Corrosion assessment of a leakage pipeline in the seabed: A case study

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Abstract. A pipeline in the seabed was successfully commissioned and had commenced production from the well. The pipeline has life time design for 20 years. However, a leakage from the flange connection was detected a couple months after start of production. The pipeline was isolated by closing the valves on the line tee, and shutdown the well production. This condition remains for 6 months before any remedial action was taken. During that period, it is believed that there is any corrosion mechanism occurred which might reduce the pipeline integrity. The paper briefly described the corrosion threats and assessed the corrosion rate of the leakage pipeline with limited information of factors that affecting corrosion rate. Additionally, recommendations for preparation of the pipeline to minimize internal risks are given.

1. Introduction
Pipeline has an important role in the oil and gas industries. It is one of the most economical and efficient means of large-scale fluid transportation for crude oil and natural gas. Pipeline is commonly made of carbon steels with some advantages, i.e. good mechanical properties, ease to fabricate, low cost and wider availability. Unfortunately, carbon steel has lower corrosion resistance than other material e.g. corrosion resistant alloy [1,2].

In the design phase, corrosion allowance is added to the pipeline thickness to encounter any internal corrosion threats from the production fluid or gas as per its design life [3]. An issue arises when unexpected incident occurs, i.e. leak which caused “un-predictable” corrosion rate and mechanism in the design phase. Hence, affect the pipeline integrity and reduce its life time.

There is a case study whereby the seabed production pipeline has been successfully commissioned and had commenced production from the well. However, a leakage from the flange connection was detected a couple months after production was commenced as shown in Figure 1. The pipeline was isolated by closing the valves on the line tee, and shutdown the well production. The condition remains for 6 months before any remedial action was taken. The pipeline data is shown in Table 1.

The objective of the paper is to assess the corrosion rate and describe the corrosion threats of the leakage pipeline with limited information of factors that affecting the corrosion rate. Additionally, recommendations for preparation of the pipeline to minimize internal corrosion risks are given.
Table 1. Leakage pipeline data.

| Pipeline Data              | Unit | Value               |
|----------------------------|------|---------------------|
| Design Life                | Years| 20                  |
| Maximum Water Depth        | M    | 101.308 (LAT)       |
| Pipeline Material          | -    | API 5L X65 PSL-2    |
| Pipeline Outside Diameter  | Mm   | 219.1               |
| Maximum Design Temperature | °C   | 78.6                |
| Maximum Design Pressure    | psi/bar | 1750/120.7        |

Table 2. Pipeline operating condition.

| Parameter                          | Unit | Value   |
|------------------------------------|------|---------|
| CO₂ (max)                          | % mole | 0.43    |
| H₂S                                | % mole | 0       |
| Operating Temperature (max)        | °C   | 46.98   |
| Maximum gas flow rate              | MMscfd | 140     |
| Maximum Production water flowrate  | BWPD | 2300    |

Figure 1. Photos of gaseous bubbles coming out from the flange guard connector on the pipeline.

2. Methodology
Due to limitation of the information about the pipeline, (i.e. pipeline data, fluid composition, produced water analysis) the corrosion threats and assessment in this study is based on literature and industrial experiences of authors.

3. Results and discussion

3.1. Corrosion threats
There was seawater ingression into the pipeline due to leaking on the flange connection. Considered the seawater ingestion, two possibilities of exposure conditions are proposed, which are:

- Line flooded with oxygenated seawater.
- Line partially flooded with oxygenated seawater.

From the above scenarios, the associated corrosion threats are CO₂ corrosion (the threats come from the production content), seawater oxygen corrosion and Microbially Induced corrosion (MIC).
3.1.1. CO₂ corrosion. The CO₂ corrosion threat occurs where the line is partially flooded with seawater whereby the produced fluids remaining inside the line. The CO₂ gas forms “weak” carbonic acid (H₂CO₃) when it is absorbed into the seawater. The carbonic acid then partially dissociates to form the bicarbonate ion (HCO₃⁻), which can further dissociate to carbonate ion (CO₃²⁻).

In the presence of carbonic acid, carbon steel will corrode. This is due to the reduction of undissociated of H₂CO₃ molecule and reduction of hydrogen ions as shown in the reaction below [4]:

\[ H₂CO₃ + e^- \leftrightarrow H^+ + HCO₃^- \] (1)

\[ HCO₃^- \leftrightarrow H^+ + CO₃^{2-} \] (2)

\[ H^+ + e^- \rightarrow H \]

The electrons required to keep the process going are provided by a single anodic reaction, iron dissolution:

\[ Fe \rightarrow Fe^{2+} + 2e^- \] (3)

CO₂ corrosion rate is strongly influenced by CO₂ partial pressure. For the case of the leakage pipeline, the CO₂ corrosion rate should be low as the pressure inside the line is expected to be similar to that of the external seabed environment.

3.1.2. Seawater oxygen corrosion. When the raw seawater enters a pipeline, the interior surface of the pipeline will undergo general corrosion due to the presence of oxygen in seawater. The concentration of the oxygen is determined by its concentration in the bulk seawater, the degree movement of seawater, the diffusion coefficient for oxygen in seawater, and characteristic of corrosion product films on the steel surface as a barrier to oxygen diffusion [5]. The corrosion process would be stifled after the oxygen has been consumed. Scenario for seawater oxygen corrosion in the pipeline is divided in two cases, which are finite supply of O₂ and unlimited supply of O₂.

- Seawater Corrosion with Finite Supply of O₂. In this scenario, the amount of seawater corrosion is limited by the amount of oxygen available in the seawater. The total expected of metal loss can be calculated using the equation below, giving the amount of wall thickness that can be expected to be lost, until all of the oxygen is consumed. Since the entry of seawater into the pipeline is through a fairly small opening, it is considered that during the initial flooding, the seawater in the vast bulk of the pipeline would not be replenished with fresh, oxygenated seawater. The equation reactions are:

\[ 4Fe(s) + 3O₂(g) + 2H₂O(l) \rightarrow 2Fe₂O₃, H₂O \] (4)

According to the above reaction, for every molecules of rust (Fe₂O₃, H₂O), it requires 2 molecules of Fe and 3/2 molecules of O₂. Thus:

\[ n_{Fe} = 3n_{O₂} \] (5)

The Internal Seawater Volume

\[ V_{internal} = V_{pipe} \cdot \rho H₂O \] (6)

Internal volume of pipe:

\[ V_{pipe} = \frac{1}{4} \pi ID^2 \] (7)

No moles of oxygen:

\[ n_{O₂} = V_{internal} \cdot SO₂ \] (8)

Mass of steel:

\[ M_{Fe} = n_{Fe} \cdot Mr_{Fe} \] (9)
Volume of steel:
\[ V_{Fe} = \frac{M_{Fe}}{\rho_{Fe}} \]  
(10)

Thickness loss of steel:
\[ t_o = \frac{V_{Fe}}{A_{pipe}} \]  
(11)

Where:
- \( M_{Fe} = \) Molecular weight of steel
- \( \rho_{Fe} = \) Density of steel
- \( SO_2 = \) Oxygen solubility of seawater

By use the above equation, the total wall thickness loss for pipe with the ID of 203 mm and 270 m length d is approximately 0.0011 mm wall loss which would be negligible.

- Seawater corrosion with unlimited supply of \( O_2 \). Considering continuous oxygenated fresh seawater exposure, field data approach is then involved. It is seen that general corrosion is very rapid initially, but falls off gradually over several months to a fairly steady rate, with the overall expected corrosion rates being essentially independent of geographic location (as the oxygen contents and temperatures balance against each other), see the following Figure 2.

![Figure 2. General corrosion rates for steel in seawater [5].](image-url)
It should be noted that these rates are for general corrosion and not pitting corrosion, and do not consider other factors such as debris in the pipeline, mill scale, biofilms, and locations with very thin water films which will be oxygen rich (such as at the water-air interfaces at the pipe walls).

3.1.3. Microbiologically Influenced Corrosion (MIC). Since raw seawater is a ‘live’ medium, which has bacteria and other nutrients dissolved in it, the pipeline interior may be subjected to microbiologically influenced corrosion. The term “microbiologically influenced corrosion” (MIC) is used to describe the corrosion processes where micro-organisms are involved in the material degradation. MIC is due to the action of microbiological communities containing several different species of bacteria. It is the interactive growth activity of bacterial consortia that stimulates the corrosion process. In addition, during the sea water ingress, bio-debris, sand and other particles may have entered, which would certainly contain bacterial species and nutrition sources for the bacteria.

**Figure 3. SRB corrosion mechanism [6].**

Pipelines where raw seawater has been introduced may suffer from corrosion induced by the activities of *acid producing bacteria (APB)* and *sulphate-reducing bacteria (SRB)*. The APB are the principle initiators of MIC [7]. Gu shows possibility that APB can increase MIC pitting rate as high as 10 mm/yr [8, 9]. APB produce organic acids (acetic and butyric acids) and inorganic acids (e.g., sulfuric acid) as well as nutrients for other species (fatty acids) [10]. The low molecular weight organic acids are not particularly corrosive, but they are the primary food source for SRB, which are the best-known group of organisms involved in the corrosion of iron and steel [11].

The initial phase of MIC involves the creation of suitable anaerobic conditions for the SRB colonies to grow. An aerobic APB create a biofilm or slime on the surface of the steel which, once thick enough, allows for the formation of anaerobic conditions at the slime–steel interface. The SRB, dormant up to that point, and begin to colonize. Once the SRB begin to proliferate their production of hydrogen sulphide increases and the environment becomes toxic to most aerobes.

Pit initiation is then thought to begin at breaks in the biofilm by SRB sulphide stimulation of the electrochemical process. Initiation of the biofilm occurs within the first two hours of immersion and develops over a 2-day period, with further changes being observed over more than a 2-week period. As the biofilm grows, the bacteria in the film produce a number of by-products amongst which are organic
acids, hydrogen sulphide and protein-rich polymeric materials commonly called slime. A schematic diagram of the biofilm development is illustrated in Figure 4 below.

The SRB are anaerobic organisms that, in the appropriate environment, can create highly corrosive localized conditions including pitting corrosion. Reports have shown that the optimum temperature for SRB incubation is 25 – 35 °C. SRB influence on the corrosion of steels can be elucidated mainly by two scenarios [10,12]:

- Chemical MIC (CMIC) of iron by hydrogen sulfide from microbial sulfate reduction occurs with “natural” organic substrates.
- SRB corrode iron by direct utilization of the metal itself. This always occurs via direct electron uptake and in only a limited number of recently discovered SRB strains. Until now, such electrical MIC (EMIC) is assumed to be widespread and of considerable technical relevance.

In contrast, Gu et al. explained that the biogenic H₂S produced by SRB is not responsible for SRB MIC of carbon steel [13]. Experimental data have shown that cathode electron harvest by an SRB biofilm from elemental iron via extracellular electron transfer (EET) for energy production by SRB is the primary cause. It has been demonstrated when a mature SRB biofilm is subjected to carbon source starvation, it switches to elemental iron as an electron source and becomes more corrosive.

It should be emphasized that the occurrence and damage rate rates caused by MIC is not easily quantifiable as it is affected by many variables including bacteria types present, seawater composition and temperature, and presence of sediment and its composition. However, indicative corrosion rates for MIC formed pits are typically of the order of 1 mm/year, although values of up to 2 mm/year have been reported where there is ample nutrient supply for the bacteria.

**Figure 4.** A schematic diagram of biofilm formation as illustrated by atomic force microscopy images [10].

- MIC rate calculation by model. The MIC corrosion rate calculation is based on the improvement on the De Waard equation which consider several factors as summarized in the Table 3 [11]. The equation is:

\[ CR = CxF^p \] (12)
Where $C$ is a constant ($C=2 \text{ mm/yr}$), the $f$'s are factors for the various influencing parameters, and $p$ is a power law index (0.57).

By using above equation, the MIC rate during 6 months is 1.5 mm. However, due to uncertainty as to what happening inside the pipe and many of input data is not available for an accurate prediction, a potential MIC pitting corrosion depth over 6 months is divided in to two cases, which are expected case (0.5mm) and worst case (1 mm).

### Table 3. MIC corrosion rate calculation factors.

| Factor when true | Factor when false |
|------------------|-------------------|
| pH between 5 and 9.5? | 1 | 0.001 |
| Todal dissolved solids (TDS) < 60 g/l | 1 | 0.2 |
| If TDS>60g/l, do SRB grow? | 0.2 | 0.0001 |
| Temperature (T) between 10 and 45 °C? | 1 | 0.2 |
| If T>45°C, do SRB grow? | 1 | 0.2 |
| Sulfate > 10 mg/l? | 1 | 0.2 |
| Total carbon (C) from fatty acids >20 mg/l? | 1 | 0.2 |
| Nitrogen (as utilisable N) > 5 mg/l? | 1 | 0.2 |
| C:N ratio <10? | 1 | 0.4 |
| Flow velocity < 1m/s | ~1 |
| Flow velocity = 2m/s | ~0.6 |
| Flow velocity = 2.5 m/s | ~0.1 |
| Flow velocity = 3 m/s | ~0.01 |
| Debris on bottom of pipeline | 2 | 1 |
| Pigging frequency never | ~1 |
| Pigging frequency 13 wks | ~0.3 |
| Pigging frequency 4 wks | ~0.001 |
| Pigging frequency 1 wk | ~0.0001 |
| Prolonged oxygen ingress > 50 ppb | 5 | 1 |
| Biocide routinely used? | 0.2 | 1 |
| Operational history: | |
| - Age pipeline < 0.5 yr | 1 |
| - Age pipeline > 0.5 yr & downtime = 1 wk | ~1 |
| - Age pipeline > 0.5 yr & downtime = 50 wks | 2 |

### 4. Discussion

The interior of the pipeline shall be exposed to raw seawater. The pipeline interior would initially corrode due to the oxygen in the seawater but, after the oxygen has been consumed by the corrosion process, the corrosion would be effectively stifled.

Calculations have shown that for the finite supply of $O_2$ scenario, general wall loss is very small (0.0011mm) and could be negligible. Meanwhile, for the unlimited supply of $O_2$ wall thickness losses in the order of 0.1mm is accounted.

It has been demonstrated that MIC can be initiated in raw seawater containing oxygen. Further, it is also not necessary to have fully anaerobic conditions before corrosion starts to affect the steel. It is considered that MIC could initiate soon after the development of a biofilm, which is reported to become
established in as little as 2 weeks. However, the occurrence of MIC is not quantifiable and it cannot be said with any certainty if MIC will occur and to what extent it will cause pitting and what size those pits may be. Indicative corrosion rates for MIC formed pits are typically of the order of 1 mm/year [14], although values of up to 2 mm/year have been reported.

Based on the discussion above, there are two major corrosion threats, which are oxygenated seawater corrosion and microbial corrosion. However, due to the uncertainty as to what happening inside the pipe, especially on microbial corrosion, it is reasonable if the corrosion case is divided into three cases:

- Best case, whereby corrosion influenced by seawater only (0.1mm), MIC insignificant.
- Expected / Base case, MIC corrosion dominant with the rate of 0.5mm in 6 months.
- Worst case, MIC corrosion dominant with the rate of 1mm in 6 months.

Table 4. Summary of estimated corrosion rate of pipeline for 6 months exposure time in seawater.

| No | Case                  | Oxygenated seawater corrosion (General corrosion) | MIC Corrosion (Localized corrosion) | Estimated Total Corrosion |
|----|-----------------------|--------------------------------------------------|-------------------------------------|---------------------------|
| 1  | Best case             | 0.00015mm                                        | Insignificant                      | 0.00015mm                 |
| 2  | Base / Expected case  | 0.00015mm                                        | 0.5mm                              | 0.5mm                     |
| 3  | Worst case            | 0.1mm                                            | 1mm                                | 1.1mm                     |

Note: This figure is not accurate as there are so many variables (i.e. pipeline data, fluid composition, produced water analysis) that an accurate prediction of corrosion is not possible, values quoted are therefore indicative only.

5. Conclusion and recommendation

5.1. Conclusion

Three possible scenarios of corrosion rate were proposed with two primary corrosion threats on the pipeline which are oxygen corrosion and microbial corrosion.

- The leakage pipeline will corrode during 6 months exposure to raw seawater, as provided in Table 4.
- Expected WT loss due to corrosion during 6 months seawater exposure is 0.5 mm.

While, Worst case WT loss due to corrosion is 1 mm. This corrosion will reduce the designed pipe life time.

5.2. Recommendation

The recommendation for preparation of the leakage pipeline to minimize internal corrosion risks are as follows:

- As soon as possible, flood / flush the line with treated, filtered water. Treatment should ideally contain a combination biocide / corrosion inhibitor and oxygen scavenger.
- Conduct cleaning pigging runs, to break up any SRB colonies, allowing the biocide to penetrate. These pigging runs should consist of alternate aggressive brush pig followed by a soft bristle brush pig to sweep debris from pits. This should be repeated until no debris is recovered from the pigging run.
- To ascertain if MIC had been active in the pipeline, samples of recovered corrosion debris could
be examined and cultured for any SRB species.

Depending on the corrosion management plan for this pipeline, consideration may be given in early life to an in-line inspection to establish a baseline of corrosion damage from the leakage.

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