Review Article

A comprehensive review on internal corrosion and cracking of oil and gas pipelines

M. Askari\textsuperscript{a}, M. Aliofkhazraei\textsuperscript{b,*}, S. Afroukhteh\textsuperscript{b}

\textsuperscript{a} Department of Materials Science, Faculty of Engineering, Tarbiat Modares University, Tehran, P.O.Box: 14115-143, Iran
\textsuperscript{b} Department of Materials Science, Faculty of Engineering, Tehran University, Tehran, P.O.Box: 193896115, Iran

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Metal loss
Environmentally assisted cracking (EAC)

A B S T R A C T

Integrity management of pipeline is vital for sustainable production. Among all of pipeline failure threats, contribution of corrosion is significant and has been reported up to 50\%. This paper focuses on the corrosion risks risen from internal media in contact with pipe wall either sweet or sour service. Internal corrosion concerns have been divided into two categories including general/localized metal loss and environmentally assisted cracking. Modes and mechanisms for both aspects have been comprehensively reviewed and discussed. Each type of defined corrosion mechanism has been actualized by some failure case studies and filed histories.

1. Introduction

Oil and gas industry has incorporated pipelines for transporting hydrocarbon and products from more than one century ago. The privileges of transporting crude oil, natural gas, and all petroleum products with pipelines as the continuous and reliable operation have been well proven in the industry.

The first pipeline system has been used by connecting the cast iron pipes in bell and spigot couplings for crude oil conveying. Then, line pipes were joined by a threading mechanism that was not reliable for high pressure systems. The first pipeline was built in the United States in 1859 to transport crude oil (Boyun Guo et al., 2013). By introduction of welding, the robust connection was ensured and volume of pipeline constructions was increased in vast majority of applications. Based on a report in 2014, totally around 3.5 million km of pipelines have been installed in 120 countries of the world (Villamizar et al., 2007).

Metallic pipelines, mostly fabricated from carbon steel and low alloy steel grade, are prone inherently to be corroded by electrochemical reactions with the environment. The type and rate of corrosion are closely dependent on material properties and environmental conditions.

Pipeline specific geometry and electrolytic isolation between the inner wall and outer wall implicates that corrosion can occur and developed internally and externally with the independent scenario. This principle causes separate corrosion mitigation measures for each side, in which internal corrosion control technique cannot be effective for control of external corrosion issues. For instance, cathodic protection intended for external corrosion is fully ineffective for internal corrosion.

In this work, pipeline means carbon steel line pipes carrying hydrocarbon fluids (single or multiphase) from wellhead and production units to process units including onshore plants, offshore platforms, and reception facilities. Internal corrosion failures of oil and gas pipelines with wet scheme have been reviewed. Other types of pipelines designed for water or gas injection are also discussed in this work.

Failure threats potentially induced by internal corrosion have been classified into two parts in this study from failure mode point of view:

1 General and localized metal loss or thinning mode which has been categorized based on configuration and mechanism of corrosion and comprises sweet corrosion, sour corrosion, top of line corrosion, under deposit corrosion, preferential weld corrosion, and microbial corrosion. Pipeline corrosion features caused by metal loss can be clustered or in isolated pattern (Benjamin et al., 2016a; Benjamin et al., 2016b; Kermani and Chevrot, 2014). Environmentally assisted cracking (EAC) which covers major cracking mechanism in wet sour hydrocarbon pipelines including sulfide stress cracking, hydrogen induced cracking, and stress oriented hydrogen induced cracking (Ford, 1989; Jarvis and Bulloch, 1992; Kermani and Chevrot, 2014; Zhou et al., 2016).

For both categories of corrosion mechanisms different researches and standards deal with the reliability analysis of corroded pipelines with the aims of risk assessment, life extension and fitness for service (Gan et al., 2018; Teixeira et al., 2008; Veritas, 2010).

\* Corresponding author.
E-mail addresses: maliofkh@gmail.com, khazraei@modares.ac.ir (M. Aliofkhazraei).

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Canadian Association of Petroleum Producers (CAPP) has developed several industry practices regarding internal corrosion of pipelines, which are practically applicable in the improvement of the integrity of upstream pipelines and reducing the risk of corrosion incidents ([CAPP], 2009a; [CAPP], 2009b). These practices have reported a number of pipeline incidents in Canada from 1985 to 2008, partitioned by different causes. Based on these documents, internal corrosion is the most dominant reason for leakage and failure for natural gas pipelines (Fig. 1) and sour gas pipeline (Fig. 2). Failure statistics revealed that 28% of the 31 sour gas pipeline incidents in Alberta in 2008 were due to the internal corrosion.

For better understanding of different form of internal corrosion by metal loss or cracking mechanism which will be discussed later in details, all type of internal corrosion predicted to occur in pipeline are schematically summarized in Fig. 3.

Recent advancements the scope of internal corrosion in oil and gas have focused in discovering the mechanism of corrosion in sour fluid and mixed H₂S + CO₂ corrosion (Genchev and Erbe, 2018; Xu et al., 2018). Due to effects of flow regime on corrosion behavior in pipeline, it is recently study of corrosion in multiphase flow has been increased including top of the line corrosion (TLC), bottom of line corrosion. Moreover corrosion control aspects including corrosion inhibitors in harsh environments such as high temperature, high pressure, high shear stress, ...are under study (Li et al., 2016, 2017; Fateh et al., 2017).

<table>
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<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>NACE</td>
<td>National Association of Corrosion Engineers</td>
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<tr>
<td>ISO</td>
<td>International Organization for Standardization</td>
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<tr>
<td>CSA</td>
<td>Canadian Standards Association</td>
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<tr>
<td>CAPP</td>
<td>Canadian Association of Petroleum Producers</td>
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<td>API</td>
<td>American Petroleum Institute</td>
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<td>OD</td>
<td>Outside Diameter</td>
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<tr>
<td>SEM</td>
<td>Scanning Electron Microscopy</td>
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<td>EDS</td>
<td>Energy Dispersive Spectroscopy</td>
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<tr>
<td>TOBC</td>
<td>Top of the Line Corrosion</td>
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<td>PWC</td>
<td>Preferential Weld Corrosion</td>
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<td>UDC</td>
<td>Under Deposit Corrosion</td>
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<td>FILE</td>
<td>Flow Induced Corrosion</td>
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<td>MIC</td>
<td>Microbiologically Influenced corrosion</td>
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<td>EAC</td>
<td>Environmentally assisted cracking</td>
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<td>HSC</td>
<td>Hydrogen Stress Cracking</td>
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<td>SCC</td>
<td>Sulfide Stress Cracking</td>
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<tr>
<td>HIC</td>
<td>Hydrogen Induced Cracking</td>
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<td>SWC</td>
<td>Step-Wise Cracking</td>
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<td>SOHIC</td>
<td>Stress Oriented Hydrogen Induced Cracking</td>
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<td>ILI</td>
<td>In-Line Inspection</td>
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<tr>
<td>MFL</td>
<td>Magnetic Flux Leakage</td>
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<tr>
<td>UT</td>
<td>Ultrasonic Test</td>
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<tr>
<td>HAZ</td>
<td>Heat Affected Zone</td>
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<tr>
<td>ERW</td>
<td>Electric Resistance Welding</td>
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<td>HRC</td>
<td>Rockwell C Hardness</td>
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<tr>
<td>HV</td>
<td>Vickers Hardness</td>
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<tr>
<td>SRB</td>
<td>Sulfate Reducing Bacteria</td>
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<tr>
<td>IOB</td>
<td>Iron Oxidizing Bacteria</td>
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<tr>
<td>APB</td>
<td>Acid Producing Bacteria</td>
</tr>
<tr>
<td>IRB</td>
<td>Iron-Reducing Bacteria</td>
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</table>

2. Metal loss mechanisms

2.1. CO₂ corrosion

As an acid gas, CO₂ is present in oil and gas reservoirs. Due to its solubility in water and brine, this gas can cause corrosion of carbon steel, called as “sweet corrosion”. This kind of corrosion is the most common type in hydrocarbon transportation pipelines and can result in localized mode failures (Kermani and Morshed, 2003).

The general electrochemical reaction for anodic dissolution of iron and cathodic evolution of hydrogen was presented by Nesic (Nesić, 2007) as below:

\[
\text{Fe} + \text{CO}_2 + \text{H}_2\text{O} \rightarrow \text{FeCO}_3 + \text{H}_2
\]  

By this reaction, carbonate scales are formed on the steel surface that can be protective depending on the nature and structure of the scales.

Many research works have been published in order to define the mechanism of CO₂ corrosion. (Chevrot, 2012; Crolet, 1994; Crolet and Bonis, 2010; Crolet et al., 1996; Dugstad, 2015; George et al., 2004; Schmitt, 2015; Schmitt and Engels, 1998). Reactions in Table 1 show generally that CO₂ can be dissolved in water, where a weak acid is produced that can be dissociated to bicarbonate anions.

Different types of metal loss corrosion induced by CO₂ in aqueous streams in the pipeline can be categorized as a flowchart in Fig. 4.

Erosion assisted CO₂ corrosion has been studied by some researchers, who mainly reported that this corrosion is dominantly in the
form of ripple marks, horse shoes, comet tails, and dinosaur footprints (Crolet, 1994; Kermani and Morshed, 2003; Rincon et al., 2006; Shadley et al., 1998). This review focuses on the electrochemical corrosion by pure CO₂ which is more common in oil and gas pipelines. Pure CO₂ corrosion as shown in Fig. 4 has been subdivided in general corrosion and localized corrosion. Each mechanism will be discussed in more details.

2.1.1. General corrosion
The uniform metal loss of pipe wall mainly results in the anodic dissolution of iron. The rate of this kind of corrosion can be predicted by many corrosion rate determination/prediction equations and models (Chevrot, 2012; Crolet, 1994; Crolet and Bonis, 2010; Dugstad, 2015; Nešić, 2007; Schmitt and Engels, 1998; Schmitt and Hörstemeier, 2006). So, if the rate of this general thinning of the pipeline is calculated correctly, it can be mitigated by the addition of corrosion allowance in thickness during design step or by chemical treatment during operation. Fig. 5 shows the internal corrosion of crude oil pipeline which is corroded due to CO₂ and salt water in pipeline stream. As it is observed the corrosion mechanism is just metal loss and formation of carbonate scales as corrosion product is also clear on the surface.

2.1.2. Localized corrosion

2.1.2.1. Pitting corrosion. Localized corrosion can be occurred in two form of pitting corrosion and mesa attack.

Pitting corrosion due to CO₂ mostly occurs at a low velocity of fluid inside the pipeline, where by rising the partial pressure of CO₂ and temperature the susceptibility of the pipeline to pitting also increases (Kermani and Morshed, 2003). Chloride ions can also affect the pitting corrosion while some researchers believe that in the presence of CO₂, chloride ions are corrosive agents in the form of pitting (Chevrot, 2012; Dugstad, 2015; Schmitt, 2015; Sun et al., 2003). Others have proved that these ions have no effect on pitting of carbon steel in CO₂

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Table 1
Chemical reactions for CO₂ corrosion.

<table>
<thead>
<tr>
<th>Chemical Reaction</th>
<th>Reaction proposed by</th>
<th>Note</th>
</tr>
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<tbody>
<tr>
<td>( \text{HCO}_3^- + \text{H}^+ + e^- \rightarrow \text{H}_2 \text{O} + \text{CO}_2 )</td>
<td>Kermani and Smith, 1997</td>
<td>RDS (rate determining step)</td>
</tr>
<tr>
<td>( \text{H}_2\text{CO}_3 + e^- \rightarrow \text{H}^+ + \text{HCO}_3^- )</td>
<td>De Waard and Milliams, 1975</td>
<td>RDS</td>
</tr>
<tr>
<td>( \text{HCO}_3^- + \text{H}^+ \rightarrow \text{H}_2\text{O} + \text{CO}_2 )</td>
<td>Nešić, 2007, Gray et al., 1990</td>
<td>For pH &gt; 4</td>
</tr>
<tr>
<td>( \text{HCO}_3^- + 2\text{e}^- \rightarrow \text{H}_2 + 2\text{CO}_3^{2-} )</td>
<td>Ogundele and White, 1987</td>
<td>For pH &gt; 7</td>
</tr>
<tr>
<td>( 2\text{H}^+ + 2\text{e}^- \rightarrow \text{H}_2 )</td>
<td>De Waard and Milliams, 1975</td>
<td>For pH &lt; 4</td>
</tr>
</tbody>
</table>

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Fig. 2. Sour gas pipeline incidents by cause (Alberta) ((CAPP), 2009a).

Fig. 3. Different forms of internal corrosion in hydrocarbon pipelines.
containing fluids (Schmitt and Feinen, 2000; Sun and Nesic, 2004).

2.1.2.2. Mesa attack. This pattern of CO2 corrosion has been observed in streams with a low to medium velocity at which carbonate scale is damaged due to flow regime. Kermani et al. (Crolet, 1994) indicate that Mesa attack appears as stepped depressions with a flat bottom and vertical sides (Crolet et al., 1996; Kermani and Morshed, 2003) with the totally different configuration of erosion corrosion. Nyborg (Kermani and Morshed, 2003) published a typical mesa attack pattern on the pipeline due to internal corrosion by CO2. From the microstructure viewpoint, Crolet et al. (Crolet et al., 1996) concluded that galvanic couplings of ferrite and cementite phases in CO2 containing environments can be a source of mesa attack propagation.

Ikeda et al. (Ikeda et al., 1984) concluded that mesa attack initiates in a location with poor protection on FeCO3 surface film and where the film is breakdown. This result was confirmed in works of Dugstad and coworkers (Dugstad, 2015) and Kermani et al. (Kermani and Morshed, 2003). Furthermore, they found out a relation between iron ion contents of fluid and mesa attack occurrence, which can lead to galvanic effects due to the localized cathodic sites and anodic regions where mesa corrosion have been initiated (Ikeda et al., 1984).

Shi et al. (2014) presented in their work the failure of a low alloy steel gas pipeline due to CO2 corrosion. They obtained the corrosion rate in the range of 1.413–1.978 mm/y that shows how CO2 corrosion can be intensive depending on the partial pressure of CO2 and temperature and nature of scales which they found out is FeCO3. For comparison of the different corrosion pattern of mesa attack and pitting, two mechanisms happened in natural gas pipeline is presented in Fig. 6.

Al-Jaroudi et al. (2015), by reporting of carbon steel tubing failure due to internal corrosion in wet sweet oil environment, highlighted that the primary failure mode was sweet CO2 corrosion in the form of mesa attack. They observed local mesa attack by deep and often flat-bottomed corrosion prints and sharp edges which were not covered by the protective film. Mesa attacked areas were preceded with intensive corrosion rates while neighbor sites were covered by protective corrosion products and rate of corrosion was low. Some photos of reported failure are illustrated in Fig. 7 revealing different patterns of CO2 localized corrosion (Al-Jaroudi et al., 2015).

2.1.2.3. Flow induced localized corrosion (FILC). With objections to two other localized corrosion mechanisms, in high flow velocities (above a critical rate (around 10 m/s)), this mechanism of CO2 corrosion is predominant, which initiates from pitting and/or mesa attack sites. This is called flow induced localized corrosion (FILC). It will be propagated by localized turbulence around pits and mesa attack steps or any projection inside the pipeline. Scales formed on pipe wall will be damaged due to effects of flow disturbance in combination with stresses of film generated during scale growth (Schmitt and Engels, 1998; Schmitt and Hörstemeier, 2006). After the breakdown of scale, flow effects does not allow recovering the film so that corrosion will proceed with a high intensity (Schmitt et al., 1999, 2000).

A classic mechanism can be defined for flow induced localized corrosion (FILC) as is shown schematically in Fig. 8. This process is attributed to the roughness of surface film which increases the micro-turbulences on flow leading to localized thinning of scales and porosity growth inside, which can cause the destruction of the film. Localized
attack will be concentrated on this local anodes and furthered formation of the protective film is impeded by flow velocity (Schmitt et al., 1999, 2000).

2.2. H2S corrosion

Oil and gas reservoirs containing hydrogen sulfide (H2S) are called sour hydrocarbon systems. Pipelines carrying sour fluid are subject to corrosion by different mechanisms due to the presence of weak H2S acid gas. H2S can dissolve in aqueous phase on stream and consequently dissociate to produce H+ cations that by capturing electrons can increase the rate of anodic dissolution of carbon steel and cathodic reduction reaction which is a source of hydrogen evolution (Brunner and Woll, 1980; Rippon, 2005).

Corrosion of carbon steel in media containing H2S has been extensively studied (Chong et al., 2014; Dapeng et al., 2014; Defo Ayagou et al., 2018; Díaz et al., 2010; Mendibide and Duret-Thual, 2018). However, due to the complicated chemistry of H2S-H2O system, it is difficult to determine the exact mechanisms of H2S corrosion. Depending on the pH and redox potential, three different species exists in aqueous solutions in the presence of H2S including H2S, HS−, and S2− (Abayarathna et al., 2003).

The overall reaction for H2S corrosion in aqueous medium is as below:

\[
Fe + H_2S \rightarrow FeS + H_2 \tag{2}
\]

Various types of iron sulfide corrosion products can be formed depending on temperature, pH, and concentration of H2S, these scales can be protective or not (Zheng et al., 2014). The types of iron sulfide include troilite (FeS), mackinawite (Fe1+xS), marcasite FeS2 (S-deficient), pyrite FeS2 (S or Fe-deficient), pyrrhotite (Fe1-xS), and kansite (Fe9S8). At temperatures below 90 °C, the main sulfide product is mackinawite for most oil and gas pipelines (Sardisco and Pitts, 1965a; Sardisco and Pitts, 1965b; Sardisco et al., 1963; Shi et al., 2016; Svenningsen et al., 1968).

Fig. 7. Photographs of the internal surface of the failed tubing showing the pinholes and deep mesa type attack at the bottom section; (A, B, D) as received, and (C) after acid cleaning (Al-Jaroudi et al., 2015).
At higher temperatures in H₂S containing environments, the predominant corrosion products include troilite (FeS) and/or pyrrhotite (Fe₁₋ₓS).

The cathodic and anodic reactions are as below (Abayarathna et al., 2003):

The cathodic reactions:

\[
\begin{align*}
2\text{H}^+ + 2\text{e}^- &\rightarrow \text{H}_2 & (3) \\
\text{FeSX} + \text{S} &\rightarrow \text{FeSX} + 1 & (4) \\
\text{FeSX} + 1 + \text{H}_2\text{O} + 2\text{e}^- &\rightarrow \text{FeSX} + \text{HS}^- + \text{OH}^- & (5) \\
\text{FeSX} + 1 + 2\text{e}^- &\rightarrow \text{FeSX} + \text{S}^- & (6) \\
\text{H}_2\text{SX} + 2\text{e}^- &\rightarrow \text{H}_2\text{S} + \text{XS}^- & (7) \\
\end{align*}
\]

Anodic dissolution reactions of iron:

\[
\begin{align*}
\text{Fe} &\rightarrow \text{Fe}^{2+} + 2\text{e}^- & (9) \\
\text{Fe} + \text{H}_2\text{O} &\rightarrow \text{Fe(OH)}^+ + \text{H}^+ + 2\text{e}^- & (10) \\
\end{align*}
\]

And iron sulfide can be formed through the following reactions:

\[
\begin{align*}
\text{Fe}^{2+} + \text{HS}^- + \text{OH}^- &\rightarrow \text{FeS} + \text{H}_2\text{O} & (11) \\
\text{Fe}^{2+} + \text{S}^- &\rightarrow \text{FeS} & (12) \\
\text{Fe(OH)}^+ + \text{H}^+ + \text{HS}^- + \text{OH}^- &\rightarrow \text{FeS} + 2\text{H}_2\text{O} & (13) \\
\text{Fe(OH)}^+ + \text{H}^+ + \text{S}^- &\rightarrow \text{FeS} + 2\text{H}_2\text{O} & (14) \\
\end{align*}
\]

2.3. Microbiologically influenced corrosion (MIC)

Kermani et al. (Chevrot, 2012; Kermani and Morshed, 2003) expressed that microbiologically influenced corrosion (MIC), as a major internal corrosion threat in pipeline, is relevant to oil pipeline and produced/injection water pipeline. They also reported that the primary parameters influencing this kind of corrosion are sulfate, nutrients, bacteria type, pH, flow rate, salinity, and temperature. Crude oil pipelines are internally affected by Microbiologically influenced corrosion (MIC), especially in water pockets at low-lying sections of the pipeline (Al-Saleh et al., 2011). MIC is seen mostly in localized corrosion configuration and is attributed to stagnant conditions of flow inside pipeline which may lead to severe pitting mainly at 6 O’clock position. Two mechanisms have been developed for MIC corrosion: classic and modern (Papavinasam, 2013).
Based on the classical mechanism, some chemicals are produced by microbial activities. These chemicals have major role in accelerating the corrosion. Major microbial species influencing MIC are sulfate-reducing bacteria (SRB), acid producing bacteria (APB), iron-reducing bacteria (IRB), and iron-oxidizing bacteria (IOB). SRB reduces sulfate to sulfide by consuming hydrogen atoms. Therefore, the rate of a cathodic reaction related to hydrogen reduction increases, followed by a subsequent acceleration in corrosion rate for anodic dissolution of iron. The corrosion product of SRB activity is FeS (Wen et al., 2007). APB converts organic materials into CO2. Carbon dioxide is dissolved in water and produces H2CO3 which is corrosive to iron. Thus, the corrosion product here is iron carbonate (Chen et al., 2014). IRB reduces insoluble Fe3+ oxide layer to soluble iron ions Fe2+ consequently leading to the dissolution of protective oxide layer and the enhanced corrosion of substrate (Chandrasatheesh et al., 2014).

Finally, IOB oxidizes soluble Fe2+ to insoluble Fe3+. Since the insoluble layer is not uniform, the localized corrosion would occur subsequently (Chen et al., 2014). According to the modern mechanism, the initial step for MIC corrosion is a biofilm formation. Oxygen content within the biofilm is reduced due to bacterial activity. Thus, the surface of the metal will be anaerobic wherever covered by biofilm. Consequently, an isolated area is provided for growth of bacteria and resulting in corrosion (Papavinasam, 2013).

Al-Sulaiman et al. (Al-Sulaiman et al., 2010) found indications of severe internal corrosion on a light crude oil (LCO) pipeline from API 5L-Grade B interconnecting a wet tank to a common header with corrosion depth of more than half of pipeline wall thickness. In spite of its 30-year design life, the pipeline was corroded within 7 years of operation. Based on morphology of localized corroded sites like large terraced pits and detection of high concentrations of SRB (Sulfate Reducing Bacteria) and GAnB (General Anaerobic Bacteria) on the coupons immersed in LCO wet tank with same medium of pipeline, they concluded that MIC is the reason of severe localized corrosion on inner wall of crude oil pipeline. Moreover, identification of H2S in the downstream fluid of LCO wet tank was another signal for MIC corrosion of inside pipeline (Al-Sulaiman et al., 2010).

Talukdar et al. (Talukdar et al., 2012) published a case study on the failure analysis of an onshore multiphase fluid pipeline (API 5L Grade A- PSL 1), where a fatal fire incident localized internal corrosion was reported at 12 o’clock and 6 o’clock position. It was reported that the intensity of internal corrosion was higher in the vicinity of weld at 6 o’clock position due to the created holes. They confirmed the results of laboratory investigations that two different corrosion mechanisms including MIC and localized corrosion of chloride have combined to cause severe corrosion at 6 o’clock position. Stratified flow regime and water accumulation and hold-up in the bottom of pipe over the length of the pipeline have provided an appropriate condition for deposition and growth of the bacteria colony (Talukdar et al., 2012).

Study of pitting morphology illustrated in Fig. 9 revealed that pits have sloped wall which is the typical representative of corrosion induced by sulfate reducing bacteria (SRB). Analysis of produced water presented the concentration of components including Sodium Chloride = 91688 mg/l, Bicarbonate = 610 mg/l, Calcium = 1880 mg/l and Magnesium = 508 mg/l. Measured pH of procured water was 6.5. They found that high water cut has intensified corrosion and due to high chloride concentration, the formation of protective FeCO3 scale is not favored. Overall, view of a pipe corroded by MIC mechanisms is indicated in Fig. 10.

2.4. Top of the line corrosion (TOLC)

This type of corrosion is attributed to water condensation at the top surface of pipeline internal typically between 10 and 2 o’clock positions. The condensed water chemistry is completely different from water existing in a bottom part of pipe (Nyborg and Dugstad, 2007; Pots and Hendriksen, 2000). Top-of-the-line corrosion (TOLC or TLC) mainly has been observed in wet-gas pipelines with a sweet hydrocarbon containing 500–3000 ppm organic acids in stratified flow regime. These acids are acetic acid, formic acid, propionic acid, and butanoic acid (Nyborg and Dugstad, 2007). Generally, factors impacting water condensation rate and consequently the top of line corrosion mechanism are gas flow rate, inlet temperature, flow regime, CO2 partial pressure in gas, and type and concentration of acid gasses (Nyborg and Dugstad, 2007). Temperature is the main factor determining the rate of water condensation in the pipeline. Hence, rapid temperature drop at initial sections of the pipeline can lead to this kind of corrosion. In addition, any location at which temperature drops below the dew point (loss of thermal insulation and concrete coating, river section, and immersed, buried or above ground pipeline exposed to low temperature) is a potential position for the top of the line corrosion. Fig. 11 displayed a schematic pattern of TOLC in a typical multiphase pipeline.
Common chemical reactions during top of line corrosion are as below:

\[ \text{Fe} + \text{H}_2\text{S} = \text{FeS} + \text{H}_2 \]  
(15)

\[ \text{Fe} + \text{CO}_2 + \text{H}_2\text{O} = \text{FeCO}_3 + \text{H}_2 \]  
(16)

\[ \text{Fe} + 2\text{HAc} = \text{Fe}^{2+} + \text{H}_2 + 2\text{Ac}^- \]  
(17)

\[ 2\text{Fe} + \text{O}_2 + 4\text{H}^+ \rightarrow 2\text{Fe}^{2+} + \text{H}_2 + 2\text{H}_2\text{O} \]  
(18)

TOLC typically takes place when water condensation rate exceeds 0.15 and 0.25 g/m²s. By applying the external thermal insulation, the gradient of temperature drop can be controlled and risk of TOLC is minimized. Insulation should be applied to the whole section of pipeline, which might be affected by TOLC. Thus, failures might be reported at portions of the pipeline with a damaged concrete coating or thermal insulation (Nyborg and Dugstad, 2007). In this regard, a special attention should be paid to the insulation of girth welds of the pipeline. Corrosion inhibitors are injected in the pipeline if condensation of water is unavoidable (Askari et al., 2018; Papavinasam, 2013).

In slug flow and annular flow regimes, corrosion inhibitors can wet the wall and control the corrosion in all orientations of pipe while in a stratified regime with the high gas flow and low liquid/gas ratio top of the line corrosion will be accelerated. It is because of not possibility of solving inhibitors in gas phase and touching the top of the pipe accordingly. High contents of CO₂ and organic acids can lead to high TOLC rates varying from 1 to 3 mm/y at high water condensation rate along the pipeline.

Nesic et al. (Kaewpradap et al., 2012, 2015; Pojtanabuntoeng et al., 2012; Singer et al., 2013; Vitse et al., 2003; Zhang et al., 2007) conducted several works to develop the mechanistic models of TOLC for prediction of general corrosion rate and a better understanding of relevant mechanisms. They studied the influence of the mass transfer in the condensed liquid film, saturation of the condensed liquid with the products of corrosion, and formation of an FeCO₃ scale. These researchers found that the protectiveness of FeCO₃ scale is associated with scaling tendency so that a full protection and coverage by the film can be provided in scaling tendency around 1 and tendency factor below 0.7, meaning that 70% of the surface is under coverage of iron carbonate scale. They also showed that for film wise condensation, corrosion rate drops slightly by increasing the thickness of condensed film due to a limitation in mass transfer of corrosive species to the wall. They modeled dropwise condensation based on the heat and mass transfer theory to predict the condensation rate. Finally, these authors verified their models with experimental data, achieving positive conformity.

One of the first corrosion failures with TOLC mode has been reported in the 1960’s for one of the pipelines in sour Lacq field in France (Estavoyer, 1981). The flow regime in this pipeline was stratified or stratified-wavy flow with a low flow velocity. The next failure reported in sour Crossfield pipeline, where the top of the line corrosion happened in low flow velocity and stratified-wavy flow regime (Bich and Szklarz, 1988). Despite the earlier reported TOLC cases for the sour pipeline, it is well understood that this kind of corrosion is mainly concerned about sweet gas streams where the partial pressure of CO₂ and organic acids are predominant agents for corrosion. Extensive works have been done on the mechanism of sweet TOLC and some models have been
developed for prediction of this type of corrosion [50–58].

Many researchers have studied the critical rate of water condensation that can initiate TOLC in gas pipelines (Jevremović et al., 2012; Li et al., 2017; Singer et al., 2013). They mostly believe that for the condensation rate less than 0.25 ml/(m².s), top of the line corrosion is not expected to occur (Larrey and Gunaltun, 2000; Smith and DeWaard, 2005).

At a low rate of condensation, pH of TOLC accumulated solution is increased because of the iron concentration and iron carbonate scale acting as a protective film. In comparison, at the high condensation rates, continuous removal of dissolved iron reduces the pH, resulting in instability of iron carbonate and therefore the high rate of corrosion by TOLC mechanism (Pugh et al., 2009a,b).

Pugh et al. (Pugh et al., 2009a,b) reported the results of in-line inspections (ILI) by magnetic flux leakage (MFL) which revealed some indications of TOLC in a large diameter carbon steel sour gas pipeline. The metal loss map obtained from ILI inspection (Fig. 12) illustrating the location and orientation of corrosion features concentrated at the upper half of pipeline. The location of detected TOLC was in areas with water condensation rate less than the mentioned critical rate for sweet TOLC. They concluded that sour TOLC cannot be predicted by sweet models and for the sour case the rate of TOLC is highly associated with temperature and its effect on sulfide scales rather than condensation rate in sweet cases. This difference can be seen in Fig. 13, where the sweet TOLC is detected at inlet section of pipeline with a high rate of water condensation. For all three pipelines (Laqc field, Crossfield, and pipeline studied by Pugh), gas flow rate was low so that corrosion inhibitor could not touch top surfaces of pipeline and not control TOLC accordingly.

TOLC failures of multiphase wet gas pipelines with wavy-stratified flow regime in the Tunu field, Kalimantan (Borneo) were studied by Gunaltun et al. (Yves et al., 1999). Wet gas and condensate from wellhead platforms (WP) are transported by the flow lines transport to satellite platforms (SP) and then to the treatment facilities. In spite of negligible internal corrosion measured by corrosion monitoring system, ILI inspection detected the severe top of line corrosion for two of Tunu flow lines. These lines are addressed in this paper as line A and line B. The length of TOLC affected region was reported from 10 to 100 m. Corroded areas were located on the unburied sections of pipes, in direct contact with river water. In these parts, rapid cooling causes a high rate of water condensation.

Recorded metal losses due to the internal corrosion by intelligent pigging for pipeline A and B are shown in Table 2. Note that no sign of internal corrosion was observed in the bottom of lines A and B.

Visual examination of removed piece of line A revealed that iron carbonate has covered the top section of line with several deep pits. Iron carbonate layer formation at the top of the line is probably because of the corrosion induced by condensed water droplets. These droplets, which have not flowed down under a gravity effect due to inadequate inclination, are then saturated with iron and pH increases from 4.1 for freshly formed water drop up to 5.2 for the saturated water.

Gunaltun et al. (Gunaltun et al., 2010) published in their other work the TOLC failure of offshore gas pipelines in Thailand, operating since 1992. In 2008, one leakage observed on the line-1 adjacent to a subsea flange connection with no coatings and two leakages were detected from line II at the anode pads (Fig. 14). For both lines, the TOLC (called here cold spot corrosion) occurred at a location with a high rate of water condensation. Corrosion control by inhibitors was inefficient due to the accumulation of corrosion products on the corroded sites. ILI results confirmed the TOLC configuration as summarized in Table 2.

Operating condition and mechanical datasheet of pipelines are indicated in Table 3. Condensation rate and corrosion rates were predicted by Topcorp model for pipeline A with and without polypropylene coating and results are summarized in Table 4. It is clear that condensation rate is much higher than the critical rate and consequently can increase the risk of TOLC failure if pipe is particularly in bare conditions.

The cause of actual case of TOLC failure on a pipeline (Fig. 15) was the condensation of water on the top of the pipe in the presence of carbon dioxide and volatile organic acids (acetic and formic acid).

Joosten et al. (2010) reported a TOLC failure for a sour gas pipeline in Canada with operation conditions specified in Table 5. The pipeline was fabricated from CSA Grade 359-line pipe with a nominal 6.625-inch O.D. and a wall thickness of 5.6 mm. This insulated buried pipeline was put in service in 2001 and severe rupture occurred in 2009. Methanol with 0.5% inhibitor has been used since 2005 in these pipes. Dehydration system was operated intermittently between 2001 and 2006 and it was permanently bypassed in 2006.

The resulting crater from rupture was roughly 5 m across and 2 m deep, while the length of the ruptured section was around 1 m (Fig. 16). As presented in Fig. 17, failure has been developed along the pipe at 12:00 o’clock position and has all the characteristics of a fast ductile fracture along a longitudinal corrosion-induced defect. No evidence of corrosion and metal loss was observed at 6:00 o’clock position. Black hue observed around the crater and the rupture point is iron sulfide and yellow color in the ruptured pipe can be attributed to elemental sulfur as a product of oxidation of iron sulfide after oxygen exposure. An indication of TOLC found detected by the visual assessment and MFL inspection is collected in Table 2.

Fig. 18 shows this failure from closer view where the thin and sharp edges of rupture and also the ductile shear failure is clearly seen. The XRD and EDS analyses confirmed the iron sulfide (Machinawite) as corrosion products.

The TOLC rate was modeled by TOPCORP V3.0 covering the three
main processes involved in TOLC including dropwise condensation, the chemical composition of condensed water, and corrosion rate. Operational data imported into the model resulted in a 0.001 ml/(m².s) water vapor condensation rate and 0.57 mm/y corrosion rate. This corrosion rate was very close to the rate that led to the failure of the pipeline after 8.6 years of operation. The calculated very low condensation rate and the rupture of this pipeline were in conflict with the basis previously mentioned regarding critical condensation rate (0.25 ml/(m².s)), indicating that for sour streams the risk of TOLC can be higher.

### 2.5. Under deposit corrosion (UDC)

Under deposit corrosion (UDC) is attributed to the localized corrosion that can develop under or around deposited components in the pipeline. Due to various aspects of this configuration #, there is not an individual definition and mechanism for this kind of corrosion.
Sour gas pipeline deposition of iron sulfide corrosion in the bottom of the line for sour hydrocarbon pipeline deposit on the bottom of the pipeline. Deposits can also increase the risk of corrosion mechanisms such as H2S corrosion, CO2 corrosion, MIC and etc. Sometimes, it is closely in relation and similarity with other corrosion mechanisms such as H2S corrosion, CO2 corrosion, MIC and etc. (Lepková and Gubner, 2010; Tajallipour et al., 2012; Tian and Cheng, 2008). Some eventual pipeline failures by UDC mechanism have been reported (Pandarinathan et al., 2013).

The frequently deposited materials in pipelines are a combination of silica sand (primary inorganic constituent), iron scales (oxides, sulfides and carbonates), clays, alumina, hydrated alumina, calcite, corrosion products, organic compounds, etc. (Pandarinathan et al., 2013). This bed of solids decreases inhibitor efficiency due to minimizing the access of corrosion inhibitor to the bottom surface of the pipeline and consequently severe localized attack in the form of pitting or crevice corrosion can occur. This type of corrosion is completely different from aqueous CO2 corrosion by the bulk of solution inside pipeline (Huang et al., 2010; Pedersen et al., 2008; Vera et al., 2012).

For sweet hydrocarbon pipelines, UDC induced CO2 corrosion is dominant when corrosion products, sand, wax and other solid particles deposit on the bottom of the pipeline. Deposits can also increase the risk of corrosion in the bottom of the line for sour hydrocarbon pipeline (Litke et al., 2013). For sour gas pipeline deposition of iron sulfide corrosion products can generate UDC (Standlee et al., 2011). Rippon (Rippon, 2005), based on his study on corrosion management of an offshore sour gas, stated that some gas reservoirs are not predicted to produce solids (carbonate reservoirs, no sand) and therefore the risk of UDC can be considered to be low under application of effective corrosion inhibitor that controls the level of iron sulfide corrosion products (Rippon, 2005).

Controlling water condensation from the vapor and minimizing free water in pipeline stream is vital for internal corrosion control. However, the general corrosion is not the only concern as the under deposit corrosion-induced by corrosion products, The serious hidden can is localized corrosion (Reza et al., 2012; Zhu et al., 2010). For a better understanding of UDC, it is highly important to analyze existing deposits in pipelines (Huang et al., 2010; Pedersen et al., 2008; Standlee et al., 2011; Tajallipour et al., 2012). The possible deposits are as follows:

- Inorganic deposits, which can be transported from the formation (e.g., sand), produced in the system due to corrosion (i.e., corrosion products such as iron sulfides, oxides and carbonate), precipitate from the water (i.e., scales such as calcium carbonate and barium sulfate, sulfur deposits).
- Organic deposits, which can precipitate from the crude oil (e.g., asphaltene, wax) or be formed on the surface due to microbiological activity (e.g. biofilms).
- The combination of different organic and inorganic deposits. For example, in produced water facilities, a thick black deposit known as “schmoo” may form and cover the entire internal surface of the pipe.

UDC mainly occurs in horizontal pipelines where the flow rate is not high enough to agitate the deposits and disperse them into the solution. Determination of the mechanism for this kind of corrosion is not simple due to variant shapes and structures of UDC, different metals (passive or active), types of deposits (reactive, inert), and corrosive species (O2, CO2, H2S, H+, microorganisms). Thus, most of the researchers, mainly have studied just the effects of UDC and loss of inhibitor efficiency in presence of deposits (Huang et al., 2010; Pedersen et al., 2008; Vera et al., 2012).

Huang et al. (2010) for understanding the mechanism of under inert deposit of CO2 corrosion studied experimentally the effects of deposit thickness and porosity, solution pH, and temperature by in-situ electrochemical techniques. They concluded that under inert deposits, general corrosion rate by CO2 is decreased by controlling both anodic and cathodic reactions. pH of bulk solution did not affect the rate of CO2 corrosion under inert solid deposits. Besides, UDC pH was more than that for the bulk of the solution.

Vera et al. (2012) proposed three different scenarios for UDC as below:

1. Coupling of anodic sites under deposits and uncovered sites acting as cathodic regions can cause UDC which preferably initiates from edge side of the deposit with the same mechanism as crevice corrosion, where different chemistry inside and outside the deposit creates galvanic driving force and an ionic path keeps on the electrochemical process. Due to the mentioned characteristic of this mechanism, this scenario of UDC will normally happen in pipeline.
streams with high water cut in which the electrolytic conductivity is high (Pedersen et al., 2008; Vera et al., 2012).

2. Local anodic and cathodic sites positioned under deposit and no external uncovered cathode exists. In this case, deposited solids create a special electrolyte with specific chemistry underside which will be appropriate media for pitting corrosion. Any local variation in chemistry raised from irregularity of deposits can separate localized anode and cathode.

3. In a third scenario, no local separation of anode and cathode is supposed to happen, and other agents like the presence of hygroscopic salts or clays may encourage under deposit corrosion under process conditions, where uncovered steel would not sustain corrosion.

The later scenario has also been addressed and confirmed by Litke et al. (2013). They noted in their work that salts like MgCl$_2$ and CaCl$_2$ have both hygroscopic and deliquescent nature and can absorb water from gas, even in pipelines with a low water cut and then form saturated brine solution which finally leads to the severe localized pitting corrosion. They developed a novel experimental test method for simulation of the deliquescence phenomenon in gas pipelines and proved their statement about the effects of hygroscopic salts on corrosion rate and pitting intensity.

Pandarinathan et al. (2013) studied the effect of mineral deposits of CO$_2$ corrosion on carbon steel in chloride containing environment by electrochemical, weight loss measurement, and surface analysis of corroded samples. They found that type and nature of mineral deposit (SiO$_2$, Al$_2$O$_3$, and CaCO$_3$) has a significant role on rate and morphology of corrosion. The surface of steel covered by mineral deposits experienced localized corrosion while the uncovered surface was corroded uniformly in brine solutions containing CO$_2$. The performance of corrosion inhibitor was depended on the nature of deposits and chemical composition of inhibitor (Pandarinathan et al., 2013). For uninhibited conditions, uniform corrosion rates for deposited surface were less than those of bare samples, indicating that deposited surfaces can act as a barrier against diffusion of corrosion agents.

2.6. Preferential weld corrosion (PWC)

Preferential weld corrosion (PWC) is a selective corrosion of weld
metal and heat-affected zone (HAZ) which are more active than base metal of pipeline to be corroded. PWC typically occurs when the weld area is exposed to corrosive environments, high temperature, and high flow rate. This kind of corrosion will further be intensified by the high flow velocity in pipelines and flow direction change in locations like seam welds, elbows, and reducers or expansions (http://www.sulphuric-acid.com/techmanual/Storage/storagetanks_welds.htm) in the pipeline (Meng and Jovancevic, 2008). PWC is one of the most challenging threats to the integrity of pipeline resulting premature failure (Dawson et al., 1999, 2010; Efird, 1991).

The exact mechanism of PWC is still unclear but it is widely accepted that through this corrosion the weld or HAZ area would be anodic to adjacent parent material and therefore result in severe localized corrosion by galvanic effect (Joosten et al., 1996; Lee and Woollin, 2005). A typical pattern of PWC is displayed in Fig. 19. Due to the complexity of involved phenomena, prediction of the rate of PWC and the exact location of corrosion (weld metal or HAZ) and effectiveness is impossible.

Primary factors affecting the preferential weld corrosion (PWC) in pipelines of oil and gas production and injection are weldment metallurgy, flow regime, type of inhibitor, and water salinity (Kermani and Smith, 1997). From an environmental point of view, factors influencing the CO2 corrosion control the severity and location of PWC. These factors are pH, the partial pressure of CO2, flow rate, flow velocity, flow regime, temperature, acetate content, etc. (Turgoose and Palmer, 2005).

In the late 1980s, based on several studies on the PWC in simulated sea water injection systems and in mildly sour service application, it was concluded that to minimize the risk of PWC in carbon steel, the nickel content of welding electrodes and fillers should be maximum 1% wt (Turgoose and Palmer, 2005). This criterion has been applied also for sweet conditions. Nevertheless, by considering the 1%wt. nickel restriction, most of the application are on the safe side from PWC, but some failures have been reported in the weld metal and HAZ region (Joosten et al., 1996). Moreover it has been proved that Nickel content more than the 1%wt. in low alloy steels decreases the resistance of steel to EAC caused by H2S (Jarvis and Bulloch, 1992).

Dugstad et al. (Singh, 1993) evaluated the effect of nickel content on corrosion of weldments by high-pressure flow loop tests at 60 °C, pH 4–6, and 0.2 MPa CO2 in chloride free environment. They proved that corrosion rate of the steels containing 1.4% and 3.35% Ni was much higher than that of low Ni steels with similar Cr contents which is in agreement with previous studies. Denpo et al. (Desimone et al., 2011b) supported this result by other tests in 10% NaCl solutions, 1 bar CO2, and 80 °C and concluded that by adding the Ni up to 1.7% the corrosion rate is doubled in comparison with nickel free API X65 pipeline carbon steel. Despite mentioned references, Gulbrandsen et al. (Gulbrandsen and Dugstad, 2005) noted that there is no general agreement about the effects of alloying elements and heat treatment on PWC. It has been reported that in the absence of proper inhibitor, Ni-alloyed welds can reduce the risk of PWC (Desimone et al., 2011a; Joosten et al., 1996; Mahajanam and Joosten, 2010; Mahajanam and Joosten, 2011; Martinez et al., 2011), except in low conductivity environments (Desimone et al., 2011a).

Through a joint industry research program, Lee et al. (Lee and Woollin, 2005) investigated the effect of weldment microstructure and composition on preferential weld corrosion in CO2 containing media for 12 weldments from X52 and X65 grades of pipeline material welded by Tungsten Inert Gas (TIG) and Manual Metal Arc (MMA) processes. They concluded that the addition of Ni and Si was detrimental to PWC while addition of Mo and Cr (up to 0.7%) did not improve the PWC behavior. The optimum resistance to PWC was achieved by autogenous weldments, made without filler additions, and by using matching composition consumables. They also found that unrefined microstructures with high hardness were harmful to PWC (Lee and Woollin, 2005).

Based on its characteristics, PWC can be categorized into preferential corrosion of the weld metal and preferential corrosion of the HAZ.

2.6.1. Preferential corrosion of the weld metal

There are differences in composition of welding electrodes and fillers from galvanic cells between subsequent passes and during remelting of root passes. Kermani et al. (Kermani and Smith, 1997) discussed on the potential variations which cause the development of small anode (weld metal) and large cathode (base metal) that can accelerate the corrosion of weld metal and generate cathodic reaction, which is rate-determining step here. Olsen et al. (Olsen et al., 1997) concluded that even in the case of same chemical and mechanical properties of weld and base metal, PWC is a concern due to flux covering the weld. They stated that rutile fluxes have more resistance to corrosion in comparison to basic fluxes. Moreover, the effect of chemical analysis of flux on raising the corrosion resistance is higher than that of post heat treatment of the weld.

Some researchers reported that adding small amounts of elements like Cr, Mo, V, Ti, Ni and Nb into fillers and electrodes can make the weld nobler by synergistic effects of elements, which can finally increase the resistance of weld metals against PWC (Lee and Woollin, 2005; Mahajanam and Joosten, 2011).

In the case of sweet corrosion process, the rate of PWC will be enhanced at low pH due to the increasing concentration of HCO3−. WELD corrosion will be also intensified in turbulent flow regime because of the high shear stress and increasing the mass transfer of corroding material. Preferential weld metal corrosion will be raised by increasing hardness, grain size, level of aligned second phase and a decreasing level of microstructure refinement of the root pass by the subsequent welding passes (Lee and Woollin, 2005).

2.6.2. Preferential corrosion of HAZ

Due to microstructural changes in heat affected zone (HAZ) during welding process, it has been reported that this zone can be corroded severely in aqueous media between pH range of 7–8 (Tebbal and
Hackerman, 1993). Small amounts (less than 0.1 wt%) of copper and nickel elements in parent metal and welding with a filler containing 1 wt% nickel will lead to self-corrosion of HAZ (Mahajanam and Joosten, 2011).

Under such conditions, weld metal and the parent metal areas will be very cathodic and then anodic sites are shifted to the HAZ area. De Waard (Hellberg and Zuberbuehler, 2014) also concluded that by the addition of Mn, Si, and carbon and controlling heat input to the low levels, the risk of PWC in HAZ can be minimized from metallurgical aspects.

Although the effect of microstructure on PWC is less than the composition, regarding to the HAZ corrosion, harder microstructures like martensite and bainite impose higher corrosion rates. It has been reported that by controlling the cooling rate of heat affected zone can reach a softer microstructure and avoid PWC in HAZ.

Lee et al. (Lee and Woollin, 2005) found out that preferential HAZ corrosion occurs in test conditions with 35 and 0.35 g/l NaCl, both at 60 °C and acidified with 1 bar CO2 when film formation happens on weld metal preferentially. They reported, not conclusively, that based on some evidence, the rate of preferential HAZ corrosion may be risen by increasing the hardness level in the HAZ.

Fig. 21 shows the preferential weld corrosion of a carbon steel flow line joint in a multiphase (oil/gas/water) offshore field. This pipe failed only after 15 days after production. The welding schedule of pipe was gas tungsten arc welding (GTAW) for root pass followed by flux-cored arc welding (FCAW) process. Fig. 20 shows PWC-induced failures in flowline section with pinhole leaks in the weld at an offshore field in the Gulf of Mexico after 30 months operation of carbon steel flowline (Mahajanam and Joosten, 2011).

Winning et al. (Alawadhi and Robinson, 2011) reported a PWC failure in multiphase production carbon steel pipeline transporting hydrocarbon and brine saturated with CO2 (Winning et al., 2004). Although nickel content of weld metal was more than 1%wt., galvanic effects of anodic and cathodic sites were the reason for severe PWC failure. Fig. 21 shows the failed pipe.

Internal corrosion in the form of metal loss on girth weld is apparent (Fig. 22) on process pipe near the flange neck. Modern techniques of inspection such as phased array technique are highly efficient methods to scan the whole weld and ensure the integrity of pipe.

Fig. 20. Corroded weld in a flowline section (Mahajanam and Joosten, 2011).
3. Environmental assisted cracking by wet H$_2$S

Environmental cracking of carbon steel pipeline in wet H$_2$S services is caused by the generation of atomic hydrogen as a byproduct of the corrosion reaction. The diffusion of atomic hydrogen into the steel can lead to different types of damages on steel. In presence of acid gases in pipeline fluid, atomic hydrogen can be produced by the following reaction:

$$\text{Fe} + 2\text{H}^+ \rightarrow \text{Fe}^{2+} + 2\text{H}_0$$  \hspace{1cm} (19)

Atomic hydrogen is sufficiently small in size to migrate into the steel structure. By recombination of atomic hydrogen inside the metal, hydrogen gas is produced as a potential agent of damage.

Some compounds such as sulfide (in the form of elemental or hydrogen sulfide), cyanides (e.g. HCN), and arsenates, recombination with poisons or catalyst poisons, impede or delay the conversion of atomic hydrogen to molecular hydrogen. In the case of mentioned poisons, atomic hydrogen concentration increases at the surface of steel leading to the enhanced volume of hydrogen diffusion into the metal (Heidersbach, 2010; Kane and Cayard, 1999; Ossai et al., 2015). Atomic hydrogen can diffuse through solid steel at rates of several cubic centimeters per square centimeter per day.

This elevated concentration of atomic hydrogen can affect the steel in several ways:

1) The hydrogen atoms are recombined at inclusions and laminations to form molecular hydrogen, which due to their large size cannot release out from the steel and will be trapped inside. By increasing the pressure buildup caused by hydrogen molecules accumulation in trapped location, steel will be subjected to bulging and blistering.

II) Where laminations on parallel planes are connected together by cracks in the through-thickness direction, the mode of failure is called hydrogen induced cracking (HIC) and where a stacked arrangement of short laminations is oriented across of a sulfide stress crack, the crack will be propagated further by Stress-Oriented hydrogen induced cracking (SOHIC) mechanism.

III) High strength pipelines and hard spots (locations with high hardness) are susceptible to direct embrittlement by a high concentration of atomic hydrogen. This kind of cracking, initiated and propagated under applied or residual tensile stress, is called as sulfide Stress Cracking (SSC) that is a frequent threat for heat affected zones in low strength steels, which have not been heat treated after welding (PWHT).

Therefore, any of mentioned forms of wet H$_2$S cracking will happen if all three below mentioned conditions are met:

- An electrochemical corrosion reaction which produces hydrogen atoms;
- An environment which retards reduction of H$^+$ to molecular hydrogen to keep it in atomic size and increases the rate of absorption of atomic hydrogen into the steel. The most common media in oil and gas pipeline which fulfill these specifications is hydrogen sulfide (H$_2$S); and
- A susceptible microstructure.

The two types of more common failures in pipelines by H$_2$S cracking with a brief description and relevant affecting parameters are presented in Fig. 23. The various wet H$_2$S damage mechanisms are discussed in greater detail in the following sections.

4.1. Hydrogen induced cracking (HIC)

Hydrogen induced cracking (HIC) is a dominant failure mode in susceptible pipelines when diffused atoms become trapped and produce H$_2$ molecules (in a gaseous state) at inhomogeneities of steel. Favorable trap sites are typically found along elongated inclusions or segregated bands typical of rolled product such as a plate. Hence, entrapment of H$_2$ results in formation of planar gas-filled defects which grow parallel to the pipe surfaces. If the defects propagate adequately in size, they may develop into a blister (Elboujdaini and Revie, 2009; Krom et al., 1997; Ossai et al., 2015; Venegas et al., 2011).

HIC is not as rapid as Sulfide Stress Cracking, the time from crack initiation to failure is generally several years. Therefore, precautions need only be taken for equipment which is continually exposed to sour...
product for long periods while the occasional exposure during start up or during fault conditions will not generally cause a problem.

The source of hydrogen atom is normally as following reactions which are the most accepted ones for the exposed carbon steel (Kim et al., 2008):

Anodic reaction: \( \text{Fe} \rightarrow \text{Fe}^{2+} + 2e^- \) (20)

Dissociation reactions: \( \text{H}_2\text{S} \rightarrow \text{H}^+ + \text{HS}^- \) (21)
\( \text{HS}^- \rightarrow \text{H}^+ + \text{S}^{2-} \) (22)

Cathodic reaction \( 2\text{H}^+ + 2e^- \rightarrow \text{2H}_2 \) (atomic hydrogen) (23)
\( 2\text{H}_2 \rightarrow \text{H}_2 \) (molecular hydrogen) (24)

From another viewpoint, HIC is the cracking that links hydrogen blisters or laminations at different planes in the metal. HIC cracking requires no externally applied stress (Hara et al., 2004; Kane and Cayard, 1999). Instead, these cracks are driven by stresses from the internal buildup of hydrogen at blisters. HIC is sometimes called stepwise cracking, in reference to its appearance. Since HIC is closely associated with blistering, it occurs most frequently in steels with high levels of sulfide inclusions. It is also associated with steels in which manganese segregation and a banded microstructure are observed. The resistance of a steel to HIC can be greatly increased by reducing sulfur levels, and by controlling the shape of sulfide inclusions through the use of calcium or rare earth additions to produce spherical inclusions rather than flattened ones (Epelboin et al., 1972; Askari et al., 2010; Mansfield, 1981). The sulfur content below 0.003 wt% in flat-rolled steel used in most of the pipelines can minimize the risk of hydrogen induced cracking and for seamless pipes (2015; Askari et al., 2010).

Elboujdaini et al. (Elboujdaini and Revie, 2009) investigated the effects of metallurgical factors in SSC and HIC. Based on their study, it can be stated that metallic inclusions increase the susceptibility of steel to HIC.

Effect of environmental parameters (pH and partial pressure of \( \text{H}_2\text{S} \)) and metallurgical factors (microstructure and inclusions) on hydrogen induced cracking of HSLA steels was also studied by Wan et al. (Kim et al., 2008). They concluded that among the environmental factors, the effect of \( \text{P}_{\text{H}_2\text{S}} \) is higher than pH on the susceptibility of steel. The explanation for such conclusion is the significant influence of \( \text{H}_2\text{S} \) on the inhibition of atomic hydrogen recombination to produce molecular hydrogen which is high enough to not diffuse into the steel structure. For initiation of hydrogen induced cracks, the rate of diffusible hydrogen trapped in steels has a higher importance than the permeated hydrogen flux through the steel. By metallurgical investigations, they also concluded that any cluster or oxide inclusion bigger than 20 μm in length will be detrimental to carbon steel with bainitic ferrite (BF) phase to be failed by HIC damage. It was also found that in the HSLA steels, in hard microstructures such as martensite and austenite (M/A) constituents, HIC cracks propagate with quasi-cleavage mode. Fig. 24 shows the process of crack propagation in different microstructures. They recommended restricting the formation of BF and MA phases by a thermomechanical process in HSLA steel.

Domizzi et al. (2001) studied the HIC susceptibility of different samples of pipelines with different sulfur contents and inclusion distributions by an ultrasonic method. They showed that to achieve a good resistance to HIC, it is not always mandatory to have extremely low sulfur steel when microstructure of steel is free of hard bands. Based on this provision, they proposed a relationship for calculation of average sulfide length, with a low susceptibility to HIC. They found step wise cracking by SEM examinations as pictured in Fig. 25.

From a different viewpoint, the hydrogen induced cracking behavior of API 5L X60 and X70 pipeline steels is compared by HIC testing, hydrogen microprint technique (HMT) test data, and SEM investigations [115]. It was recognized that trapping sites and reversible trapping sites in X70 are higher than those in X60 and consequently higher concentration of hydrogen charging and mobile hydrogen facilitates the crack growth. Hydrogen induced cracking testing showed X70 is more susceptible to HIC than X60. No MnS inclusion was found in X60 based on SEM and EDX assessment while in X70 the role of MnS was apparent and proved with elemental analysis. Authors have also observed a
relation between HIC susceptibility and hardness level in which the higher hardness can induce more susceptibility to HIC in carbon steels [115]. This conclusion can be a matter of challenge as it was previously believed that hardness is a concern just for stress incorporated cracking like SSC discussed in the next section.

Masouri et al. (Askari et al., 2010) reported a case study of API 5L X52 gas pipeline failure in H2S-containing production fluids. Their failure analysis showed that hydrogen induced cracking (HIC) was the cause of pipeline rupture. They discussed on the supplementary requirements which can prohibit the failure of ERW pipeline in sour service and make pipeline more reliable in H2S media. Pipeline was installed from Wellhead Separators to Gas Injection Station with the length of 40 km from API ERW pipes (size: 8″, thickness: 7.1 mm). Pipeline operation condition and chemical composition of fluid are mentioned in Table 6. In Nov 2005, the pipeline was commissioned by above-mentioned stream and after 4 days of operation it failed in distance 1350 m from Separator at 2 o’clock position between welds No.112 and 113 (Fig. 26-a). After repair and re-commissioning the line, it burst again in distance between welds No.131 and 132 from the separator, 250 m away from the first failure and again at 2 O’clock position (Fig. 26-b). These two failure cases urged to stop production completely and take a safe repair plan in summer 2006 including cutting out 28 branches of existing pipes (7 branches near separator and 21 in location between two occurred failures) to be replaced by SMLS pipes.

Finally, after taken remedial actions and replacing the pipes with the highest failure probability, hydrostatic tests were done successfully and dewatering pigging operations were carried out with 500 psi pressure of sour gas from the separator. However, another failure occurred in distance 350 m away the second failure between weld numbers 157 and 158 at 2 o’clock same as two earlier failures. Fig. 27a and b illustrate an actual view of the third failure.

The chemical composition of the failed pipes showed that they are in the API 5L range. The analysis is reported in Table 7.

Metallographic assessments were executed on specimens taken from failed pipes. Ferrite-Perlite microstructure was observed by Nital reagent. Microscopic observations showed that cracks have been initiated from welds (due to the electrical resistance welds of pipes). These experiments revealed significant segregation in base metal and welds. Fig. 28a and b shows clearly the segregation in the weld and stepwise cracking of pipes occurred by HIC mechanism due to the effects of H2S.

Further, typical examples of hydrogen induced cracking (HIC) in an oil pipeline are shown in Figs. 29 and 30.

### 4.2. Sulphide stress corrosion cracking (SSC)

According to the definition of ISO15156/NACE MR 0175, SSC is “cracking of metal involving corrosion and tensile stress (residual and/ or applied) in the presence of water and H2S” (2015).

SSC is a form of hydrogen stress cracking (HSC) which is the result of embrittlement of the metal by atomic hydrogen produced by the cathodic reaction in sour media. Hydrogen sulfide as a cathodic poison inhibits the formation of molecular hydrogen in cathodic reaction. Therefore, atomic hydrogen can diffuse into the metal, remain in solid solution in the crystal lattice, and consequently reduce ductility and deformability which causes increase in susceptibility to stress cracking (2009; 2015; Kane and Cayard, 1999; Ossai et al., 2015; Papavinasam, 2013). Under tensile stress, whether applied or residual, cracking initsiate in embrittled to form sulphide stress cracks. SSC can occur in carbon steel, low alloy steel, and corrosion resistant alloys. In the case of carbon steel pipelines, the high-strength grades of line pipes and hard weld zones are more susceptible to SSC. The tendency for SSC to occur in steels is a function of the material type, condition, tensile stress level, partial pressure of H2S, system pH, and the presence of chlorides. Kermani (Kermani and Chevrot, 2014) pointed out that the primary
parameters influencing the SSC are pH, the partial pressure of H$_2$S, temperature, and metallurgy of steel.

SSC in the pipeline can have two aspects including internal SSC, the most common type which is associated with a pipeline carrying wet sour fluid and external SSC. The later type is relevant to pipelines buried with SRB contaminated soils or submerged in water with SRB which can be a concern for sea lines in seabed or mud environment. This type of SSC is not common and rarely has been reported.

Microstructure including hard zones, high strength, uncontrolled martensite or bainite, inclusions as oxide and sulfide type, and impurities such as C, Mn, P can increase the susceptibility of carbon steels to SSC in the presence of residual or applied stress and wet H$_2$S environment (Al-Mansour et al., 2009; Astafjev et al., 1993; Dapeng et al., 2014; Forero et al., 2014; Gomez et al., 2003; Huang et al., 2014; Kim et al., 2010; Li et al., 2015; Singha and Quraishi, 2015).

The threshold conditions above which precautions have to be taken to avoid SSC are defined in NACE standard MR 0175/ISO 15156.

Precautions to prevent SSC must be taken when the partial pressure of H$_2$S in the gas phase is equal or greater than 0.3 kPa (0.05 psi/0.003 bar) as defined in NACE MR 0175/ISO 15156 (2015).

According to NACE MR0175/ISO 15156-2, regarding to the carbon steel and low alloy steel, three aspects including material composition, heat treatment, and hardness shall be considered and some conditions (Table 8) shall be met to minimize the potential of sulfide stress corrosion cracking. Maximum acceptable hardness for carbon steels, C-Mn steels, and low alloy steel, is 22 HRC for weld root, base metal, and HAZ and weld cap (2015). These criteria have been specified also by EFC 16 document (2009).

### Table 7

<table>
<thead>
<tr>
<th></th>
<th>C</th>
<th>Mn</th>
<th>P</th>
<th>S</th>
<th>Si</th>
<th>Fe</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sample (Failure 1)</td>
<td>0.11</td>
<td>1.29</td>
<td>0.017</td>
<td>0.004</td>
<td>Base</td>
<td></td>
</tr>
<tr>
<td>Sample (Failure 3)</td>
<td>0.11</td>
<td>1.30</td>
<td>0.014</td>
<td>0.004</td>
<td>0.22</td>
<td>Base</td>
</tr>
<tr>
<td>API 5L/X52</td>
<td>0.28 max</td>
<td>1.35 max</td>
<td>0.030 max</td>
<td>0.030 max</td>
<td>–</td>
<td>Base</td>
</tr>
</tbody>
</table>

Precautions to prevent SSC must be taken when the partial pressure of H$_2$S in the gas phase is equal or greater than 0.3 kPa (0.05 psi/0.003 bar) as defined in NACE MR 0175/ISO 15156 (2015).

According to NACE MR0175/ISO 15156-2, regarding to the carbon steel and low alloy steel, three aspects including material composition, heat treatment, and hardness shall be considered and some conditions (Table 8) shall be met to minimize the potential of sulfide stress corrosion cracking. Maximum acceptable hardness for carbon steels, C-Mn steels, and low alloy steel, is 22 HRC for weld root, base metal, and HAZ and weld cap (2015). These criteria have been specified also by EFC 16 document (2009).

![Fig. 26. As received failed pipe: a) first failure and b) second failure (Askari et al., 2010).](image1)

![Fig. 27. a) General view of location of the pipe failure and b) As-received pipe after third failure (Askari et al., 2010).](image2)

![Fig. 28. a) segregation of weld and b) HIC cracking of failed pipeline (Askari et al., 2010).](image3)

![Fig. 29. Hydrogen induced cracking (HIC) of an oil pipeline. Source: http://faculty.kfupm.edu.sa](image4)
It shall be noted that even though measurement of hardness is an essential criterion to prevent cracking, it is not enough to guarantee the cracking in any condition as some failures have been reported for cases which hardness requirement fulfilled (Masouri, 2003; Masouri and Zafari, 2004).

Sulfi de stress cracking (SSC) happens very quickly, with the time from crack initiation to failure sometimes being measured in hours. This kind of cracking must considered in lines which are typically non sour but occasionally during startup/shut down or during upset conditions the equipment may temporarily expose to wet H2S above the NACE MR0175/ISO 15156 threshold. This also applies to lines which have H2S above NACE MR0175/ISO 15156 threshold as well as those that are normally dry. Considering the high speed of SSC, ingress of moisture during all possible operational, upset, and maintenance conditions so that even hydro testing must be considered.

Fig. 31 shows schematically the nucleation and growth of SSC. Sulfi de stress cracks can be developed within 5 following steps:

1. Cathodic reduction of hydrogen;
2. Adsorption of hydrogen atoms;
3. Diffusion into the metal;
4. Trapping of atomic hydrogen in dislocations; and
5. Propagation of SSC cracks along carbides at grain boundaries.

Weld heat affected zones are the common locations for SSC, even in nominally low strength steel, particularly for single pass fi llet weld attachments, which are usually made with low heat input and without preheating of the base metal. Welding heats a narrow band of base metal into the austenitizing temperature range, and the subsequent rapid cooling can leave a hard zone adjacent to the weld. Weld heat input, steel composition, thickness, preheat temperature, and other factors affect whether this will occur on any given weldment. On multipass welds, the root passes and fi ll passes are tempered by the heat
of the subsequent passes, leaving only the HAZ of the cap pass in the untempered and therefore most vulnerable condition. Post weld heat treatment reduces weld HAZ hardness and virtually eliminates SSC in most refinery steels. However, microalloying elements such as Nb or V can cause steels to be resistant to tempering and to retain high HAZ hardness even after PWHT.

Masouri et al. (2008) reported SSC cracking failure on API 5L-X52 6in pipeline only after two weeks of operation with 1200 psi pressure.

<table>
<thead>
<tr>
<th>Table 9</th>
<th>Operating conditions of failed pipeline.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total pressure</td>
<td>Temperature</td>
</tr>
<tr>
<td>390 psig</td>
<td>52 °F</td>
</tr>
</tbody>
</table>

Fig. 33. Microscopic image of transgranular and branched crack (Masouri et al., 2008).

Fig. 34. Severe SSC on a non-NACE grade steel (Chong et al., 2014).

Fig. 35. Longitudinal section of an X100 specimen loaded at 65%YS showing the main SSC crack (right of image) and small microcracks (left of image) (Al-Mansour et al., 2009).

Fig. 36. Stress Orientated Hydrogen Induced Cracking (SOHIC) adjacent to a girth weld (Fowler, 2010).

Fig. 37. Ring cut from failed spiral pipe showing the compressive macroscopic residual stress (James and Hudgins, 2016).
The failed pipeline was designed to transport sour crude oil containing 1.2% CO₂ and 2.5% H₂S. The line pipes meet NACE requirements of sour service, and no crack or defect was detected after 100% UT by the manufacturer. Moreover, hydrostatic tests have been done at 3300 psi pressure by proof ring test as per NACE TM0177. They found that X100 line pipe material is susceptible to SSC in applied tensile stress equivalent to 46% yield strength. They concluded that cracks have been nucleated by pitting generated due to the high corrosion rate (97 mpy), which increased the rate of migration and diffusion of hydrogen into steel. Moreover, hydrogen embrittlement has been promoted due to the inhomogeneous microstructure of X100 material. Microscopic image of SSC crack is presented in Fig. 35 (Al-Mansour et al., 2009).

### 4.3. Stress oriented hydrogen induced cracking (SOHIC)

SOHIC is defined as SOHIC in which hydrogen induced blistering (HIBC) and cracks are formed parallel to the applied/residual tensile stress and by the interconnection of these cracks SOHIC is propagated perpendicular to applied/residual tensile stress. Type II SSC is attributed to hydrogen embrittlement (Kim et al., 2010).

Some researchers state that SOHIC is a particular form of HIC in the presence of stress and mainly develops near to weld zone because of the residual stresses. HIC and SOHIC are similar from two aspects: I) Hydrogen blisters are formed due to the internal pressures and II) After nucleation of cracks, both HIC and HIBC (in SOHIC) are propagated in the direction of rolling (Kim et al., 2010).

It should be highlighted that both groups of material either resistant to HIC or susceptible to HIC are prone to SOHIC. In this regard, Pargeter (2015) studied the SSC of API-X100 and evaluated SSC has been also reported by Chong et al. (2014) on a Non-NACE grade welded coupons illustrated in Fig. 34.

<table>
<thead>
<tr>
<th>Table 10</th>
<th>Mechanical properties failed pipe and un-failed pipe.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Residual stress</td>
</tr>
<tr>
<td>Filed pipe</td>
<td>For ID surface:</td>
</tr>
<tr>
<td>(not- cold expanded)</td>
<td>-Centerline of weld: 82 ksi</td>
</tr>
<tr>
<td></td>
<td>-HAZ: 72 ksi</td>
</tr>
<tr>
<td></td>
<td>-Far field: 6 ksi</td>
</tr>
<tr>
<td>Not failed pipe</td>
<td>For OD surface:</td>
</tr>
<tr>
<td>(cold expanded)</td>
<td>-Centerline of weld: 19 ksi</td>
</tr>
<tr>
<td></td>
<td>– 1/16 in from weld: 16 ksi</td>
</tr>
</tbody>
</table>

The failed pipeline was designed to transport sour crude oil containing 1.2% CO₂ and 2.5% H₂S. The line pipes meet NACE requirements of sour service, and no crack or defect was detected after 100% UT by the manufacturer. Moreover, hydrostatic tests have been done at 3300 psi pressure by proof ring test as per NACE TM0177. They found that X100 line pipe material is susceptible to SSC in applied tensile stress equivalent to 46% yield strength. They concluded that cracks have been nucleated by pitting generated due to the high corrosion rate (97 mpy), which increased the rate of migration and diffusion of hydrogen into steel. Moreover, hydrogen embrittlement has been promoted due to the inhomogeneous microstructure of X100 material. Microscopic image of SSC crack is presented in Fig. 35 (Al-Mansour et al., 2009).

Fig. 39. SOHIC at the tip of one crack showing stacking of cracks perpendicular to the applied stress. As polished, Magnification: 50X (James and Hudgins, 2016).

Fig. 38. Locations of SOHIC cracks were 0.2–0.5 in. away from the weld (James and Hudgins, 2016).
(2007) reported that there is no certainty about the correspondence between HIC resistance and SOHIC resistance. Therefore, even in the absence of any inclusion and in high levels of metallurgical cleanliness, high stress regions adjacent to weld seam can provide proper locations for the accumulation of hydrogen. Consequently, rapid through-thickness HIC cracking in stepwise pattern will propagate perpendicular to the direction of tensile stress (Al-Anezi et al., 1999; James and Hudgins, 2016).

Depending on different pipe manufacturing process, the level of susceptibility to SOHIC is varied. Since this failure mode is mostly concentrated around weld line, the weld will be a weak point for this cracking as is for SSC. The pipe fabrication with more weld line is further risky for stress relevant H₂S assisted cracking. Stress revealing by heat treatment can lessen the risk of SOHIC (James and Hudgins, 2016; Kim et al., 2010; Kobayashi et al., 2014). For longitudinally welded pipes, SOHIC has been reported in parent metal of pipes and in pressure vessels it has been observed in HAZ. Due to the participation of stress in the development of cracks, SOHIC is not a common phenomenon for low-strength ferritic pipe and pressure vessel steels (2015).

Regarding SOHIC, spiral welded pipes are more prone due to the highly stressed region during edge forming and welding activates for non-cold-expanded pipes. Heat treatment of spiral welded pipelines is economically justified and moreover mechanical properties and dimensional integrity like straightness and roundness will be negatively affected (Al-Anezi et al., 1999; James and Hudgins, 2016).

Fig. 37 shows the failure of a 24-in API-X52 pipeline fabricated by spiral weld process from HIC resistance plates only after 7 months operation in sour service. Operating conditions of the pipeline are presented in Table 9.

The pipe was not originally cold expanded or stress relieved to minimize residual stresses during welding or manufacturing. As presented in Fig. 38, long crack is parallel to weld line with 0.2-0.5 in away from the seam. Through observation by microscopic examination revealed SOHIC cracking mode including stacked arrangement of HIC-like cracks along with the rolling direction of the plate and connected together by micro-cracks perpendicular to stress direction as shown in Fig. 39.

Mechanical properties including residual stress analysis and hardness measurement were conducted on failed pipe and un-failed pipe which was originally cold expanded. The results are presented in Table 10.

Chemical analysis of corrosion products detected 10% elemental sulfur and inclusion analysis around crack by electron probes indicated oxides of calcium and aluminum.

Carneiro et al. (2003) studied the influence of chemical composition and microstructure of API line pipe steels on HIC and SSC by executing laboratory tests based on NACE TM0284 and TM0177 test procedures. For a typical pipe steel with chemical analysis in the range of API X60 grade in presence of applied stress equal to 100% YS of steel, SOHIC cracks were detected in some three steps. Firstly, HIC cracks nucleated from imperfection and then propagated parallel to stress direction. The applied tensile stress raised the internal stress around HIC cracks causing localized yielding which led to the initiation of secondary cracking perpendicular to applied stress direction. Stress field of developed cracks produced deformation bands which then merged the crack edges and induce nucleation of small HIC cracks in deformation bands. Small cracks linked two HIC main cracks and by repetition of this process consequently generate SOHIC cracks. Fig. 40 shows all steps of nucleation to the propagation of cracks.

5. Conclusions

Internal corrosion is the most predominant cause of pipeline failures in comparison with other failure modes. Due to the connections between internal corrosion and electrochemical, mechanical, metallurgical, hydrodynamic and chemical parameters, understanding of exact mechanisms and concerned issues is still challenging. Since many points can be concluded from each section of this work, just some highlighted conclusions for each corrosion/cracking mode are presented in the following.
- Influencing parameters in corrosion of upstream hydrocarbon pipelines in a wet scheme are acid gases (H₂S and CO₂), organic acids, chloride ions, water cut, flow regime, temperature, and pressure.
- Mechanism of CO₂ corrosion changes from pitting to mesa attack and then to flow induced localized corrosion with increasing the flow velocity inside the pipeline.
- Microbial-influenced corrosion usually occurs as with the localized pattern and mainly in stagnant conditions of flow inside pipeline than can cause severe pitting at bottom sites in the pipeline. Water hold-ups and stratified flow regime provide prone conditions for deposition and bacterial growth.
- Top of line corrosion is mainly concerned for stratified flow regimes. TOLC can be controlled for sweet hydrocarbon pipelines if water condensation rate is kept below 0.25 g/m²s. In comparison, for sour gas pipelines, TOLC was reported at much lower rates of water condensation. Any sharp temperature fall and presence of organic acids can activate the risk of TOLC for all systems. ILI was proved as a reliable technique for detection of TOLC.
- Under deposit corrosion is predominant when pipeline flow rate is not high enough to agitate the deposits and disperse them in solution and deposited materials minimize the access of corrosion inhibitor to the bottom surface of the pipeline. UDC is the localized attack in the form of pitting or crevice.
- Galvanic effects between weld/HAZ and the adjacent base is the most accepted mechanism for preferential weld corrosion. Primary influencing factors are weldment metallurgy, flow regime, type of inhibitor, and water salinity. The risk of PWC can be minimized by controlling the nickel content of welding electrodes and fillers below 1%wt. PWC is categorized into two types, for weld metal, and for HAZ and each has different aspects in the mechanism.
- In sour streams and in fluids containing cathodic poisons, hydrogen atoms can be trapped in pipe wall metallurgical defects such as elongated inclusions or segregated bands and produce H₂ molecules (in a gaseous state) which can cause hydrogen induced cracking, either planar or stepwise. This kind of cracking does not need the stress. The impact of H₂S concentration is higher than pH. Steels with lower strength are more prone to HIC, SWC and hydrogen blistering.
- HIC is not as rapid as Sulfide Stress Cracking The internal build up pressure of entrapped hydrogen gas inside inclusions and inhomogeneity can be high enough to cause cracking or blistering these steels. By reducing sulfur levels and spherodizing the sulfide inclusions by calcium treatment, the risk of HIC can be minimized.
- SSC is a rapid failure in carbon steel pipeline which is the result of corrosion and stress (applied or residual) in H₂S containing service. The primary influencing parameters on SSC include pH, the partial pressure of H₂S, temperature, and metallurgy of steel. SSC, which is mostly relevant to high strength steels and structure with high hardness, can be prevented by following the requirements of ISO 15156/NACE MR0175.
- SOHIC is a type of SSC resulted from external tensile stress and local strain around hydrogen induced cracks. This cracking is the combination effects of H₂S and tensile stresses in either applied or residual from. Materials either resistant to HIC or susceptible to HIC are prone to SOHIC and even in the case of high levels of metallurgical cleanliness, SOHIC can be a risk.

References


International,