This article presents the failure investigation of internal pitting corrosion on a 30-in (0.762-m) diameter subsea oil pipeline in western offshore India. Detailed laboratory and analytical studies were made on the failed sample to establish the cause and mechanism of failure. This article describes the analysis methodology, the probable corrosion and failure mechanism, and recommended preventive measures.

A 30-in (0.762-m) subsea crude oil pipeline ruptured after a service life of ~25 years. This 203-km pipeline operates in 80 m of water and transports crude from an offshore process platform to the shore terminal. The leak was located ~815 m from the riser bend at the process platform and at the 6 o’clock position. The pipeline was API 5LX-60 with a wall thickness of 17.48 mm. At the time of failure, the pipeline was operating at 1,350 psi (9.3 MPa); the design pressure was 1,981 psi (13.7 MPa). The line is externally coated with coal tar enamel and concrete, and is buried 3 m below the sea bed. It is cathodically protected by sacrificial bracelet anodes. Table 1 shows the operating parameters and leakage history.

**Laboratory Investigations**

**Visual Examination**

Visual inspection revealed the following observations:
- The external surface of the pipe showed no noticeable corrosion.
- The pipe rupture had a maximum width opening of 120 mm and length of 1,250 mm.
- Visual inspection revealed severe localized internal corrosion at the 6 o’clock position with deep trench-like attack that caused excessive wall thickness reduction; this ultimately caused the pipeline rupture (Figures 1 and 2). Stereomicroscopic studies showed Mesa-type corrosion (Figures 3 and 4).

**Corrosion Product Analysis**

The corrosion product was analyzed by chemical methods and further authenticated through x-ray diffraction technique. The corrosion product analysis showed that it was predominantly carbonate, sulfide, and iron oxides with chloride. The deposits were formed from
the corrosive action of carbon dioxide (CO$_2$) and hydrogen sulfide (H$_2$S) present in the associated gas. The diffractogram reproduced in Figure 5 reveals the predominant presence of siderite (FeCO$_3$).

**Analysis of Produced Water**

The chemical analysis of produced water showed a significant presence of chloride (18,460 mg/L) while bicarbonate was 549 mg/L. The water analysis also revealed the presence of considerable amounts (8 to 362 mg/L) of corrosive volatile organic fatty acids like acetic, propionic, and butyric acids (CH$_3$COOH, CH$_3$CH$_2$COOH, and CH$_3$CH$_2$CH$_2$COOH).

**Microbial Analysis**

Analysis of sulfate-reducing bacteria (SRB) per API-RP-38 serial dilution technique showed constant presence of SRB in produced water; this implied that microbiologically influenced corrosion (MIC) also contributed appreciably to the failure. The cross sectional view of a deep pit during metallographic examination was also typical of MIC (Figure 6).

**Verification of Material Integrity**

Elemental compositional analysis of the failed pipeline sample by spark spectroscopy conforms to the requirements of the specification API-5LX-60. Metallographic studies indicated that the pipe material has acceptable normalized ferrite-pearlite microstructure, typical of rolled carbon steel (Figure 7). The average hardness, yield strength, ultimate tensile strength, percentage elongation, and toughness of the pipe material are within the acceptable limits for API-5LX-60.

**Simulated Corrosion Rate Evaluation**

The gravimetric corrosion rate of the pipeline material was determined by simulating actual pipeline conditions on

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**TABLE 1**

<table>
<thead>
<tr>
<th>Particulars</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating pressure (psi)</td>
<td>1,350/150 to 200 (up/down)</td>
</tr>
<tr>
<td>Operating temperature (°C)</td>
<td>65/35 (up/down)</td>
</tr>
<tr>
<td>Flow rate: (a) oil (BOPD)</td>
<td>194,502</td>
</tr>
<tr>
<td>(b) water (%)</td>
<td>1 to 7</td>
</tr>
<tr>
<td>H$_2$S (ppm)</td>
<td>150 to 375</td>
</tr>
<tr>
<td>mol% CO$_2$</td>
<td>2.10</td>
</tr>
<tr>
<td>pCO$_2$ (psi)</td>
<td>28</td>
</tr>
<tr>
<td>SRB</td>
<td>Present</td>
</tr>
<tr>
<td>Location of leak/rupture and size</td>
<td>815 m from riser: 800 by 50 mm</td>
</tr>
<tr>
<td>Configuration of the line at the location of leakage</td>
<td>Straight</td>
</tr>
<tr>
<td>Position of the leakage</td>
<td>6 o’clock</td>
</tr>
<tr>
<td>Corrosion monitoring techniques</td>
<td>Iron counts and SRB monitoring</td>
</tr>
<tr>
<td>Thickness survey</td>
<td>Nil</td>
</tr>
<tr>
<td>Oil corrosion inhibitor dosing</td>
<td>4.70 ppm: continuous</td>
</tr>
<tr>
<td>Bactericide dosing</td>
<td>In batches on quarterly basis</td>
</tr>
</tbody>
</table>

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**FIGURE 1**

External view of a failed specimen.

**FIGURE 2**

View of the internal surface of a pipeline showing pitting and rupture.
a multiphase dynamic flow loop. The corrosion rate was ~28.32 mpy (0.71 mm/y), which is much higher than the normal corrosion rate.

**Analytical Investigations**

**Flow Velocity Profile**

Flow velocity was 0.80 m/s as compared to the generally minimum recommended velocity of ~1 m/s. The low velocity provides the conditions for possible segregation and accumulation of water along the 6 o’clock position, particularly in low-lying areas. This, in turn, aggravates the corrosion attack, thereby increasing the rate of wall thinning.

**Modeling for Moisture Condensation**

**Simulation Model for Segregation of Water**

To determine the possibility of water segregation and accumulation during oil transportation, in-house developed software (based on a rigorous mechanistic model) was run with various inputs and a bathymetry profile of the pipeline. Software analysis revealed segregation of water in varying quantities in the pipeline, particularly in low-lying areas, which are more prevalent in the first 50 km than elsewhere.

**Bathymetry Profile**

The bathymetry profile of the pipeline showed that there are more vulnerable portions in the first 50 km than elsewhere, based on their dip from the normal slope. Thus, the accumulation of water is more likely in this region than elsewhere.

**Probable Mechanism of Failure**

The presence of 1 to 7% produced water in the flowing stream is quite high for oil transportation lines. The partial pressure of CO2 is 28 psi (0.19 MPa). This partial pressure is significantly high for initiating and abetting pitting/general corrosion. The pitting was further ag-
gravitated by separated water containing dissolved salts, particularly sodium chloride (NaCl) within the pitted surface. In this case, the presence of 150 to 375 ppm \( \text{H}_2\text{S} \) along with \( \text{CO}_2 \) makes the environment more corrosive.

The formation water was found to have a significant quantity of volatile fatty acids such as acetic, propionic, and butyric acids, which have a preferential affinity toward iron. They react to form an organic acid salt of iron, which is soluble in water and hence washed away by the free-flowing water cut. These effects add to the severity of \( \text{CO}_2 \) corrosion by breaking down protective corrosion product scale (predominantly siderite) at localized sites. With the bare metal surface exposed, fatty acids react further to increase corrosion and subsequent severe localized wall thinning. The chemical reactions are shown in Equations (1) through (4).

\[
\begin{align*}
\text{H}_2\text{O} + \text{CO}_2 & \rightarrow \text{H}_2\text{CO}_3 \\
\text{Fe} + \text{H}_2\text{CO}_3 & \rightarrow \text{FeCO}_3 + 2\text{H}^+ \\
\text{Fe} + 2\text{CH}_3\text{COOH} & \rightarrow \text{Fe} (\text{CH}_3\text{COO})_2 + 2\text{H}^+ \\
\text{FeCO}_3 + 2\text{CH}_3\text{COOH} & \Rightarrow \text{Fe} (\text{CH}_3\text{COO})_2 + \text{CO}_2 + \text{H}_2\text{O}
\end{align*}
\]

High water content (1 to 7%) in the crude and low flow velocity of <1 m/s favors the segregation of water in the pipeline, particularly at low-lying areas, creating a good habitat for bacterial growth. Software analysis also confirmed segregation of water in the pipeline. Microbial analysis confirmed significant presence of detrimental SRB.

**Conclusions**

Based on the various laboratory and analytical investigations, causes of the failure are attributed to the significant presence of high water content in the crude oil, \( \text{CO}_2, \text{H}_2\text{S}, \text{SRB (MIC)}, \) high chloride content, and the presence of volatile organic fatty acids. Low liquid flow velocity led to the separation of water and its accumulation in undulated areas. The synergistic effect of corrodants and a conducive environment led to internal pitting corrosion, particularly at the 6 o’clock position, causing localized wall thinning and the subsequent rupture of the pipeline.

**Recommendations**

- Water content of the crude oil transported in the pipeline should not be >1%.
- State-of-the-art corrosion monitoring techniques, such as weight loss coupons in combination with electrical resistance/linear polarization resistance probes, need to be installed both up- and downstream of the pipeline to obtain more reliable data to help definitive prediction of corrosion rates in the pipelines.
- In view of the significant levels of bacterial activity observed, use of flush-mounted bioprobes at the 6 o’clock position is recommended to monitor the bacterial activity in the pipelines.
- An effective corrosion mitigation program through chemical inhibition (corrosion inhibitors and biocides) needs to be put into operation.
- Regular pigging needs to be carried out for removing accumulated water, sludge, debris, microbial colonies, etc.
- Intelligent pigging, if possible, needs to be carried out periodically to assess the appropriate health of the pipeline.
- As pipelines are more susceptible to corrosion due to water accumulation in low-lying areas, utmost care needs to be taken to avoid undulations while laying the pipelines to avoid water accumulation in low-lying areas of the pipelines.

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References

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