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Analysis of The Causes of Failure in The Crude Oil Transmission of PT PQR: Segment BS CLM–BS CMS

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ABSTRAK

The pipeline refers to the API 5L Grade B standard and has a diameter of 8 inches and a total length of 212 km. The design life of the pipeline is 20 years. However, after being in operation, it experienced two leak incidents in the same segment within one year. This condition disrupted the oil delivery from PT PQR's field. Therefore, a study is needed to determine the causes of the pipeline's failure before reaching its design life. The investigation involved visual observation of the pipeline samples, pipe thickness testing, chemical composition testing, and microstructural analysis of the leakage area. In addition, characterization tests were conducted on the elements that were present in the corrosion product deposits. Process fluid testing was also performed to determine the anion, cation, and scale formation tendency based on Valone & Skillern's guidelines. The results showed visual thinning on the inner surface of the pipeline at the 6 o'clock position. Chemical composition testing revealed no differences from the standard API 5L Grade B composition. SEM analysis in the leakage area identified corrosion morphology caused by dissolved CO2. XRD analysis of the corrosion deposits indicated the presence of siderite (Fe2CO3), hematite (Fe3O4), and iron (Fe) compounds. The pipeline failure occurred due to the presence of corrosive substances, specifically produced water. This condition caused the pipe surface at the 6 o'clock position to be exposed to produced water, initiating the formation of hydrogen ions *(H^+)* and bicarbonate ions *(HCO_3^-).*

1. INTRODUCTION

PT PQR is a subsidiary of PT Pertamina (Persero) and part of the Upstream Subholding, managing crude oil transportation using a trunkline that spans 212 kms. This trunkline plays a vital role in transporting crude oil from the fields to the Gathering Terminal, where it undergoes shipping processes. The trunkline is generally made of carbon steel material, adhering to the API 5L Grade B standard. This material is chosen due to its good mechanical properties and ample availability domestically. However, it has a relatively low resistance to corrosion [1]

The transportation of crude oil that still contains produced water also affects the corrosion rate in transmission pipelines, leading to internal corrosion. This internal corrosion is caused by the presence of corrosive compounds such as CO_2, H_2S, and Cl^- in the process fluid solution [2]. These compounds dissolve in the liquid phase and can accelerate the corrosion process on carbon steel materials [3]. Formation water is a byproduct fluid that is transported along with crude oil during the fluid delivery process from oil wells. Therefore, during transportation, a separation process between crude oil and produced water is commonly carried out (Nasrazadani et al., 2018). Produced water contains dissolved Cl^- and CO_2 compounds, which can cause corrosion on the surface of transmission pipelines [5]
Based on internal data from PT PQR, the asset owner, there were two pipeline failures along the segment during 2014. These incidents resulted in production losses and environmental pollution management costs, which have become a significant concern for management. Therefore, an analysis of the causes of

these failures is necessary to address the issue effectively. The objective is to identify the root cause of these incidents to prevent similar occurrences in the future. Based on the current situation, further investigation is required, focusing on pipeline design, pipeline material data, fabrication data, thickness measurements, and fluid analysis.

2. RESEARCH METHODS

This descriptive study employs a case study approach. The research was conducted by testing pipeline samples that did not fail and those that failed at the KM 14 point. The testing process was categorized into two main areas: fluid analysis and pipeline material characterization. Each test was carried out in accordance with relevant technical standards [12], or, when unavailable, validated laboratory procedures were applied [2], [9].

The process began with the analysis of produced fluid composition, with the primary aim of identifying dissolved ionic species that may act as corrosive agents within the pipeline environment. Rather than focusing on gaseous compounds such as CO_2 and H_2S, which were not part of this analysis, the study emphasized the detection of aggressive anions and reactive cations that are commonly associated with corrosion processes, particularly in oil and gas pipelines [2], [6].

This was followed by a detailed produced water analysis, which plays a crucial role in evaluating the corrosivity of formation water that is transported alongside crude oil. The parameters assessed included chloride (Cl^-), sulfate (SO_4^{2-}), bicarbonate (HCO_3^-), carbonate (CO_3^{2-}), sodium (Na^+), calcium (Ca^{2+}), magnesium (Mg^{2+}), and iron (Fe^{2+}). These ions are known to significantly influence the electrochemical conditions that drive corrosion [5], [8].

On the material side, visual inspection of the pipeline was performed using thickness meter. Where measurements were taken at four points along a distance of 12 meters. The thickness measurements were conducted at positions 0°, 3°, 6°, and 9° around the circumference of the pipeline. The detailed description and locations of the thickness measurement points are illustrated in Figure 2, which depicts a sketch of the measurement points on the failed pipeline. The measurements were conducted using an ultrasonic thickness gauge, and the results showed a significant reduction in thickness in the leak-prone areas (6 o'clock and 9 o'clock positions) compared to the pipeline's nominal thickness.

To identify corrosion products and deposits, X-Ray Diffraction (XRD) analysis was conducted. This test helps determine the crystalline phases present in the corrosion scale, such as iron oxides and salts [9], [13]. Metallographic examination followed, involving sample preparation (mounting, grinding, polishing, and etching) to observe the microstructure of the steel. This procedure reveals grain boundaries, phase distribution, and potential micro-cracks [4], [16]. Further examination was performed using a Scanning Electron Microscope (SEM), coupled with Energy Dispersive X-ray (EDX) analysis, to investigate the surface morphology and identify elemental distribution in localized corrosion areas [9].

Finally, a tensile test was carried out to measure the ultimate tensile strength, yield strength, and elongation of the material. This test is essential in evaluating the extent of mechanical degradation caused by corrosion [1], [3], [17]. The findings from all tests were compiled and analyzed during the results and discussion phase to determine the key factors contributing to pipeline failure. This comprehensive approach has been widely applied in previous pipeline failure investigations [2], [4], [5], [14]. For a detailed explanation of the research methodology, please refer to the Figure 1 and the specifications and operating conditions of the Trunkline segment BS CLM – BS CMS are outlined in Table 1.

Table 1. Operational Data and Pipeline Dimensions

Spesifikasi		Details
Material	:	API 5L *Grade* B
Diameter	:	8″
Operating Temp.	:	26-30 ^{o}C
Operating Pressure	:	450 Psi
Wall Thickness	:	0 (Pipa Bocor)
Fluida	:	Gross (Oil + Water)
Transfer Process	:	Intermitten
Year Of Construction	:	2006

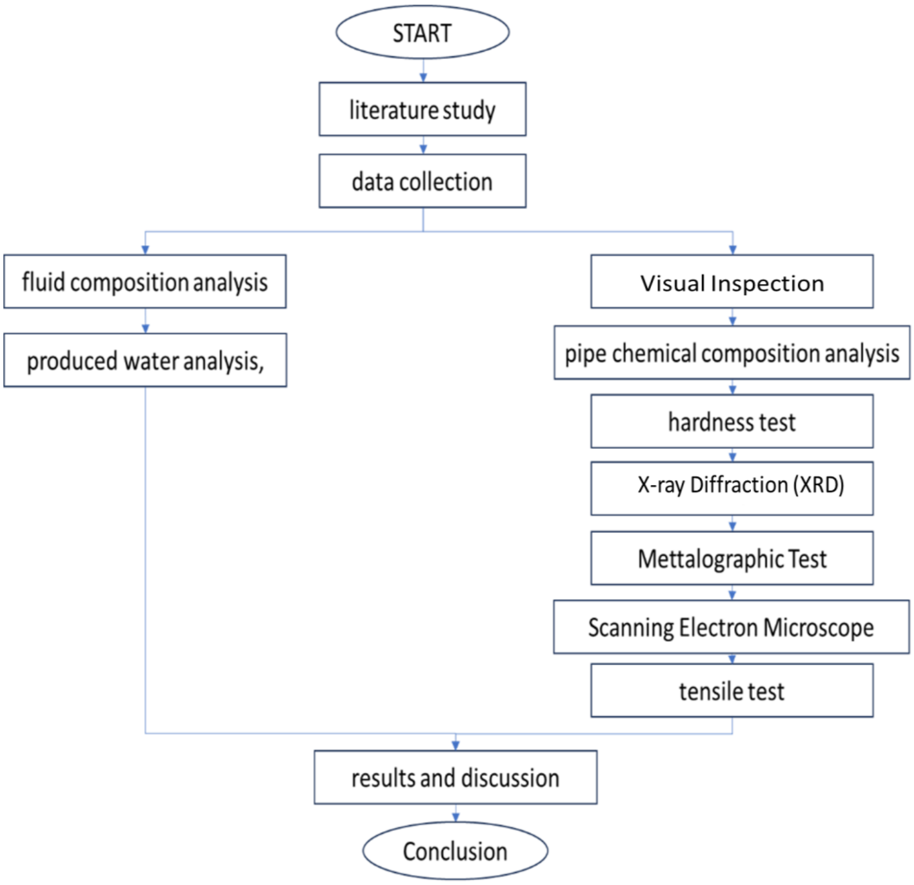

Figure 1. Flowchart for Failure Analysis of Pipelines

Data collection was carried out by analyzing the process fluid, specifically produced water, and examining the failed pipeline. The analysis of produced water included determining the content of anions and cations. For the pipeline samples, several analyses were conducted, including physical inspection, chemical composition analysis based on API 5L Grade B, scale analysis, metallographic testing, and tensile testing. The results were then compared with the standards for the pipeline samples [1], [2], [5], [6]

3. RESULT

3.1 Physical Analysis of the Pipeline

It is evident that the crude oil transport operations intermittently include produced water components (gross). Regular maintenance is performed using pigging to ensure pipeline cleanliness and operational efficiency. External corrosion protection is provided through the installation of cathodic protection using carbon anodes. Carbon anodes are a form of external pipeline corrosion protection, made from a galvanic metal alloy series with an electrochemical potential that is more negative than the pipeline it protects. This setup effectively mitigates external corrosion by directing corrosive reactions away from the pipeline surface [7]. Environmental factors, such as soil-induced corrosion, also influence the corrosion rate on the external surface of pipelines. Anti-corrosion technology, such as three-layer polyethylene (3PE) coating, can be applied to pipelines with underground construction designs. This technology provides excellent protection by creating a durable barrier against moisture, chemicals, and other corrosive elements present in the soil, significantly enhancing the pipeline's resistance to external corrosion [8]

The pipeline thickness data is presented in Table 2, This reduction highlights the critical areas of corrosion that contributed to the failure.

Table 2. Thickness Measurements

Position	*Nominal Thickness*	Area 1 (mm)	Area 2 (mm)	Area Leak (mm)	Area 3 (mm)	Area 4 (mm)
0'	8,18	8,14	8,11	8,14	8,14	8,14
3'	8,18	8,12	8,15	8,15	8,14	8,12
6'	8,18	8,12	8,14	0	8,12	8,13
9'	8,18	8,12	8,14	6,85	8,12	8,12

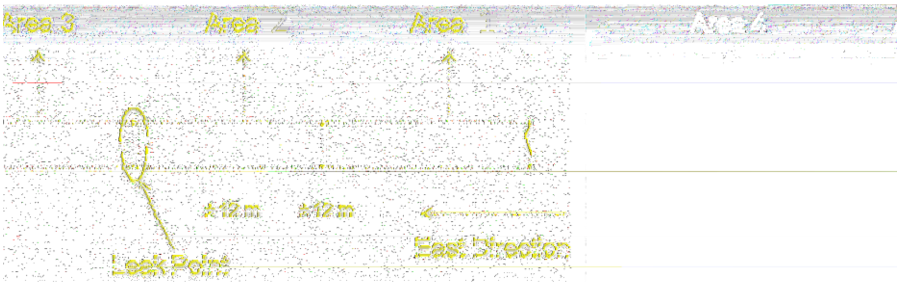

Figure 2. Thickness Measurement Points on the Pipeline

The pipeline measured thickness, as presented in Table 2, indicate that the nominal thickness of the pipeline is 8.18 mm. Measurements at various positions (0°, 3°, 6°, and 9°) show consistent thickness values across most areas, except for the locations identified as leak-prone. At the 6 o'clock position, the thickness was reduced to 0 mm, indicating complete material degradation due to severe internal corrosion. Similarly, the 9 o'clock position displayed significant thinning, with a thickness of 6.85 mm, suggesting localized material loss. These findings highlight the critical areas where corrosion has had the most impact, particularly at the bottom of the pipeline (6 o'clock position), which is prone to fluid accumulation and prolonged exposure to corrosive agents. The 9 o'clock position also shows notable thinning, likely influenced by the flow dynamics or sedimentation effects within the pipeline. This analysis underscores the need for improved corrosion mitigation strategies, such as enhanced drainage systems, internal coatings, and more effective separation of produced water from the transported crude oil.

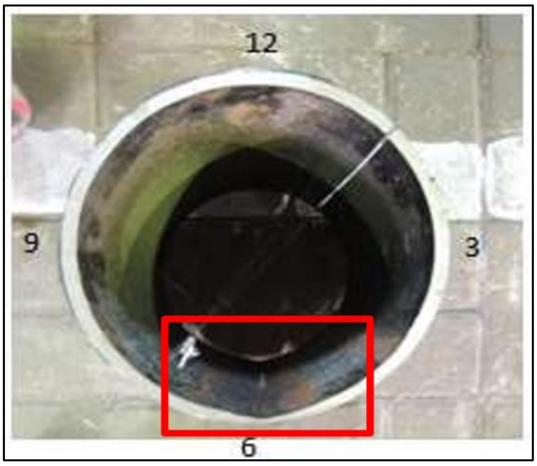

Figure 3. Visual Inspection of Pipeline Thinning

The next step involved macro observation, which was conducted to determine whether the failure occurred in the Heat-Affected Zone (HAZ). This step is critical to confirm whether the failure point was located in the HAZ or not. The HAZ is considered the weakest area in a welded joint because it undergoes heating during welding, leading to microstructural changes. These changes can significantly affect the material's mechanical properties and its resistance to corrosion, potentially making the area more susceptible to failure [2].

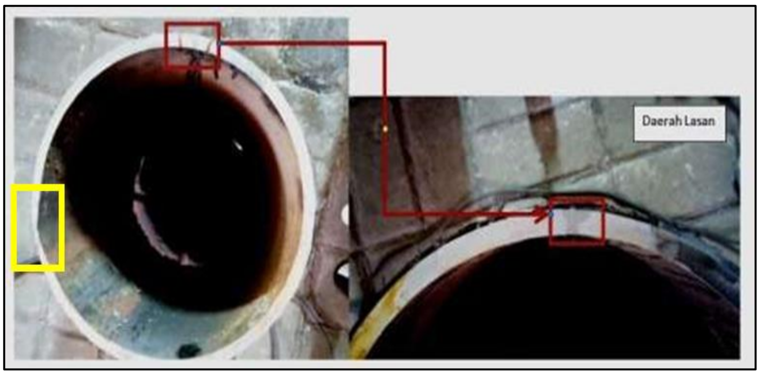

Figure 4. The HAZ Area Did Not Experience Failure/Thinning

3.2 Analysis of the Pipeline

The failed pipeline was then analyzed to determine its chemical composition through a series of tests, including chemical composition analysis, metallographic examination, tensile testing, and hardness testing. The results were compared to those from a non-leaking pipeline sample and the standard composition requirements for API 5L Grade B pipes. These tests aimed to verify the pipeline material's compliance with API standards, identify any microstructural changes, and evaluate the mechanical properties such as tensile strength and hardness. The comparative analysis provided insights into whether the material properties contributed to the pipeline failure or if the cause was predominantly environmental or operational factors [4]. Table 3 demonstrates that the chemical composition of the failed pipeline sample falls within the acceptable range specified by the API 5L Grade B standard. This indicates that the material composition of the pipeline was not a contributing factor to the failure. The conformity to the standard suggests that the failure was likely due to other factors, such as operational conditions, environmental influences, or internal corrosion mechanisms.

Table 3. Results of Pipeline Composition Analysis

Sample Code		C	S	P	Mn	Ti	Fe
Failed Pipe	(%)	0,088	0,0063	0,003	0,003	0,002	99,274
Normal Pipe	(%)	0,101	0,003	0,003	0,805	0,002	99,086
API 5L Gr. B	(% max)	0,26	0,03	0,03	1,2	0,4	98,08

Testing the corrosion deposits formed on the pipeline is crucial, as it serves as an indicator of chemical interactions between corrosive materials and the pipeline's material. To identify the corrosion products, an analysis using Scanning Electron Microscope (SEM) was conducted. This method allows for detailed observation of the morphology and composition of the corrosion products, providing insights into the mechanisms and severity of the corrosion process [1], [4]. The results of Scanning Electron Microscope (SEM) analysis confirm the presence of corrosion in the failed pipeline, as evidenced by the formation of scale composed of iron carbonate (Fe_2CO_3) observed in Figure 5 and magnetite (Fe_3O_4) in Figure 6. These findings demonstrate that chemical reactions between the pipeline material and corrosive elements, such as CO_2 and water in the process fluid, have occurred, contributing to the pipeline's failure.

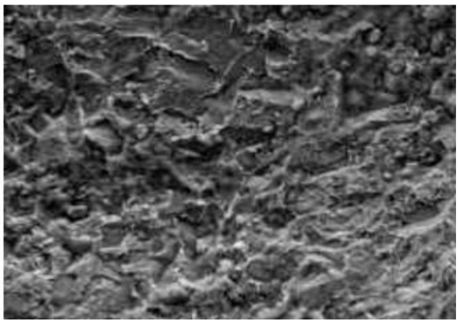

Figure 5. Siderite (Fe_2CO_3) scale

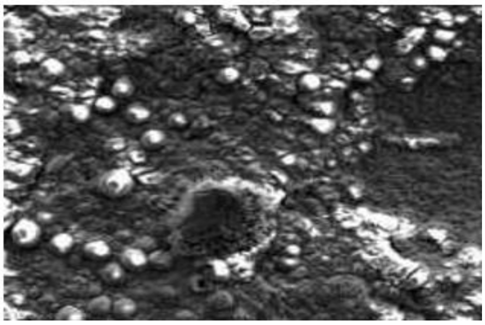

Figure 6. Fe_3O_4 scale

The next step in analyzing the root cause of pipeline failure involves examining the corrosion products through a metallurgical test. This procedure is performed using an optical microscope combined with Energy Dispersive X-ray (EDX) analysis [9]. This method allows for the identification of the elemental composition of the corrosion products and provides insight into the chemical interactions between the pipeline material and the corrosive environment. The results from this analysis help confirm the mechanisms contributing to the failure and provide valuable information for preventive measures. [9].

Table 4. Results of EDX Analysis on Pipeline Corrosion Products

Element (wt %)	Titik 1	Titik 2
C (Carbon)	8.94	4.66
O (Oxygen)	24.37	46.28
S (Sulfur)	1.09	0.46
Cl (Chlorine)	0.38	1.97
Fe (Iron)	63.94	46.63
Si (Silicon)	1.11	-
Cr (Chromium)	0.80	-

The EDX analysis results of the pipeline's corrosion products reveal significant oxygen content (24.37% and 46.28%), indicating the formation of oxides, primarily iron oxides (e.g., Fe_2O_3 or Fe_3O_4). Iron (63.94% and 46.63%) dominates the composition, confirming the material's susceptibility to oxidation. Chlorine (0.38% and 1.97%) suggests the involvement of chloride ions from produced water or the environment, contributing to the corrosion process. Carbon (8.94% and 4.66%) indicates the potential presence of carbonates, such as siderite (Fe_2CO_3), while sulfur (1.09% and 0.46%) points to possible sulfide interactions, likely from hydrogen sulfide (H_2S). Trace amounts of silicon (1.11%) and chromium (0.80%) are also detected, potentially from the pipeline material or external factors. These findings confirm that internal corrosion, driven by chloride ions, oxygen, and sulfides, is the primary factor leading to pipeline failure.

The SEM and EDX testing results on the failed pipeline, as shown in Table 5, reveal the presence of Fe_2CO_3 (iron carbonate) and Fe_3O_4 (magnetite) as the primary corrosion products. The analysis also confirms the absence of sand particles and no indications of Sulphate Reducing Bacteria (SRB) activity, which is typically characterized by the formation of tubercles. These findings suggest that the corrosion process was predominantly chemical, driven by interactions between the pipeline material and the corrosive environment, rather than biological influences [10]

Table 5. Corrosion Products

Corrosion Product Name	Phase	Mass (% wt)
Siderit	Fe_2CO_3	53
Hematite	Fe_3O_4	21
Iron	Fe	26

The corrosion product analysis indicates that the majority of the corrosion by-products consist of siderite (Fe_2CO_3), contributing 53% of the total mass. This confirms that iron carbonate formed due to the reaction between dissolved CO_2 in the process fluid and the pipeline material. Hematite (Fe_3O_4), a common iron oxide, constitutes 21%, indicating further oxidation. The remaining 26% consists of elemental iron (Fe), suggesting unreacted pipeline material or remnants of partially corroded metal. These findings highlight that the primary corrosion mechanism is chemically driven by CO_2 exposure and oxidation.

Siderite (Fe_2CO_3) is a corrosion product formed from the reaction between iron (Fe) and carbon dioxide (CO_2). CO_2 can dissolve in produced water, forming a weak acid known as carbonic acid (H_2CO_3). This condition increases the corrosivity of the water, accelerating the corrosion process on the pipeline's surface and leading to the formation of iron carbonate as a corrosion by-product [5]. CO_2 dissolved in water forms carbonic acid (H_2CO_3) through the following chemical reaction [1].

$$CO_2 \rightarrow CO_2 \quad (1)$$

$$CO_2 + H_2O \rightarrow H_2CO_3 \quad (2)$$

Carbonic acid (H_2CO_3) dissociates into bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}) ions in two stages. Each stage of the reaction releases hydrogen ions (H^+), as shown in the chemical equations below:

$$H_2CO_3 \leftrightarrow H^+ + HCO_3^- \quad (3)$$

$$HCO_3^- \leftrightarrow CO_3^{2-} + H^+ \quad (4)$$

The reaction between Fe (iron) and carbonic acid (H_2CO_3) begins with the formation of iron ions as described in the reaction below.

$$Fe + 2\,H_2CO_3 \rightarrow Fe^{2+} + 2HCO_3^- + H_2 \quad (5)$$

$$Fe^{2+} + CO_3^{2-} \rightarrow Fe_2CO_{3\,(s)} \quad (6)$$

Table 6 presents the data from hardness measurements. From the hardness testing, it can be observed that the hardness values of the failed pipe do not exceed the material standard for API 5L Grade B pipes.

Table 6. Hardness Test Result

Sampel	Hardness Value	Description
Failed Pipe	75	Rockwell HRB Load 100 Kgf
API 5L Gr. B	82	Rockwell HRB Load 100 Kgf

Table 7 presents the results of the analysis of the associated water inside the pipe. The data reveals the presence of corrosive anions and cations, such as chloride, bicarbonate, and carbonate ions. These components contribute to the potential for corrosion in the pipe, as evidenced by the presence of corrosion products formed from carbonate compounds [5].

Table 7. Analysis of Anions and Cations in Produced Fluid

Kation	mg/l	Anion	mg/l
Calsium	120.240	Chloride	3.747.863
Magnesium	41.344	Bicarbonate	823.770
Berium	-	Carbonate	60.010
Iron (Ferrum)	1	Hydroxide	-
Natrium	2.572.849	Sulfate	25.000

From the table, it can be observed that the produced fluid contains high concentrations of chloride, bicarbonate, and carbonate ions, which are corrosive in nature. These ions increase the risk of corrosion in the pipe, as confirmed by the presence of carbonate-based corrosion products. Table 8 shows the results of the analysis of associated water inside the pipe to determine the tendency for scale formation. From the data, it is evident that there is potential for the formation of carbonate-based scale, as indicated by the Valone & Skillern Method value of 32.86 PTB, which falls under the category of Few Scale Problem [11].

Table 8. Valone & Skillern Formula

Q Value (PTB)	Keterangan
PTB < 0	No Scale
0 < PTB < 100	Few Scale Problem
100 < PTB < 250	Moderate Scaling Problem
PTB > 250	Severe Scaling Problem

Based on the analysis, the Q Value of 32.86 PTB falls within the range of 0 < PTB < 100, which indicates a Few Scale Problem. This suggests a minimal potential for scale formation within the pipe system.

4. DISCUSSION

The results of the thickness measurements on the failed pipe indicate the occurrence of internal corrosion within the pipe. The thinning of the internal section of the pipe caused leakage. Based on the thickness measurements taken from the time of initial construction to the point of failure, the corrosion rate was determined to be 1 mpy. A corrosion rate of 1 mpy is considered high and significantly impacts the safety factor of the process, as it accelerates the degradation of the pipe material and increases the risk of structural failure [12]. This relatively high corrosion rate requires further mitigation measures to prevent similar incidents at other location

The chemical composition inside the failed pipe showed no significant differences, indicating that the failed pipe conforms to the API 5L Grade B standard. The chemical composition of elements such as C, S, P, Mn, Ti, and Fe remains within the acceptable standard limits [13]. Thus, it can be concluded that the pipe still meets the API 5L Grade B standard. Visual inspection revealed that the failure point was not located in the Heat Affected Zone (HAZ). The pipe leakage occurred in the main body of the pipe, specifically at the 6 o'clock position.

The analysis of anions and cations in the produced water associated with the crude oil transfer process revealed the presence of Cl^- ions at 9,571 mg/L and HCO_3^- ions at 3,859 mg/L. These concentrations of Cl^- and HCO_3^- in the produced water make it highly corrosive to metals, particularly those made of carbon steel ([14]. The intermittent pumping process also influences the corrosion rate of the pipe, as it potentially leads to the accumulation of produced water at the 6 o'clock position [15]

Scanning Electron Microscopy (SEM) was performed to study the surface morphology of corrosion products on the metal surface [16]. The corrosion products formed are generally in the form of an insoluble mixture [1]. The SEM analysis of the corrosion products on the failed pipe revealed that the dominant corrosion products were oxides (Fe_3O_4) and carbonates (Fe_2CO_3). Most of the corrosion products on the failed pipe contained Fe, O, and C components. The percentage composition of these elements was as follows: Fe ranged from 46–63 wt%, O ranged from 24.37–46.28 wt%, and C ranged from 8.84–4.66 wt%. These three elements combined to form iron oxide and carbonate compounds as the main corrosion products.

The oxygen present in the fluid flow generally originates from the oil well reservoir. The carbon element comes from the dissolved CO_2 in the solution, which is also derived from the oil well reservoir and forms through the equilibrium of the weak acid H_2CO_3 [14]. The presence of produced water and dissolved CO_2 exacerbates the detrimental effects of corrosion within the pipe. The contact between the produced water layer and the pipe's internal surface increases the potential for internal corrosion [17]. The process of corrosion caused by dissolved CO_2 is highly dependent on the partial pressure and temperature of the system. These factors increase the concentration of PCO_2 in H_2CO_3, which in turn accelerates the corrosion rate [5].

Siderite (Fe_2CO_3) is a corrosion product formed from the reaction between iron (Fe) and carbon dioxide (CO_2). CO_2 dissolves in the produced water, forming a weak acid known as carbonic acid (H_2CO_3). This condition increases the corrosiveness of the water, enhancing the potential for internal pipe corrosion [5]. The measurement data revealed the presence of corrosive anions and cations, including chloride, bicarbonate, and carbonate ions. These components contribute to pipe corrosion, as evidenced by the formation of corrosion products derived from carbonate compounds [5]. The presence of Cl^- acts as a corrosive catalyst, significantly increasing the level of corrosivity on the metal surface [5]

5. CONCLUSION

The leakage in the pipe at the 6 o'clock position was caused by internal corrosion, as indicated by visual inspections and thickness measurements showing significant wall thinning. The failure point was not located in the Heat Affected Zone (HAZ) but in the main pipe body, with no significant differences in composition or hardness compared to the API 5L Grade B standard, confirming the material met required standards. The corrosion was primarily due to dissolved CO_2 in the produced fluid, evidenced by the presence of corrosion products such as Fe_3O_4 (hematite) and Fe_2CO_3 (siderite), identified through EDX, XRD, and SEM analyses. High concentrations of corrosive ions like chloride (Cl^-) and bicarbonate (HCO_3^-) in the associated fluid significantly increased the corrosivity, and the scale formation tendency, classified as a Few Scale Problem, further contributed to the internal corrosion. These findings highlight the need for proactive measures such as regular monitoring, corrosion inhibitors, and protective solutions to prevent similar failures.

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