operators replaced piping the suspect range for maximum assurance from HTHA concerns. Some of the larger equipment (exchangers, reactors) were either restricted in operation or replaced due to uncertain results of HTHA NDE inspections. The C-1/2 Moly curve was removed from API 941 in 1991.

The C-1/2 Mo experience is mentioned since recently[9] some carbon steel may hay suffered HTHA in conditions significantly below the Carbon Steel Nelson Curve. There is discussion in certain Industry Groups as to potentially downward adjustments of the curve. Should this occur, the industry would be faced with a similar challenge as found in the mid-1980 for C-1/2 Mo. The aforementioned NDE methodologies for screening and detection have proven questionable in reliability and repeatability. Owner-users often employ destructive metallographic samples for confirmation of HTHA. It should be noted that HTHA is not uniform even on the microscopic level and the depth and severity of attack can be significantly influenced by variations in chemistry, thickness, applied or residual stresses from micro sample to micro sample.

The detection and characterization of HTHA in Carbon Steel operating just below the existing API 941 limits may present one of the more significant NDE challenges of this decade. If a more repeatable, reliable NDE methodology is not developed, owner-users may be faced with difficult run-restrict-replace decisions in the very near horizon.

CONCLUSIONS

The authors have attempted to summarize some of the current challenges that face the owner-users of oil production, transportation and refining assets. In some applications, technology has been imported from other industries to create cost-effective solutions for existing problems in this industry. In other situations, technology has evolved to overcome some historic challenges or produce previously unachievable accuracy. There are still many technical and commercial challenges that elude current inspection capabilities.

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