CAAP Quarterly Report

03/30/2022

Project Name: *Easy Deployed Distributed Acoustic Sensing System for Remotely Assessing Potential and Existing Risks to Pipeline Integrity*

Contract Number: *693JK3215002CAAP*

Prime University: *Colorado School of Mines*

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Reporting Period: *[12/31/2021 – 03/30/2022]*

Project Activities for Reporting Period:

The activities completed during the reporting period were all on track. These activities are summarized below:

1. The two Ph.D. students started their studies in January as planned. They were trained on facility operations, DAS preparation and data acquisition, as planned.
2. Received three types of fiber cables (Figure 1), same as the ones in the proposal.

Figure 1. Photographs of the 3 types of fiber cables (thick, thin, and flat)

3. Discussed with the School's Information and Technology Solutions Center about options to increase reliability of Wi-Fi signal for stable connections to the equipment inside the Edgar Mine. Future access points will be added inside the section where the facilities are at complying with the cybersecurity prevention protocols.
4. Activities for Task #1 and #2: Detection of Liquid Accumulation and Dynamic Intermittent (Slug) Structures

- Ordered and received 12 pieces clear PVC pipes (Schedule 40) with a total length of 120 ft and 14 connectors.
- Construction of facility for Task#1 and#2 has been started (Figure 2).
- Tailored a V-section with 2° downward and 2°upward inclinations (Figure 3). The clear PVC pipe was heated and bent to meet the geometrical requirement. This enables clear visualization of the liquid phase inside the pipe.

Figure 2. Photographs of the 2° upward inclined section (left) and a connector for PVC pipe piece (right)

Figure 3. Photographs of the V-shaped section (2° downward + 2°upward)

5. Activities for Task #3-6: Detection of Corroded Spots, Deformation, and Infrastructure Damage
   - The order of the steel pipe has been placed, with specifications: API 5L, Schedule 40 NPS 4in, Grade X65 Carbon steel and seamless, same as the ones in the proposal. The pipe consists of four 5-m sections and one 1-m section, with a total length of 21m. The 1-m section is replaceable. We ordered multiple 1-m sections, which will be modified by creating corrosion, dent, leakage, at different degrees, according to the Tasks. More 1-m sections can be ordered as needed.

- Steel specimens have been ordered for lab tests with the same specifications as the steel pipe described above. Several specimens have been ordered for comparison purposes. We decide to use hydrochloric acid (Figure 4) for corrosion preparation, after a complete literature view and consultation with experts in the relative area.
- The students have been trained to use acid in the lab.
- The students have started reviewing the literature on natural gas pipeline corrosion. A brief literature review report on types and sources of natural gas transmission pipeline internal corrosion is in Appendix A.
- The students have started reviewing the literature on the application of distributed fiber-optic sensing (DFOS) on pipeline integrity monitoring. A brief literature review report on pipeline integrity monitoring using DAS is in Appendix B.

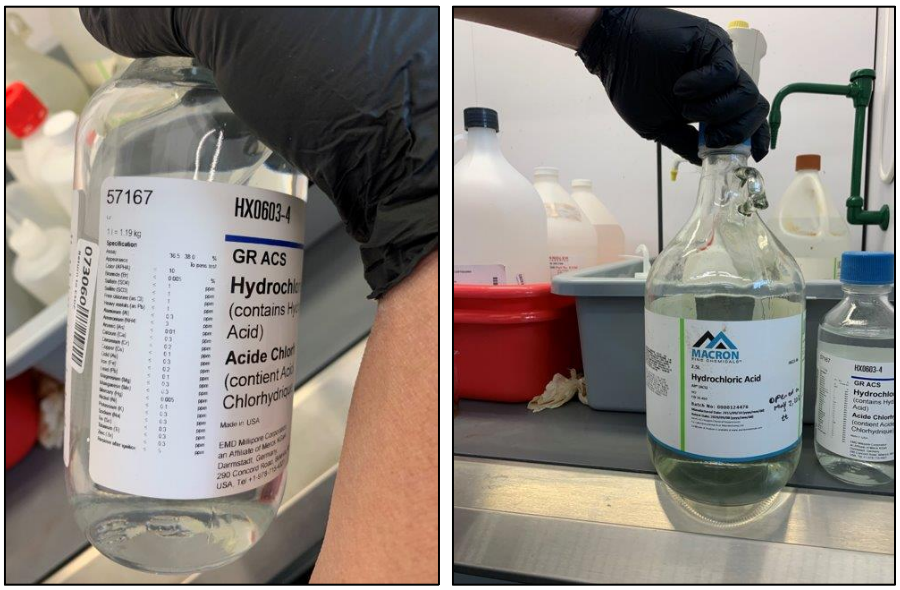

Figure 4. Photographs of the hydrochloric acid available in the Acidizing Laboratory (Dr. Jennifer Miskimins's lab, co-PI of this project)

Project Activities with Cost Share Partners:

The cost shares are the AY efforts of the PI and co-PIs. Activities are the same as above.

Project Activities with External Partners:

No external partners.

Potential Project Risks:

1. Since the project started immediately after the announcement, we did not have a chance to hire students in advance. The two Ph.D. students hired for this project started their studies in January 2022. Due to this timing, we anticipate a slight delay to the timeline proposed in the original proposal. However, it is still possible to complete everything before 09/29/2024 (the end date of the project).

2. There is a possibility of delay due to weather, especially during the snow season. Edgar Mine will be closed if there is heavy snow for safety concerns. In such a case, the students will not be able to work at the Mine during that period. Please note that the weather will not damage our facilities and equipment since they are inside the Mine.
3. The prices for pipes/equipment and other associated costs have been increased dramatically since the submission of the proposal. We will try to balance the total experimental expenses to keep it within our total budget for the experimental expenses, as much possible as we can at the current stage.

Future Project Work:

In the next 30 days, we will:

1. Continue constructing the facility for Task#1&2.
2. Start lab test for Task#3 once receiving the specimens, determining the acid concentration for the flow loop tests.

In the next 60-90 days, we will:

3. Complete the flow loop construction for Tasks#1&2.
4. Complete the lab tests for Task#3.

Potential Impacts to Pipeline Safety:

During the past period, we conducted literature review on the types and sources of natural gas transmission pipeline internal corrosion, and the application of DAS on pipeline integrity monitoring. Please see the details in the appendices.

Appendix A. Gas Transmission Pipeline Internal Corrosion Types and Sources – A Brief Literature Review Report

CAPP (Canadian Association of Petroleum Producers) reports that internal pipeline corrosion is the most dominant reason for leakage and failure for natural gas transmission pipelines. According to NACE, internal corrosion can be defined as the deterioration of the internal steel pipe wall because of the electrochemical reaction with its environment [1]. The failure related to internal corrosion can be classified into two main categories from a failure mode standpoint. It can be associated with localized and general metal loss and environmentally assisted cracking [2].

1. Metal Loss Mechanisms

1.1 CO_2 Corrosion: CO_2 can be present in most gas pipelines, causing a type of corrosion known as "sweet corrosion". This type of corrosion is prevalent. It can induce uniform metal loss along the pipe wall resulting in general corrosion, and/or localized corrosion resulting in pitting and mesa attack. Based on the general electrochemical reaction of CO_2 with the steel pipe, carbonate scales are formed. The deposited scales are affected by the flow regime. CO_2 pitting corrosion is particularly common at low flow rates [3]. When the flow velocity is low to medium, Mesa attacks form with flat bottom and vertical sides [3,4]. Flow-induced localized corrosion occurs at pitting and/or mesa attack sites due to localized turbulence that destroys the generated scales and prevents the film from recovering at high flow velocities, producing high-intensity corrosion [5]. Figure A-1 illustrates some photographs showing pitting and mesa attack corrosion in natural gas pipelines.

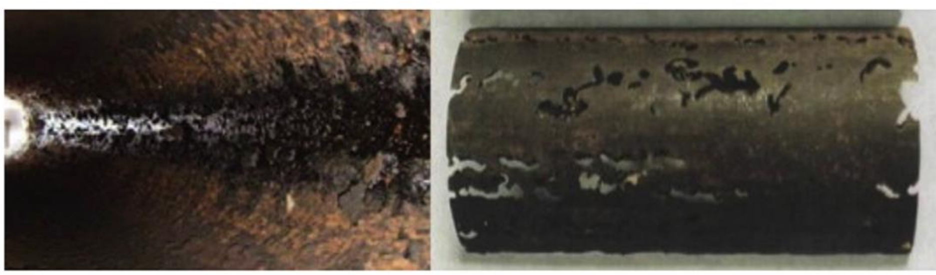

Figure A-1: Mesa attack and pitting corrosion in L485 natural gas pipeline in CO_2 environment [4]

1.2 H_2S Corrosion: In sour gas systems, where H_2S is present, pipelines are subject to corrosion. H_2S increases the rate of anodic dissolution of the steel. For this kind of corrosion, the overall reaction is as follow: $Fe + H_2S \rightarrow FeS + H_2$. Based on the equation, different types of iron sulfide corrosion products can be formed function of the PH, H_2S concentration and temperature. These scales can be protective or not [6].

1.3 Top of the Line Corrosion (TOLC): This corrosion type is most common under wet-gas pipelines with a sweet hydrocarbon, including organic acids in stratified flow regimes. It is caused by water condensation between the 10 and 2 o'clock positions. The rate of water condensation, and hence the severity of top-of-the-line corrosion, is determined by temperature, gas flow rate, flow regimes, CO_2 partial pressure in gas, and the acid gas type and concentration [7]. Figure A-2 displays a schematic pattern of TOLC.

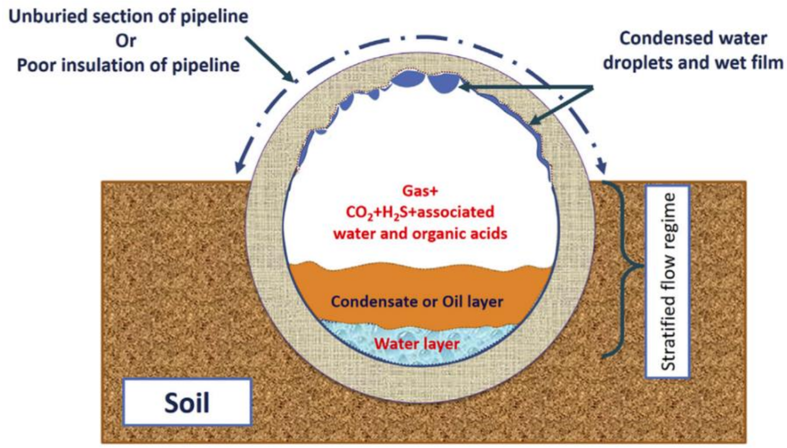

Figure A-2: Condensation and TOLC in unburied section of pipeline [2]

1.4 Under Deposit Corrosion: Localized corrosion can form under or around deposited components in the pipeline, resulting in under deposit corrosion. In sour gas pipelines, UDC can be generated by the deposition of iron sulfide. UDC is most common in horizontal pipelines where the flow rate is insufficient to agitate and distribute the deposits into the solution [8].

1.5 Preferential weld corrosion: When subjected to corrosive conditions, high temperatures, and high flow rates, selective corrosion targets the welded and heat-damaged zones, which are more susceptible to corrosion because of the microstructural changes caused by the welding process. In addition, the high flow velocity in pipelines and flow direction changes in seam welds, elbows, and reducers or pipeline extensions exacerbates this type of corrosion [9].

2. Environmental assisted cracking

The formation of atomic hydrogen due to the corrosion reaction in wet H_2S services causes environmental cracking of carbon steel pipelines (Figure A-3). The atomic hydrogen has enough small size to diffuse into steel and result in various steel problems. Once inside the material, the atomic hydrogen recombines to create hydrogen gas trapped and produced as a potential damage agent. The increasing concentration of atomic hydrogen causes the pressure to accumulate and build up in the trapped locations, which causes the steel to blister [10,11].

Figure A-3: Hydrogen induced cracking (HIC) of an oil pipeline. (Source: *https://en.wikipedia.org/wiki/Hydrogen_embrittlement*)

Appendix B. Monitoring Pipeline Integrity with DAS – A Brief Literature Review Report

As pipeline infrastructure grows both in the area of coverage and age, demand for the monitoring of pipelines also grows. Several factors can contribute to pipeline failure including internal corrosion, dents, and deformations. There are a number of different technologies that can be used to monitor pipelines through both internal and external technological methods. The current and commonly used internal methods include Inline inspection (ILI) tools, however, these tools do not allow for real-time monitoring during operations and instead require pipeline operators to conduct periodic investigations. Some methods rely on sensors along the pipeline, however, these are point sensors, not continuously/uniformly covering the entire length of the entire pipeline. An alternative method that has gained more attention is distributed acoustic sensing (DAS), which belongs to part of the Distributed Fiber Optic Sensors (DFOS), which relies on Rayleigh scattering within the fiber-optic cable [12].

Studies have demonstrated DAS as being an effective method for monitoring pipeline integrity while in production or while being used to transport a fluid resulting in different types of defects, corrosion being one of them. The severity of the corrosion leads to the material being compromised which then yields fracturing and causes leaks. These two defects (corrosion and leaks) are the most common ones studied using DAS applications and will be discussed in detail below.

As concluded by [13], reduction of wall thickness is one of the most common phenomena caused by corrosion. Wall thinning results in a change to the hoop strain, and this change correlates with the change in wall thickness. In this study, the processing of optical frequency domain reflectometry (OFDR) is able to measure and distribute strain in a millimeter-scale resolution. Thanks to the small resolution, two main forms of corrosion are characterized. The first form is uniform corrosion where the change of the internal diameter is tested with a range from 1.5 mm to 6 mm total. Through the Principle of Materials Mechanics, the relation between hoop strain and wall thickness change can be obtained:

$$\varepsilon = \frac{PD}{2Et}$$

Where ε is the pipeline hoop strain, E is the Young's modulus, t is the pipeline wall thickness and both P and D are treated as constants for internal pressure and diameter of the pipeline.

The second form is local corrosion which follows the Finite Element method. This form occurs on only one section of total diameter and is measured as an angle. Both types of corrosion were identified with DAS using hoop strain. In uniform corrosion, changes of about 20 microstrains were observed for changes of 1 mm in diameter. For local corrosion with varying angles of wall thinning, sections in the diameter were identified as areas of corrosion but the signals were not discernible between the different wall thinning angles. These cases were presented by [14] using an external deployment of the fiber optic cable mostly following a helically wrapped path around the pipeline.

This form of deployment is one of the most commonly observed in the literature. One of the main advantages is that it offers a higher resolution allowing for almost full circumference observations. Such deployment is also commonly used in studies of leaks detection in pipes. The vibrations induced as a result of leaks cause distinguishable patterns that demonstrate the efficiency of DAS in regards to the detection of leaks as presented by [15].

Using pinhole leaks of varying sizes and varying pressures, [15] demonstrated DAS signals in the frequency domain, and were able to detect gas pipeline leaks at rates of less than 1% of the pipeline flow as well as their location. While the leak size did not provide a consistent pattern of signals observed in the frequency domain, natural vibration modes induced by the leak-noise excitation were observable in the pipeline. These limitations emphasize the importance of vibration damping which may provide an additional layer to such studies.

Another more simple deployment of fiber optic cable for DAS purposes would be for a cable to be freely suspended along the length of the fiber, near a pipeline. This implementation was presented by [16] where the cable was about 0.05 m away from the pipe wall. In this study, the proposed algorithm based on frequency domain cumulative averaging was successful in its detection of the leak location. This algorithm uses wavelet transformation and is efficient with varying pressures utilized inside the pipeline. Additionally, the range of leakage signals in practice should be able to be adjustable in order to obtain the location distribution map of the pipeline leakage signals.

In conclusion, DAS is shown to be a feasible method for monitoring pipeline integrity while being subjected to the pressures of gas. The discussed studies all used varying gas pressures, successfully demonstrating the deformations that can compromise gas pipeline integrity. Laboratory experiments and signal processing are efficient in doing so. Even more so than that, successful algorithms such as the one presented by [16] provide foundations for DAS monitoring systems detecting the location of leaks. Here the scope was limited to external deployments, however, internal deployments are one area that lacks focus, but can hold similar potential through the relation of practical laboratory studies and signal processing.

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