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Cathodic Protection, Defective Coatings, Corrosion Pitting, Stress Corrosion Cracking, Soil Corrosivity Mapping and Corrosion Assessment in Aging Pipelines

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ABSTRACT

Pipelines are among the most common means used for transporting hazardous gases and liquids in the United States. However, underground pipelines are aging and are at risk of corrosion failure due to coating degradation/disbondment, pitting corrosion and stress corrosion cracking. Those tasked with maintaining these pipelines require an in-depth understanding of the locations where these aging pipelines are at risk of localized corrosion attack and cracking. Corrosion failures in aging pipelines are either sudden catastrophic ruptures or gradual leaks due to localized corrosion. Many factors associated with these corrosion areas are coating failure, degradation, disbondment, blistering, delamination, mechanical pressure and stress concentration, galvanic action, corrosive ions, the presence of moisture, corrosive soils, AC interference, inadequate cathodic protection and shielding. These areas have a much higher statistical probability of catastrophic failure and rupture. Most of the time initiation of stress corrosion cracking (SCC) and pitting corrosion are detected by coincidence in excavation and digs and is not targeted or predicted by analysis of corrosion performance parameters. Internal or In-line inspection (ILI) tools have limited capability for detecting or identifying stress corrosion cracking and pitting corrosion initiation. Here we would like to elaborate on corrosion risk assessment based on soil corrosivity mapping in addition to procedures outlined in NACE SP 0204-2015.

Key words: stress corrosion cracking (SCC); pitting corrosion; corrosion risk assessment; soil resistivity; soil corrosivity mapping; coating disbondment; cathodic protection.

INTRODUCTION

There are over 2.9 million miles of pipelines many of them aging coated pipelines transporting natural gas, oil, and hazardous liquid in the United States. Close to 50 percent of gas transmission and gathering pipelines were constructed in the 1950's and 1960's, over fifty years old. Barrier protective coatings and cathodic protection (CP) have been used to prevent corrosion. However, for aging pipelines, coating degradation/defects, shielding, disbondment, delamination and blistering can result in less than adequate protection, no protection, pitting and or stress corrosion cracking. Corrosion failure and rupture of aging pipelines poses a significant risk to the operators such as public safety in populated areas, environmental damage and halt in transport of products.

So how can we know what's cooking down there? Down there being the aging coated pipes and assets which are located in corrosive soils exhibiting disbondment and delamination of the coating with little or no protection because of poor CP design or shielding. Murphy's famous law states that "left to themselves, things will always go from bad to worse." This can be related to the second law of thermodynamics that stated entropy (disorder) increases. To offset the effects of entropy, energy must be injected; otherwise the system will become increasingly disordered and unstable. This is indeed true because the past is not an indication of the future for aging structures. A well thought out corrosion risk assessment process enables asset owners and integrity engineers to carry out effective risk management by providing specific actions/tasks that can reduce the risk. The intention is to minimize risk to the lowest practical level such that no unacceptable risks remain. It is generally not practical to completely remove all risks due to feasibility, time, and cost.

The development of pipeline integrity assessment methods and criteria for determining unacceptable risk is of great importance in preventing corrosion failure, SCC, and rupture. Corrosion risk assessment of aging pipes must rely on a variety of tools and techniques to determine existing condition and to measure the probability and consequences of all the potential corrosion related hazards. In addition to the age of the pipe, the design as well as in-service utilization must be accounted for. As a starting point, an overview of the coatings and failure mechanisms is presented followed by the methods that are performed by field inspectors to determine the condition of an aging pipeline below grade and its projected serviceability or life expectation. Here, corrosion risk assessment based on soil corrosivity mapping in addition to procedures outlined in NACE standards such as NACE SP 0204-2015.

Primary Forms of Corrosion attack in Corrosive Soils and Corrosive Water Tables

The two main forms of corrosion that have been observed are pitting (localized) pitting corrosion and stress corrosion cracking. Both pitting corrosion and stress corrosion cracking are localized in nature and occur when corrosive ions are exposed to the steel surface under delaminated coating or at coating defects.

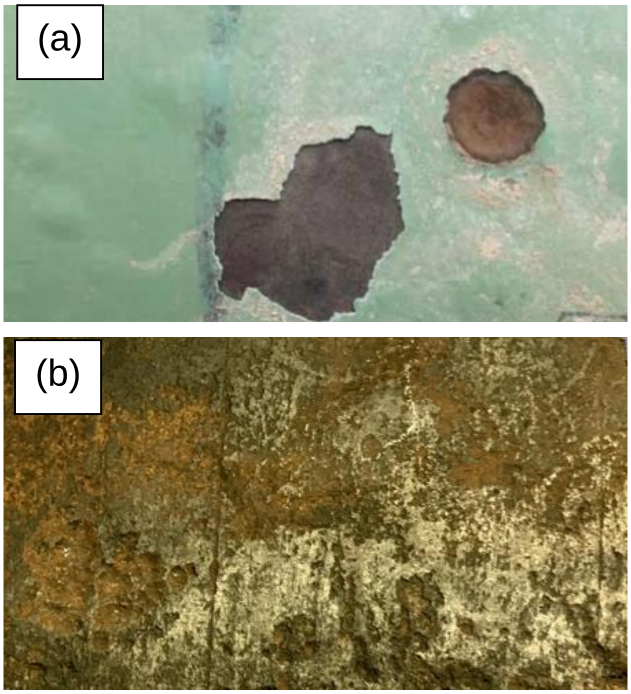

Figure 1: Localized corrosion under a blistered (a) FBE coated pipe and under (b) wax coating.

Pitting corrosion is a type of corrosion that is confined to small area. Figure 1. It usually is an autocatalytic process in the absence of AC/DC stray current corrosion. Active pitting corrosion is considered structural corrosion when the corrosion penetrates the steel. Pitting corrosion can be initiated due to presence of corrosive ions under a disbonded coating that acts as a shield to cathodic protection or in the presence of AC interference.

Stress corrosion cracking (SCC) near-neutral pH is a form of corrosion cracking that is associated with near-neutral pH or high pH. For near-neutral pH stress corrosion cracking, the electrolyte contains a dilute solution of carbon dioxide and bicarbonate ions with a pH between 6 and 7. This type of corrosion cracking is associated with limited branch transgranular cracking and the crack walls contain corrosion products. Figure 2 exhibits the fracture surface and branched cracking in a ruptured pipe. High pH SCC is caused by a solution of carbonate ions with pH between 9 and 10.5 exhibiting intergranular cracking with limited branching. Stress corrosion cracking can initiate under disbonded coatings that may shield cathodic protection.

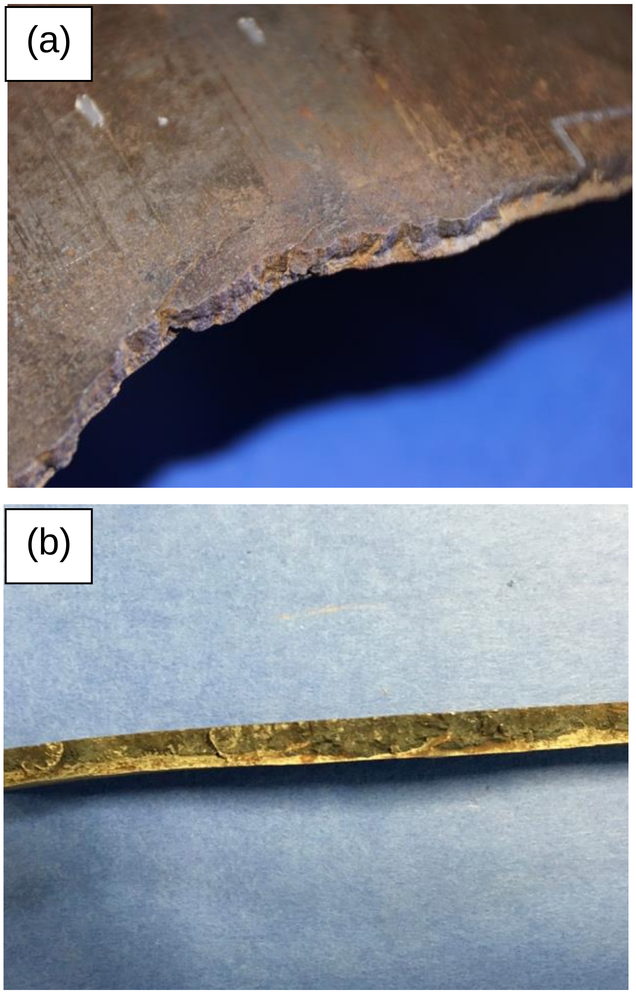

Figure 2: Stress corrosion cracking of natural gas pipeline that ruptured in service

It should be noted that external SCC has rarely been observed in the case of mill applied coatings such as FBE (fusion bonded epoxy), most likely due to better surface preparation and compressive stresses. On the other hand, SCC and pitting corrosion have been observed under repair coatings and deposits that act as a shield in cathodically protected pipelines.

Coatings as Corrosion Control

One of the oldest means of corrosion protection is to coat the substrate with a polymeric material. An organic coating can protect a metal substrate by serving as a barrier for the corrosive reactants: water, oxygen, and corrosive ions.

There are a number of different types of coatings that have been used specifically to provide corrosion protection for buried or submerged metal structures, including coal tar based coatings, polyolefins, shrink sleeves, wax-based coatings, asphalt, urethanes and urethane-blends, epoxy phenolics, polyureas, esters, and fusion based epoxy coatings. These coatings are used for corrosion control but they also age and exhibit disbondment as they age if surface contamination is present. Underground coatings are applied much thicker than above ground coatings as they must be able to withstand an underground environment. In order for a coating to operate safely for the intended life of the pipe it is important to choose the right coating for the environment, not to exceed the operating requirements for the coating, and ensure proper installation and handling of the coated pipe. When the pipe is to be buried, soil stress is the most critical factor. Coatings with little or no elongation but good adhesion to the steel pipe are less susceptible to soil stress. Service temperature is also a critical criterion. The maximum and minimum temperatures must be considered compared to the thermoset temperature and the glass transition temperature of the coating in question. Simply put, coatings that perform well at very high temperatures (thermosets) will probably not function well at very low temperatures. Similarly, coatings that perform well at very cold conditions such as rubbers will not function well at very high temperatures. At temperatures greater than 65^o C, rubber adhesives can flow and causing a lack of corrosion protection because water can penetrate into the voids and spaces of the flowing adhesive.

For a coating to be effective, it should have the following properties:

- Excellent bond strength to ensure continuous and permanent contact with the metal structure
- Low water absorption in order to maintain the dielectric strength and physical properties of the coating and prevent interfacial contamination
- Good physical strength to avoid damage to the coating during shipping, installation and soil stress.

Cathodic Protection

Cathodic protection is a method for reducing the corrosion rate by minimizing the potential difference between the anodic and cathodic areas in a corrosion cell. In this method, a direct current (DC) is applied from an outside source to the structure to be protected, such as a pipeline. When enough current is applied, the whole structure (pipeline) will exhibit one potential and anodic sites on the pipe will cease to exist. For underground applications, there are two types of cathodic protection systems: galvanic systems and impressed current systems. A galvanic cathodic protection system utilizes the difference of corrosion potential between two different metals.

Without cathodic protection, certain areas of the structure will exhibit a more negative potential compared to the remaining areas. This results in the formation of corrosion cells. If an object with sufficiently negative potential is placed adjacent to a corroding pipeline with a metallic connection (installed between the object and the pipeline), then the object will become the anode and the entire pipeline becomes the cathode. Technically, the object’s so-called galvanic anode will be sacrificed to protect the pipeline. Sacrificial anodes (also referred to as galvanic anodes) are usually made of magnesium or zinc because these metals have active potentials compared to steel in most soil environments.

The second form of cathodic protection is impressed current cathodic protection. The impressed current system uses an external power source, usually a rectifier that changes input alternating current (AC) to the desired direct current (DC). The rectifier can be adjusted so that the proper output is maintained throughout the pipeline's lifecycle. Impressed current anodes are usually made of high-silicon cast iron, graphite or noble metals with mixed metal oxide coating.

Stray Current Corrosion

Stray current from external sources can result in accelerated corrosion of pipe in a rather short time, even if it has the best coating system. Stray current corrosion is the result of electrical interference between cathodic protection systems of a pipeline with an external structure (for example a foreign pipeline). As a result of the interference, protection currents follow through paths other than the intended circuit. The extent of corrosion damage and loss in thickness can be estimated by Faraday's law (soil resistivity and time-in-service) and is directly proportional to the magnitude of stray current. This type of corrosion is localized in coated pipes and takes place at discharge points such as pinholes (Figure 3) and mechanically damaged areas. The following figure shows localized corrosion due to stray current. It has occurred in a rather short service time (six months). Stray current corrosion can be prevented by eliminating the source, shielding or cathodic protection.

Figure 3: Stray current corrosion of a new FBE coated pipe.

AC Interference

Typically, FBE coated pipelines are used near electric transmission lines and run parallel to high voltage transmission lines. AC interference can take place by conduction and/or induction mechanisms causing accelerated corrosion in the blistered areas of the FBE coated pipe. The presence of AC interference can cause serious pitting corrosion even on pipes under cathodic protection, and even if the -0.850 V CSE criterion is met. Uncertainties exist as to the reason for this phenomenon. We believe the corrosion attack in blistered areas and the formation of corrosion products inside the pit can be detected by analyzing electrochemical data prior to initiation of pits penetrating the pipeline wall thickness, monitor AC interference, on time CP data, and ER (electric resistance) corrosion rate monitoring. This enables corrosion attack to be detected prior to deep penetration into the pipeline wall thickness.

Failure Mechanisms

Coated pipelines degrade and fail for a variety of reasons. These can be categorized as either environmental (moisture and/or oxygen transmission through the coating) or coating application effects such as surface preparation and coating thickness. This can be exacerbated by complimentary corrosion protection processes.

Cathodic protection can introduce other problems for the coating. For instance, H^+, OH^-, and other electrochemical reactants caused by cathodic protection at the cathode may cause blistering or cathodic delamination of the coating in presence of water soluble surface contamination, resulting in loss of adhesion between the metal and coating and eventual exposure of the metal surface to the environment. Hydroxyl ions (OH^-) are one of the most aggressive chemical species and nearly all organic binders and oxides are capable of reacting with them.

Cathodic Delamination and Increase in pH in Blister

Many times coated pipes are subjected to mechanical damage, stress, scratches and dents due to transportation and installation damage. One undesirable consequence of cathodic protection of a coated structure is that the coating adjoining a defect may separate from the substrate pipe surface under certain conditions. This loss of adhesion is known as cathodic delamination. This type of failure may also occur in the absence of an applied potential due to corrosion processes along the surface of the pipe. Hence, this process may lead to additional damage in cathodic regions around blisters that are actively corroding.

As coated steel parts are subjected to disruptions in the coating, these areas are being protected from corrosion through an applied cathodic potential. The downside is that the cathodic reaction that occurs in the area in the presence of oxygen will produce hydroxyl ions, as indicated below.

$$H_2O + \tfrac{1}{2} O_2 + 2e^- \rightarrow 2OH^-$$

The production of hydroxyl ions can have a destructive effect on the organic coating/substrate bond. The strong alkaline environment will attack the polymer at the interface. This alkaline solution essentially cleans the coating off the surface of the metal in much the same way that alkaline solutions are routinely used to clean oil films from a metal surface.

Figure 4: Disbondment of FBE coated pipe under cathodic protection.

After one blister has been observed, or a few blisters formed, the condition advances to general disbondment in that area. At this stage, the larger delamination of the coating occurs, resulting in exposure of the steel to the environment under the disbonded coating that may acts as shield to cathodic protection. The coating no longer protects the steel and corrosion proceeds unchecked if the cathodic current is no longer sufficient to suppress corrosion over this newly created exposed surface area. At this point, corrosion proceeds at a rapid and aggressive rate causing considerable structural corrosion in a rather short time in the presence of corrosive soil and water table.

Following questions should be answered for finding cause of blistering in the FBE coatings and corrosion pits:

(1) Surface contamination during manufacturing and transportation
(2) Corrosive soils
(3) Less than adequate cathodic protection on the line.
(4) AC interference from nearby AC lines.
This also depends on soil resistivity and moisture level in the soil, so your low AC current reads (<30 A/m^2) may exceed 100 A/m^2 depending on loads on AC lines and variation in soil resistivity.
(5) Cathodic electrodeposition of calcareous deposits that may shield CP currents.
(6) Delaminated coatings that shield cathodic protection.
(7) A combination of the above conditions.

Corrosion Assessment and Structural Integrity of an Aging Pipeline

The methods available to assess the structural integrity of a pipeline per Code of Federal Regulations (CFR) 192 (gas) and CFR 195 (liquid) are:

- In-line inspection (ILI)
- Hydrostatic testing
- Direct assessment (DA) per NACE International Standard Practice SP0204-2015

Direct assessment relies on the focused examination of the pipeline at pre-selected locations to evaluate a pipeline for external corrosion, internal corrosion, or stress corrosion cracking risks.

Besides an ILI inspection analysis of the line, the internal and external environments of the line must be considered to arrive at the possible factors that may cause the pipe to fail due to corrosion.

In order to fully understand the corrosion risk for an aging pipeline, it is best to establish a basis for estimating the probability of corrosion for the pipe surface in contact with soil. However, the probability of corrosion is not only governed by the corrosiveness of the soil and the properties of the coated pipe, but also by designing terrain and topography, and by external electrochemical effects such as stray currents, AC interference, etc. Since these parameters cannot always be described with accuracy, the likely corrosion behavior can only be estimated.

NACE SP0204-2015 recommends a process for assessing the extent of stress corrosion cracking on a section of buried pipeline that the asset owner has identified as an area of interest based on risk assessment.

Soil Corrosivity Mapping

Most of the times initiation of SCC and pitting corrosion are detected by digs and are not targeted or predicted by analysis of corrosion performance parameters and soil corrosivity mapping. ILI results have limited capability for detecting or identifying SCC initiation and pitting corrosion. Here we would like to elaborate on corrosion risk assessment based on soil corrosivity mapping in addition to procedures outlined in the above mentioned standards.

Figure 5: A fusion bonded epoxy (FBE) coated pipe and water table.

Soil corrosivity and cathodic protection data records are very important in the pre-assessment step in addition to other records of corrosion, repairs and maintenance. Soil corrosivity mapping along the pipeline is complimentary to other corrosion assessment methods such as ILI and is not necessarily an alternative or replacement for these methods. It can be used to prioritize a segment of pipeline for electrochemical potential mapping, coating evaluation, ILI or hydrostatic testing. Therefore, soil corrosivity must be considered and samples collected for analysis, as appropriate. For example, soil in the immediate area of the failure, soil at the depth of pipe, and soil that had adhered to the pipe may have to be collected for laboratory analysis and corrosion assessment.

In determining the corrosivity of a soil, the different constituent soil characteristics and relevant attributes of the physical environment should be considered. A ranking of the various factors is assigned in order of importance relevant to corrosion science. The sum of those rating factors is a measure for the overall soil corrosivity rating.

It is important to have an understanding of the key factors that are measured or assessed in order to accurately and adequately interpret the results. For example, soil resistivity, which is an approximate measure of the concentration of reactant ions that lead to corrosion, typically decreases as the moisture and ionic concentration increase. Generally, soils with lower resistivity and reducing properties experience higher corrosion rates.

All tests for the defined corrosion factors are typically performed using standard ASTM, CSA (Canadian Standard Association), NACE or AASHTO (American Association of State Highway and Transportation Officials) methods or modified methods developed from experience and testing.

For example, one method of measuring soil resistivity is that described in AASHTO T 288, *Determining Minimum Laboratory Soil Resistivity*. This method was developed from a California Department of Transportation procedure sanctioned by the Federal Highway Administration (FHWA) for evaluating mechanically stabilized earth (MSE) backfill. The American Society for Testing and Materials (ASTM) has a different procedure. The method described in ASTM G57, *Standard Test Method Field*

Measurement of Soil Resistivity Using the Wenner Four-Electrode Method, has been replaced by a two-part standard: Part A will cover the four-electrode method for in- situ field measurements, and Part B will cover the use of a soil box for laboratory and field-test measurements.

Corrosion tests are performed by soil resistivity measurements at different depths, pH measurements, TDS (total dissolved solids), chlorides and sulfate, carbonates/bicarbonates, sulfides, redox potentials, bacteria activity, resistance polarization measurements (Rp) and corrosion measurements. It should be noted that there is a decrease in corrosion rate for oxidizing soils due to formation of a protective layer on steel. However, in reducing soil such a layer is absent and therefore the corrosion rate may increase as a function of time. The pipe should be adequately protected when located in reducing soils with coatings and cathodic protection.

Agricultural soils are typically more corrosive due to the high concentration of nitrates, and sulfates in fertilizers. Likewise, structures exposed to excessive amounts of road salts or sea water experience higher corrosion rates due to more exposure to chlorides. Soil samples, ground water samples, liquid samples in blisters should be collected in sterile bottles, bags and syringes and stored on ice in a cooler on-site and shipped overnight on ice in a cooler to the soil corrosivity testing laboratory for testing and evaluation.

Figure 6: Blister liquid extraction - high pH solution due to cathodic delamination.

Inspection Techniques and Confidence Level

The methods for determining corrosion risk include knowledge-based assessments bringing together materials science, electrochemical, soil and corrosion science as well as an understanding of how the pipeline is designed, built and assembled. The key techniques involved are geared towards quantitatively determining the soil and physical environment characteristics in order to carry out a qualitative multi-factor risk based assessment of corrosion risk. The following activities are recommended:

- Assessment of the soil service environment to rate corrosivity
- Electrochemical potential values and soil resistivities to predict corrosion profile at lower depths
- Coating assessment of the buried pipeline

In risk assessment, these test results should be taken into consideration along with pipe age, location and importance. Each segment is then assigned a corrosion risk rating or condition assessment value. This rating along with other assessment methods are used to recommend appropriate remediation and mitigation procedures. Special attention should be given to soil chemistry for stress corrosion cracking assessment. Depending on the method of evaluation, a level of confidence can be assigned to indicate the ability of that procedure to produce reliable corrosion risk data.

Soil Testing and Soil Sampling

Soil testing and sampling can be conducted by testing parameters in the soil corrosivity equation, namely resistivity and electrochemical potentials of the soil. The resistivity measurements will express the capacity of the soil to act as an electrolyte and the electrochemical potential measurements and CIS will express the soil's corrosion activity, or how active it is towards an oxidative/reductive corrosion reaction. Corrosion rate measurements provide estimates of maximum thickness loss and life or remaining life under worst possible condition when cathodic protection is not active.

Assigning Soil Corrosivity Values

The soil around each segment of pipe is assigned a soil corrosivity rating based on a number of parameters including soil resistivity, pH, chlorides, carbonates and bicarbonates, sulfates, MIC (Microbiologically Induced Corrosion) and electrochemical polarization. We have developed an algorithm to rate the corrosivity as it relates to buried structures.

Data Collection, Sorting and Analysis

Collection of data and analysis should be given special attention as it is directly related to the quality of the assessment and subsequent analysis. It is not recommended that paper forms be used. A computerized platform with data capture, storage and analysis is preferred. We have worked with several clients and software developers to achieve this goal and there is a lot of promise in this field. In general, the computer platforms designed should have the following attributes:

- Mobile device compatibility
- GIS capable
- Multi-platform and multi-format capability
- Ease of data entry user interface is key
- Live data validation
- Live risk analysis based on risk algorithms
- Data management strategy & administration

Corrosion Mitigation for Aging Structures

In carrying out or developing a corrosion mitigation strategy for pipe, we have seen that it is crucial that the corrosion risk be well-defined through knowledge-based inspection focused on the relevant criteria. The key steps to properly manage and access conditions are:

<u>Plan ahead</u>

- Develop corrosion management and risk assessment programs
- Require coating suppliers to provide scientific testing for coating recommendations and provide advanced notification of coating formulation changes.

<u>Assess</u>

- Perform pre-assessment, corrosion risk assessment and post assessment. Utilize modern computer platforms for data collection, sorting and analysis.

<u>Manage Risk</u>

- Consider protective coatings with adequate thickness in corrosive environments and consider non-corrosive backfills.

- Utilize wireless corrosion monitoring and inspection in corrosive areas.
- Consider adequate cathodic protection and AC mitigation in cases of AC interference.

In summary, corrosion risk assessment is an evolving field and should be looked at as such. Various corrosion performance parameters should be considered to increase the confidence level. Outside interference and stray currents should also be considered. It is vital that competent NACE Certified corrosion specialists and engineers participate in the efforts of asset owners to deal with this issue so as to avoid preventable risks.

CONCLUSION

In addition to methods recommended by NACE, onsite corrosion assessment and soil corrosivity mapping should be performed along with the laboratory investigation to determine and verify corrosion risk parameters:

- Soil corrosivity assessment in different segments of the pipeline
- Setting up remote monitoring which will add consistency to the data collected and remove any human error or varying copper sulfate electrode placements.
- The new test station locations will be determined by evaluating the ILI data as well as finding locations with extreme moisture/low soil resistance fluctuations.
- Feasibility of constant self-regulating current rectifiers or constant potential rectifiers should be explored
- Soil corrosivity, terrain type, soil moisture, pH, soil resistivity, MIC and corrosive ion concentration should be analyzed for corrosion mapping and early detection of corrosion activity and cracking.

NACE STANDARDS AND REFERENCES

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