

Investigation into a Microbiologically Induced Corrosion (MIC) failure of an onshore pipeline

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Aging assets across the oil and gas industries are a well-known challenge incorporating additional risks for onshore and offshore operators. From the materials point of view the main threats are corrosion, erosion, fatigue or materials cracking. Materials degradation can be controlled relatively well assuming detailed knowledge of the processes and original conditions of the materials. Lack of data, process changes or repairs often lead to safety and business risks due to unpredictable failures.

In recent years the UK Health and Safety Executive have investigated a number of failures in offshore and onshore pipelines. This paper describes the investigation of a failure a 6" (153 mm) diameter steel pipeline resulting in the loss of approximately 450 m³ of liquid hydrocarbon and water. The investigation was carried out on two sections removed from the pipeline. One section contained pipe clips as a temporary repair. The investigation utilised optical microscopy and laser scanning techniques to identify and characterise wall thinning.

The pipeline material was confirmed to be compliant with API 5L grade B steel. A large proportion of the pipeline wall thickness loss was found to be due to internal corrosion. Quantitative Polymerase Chain Reaction (qPCR) analysis was used to help determine a probable corrosion mechanism. The results suggested a considerable microbiological load (Total Bacteria), moderate to elevated levels of Sulphate Reducing Bacteria (SRB), and moderate levels of Sulphate Reducing Archaea (SRA).

The investigation concluded Microbiologically Induced Corrosion (MIC) as a contributing factor to the failure, which was consistent with the presence of crude oil and sea water under stagnant conditions. Recommendations to the maintenance and inspection regimes were made and implemented.

Keywords

Microbiologically induced Corrosion; MIC; hydrocarbon pipeline; quantitative Polymerase Chain Reaction; Failure investigation; API 5L steel.

Introduction

Asset Integrity

Onshore carbon steel pipe networks are subject to a number of internal and external corrosion degradation mechanisms. External mechanisms include general atmospheric corrosion (in particular at coastal regions and locations with high levels of industrial pollution), crevice corrosion (e.g. under pipe supports), galvanic corrosion and corrosion under insulation (CUI). Internal mechanisms include erosion-corrosion, galvanic corrosion, CO₂ corrosion, stress corrosion cracking (SCC) and microbiological corrosion (MIC). Each mechanism requires specific conditions for the corrosion to occur.

Understanding the various mechanisms, identifying and implementing inspection and monitoring strategies is key to successful asset management. Failure to adopt a suitable asset management strategy can result in catastrophic releases with highly damaging consequences including loss of production, reputational damage, death, severe injury and ill health to employees and neighbours, and significant environmental damage.

Microbiologically Induced Corrosion

Microbiological corrosion is caused by living organisms such as bacteria, algae or fungi and is usually found in aqueous environments, particularly in stagnant or low flow environments. Fast fluid flow environments serve to wash away the offending bacterial species and MIC is not normally present in such systems. MIC can be generated by a variety of microorganisms, which can survive and grow under severe conditions of light or dark, high salinity, low to moderately high pH, and temperatures from as low as -17°C to +113°C [1]. Different organisms thrive on different nutrients including

inorganic substances such as sulphur, ammonia, H₂S and organic substances such as hydrocarbons and organic acids. All require a source of carbon, nitrogen and phosphorous for growth.

MIC can be found in heat exchangers, the bottom of storage tanks, stagnant or low flow pipework and pipework in contact with soils. Other affected equipment can be product storage tanks and water cooled heat exchangers in systems with poor water treatment.

Corrosion is not caused by the microorganisms themselves but by the acidic by-products of their metabolism and there are several types of MIC as described by Stott, J.F.D., 2010 [2].

Sulphate reducing bacteria (SRB) are an important group of microorganisms, which are responsible for the majority of MIC failures. SRB live in oxygen-free environments, i.e. they are anaerobic bacteria that live on organic nutrients and derive their energy from the reduction of sulphate ions to sulphide. MIC is often characterised by the presence of deep pits, however deep pits are not confined to MIC. In order to confirm MIC, microbiological testing such as culture-based testing, optical microscopy such as 4', 6-diamidino-20phenylindole (DAPI) molecular microbiological methods such as Fluorescence in situ hybridisation (FISH), or DNA analysis, e.g. Quantitative Polymerase Chain Reaction (qPCR) analyses are recommended.

The mere presence of SRB does not in itself confirm the mechanism of MIC, however it is an indication that MIC is possible. Other conditions need to be satisfied such as low or intermittent flow rates, or stagnant conditions. Deep flask-shaped pits and high sulphur contents of corrosion products can also be indicators of MIC. NACE standard TM0212-2018 [3] gives guidance on conducting assessments for the presence of MIC.

Onshore Incident

This work describes the investigation of an incident that occurred at a UK refinery installation, in which there was a loss of containment of approximately 450 m³ of liquid hydrocarbon and water mixture from a 6 inch nominal bore (NB) pipe section used to transfer fluid (oil and sea water) from a water separator to storage in a crude slops tank. The transfer was conducted through a length of pipework that was normally dormant due to the normal routing being temporarily out of commission. Two sections of pipe were retrieved from the site.

Methodology

Visual examination

A section, which contained a thinned area that had resulted in the loss of containment event will be referred to as the incident pipe. The other retrieved section, the non-incident pipe, contained six temporary repair clips (clamps). The two sections were removed from the same pipeline and were separated by a single isolation valve see Figure 1.

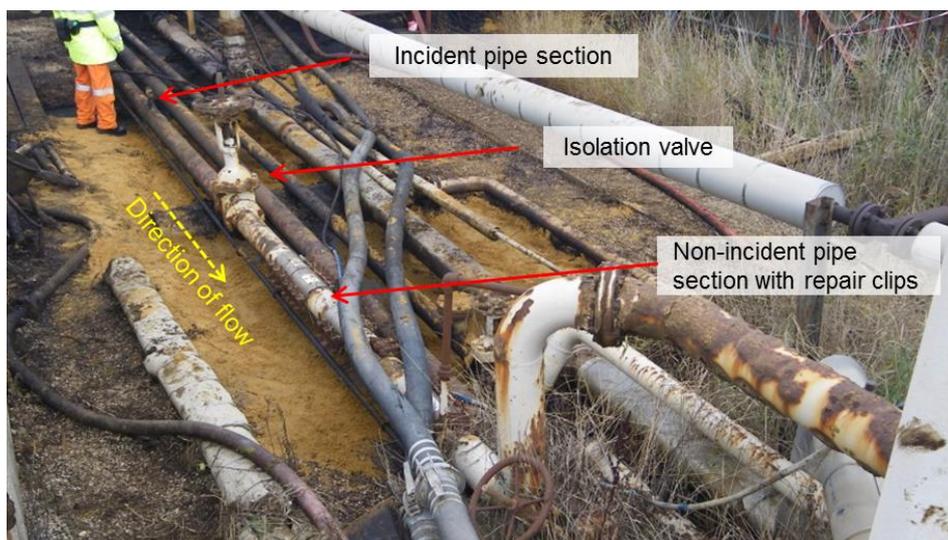


Figure 1 Location of incident and non-incident pipe sections

Before receipt at the laboratory, the pipe sections were decontaminated to remove most of the oil residues. Visual and dimensional examinations were carried out before and after longitudinal sectioning at the 3 o'clock and 9 o'clock positions. After sectioning, the pipe was photographed and visually inspected before removing corrosion products and paint in order to measure the pipe wall thickness by laser scanning.

Materials analyses

Samples from the incident and non-incident pipes were analysed using Inductively Coupled Plasma Optical Emission Spectroscopy (ICP OES) and Combustion to assist in determining the grade of the pipe material. Internal deposits and corrosion products from the incident pipe were analysed using X-ray Fluorescence (XRF) and X-ray diffraction (XRD).

To assist with determination of material grade, a section from each pipe was cut and mounted in resin and polished to a one micron finish. The metallographic samples were examined using light microscopy at up to x500 magnification before and after etching in 2% nital.

Hardness tests were conducted on the metallographic samples using a calibrated Vickers diamond hardness testing machine with an accuracy of $\pm 3\%$, and in accordance with BS EN ISO 6507, Parts 1 [4] and 4 [5]. The average hardness value was converted to an approximate ultimate tensile strength in accordance with BS EN ISO 18265 [6].

Laser scanning

Laser scanning was conducted using an integrated laser scanner on a Romer Absolute arm on the two sections of pipework before and after removal of deposits and scale to assess the corrosion pattern and to conduct wall thickness measurements. Measurements were conducted using Polyworks 2018 software. Two areas, approximately 800 mm long from the top and bottom of each pipe were identified for laser scanning, together totalling eight sections. Pipe sections were reconstructed to show visual colour contour maps. Longitudinal and circumferential reconstructions were generated, with measurements, to show the extent of wall thinning.

Microbiological analysis

Microbiological analysis was carried out on swabs taken over a defined area using Quantitative Polymerase Chain Reaction (qPCR) analysis to determine total bacteria, Sulphate Reducing Bacteria (SRB) and Sulphate Reducing Archaea (SRA).

The qPCR analysis can detect both viable, dormant and some dead microbial cells. Using qPCR analysis, the DNA (target) is extracted directly from the solids. DNA can persist for up to 2-4 weeks after a cell has died. The method might pick up cells that are dead at the time of the testing, but they were most likely viable at some point.

Results and discussion

Visual examination

A small bore steam line running parallel to the parent pipe shown in Figure 2 suggested that the pipework route had previously been steam trace heated. Therefore it can be assumed that the line had been originally insulated and that it had been removed.

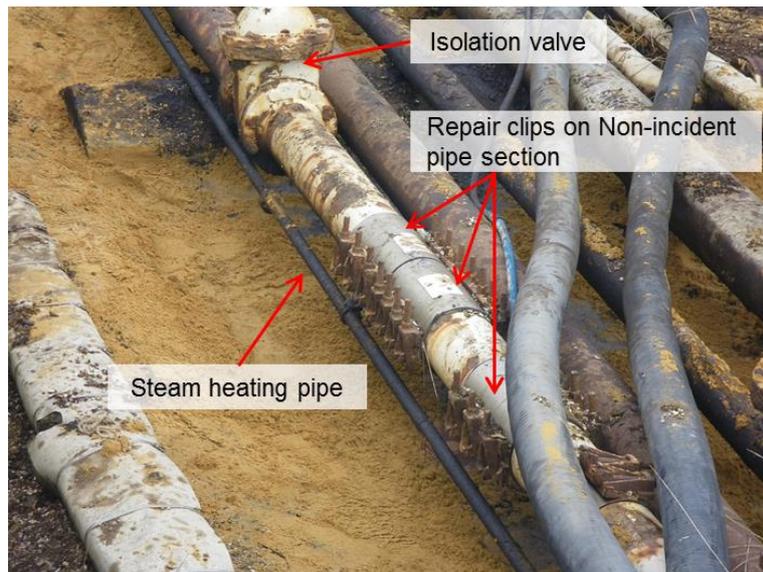


Figure 2 Steam heating pipe and temporary repair clips installed on non-incident pipe

The outside diameter of both pipes was approximately 170 mm, which corresponds to a 6 inch (153 mm) nominal bore (NB) pipe. The original wall thickness was not known. A wall thickness estimation based on the measurements in the less corroded areas was 5 mm. However, according to ASME B36.10 [7], the wall thickness should be 7.11 mm for a schedule 40 pipe, suggesting a loss of wall thickness of approximately 2 mm in the less corroded locations.

The pipes had originally been painted, however the presence of external corrosion products indicated that the protective paint layer had been breached some time previously, Figure 3a. The protective coating was multi-layered on both pipes. The outer layer had the appearance of paint, the middle layer appeared metallic and the inner layer was a grey paint-like base. In some places, the coating had peeled off, with signs of blistering and corrosion attack underneath. The incident pipe showed significantly less of the remaining coating compared to the non-incident pipe.

Both pipes were heavily corroded, with corrosion products reaching a thickness of up to approximately 10 mm on the outer surface

(Figure 3b). Delamination and spalling of the corrosion products, blistering and a number of through-wall perforations were observed on the external surface of both pipes. External corrosion is common at the six o'clock position due to increased moisture content underneath pipework due to poor ventilation and shading. The size of the holes on the non-incident pipe were larger compared to the perforations on the incident pipe. The holes were located at the 6 o'clock position under the temporary repair clamps.

The vent on the incident pipe and the drain on the non-incident pipe were both heavily corroded. The amount of corrosion product observed would have significantly restricted their function and purpose. A photograph of the drain is shown in Figure 3c.

Figure 3d shows the defect associated with the loss of containment. Its length was 73 mm. The wall in its surroundings was very thin with a tendency to break.

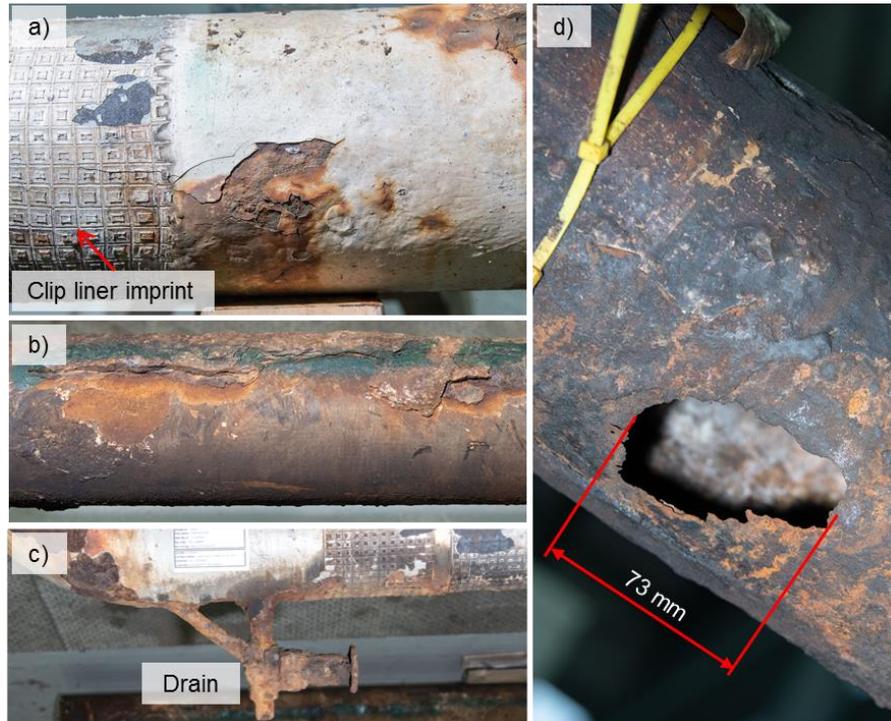


Figure 3 a) Remaining coating on non-incident pipe, b) Thick layer of corrosion product on incident pipe, c) Drain on non-incident pipe, and d) Defect associated with loss of containment on incident pipe

Six temporary repair clips of various widths had been installed on the non-incident pipe. Two of them were placed next to each other leaving no gap between them. The clips were removed after arrival at the laboratory. An example of the removed repair clip is shown in Figure 4a. Where the clips were removed, the top paint layer had the imprint of the pattern from the polymer liners used between the pipe and the clip, see Figure 3a. This suggested either that at the time when the clips were installed, the paint was not fully cured, or that the paint had been softened by chemical reaction/temperature or other external effect during the lifetime of the temporary repair clamps. The coating under the clamps had partially delaminated and stayed attached to the polymer liners when they were removed. Some of the polymer liners had splits in them, presumably due to reaction with the oil/water mixture and/or acidic conditions created by microorganisms, Figure 4b.

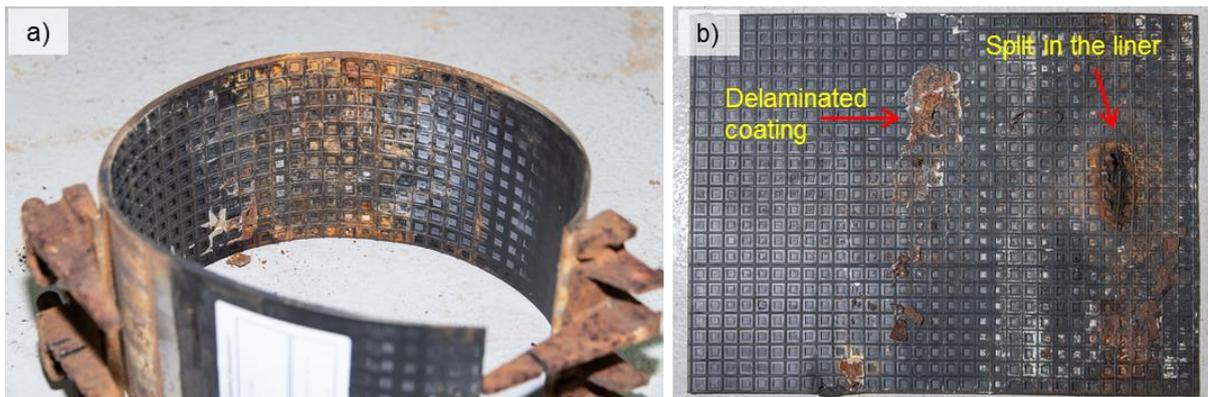


Figure 4 a) Temporary repair clip removed from non-incident pipe, and b) Inner side of a pipe clip liner showing split at hole location and pick-up of paint

Both pipes were cut in the horizontal plane at the 3 and 9 o'clock positions (giving two half pipes, i.e. upper 180° and lower 180°) to allow observation of the inner surfaces. The examination of the internal surfaces showed the extent of degradation under the temporary repairs. Some of the pin holes on the non-incident pipe caused by internal corrosion appeared only after disturbing corrosion products. The length of the holes reached sizes of up to 160 mm, Figure 5a. Wall thinning was observed

on the incident pipe in the horizontal plane at the 3 and 9 o'clock positions. Wall loss to a thickness of less than 2 mm is shown in the horizontal cross-section of the incident pipe in Figure 5b. Figure 5c shows a presence of large quantities of solid debris inside the incident pipe. The layer of attached and loose product/sediment was approximately 30 mm thick, which would create a significant change in the effective pipe bore diameter and restrict flow.

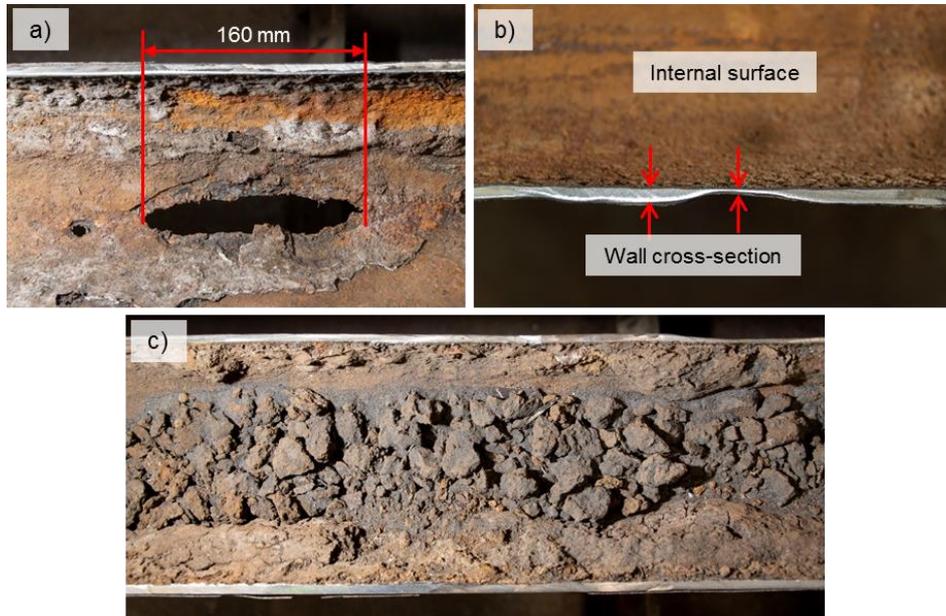


Figure 5 a) Internal corrosion with perforations on the non-incident pipe, b) A photograph of wall thinning shown on the cross-section of the incident pipe, and c) Solid debris inside the incident pipe

Materials analyses

Results of chemical analysis of the pipe sections materials determined by ICP-OES and combustion are given in Table 1. The material of both sections was consistent with low-carbon manganese steel, which complied with the composition of API 5L grade B [8] also included in Table 1.

The debris from inside the incident pipe was analysed using XRF and XRD. The results of XRF analysis showed presence of Al, Si, S, Cl, K, Ca, Mn, Fe and Zn was identified. The XRD analysis revealed the presence of quartz (SiO₂) and Siderite (FeCO₃), which are consistent with sand and the corrosion products of steel in the presence of seawater.

Table 1 Chemical analysis of the incident and non-incident pipes in mass %.

<i>Element</i>	<i>Incident pipe</i>	<i>Non-incident pipe</i>	<i>API 5L grade B [8]</i>
Carbon	0.16	0.14	Max.0.26
Silicon	0.19	0.17	-
Manganese	0.60	0.68	Max.1.15
Phosphorous	0.017	0.021	Max. 0.04
Sulphur	0.029	0.035	Max. 0.05
Chromium	0.05	0.04	-
Copper	0.23	0.15	-

The microstructures of the incident and non-incident pipes are shown in Figure 6a and Figure 6b respectively. Both microstructures consisted of ferrite/pearlite grains in the range between 10 μm and 40 μm . The ratio of pearlite to ferrite was approximately 20%, which is in agreement with the carbon content of 0.15%.

Both materials contained at least two types of inclusions. One type was globular and the other elongated in the rolling/drawing direction. These were not analysed in detail but it is suspected that the elongated inclusions were manganese sulphides and the globular inclusions were oxides, which are typical for this grade of material.

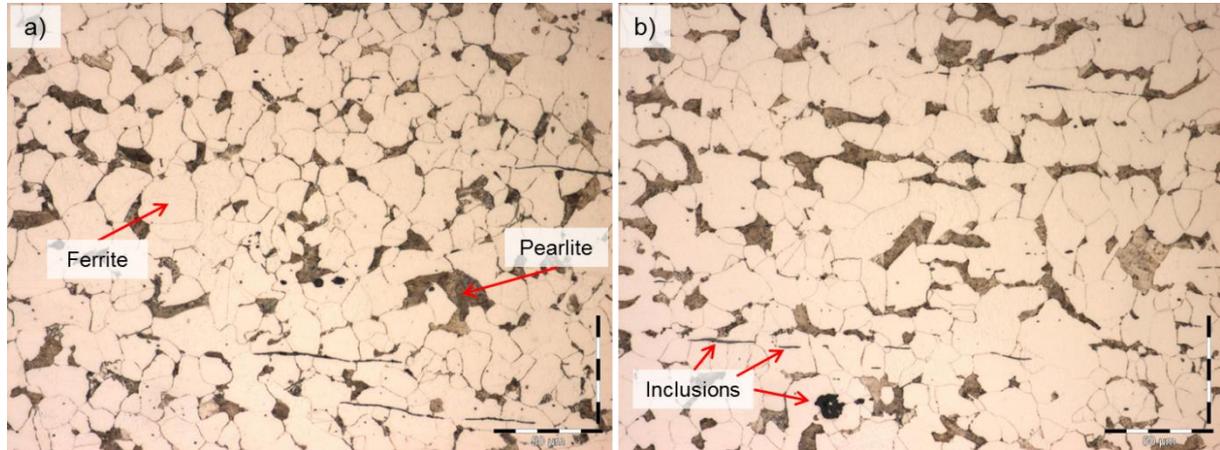


Figure 6 Microstructure of a) incident and b) non-incident pipes

The hardness obtained as an average value from five measurements was 136 HV10 for the incident pipe, and 130 HV10 for the non-incident pipe. The hardness values were converted to an approximate equivalent ultimate tensile strength in accordance with BS EN ISO 18265 [6] giving UTS of 430 MPa for the incident pipe, and 415 MPa for the non-incident pipe. These values are in agreement with the material specification for API 5L grade B [8].

Laser scanning

Two sections from each pipe approximately 800 mm long from the upper 180° and lower 180° were laser scanned. Reconstructions of the representative top and bottom sections of the incident pipe after removal of corrosion products are shown in Figure 7. The results were compared with laser scans taken before the corrosion had been removed (not included in this paper). Thickness of the corrosion products was over 12 mm.

The through-wall defect, 73 mm x 55 mm in size, associated with the loss of containment at the position between 6 and 8 o'clock on the incident pipe is shown in Figure 7a and Figure 7b. The area adjacent to the incident perforation showed wall thickness less than 1 mm. Localised wall thinning and perforations were observed at the 4 o'clock position in the axial direction to the pipe axis. This area, marked in Figure 7b with black arrows, was adjacent to the steam heating pipe that had been used on this line under insulation in the past. Additionally, there was significant wall thinning leading to perforations at the location between the 11 and 1 o'clock positions associated with external corrosion.

Longitudinal sections at the 12 and 6 o'clock positions (Figure 7c) and two cross-sections (Figure 7d and Figure 7e) of the reconstructed incident pipe, showed minimal remaining wall thickness of 0.7 mm at the 12 o'clock position of the longitudinal section. The cross-section B-B in Figure 7e showed a remaining wall thickness of 1.8 mm at the 4 o'clock position.

The loss of material was observed locally, i.e. large perforation and pin holes, as well as uniform loss of material at the bottom section. The wall thinning was due to both external and internal corrosion.

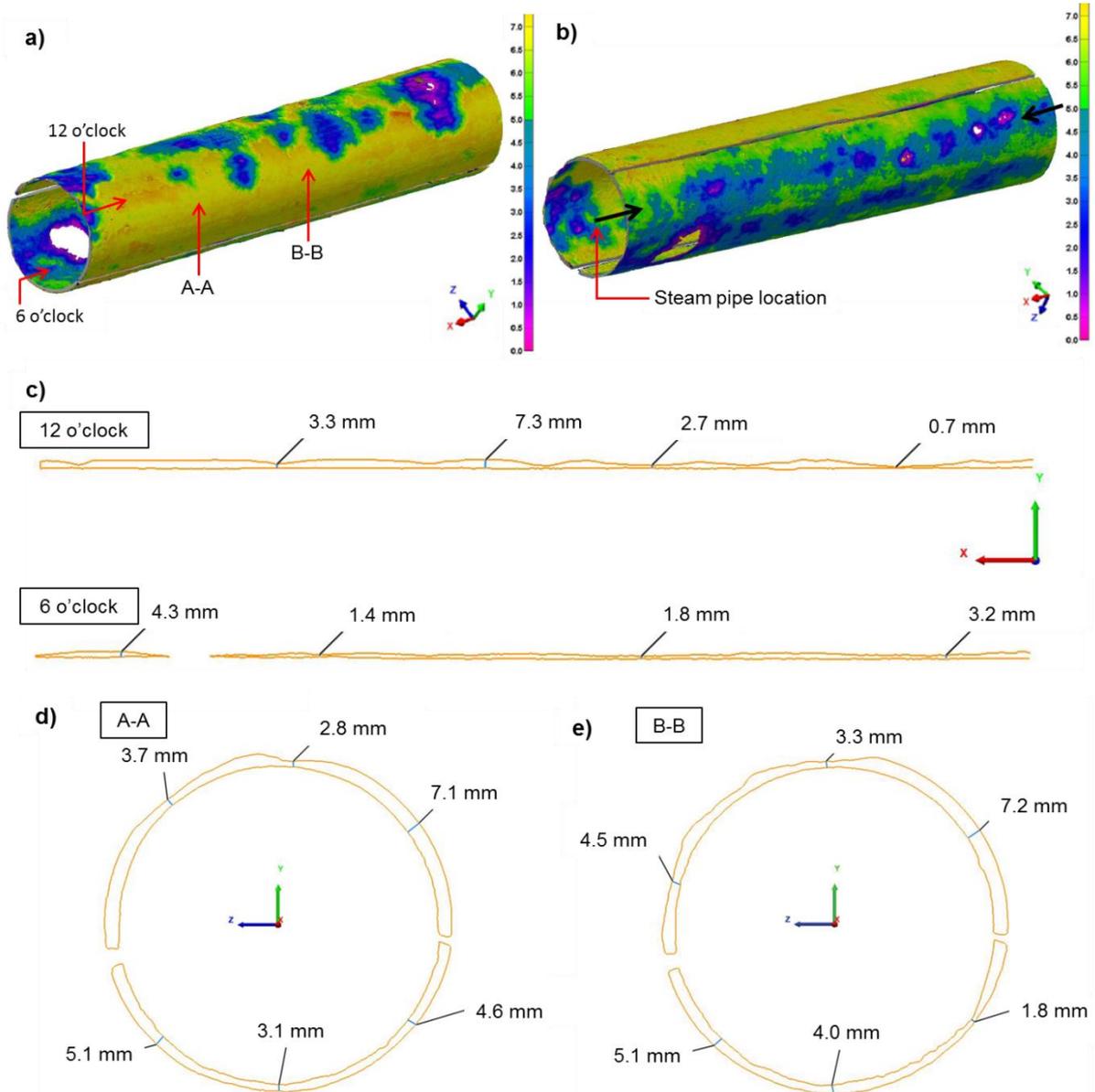


Figure 7 a) and b) Reconstructed top and bottom sections of the incident pipe without corrosion products in two different orientations, c) longitudinal sections at the 12 and 6 o'clock positions, d) and e) cross-sections marked in figure a)

Reconstructions of the representative top and bottom sections of the non-incident pipe after removal of corrosion products are shown in Figure 8a) and Figure 8b). The surface area covered by remaining paint was larger on the non-incident pipe compared to the incident pipe. Therefore, it had better protection against external corrosion compared to the incident pipe. Longitudinal sections are shown in Figure 8c), and cross-sections in Figure 8d) and Figure 8e). The remaining wall thickness measured on the longitudinal section at the 6 o'clock position was less than 2 mm. Holes of size up to 160 mm long and 25 mm wide were present at the 6 o'clock position. These had been covered with the temporary repair clamps. A groove was found at the 6 o'clock position along the whole length of the two laser scanned sections of the non-incident pipe. Additionally, localised areas of material loss were found at the top of the pipe.

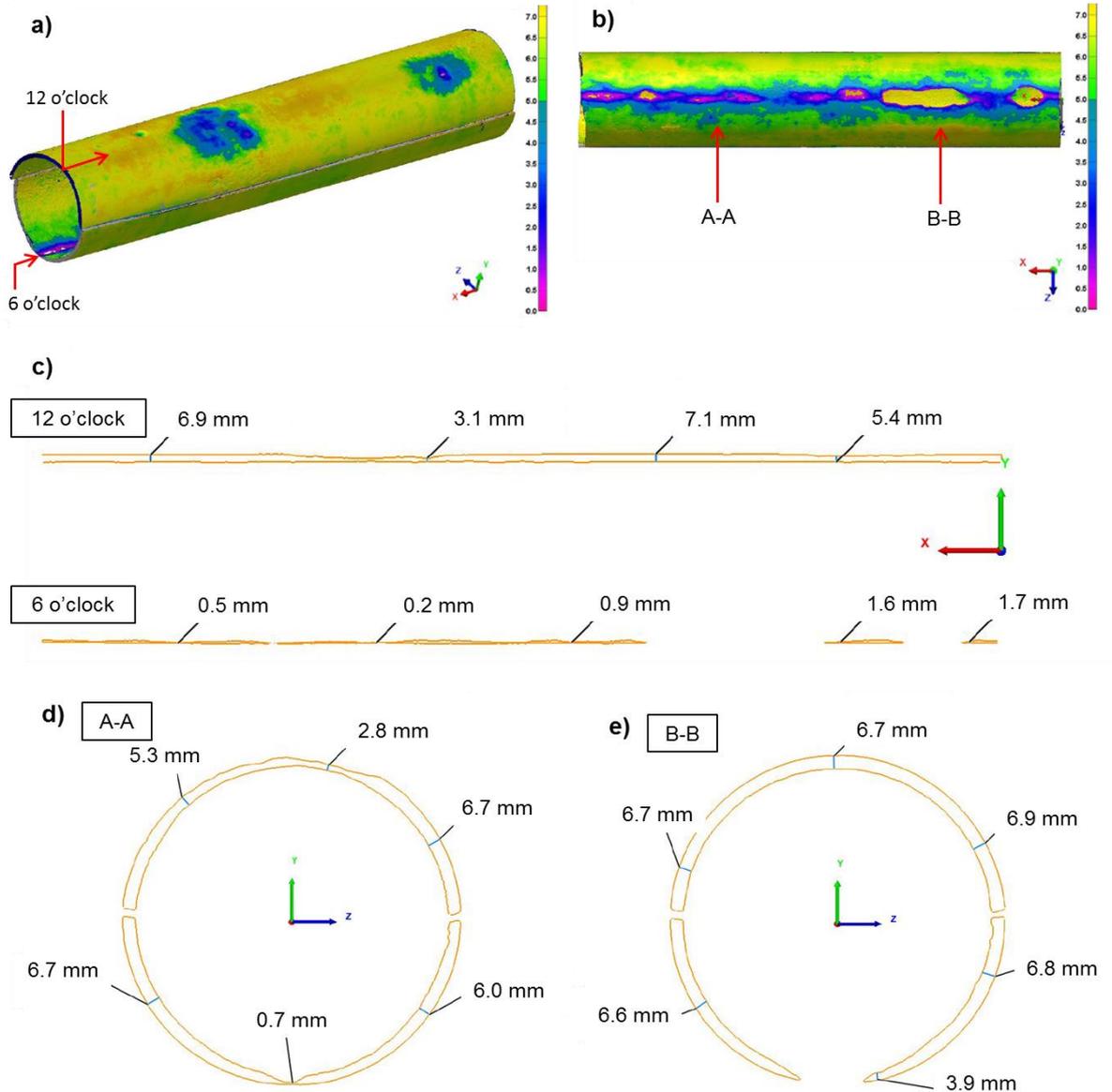


Figure 8 a) and b) Reconstructed top and bottom sections of the non-incident pipe without corrosion products in two different orientations, c) longitudinal sections at the 12 and 6 o'clock positions, d) and e) cross-sections marked in figure a)

Microbiological analysis

Three swabs from each pipe were sent for Quantitative Polymerase Chain Reaction (qPCR) to determine total bacteria, Sulphate Reducing Bacteria (SRB) and Sulphate Reducing Archaea (SRA).

Two samples, both from the incident pipe, showed insufficient DNA for further analysis – suggesting a low/no microbiological load. These two swabs were taken near the horizontal section and next to the through-wall defect. There was potentially easier access during decontamination, which could have facilitated removal of the DNA.

All other samples showed either slightly elevated levels of total bacteria and moderate to elevated levels of SRB. SRA were also enumerated at moderate levels. The results indicated a considerable microbiological load (total bacteria) in four samples out of six; with targeted microorganisms associated with corrosion also having been detected in the portion of samples tested. The highest load of total bacteria i.e. 2.0×10^6 cells per cm^2 was detected on the non-incident pipe inside the drain. SRB and SRA in this location reached 2.5×10^4 cells per cm^2 and 1.2×10^3 cells per cm^2 , respectively.

NACE standard TM0212-2018 [3] explains that Key Performance Indicators (KPIs) are considered system-specific. Therefore, microbial monitoring data should be viewed in combination with corrosion data. An example of an empirically derived KPI for MIC monitoring from Adenosine Triphosphate Photometry (ATP) analysis of corrosion coupons is shown in Figure 9. The graph presents data from laboratory experiments where very severe cases of MIC have been observed. In several cases, the biofilm ATP count was above 5×10^5 microbial equivalents (M.E.)/cm², which is directly related to the corrosion rate and the depth of corrosion features (Figure 9). However, as mentioned earlier, the data are system-specific as well as dependent on the type of the analysis. Therefore, long term monitoring may be necessary in cases where specific conditions may lead to development of MIC.

The presence of an active biofilm with a high number of surface-attached microorganisms does not necessarily indicate active MIC [3]. It is acknowledged that ATP analysis is for detecting active bacteria, whereas qPCR can detect viable, dormant and dead microbial cells. As the pipework examined in the present study was decontaminated and the swabs were taken after a considerable amount of time, it is likely that some of the DNA was removed. It is therefore possible, that the qPCR results are likely to be conservative.

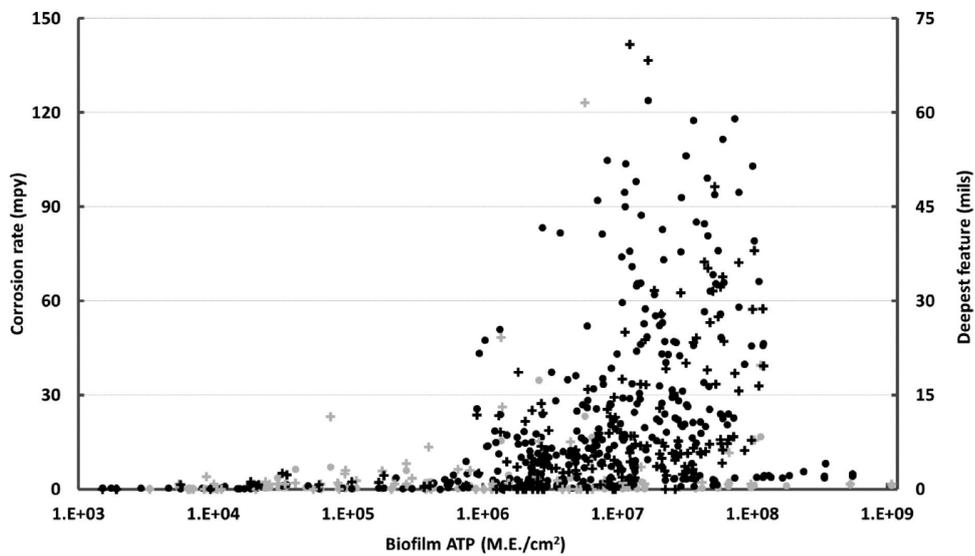


Figure 9 Example of an empirically derived key performance indicator (KPI) for MIC monitoring from Adenosine Triphosphate Photometry (ATP) analysis of corrosion coupons [3]

Recommendations

Dutyholders should be mindful of the possibility of MIC within pipelines tanks and vessels, in particular, in plant with stagnant or low flow conditions. In such cases, in-service monitoring should be carried out.

In service monitoring techniques are detailed in NACE TM0212-2018 [3], which recommends various tests and inspection strategies, including, but not limited to:

- Sampling for microbiological activity, preferably in the field to minimise degradation of the sample once removed from the pipeline/tank/vessel environment. Tests may include culture-based testing, enzyme and immunological assays, microscopy-based methods and DNA analyses, including Quantitative FISH and qPCR methods.
- Sampling over a period of time to gain statistical reliability and identification of trends
- Biological activity should be integrated with corrosion product analyses and measurements of wall thinning or corrosion pitting by Non-Destructive Testing (NDT) such as ultrasound or radiography. Internal visual inspections (e.g. using remote visual inspection techniques) for corrosion should be conducted where possible.

- Consideration should be given to the insertion of corrosion tests coupons in areas suspected to be at risk of MIC. The coupons should then be examined for biofilms, corrosion loss and physical corrosion damage such as pitting and corrosion product build-up.
- Once MIC has been identified from the integrated analysis (rather than just microbiological species detection), mitigation measures can be put in place, however it is important to continue routine sampling and inspection to monitor the effectiveness of the regime adopted.

Whatever methods are selected to inspect, sample and monitor for MIC, they should be applied diligently and consistently to avoid erroneous or misleading results.

Conclusions

The material of both pipe sections and its properties were consistent with low-carbon manganese steel and complied with commonly used steel API 5L grade B.

Both pipes showed extensive corrosion, paint spalling, and delaminating and blistering of both the paint and corrosion products. The size of defect associated with the loss of containment on the incident pipe was 73 mm x 55 mm. Localized wall thinning, both external and internal, was observed in the location adjacent to a steam heating pipe. Significant wall thinning due to external corrosion was found at the 12 o'clock position.

The non-incident pipe had a larger area protected by the remaining paint. The greatest extent of the corrosion was at the 6 o'clock position, which had created an internal groove leading to through-wall perforation of up to 160 mm long. The internal corrosion was accelerated by the presence of liquid hydrocarbon and sea water mixture.

The presence of external corrosion at the 6 o'clock position is common on steel pipework due to the presence of vegetation, shade and poor air flow creating damp conditions. As such, the undersides of pipework are particularly vulnerable to corrosion.

Temporary repair clips had been installed on the non-incident pipe. The condition of the clips and the size of the holes underneath suggested that they had been in-situ for a prolonged period of time. Some of the polymer liners under temporary repair clips had cracked in the location of the holes.

A considerable microbiological load was found on both the incident and non-incident pipes, which included microorganisms associated with corrosion. This indicates a contribution of microbiological corrosion (MIC) to the pipeline degradation.

In summary, the corrosion mechanisms of both the incident and non-incident pipes were a combination of external and internal corrosion. The internal corrosion was associated with the presence of sea water and MIC due to stagnant conditions. The external corrosion was associated with the atmospheric corrosion due to a lack of maintenance leading to spalling of a protective layer.

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