

Corrosion Under Insulation and Atmospheric Corrosion in the Refinery Industry. An Accurate Approach to Estimate Corrosion Growth Rates, A Texas Refinery Case Study

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ABSTRACT

Corrosion under insulation (CUI) is corrosion that results from moisture buildup on pipelines covered by insulation. Atmospheric corrosion is the electrochemical decay of a carbon steel pipeline in an air environment, under the presence of an electrolyte such as rain, dew, humidity, or snow. Salt and pollutants in the air and soil aggravate atmospheric corrosion and CUI. Both CUI and atmospheric corrosion are costly problems in refineries. In a Texas refinery, CUI causes approximately 60% of all pipe leaks and was particularly difficult to prevent, track, and mitigate. In this paper, a case study will be presented that addresses one of three different methods to calculate corrosion growth rates, remaining life, and reinspection interval. The traditional approach includes an initial inspection and the estimation of aggressive corrosion growth rates that will require frequent and costly re-inspections. This paper presents an ILI data point-to-point comparison methodology to address the damage caused by CUI so that it can be easily quantified, and its growth rate accurately estimated. This method will save time and money by decreasing expensive shutdowns and unnecessary direct examination of insulated areas. Based on the results of the point-to-point comparison, the pipeline operator conducted a cost-based analysis, resulting in a repair program that maximizes the re-inspection interval.

In addition, the paper shows typical examples of CUI and points out some of the major impacts of CUI on in-line inspection (ILI) technologies like magnetic flux leakage (MFL) and ultrasonic compression wave also called ultrasonic wall thickness measurement. The results of different assessment methods for pressure-based assessment as well as for the estimation of corrosion growth rates from consecutive ILIs

are compared. The discussed integrity assessment method also includes a new method specifically designed for pipelines difficult to inspect in a refinery setting. In this paper, a case study will be presented that addresses a pipeline that was subjected to both CUI and atmospheric corrosion. A 6-inch diameter pipeline was subject to CUI with corrosion rates as high as 0.047 inches per year (1.2 mm/yr.) The paper will explain a simple methodology to filter the results of the inspection data to avoid unnecessary and expensive repairs. The results are also applicable to atmospheric corrosion.

Keywords: Corrosion under insulation, CUI, atmospheric corrosion, corrosion growth rate, CGR, in-line inspection, ILI, magnetic flux leakage, MFL, ultrasound, ultrasonic testing, UT, PHMSA, CFR 192.493, CFR 195.591, CFR 195.3, CFR 192.7, cathodic protection shielded, data integration, API 1163, verification, validation, data integration.

INTRODUCTION

External corrosion in *uninsulated* pipelines is normally able to be prevented by cathodic protection (CP). Generally, external corrosion on buried pipelines cannot occur if CP current is getting onto the pipe. CP is an electrochemical means of corrosion control in which the oxidation reaction in a galvanic cell is concentrated at the anode and suppresses corrosion of the cathode (pipe) in the same cell. For instance, to make a pipeline a cathode, an anode is attached to it. The anode and the cathode must be in an electrolyte such as soil or water. CP current creates an oxygen-free environment around the pipe which will stop the electrochemical process of corrosion, barring additional circumstances. Where external corrosion does occur, current can get off the pipe and migrate into the surrounding soil. When this happens, the current takes metal ions with it causing external corrosion. There is little to no “corrosion product” that remains at the pipe surface. However, in a buried *insulated* line, the coatings and insulation do not allow the metal ions that result from the electrochemical process of corrosion to migrate away from the pipe surface. Thus, the “corrosion product” will remain close to the pipe and it will become dormant when the electrochemical process depletes all the oxygen in the moisture. This is known as the dry cycle. When fresh “oxygenated” moisture infiltrates the coating and reaches the area of external corrosion on the pipe, the corrosion process reactivates and again continues until the oxygen is depleted. This is known as the wet cycle. For this reason, corrosion growth rates of CUI are very high.

Atmospheric corrosion is the degradation of steel pipelines caused by air and the pollutants contained in the air. It is an electrochemical process due to rain, humidity, and salt in marine environments. In a pipeline near the coast, the air has a high content of chlorides that increases the rate of corrosion. Atmospheric corrosion cannot be mitigated using cathodic protection (CP). In a similar manner, CUI is difficult to address through conventional cathodic protection systems. Estimation of accurate corrosion growth rates (CGRs) is of paramount importance to ensure the safety of insulated pipelines above and below ground. CGRs may be calculated using several methods. There are many unique factors that can make each situation different, for this reason, it is important to determine which method is achievable and will produce the most accurate results depending on the factors that make each situation different. Presented here are three common methods:

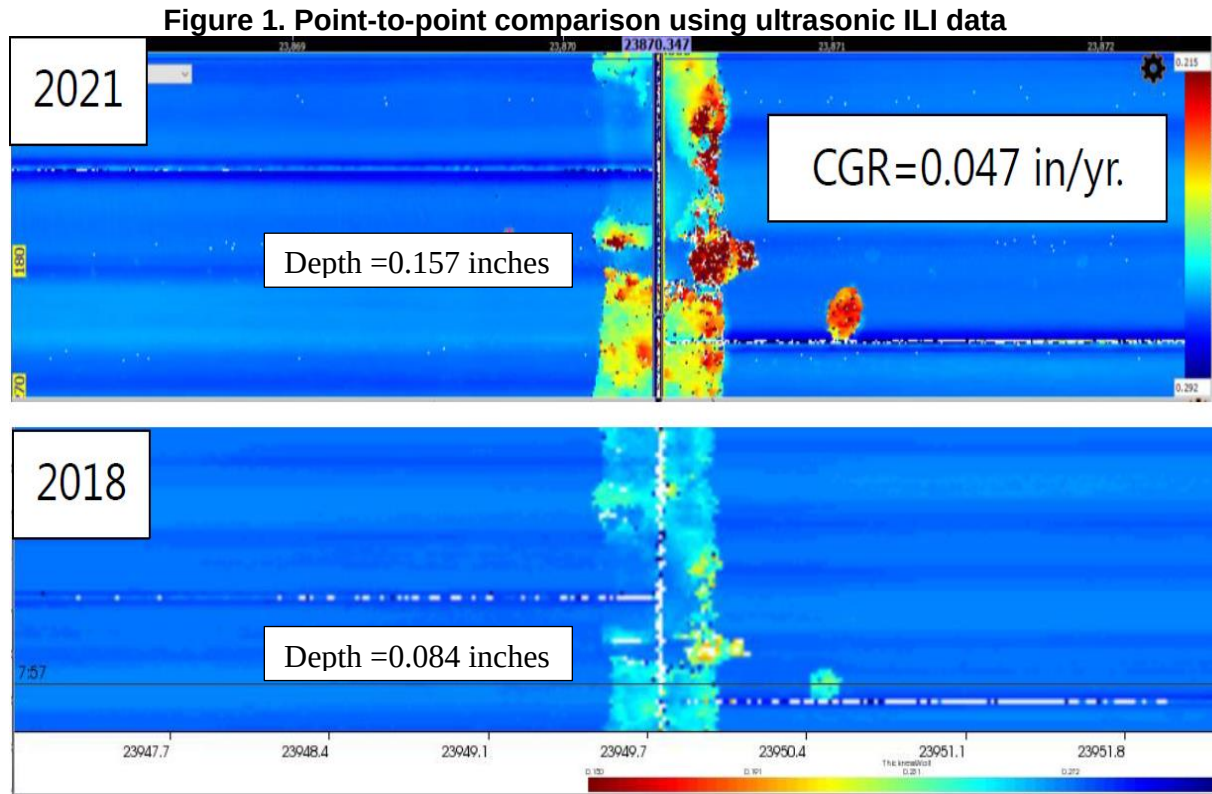
1. Use of actual data from corrosion probes or corrosion coupons (usually for internal corrosion only).
2. ILI data point-to-point comparison: When individual anomalies on subsequent ILI runs can be reliably matched, then individual growth rates can be determined. (In this case, the differences in tool biases and error between ILI runs must be accounted for, either by assuming the worst-case or by using statistical analysis of the unity plot). Figure 1 shows an example of the corrosion growth rate (CGR) calculated using ultrasonic ILI tools with the help of equation 1.

$$CGR[in./year] = \frac{Current\ Depth\ [in.] + tolerance\ [in.] - (Previous\ Depth\ [in.] - tolerance\ [in.])}{Time\ between\ inspections\ [year]} \quad (1)$$

$CGR = [(2021\ Depth + 2021\ tool\ tolerance) - (2018\ depth - 2018\ tool\ tolerance)] / 2.62\ yr.$
(the time between inspections in years, for this example 956 days).

In this example the tool tolerances are the same for both inspections (+/-0.025 inches)

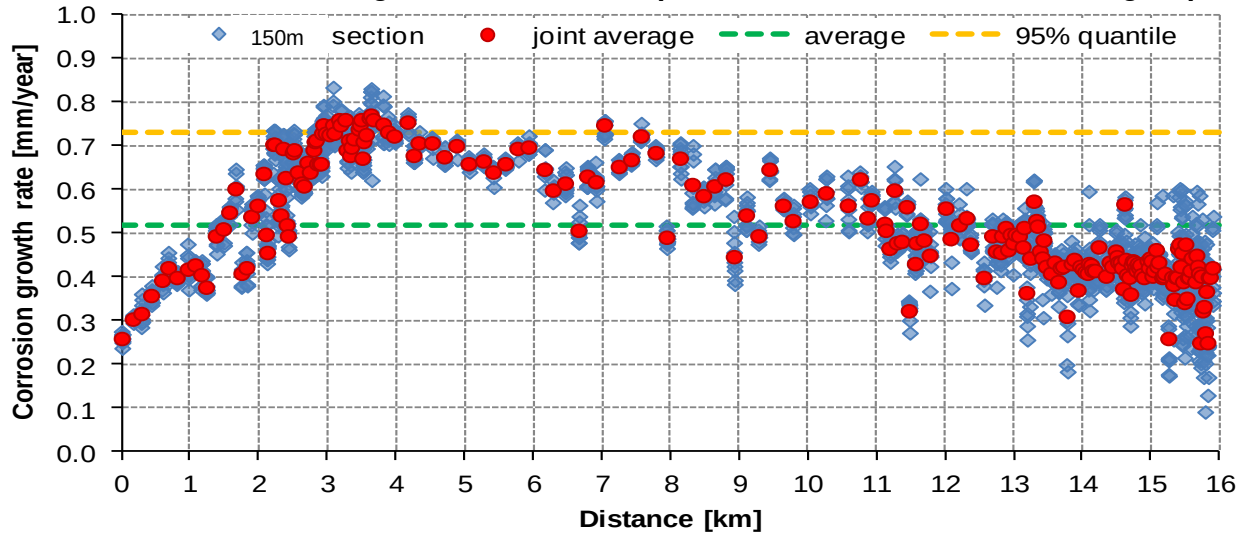
$$CGR = [(0.157 + 0.025) - (0.084 - 0.025)] / 2.62\ yr. = 0.047\ in./yr.$$



3. Rather than conducting the point-to-point comparison, data sets can be compared by statistical run comparison calculations. In other words, a statistical growth rate is assumed for a group of anomalies that correspond to a particular region on the pipe based on regional conditions:

- On joints, or in areas, with multiple anomalies, perform statistical analysis of a statistically valid number of data point sets, and use the 80% confidence value (1.28 standard deviations) of the corrosion growth.
- Statistical analysis can be performed when the anomaly density is greater or equal to 30 anomalies per 500 linear feet (or ~150 m), see Figure 2. A sample size exceeding 30 anomalies will usually yield a sampling distribution that is approximately normal.
- When less than 30 anomalies per 500 feet, individual analysis should be used. A linear length of 500 feet was chosen to be small enough for pipe and soil characteristics to likely be similar but large enough to have a statistically valid number of anomalies. See Recommended Practice DNVGL-RP-F101, Corroded Pipelines, May 2017,¹ Appendix D for detailed information.

Figure 2. CGRs calculated using statistical run comparison calculations for different groups



This paper illustrates the use of the ILI data point-to-point comparison using the insulated pipeline shown in Figures 3 and 4.

Figure 3. Insulated heated pipeline with part of the insulation removed



Figure 4. Section of an insulated heated pipeline after insulation removal

