

Qualitative Analysis of Corrosion Inhibitor Testing: Case Study of CO₂ Bubble Gas

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Abstract—Corrosion management in the oil and gas industry remains a critical challenge due to complex operating conditions such as temperature variations, fluctuating flow rates, and pressure changes. While corrosion cannot be entirely eliminated, the strategic use of inhibitors significantly mitigates internal corrosion through continuous injection. However, no single corrosion inhibitor is universally effective for all environments, necessitating rigorous testing methodologies such as the CO₂ bubble test to assess their performance under specific conditions. In this study, representative produced water samples were collected from key points within the production system, including the test separator, first stage separators A and B, and the electrostatic dehydrator—each located downstream of corrosion inhibitor injection points. The measured corrosion rates (mm/year) for these locations were 0.05, 0.11, 0.08, and 0.06, respectively, with all values meeting the industry target of 0.1 mm/year except for first stage separator A. To address this, the corrosion inhibitor dosing rate for first stage separator A was optimized, ensuring improved inhibitor efficiency and bringing the corrosion rate within the acceptable threshold. The findings highlight the effectiveness of site-specific corrosion inhibitor adjustments in maintaining long-term asset integrity and operational reliability. Regular monitoring and proactive optimization of inhibitor dosing strategies are recommended to sustain corrosion control across all process units.

Keywords—Produced Water, Corrosion Inhibitor, Corrosion Rate, Prevention, Control.

I. INTRODUCTION

In both offshore and onshore oilfield production, pipelines transporting oil and gas operate under two-phase (oil-water) or three-phase (gas-oil-water) flow conditions, which are crucial to the oil and gas industry [1]. Crude oil, natural gas, and formation water are transported by risers from downholes to wellhead platforms. Well fluids are then carried by flowlines from wellhead platforms to a treatment platform, also known as a central gathering platform, where oil and gas from different wells are mixed. At this stage, separators are used to separate the components [2]. Oil and gas are subsequently transported separately via pipelines to treatment facilities, storage facilities, and refineries. Despite the separation process, some produced water-ranging from 0.5% to 2% water cut (the volume ratio of the water phase to the total liquid phase)-remains in oil transportation pipelines. After separation, the formation water is injected back into the reservoirs, sometimes along with seawater and carbon dioxide gas, to maintain or increase reservoir pressure for oilfield recovery. Over the years, the

volume of produced water in aging oilfields has steadily increased [3].

Organic corrosion inhibitors are widely used to protect carbon steel pipelines in oilfields. They function by forming an adsorbed organic compound film on the steel surface, effectively slowing down the corrosion process caused by carbon dioxide [4]. In addition to their primary role, inhibitors influence phase wetting properties, particularly by reducing oilwater interfacial tension and altering steel surface wettability. These factors impact the hydrodynamic interaction between oil, water, the inhibitor film, and the steel surface, influencing corrosion rates [5].

Among various organic corrosion inhibitors, imidazolinebased inhibitors are particularly effective in acidic environments and are extensively used to mitigate carbon dioxide-induced corrosion in oil and gas pipelines [6]. The transportation of multiphase fluids—consisting of oil, saltwater, and gas—aggravates corrosion issues, with flow regimes such as slug flow posing a significant risk. Slug flow, characterized by high turbulence and intense bubble impact on pipe walls, enhances internal corrosion and reduces the effectiveness of inhibitor films due to high shear stress [7]. The severity of slug flow is quantified using the dimensionless Froude number, which correlates with turbulence intensity and its impact on pipeline surfaces [8].

Several studies have explored corrosion inhibitor efficiency in oil and gas environments. Adams et al. [9] investigated the effect of corrosion inhibitors on water wetting and carbon dioxide corrosion in oil-water two-phase flow. Their findings highlighted the direct correlation between free water presence and corrosion severity in offshore and onshore production, particularly when carbon dioxide gas is present. Corrosion inhibitor injection remains a standard practice for internal pipeline protection. Angeli et al. [10] assessed combined scale and corrosion inhibitors using a jar test and bubble cell methodology, addressing both calcium carbonate scaling and CO2-induced corrosion. Their research underscored the need for comprehensive inhibitor evaluations that consider both scaling and corrosion factors. Arirachakaram et al. [11] reviewed testing methods and standards for oilfield corrosion inhibitors, proposing a methodology for predicting field performance based on laboratory data.

Barnea [12] studied corrosion inhibition in high-salinity solutions, focusing on carbon steel corrosion under CO₂saturated conditions. Cai et al. [13] analyzed environmentally friendly corrosion inhibitors for mild steel in CO₂-saturated



chloride solutions, emphasizing the role of carbonic acid speciation in corrosion progression. In a related study, Cai et al. [14] investigated small organic inhibitors on API 5LX60 steel in a 3.5% NaCl solution, reinforcing the need for effective corrosion protection strategies in aging oilfields.

Despite extensive research on corrosion inhibitors, gaps remain in evaluating their qualitative performance using CO_2 bubble tests. Previous studies have explored pyridine-based corrosion inhibitors in CO_2 environments [15], nanobubbles as corrosion inhibitors in acidic geothermal fluids [16], and adsorption mechanisms in produced water corrosion [17]. However, none have conducted a comparative analysis of corrosion inhibitor testing using the CO_2 bubble test as a case study.

This study aims to investigate the qualitative analysis of corrosion inhibitor testing using the CO_2 bubble test. The research objectives include collecting produced water samples from various locations, analyzing their composition, conducting CO_2 bubble tests, and evaluating corrosion rates over time. The findings will provide valuable insights into optimizing corrosion inhibitor performance for enhanced pipeline integrity.

II. MATERIALS AND METHODS

2.1 Materials

Materials for the study are one litre Glass cell with preference flat bottom, thermo stated reactor, heating magnetic stirrer, aluminum adapter, O-ring gasket, Clamp collar, separating funnel, gas tube, Plastic tubing, Corrater probe, Carbon steel electrodes, and Magnetic stirrer.

2.2 Methods

2.2.1 Equipment Assembly and Preparation

The different components were assembled, ensuring proper alignment and secure sealing. A 1000-sensor probe was inserted to monitor key parameters, and a porous gas distribution system was installed at the bottom of the reactor (water phase). Care was taken to ensure that all parts remained clear of the stirrer to prevent mechanical interference.

2.2.2 Sample Collection

Produced water samples were collected at designated sampling points downstream of the injection point. A total of 500 mL of water was separated for each experiment to ensure effective corrosion inhibitor assessment across the flow line.

2.2.3 Experimental and Electrochemical Procedures

All experiments were conducted under static conditions using the setup depicted in Figure 2. Four 1 cm² carbon steel samples were placed in each test cell:

- Two samples were used for electrochemical measurements.
- Two samples were analyzed post-experiment for surface characterization.

Electrochemical Measurements

Electrochemical tests were conducted using an IviumPotentiostat connected to a three-electrode system:

- Reference Electrode: Ag/AgCl
- Counter Electrode: Platinum

• Working Electrode: API X65 steel

Linear Polarization Resistance (LPR) Measurements

LPR measurements were performed by polarizing the carbon steel sample ± 15 mV about the open circuit potential (OCP) at a scan rate of 0.333 mV/s. Measurements were taken every 30 minutes over a 24-hour period.

Potentiodynamic Polarization Measurements

Potentiodynamic polarization tests were performed separately on two samples:

- 1. Cathodic Sweep: Polarized from OCP to -500 mV.
- 2. Anodic Sweep: Polarized from OCP to +300 mV. Both

sweeps were performed at a scan rate of 0.333 mV/s. 2.2.4 Corrosion Rate Determination



Fig. 1: Experimental Set-up for the Corrosion Inhibition Process

The resulting polarisation resistance obtained from the LPR measurements was subsequently converted into a corrosion rate through the application of the Stern-Geary relationship (using the measured anodic and cathodic Tafel slopes) and Faraday's Law as shown in equation 2.1 to 2.3.

$$B = \frac{\beta_{\alpha}\beta_{c}}{2.303(\beta_{\alpha}+\beta_{c})} \tag{1}$$
$$i_{corr} = \frac{\beta_{\alpha}\beta_{c}}{2.303R_{-r}(\beta_{c}+\beta_{c})} \tag{2}$$

$$CR = \frac{3.27i_{corr}M_{Fe}}{np}$$
(2)

Where a and c are the coefficients which characterize the anodic and cathodic Tafel slopes of corrosion process in (V), 3.27 is a conversion factor (mm g (mA cm year⁻¹), i_{corr} is the corrosion current density (mA cm⁻²), MFe number of electrons and the density of iron (g cm⁻¹), i_{corr} is the atomic weight of iron = 55.845, n is the number of electrons and p is the density of iron (g cm⁻³).

The inhibition efficiency (IE%) was calculated at the end of the experiment and was determined using Equation 2.4:

(4)

$$IE(\%) = \frac{CR_{blank} - CR_{inhib}}{CR_{blank}}$$

where CR_{blank} and CR_{inhib} are the final corrosion rate in the absence(blank) and presence of the blends, respectively.

2.2.5 Corrosion Measurements

Also, the corrosion probe is inserted into the reactor with carbons steel electrodes in the vapour phase. The corrosion measurements were carried out accordingly: Introduce the probe into the production water phase until complete immersion of carbon steel electrodes. It is possible to unscrew lightly the compression of the seal O ring to make it easier, connect the probe to the corrosion monitor and make several measurements separated by 15 minutes for two hours or until the value become



stable. If the corrosion monitorpermit it is possible to graph the results as corrosion rate function of time.

2.2.6 Cleaning the Material

After the experiment, the material was carefully cleaned after all measurement to avoid interactions from previous test. Rinse glass cell internals and probe firstly with water then with distilled water. Throw alcohol on wall side then wipe with absorbent paper. Also, rinse the separator funnel with water, if oil was present on wash it with toluene and finish with acetone.

III. RESULTS AND DISCUSSION

The experiment was conducted on four produced water samples to evaluate corrosion rates using the carbon dioxide bubble testing method. Proper laboratory procedures were followed to minimize errors, and the results were presented in tables and figures.

The data in Table I indicates that the corrosion rate decreases progressively with time. At the initial stage (1 minute), the corrosion rate is at its highest (1.38 mm/year), showing significant metal degradation due to the lack of a protective inhibitor layer. As time progresses, the corrosion rate steadily decline; reaching 0.11 mm/year at 90 minutes. This trend suggests that the corrosion inhibitor gradually forms a protective film on the metal surface, effectively reducing the rate of metal degradation. The observed trend highlights the effectiveness of corrosion inhibitors over time, as the reduction in corrosion rate correlates with inhibitor adsorption and stabilization.

TABLE I: Corrosion Rate Analysis for First Stage Separator A

Time (Minutes)	Corrater Readings	Corrosion rate (mm/year)
1	136	1.38
3	100.2	1.02
5	80.5	0.82
10	58.1	0.59
20	40.7	0.41
40	23.5	0.24
60	14.1	0.14
90	10.8	0.11



Fig. 2. Graph of corrosion rate (mm/year) against time (minutes) on First Stage Separator A

Fig. 2 visually represents the declining corrosion rate over time for First Stage Separator A. The graph exhibits an exponential decrease, reflecting a rapid drop in corrosion rate within the first 20 minutes, followed by a more gradual decline. This indicates that the corrosion inhibitor quickly reacts with the metal surface to reduce the corrosion rate significantly in the early stages. After 40 minutes, the corrosion rate stabilizes at a much lower level, suggesting that the inhibitor has achieved near-optimal surface coverage, thereby minimizing further corrosion effects.

Table 2results for First Stage Separator B show a similar decreasing trend in corrosion rate. The initial corrosion rate is 1.04 mm/year at 1 minute, gradually declining to 0.08 mm/year at 90 minutes. This decrease suggests that the corrosion inhibitor is effectively adsorbing onto the metal surface, forming a protective barrier against further corrosion. Compared to First Stage Separator A, the final corrosion rate at 90 minutes is lower, indicating that the inhibitor is more effective in this system. The differences in corrosion rate trends between the two separators could be attributed to variations in fluid composition, temperature, or initial surface conditions.

TABLE II: Corrosion Rate Analysis for First Stage Separator B

Time (Minutes)	Corrater Readings	Corrosion rate (mm/year)
1	102	1.04
3	86	0.87
5	70.8	0.72
10	58.3	0.59
20	38.7	0.39
40	19.8	0.20
60	11.9	0.12
90	8.1	0.08



Fig. 3. Graph of corrosion rate (mm/year) against time (minutes) on First Stage Separator B

Fig. 3 confirms the downward trend in corrosion rate observed in Table 2. The corrosion rate declines significantly within the first 20 minutes, indicating a rapid inhibitor response. The rate of decline slows down between 40 and 90 minutes, signifying a saturation point where the inhibitor has effectively coated the reactive sites. The graph demonstrates that the corrosion inhibitor successfully mitigates metal degradation over time, reinforcing its effectiveness in reducing corrosion in First Stage Separator B.

Table III, the test separator exhibits a more pronounced reduction in corrosion rate, starting at 0.79 mm/year at 1 minute and decreasing to 0.05 mm/year at 90 minutes. This significant reduction suggests that the inhibitor performs exceptionally well in this environment. The lower temperature (55.0°C) compared to the first stage separators may contribute to enhanced inhibitor efficiency. Additionally, the test separator's

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corrosion rates indicate that a strong inhibitor film formed earlier in the process, effectively preventing further metal degradation

TABLE III: Corrosion Rate Data from Test Separator	
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Time (Minutes)	Corrater Readings	Corrosion rate (mm/year)
1	77.8	0.79
3	35.8	0.36
5	21.7	0.22
10	13.1	0.13
20	8.82	0.09
40	6.61	0.07
60	5.86	0.06
90	5.32	0.05



Fig. 4: Graph of corrosion rate (in mm/year) against time (in minutes) on Test Separator

Fig. 4 illustrates the steady decline in corrosion rate over time in the test separator. The graph follows an exponential decay trend, signifying the rapid formation of a protective inhibitor layer within the first 20 minutes. Unlike previous systems, the corrosion rate stabilizes at a lower value much earlier, likely due to more effective inhibitor distribution. This suggests that optimizing inhibitor concentration in other separators could further enhance corrosion protection.

Table IV shows the corrosion rate starts at 0.58 mm/year and gradually decreases to 0.06 mm/year at 90 minutes. The temperature in this system (79.5°C) is significantly higher than in other sampling points, which can influence inhibitor performance. The decreasing corrosion rate trend suggests effective inhibitor adsorption, but the slightly higher final corrosion rate compared to the test separator may indicate partial inhibitor degradation at elevated temperatures. Despite this, the overall corrosion rate remains low, demonstrating the inhibitor's effectiveness in reducing metal degradation.

TABLE IV:	Corrosion	Rate Data	from	Electrostatic	Dehydrator

Time (Minutes)	Corrater Readings	Corrosion rate (mm/year)
1	56.8	0.58
3	28	0.28
5	18.3	0.19
10	12.5	0.13
20	9.54	0.10
40	8.16	0.08
60	6.86	0.07
90	5 89	0.06



Fig. 5: Graph of corrosion rate (in mm/year) against time (in minutes) on Electrostatic Dehydrator

Figure 5 displays a decreasing corrosion rate trend similar to other systems, with a sharp decline within the first 20 minutes, followed by a gradual reduction. The higher temperature in this system might influence inhibitor efficiency, yet the results indicate successful corrosion mitigation. The stabilizing trend beyond 40 minutes suggests that an optimal protective film has formed, effectively reducing corrosion risks

Table V presents the corrosion rate comparisons across all sampling points, revealing that the test separator exhibits the lowest corrosion rate (0.05 mm/year), while First Stage Separator A has the highest (0.11 mm/year). This variation suggests that different process conditions impact inhibitor performance. The effectiveness of corrosion inhibition is influenced by factors such as temperature, flow rate, and initial corrosion activity, emphasizing the need for tailored inhibitor application strategies.

Sampling Points	Corrosion Rate (mm/Year)
First Stage Separator A	0.11
First Stage Separator B	0.08
Test Separator	0.05
Electrostatic Dehydrator	0.06

TABLE V: Comparative Corrosion Rate Data for Sampling Points

Table VI highlights the residual corrosion inhibitor concentrations at each sampling point, with First Stage Separator A exhibiting the highest inhibitor presence (24.5 ppm) and the test separator showing the lowest (18.4 ppm). This indicates that higher inhibitor concentrations do not always correlate with lower corrosion rates. The efficiency of the inhibitor depends on its distribution and reaction with the metal surface, demonstrating the need for optimized dosing strategies to achieve maximum corrosion protection.

Sampling Points	Residual Corrosion Inhibitor (Pnm)
TABLE VI: Residual Corrosion Inhi	ibitor Concentration for Sampling Points

Sampling Points	Residual Corrosion Inhibitor (Ppm)
First Stage Separator A	24.5
First Stage Separator B	28.7
Test Separator	18.4
Electrostatic Dehydrator	20.9

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VI. CONCLUSION

The experimental results demonstrate that corrosion inhibitors play a significant role in mitigating corrosion in produced water systems. The corrosion rates observed in the different sampling points showed a clear decreasing trend over time, confirming the formation of a protective inhibitor film. First Stage Separator A exhibited a final corrosion rate of 0.11 mm/year, while First Stage Separator B recorded a lower rate of 0.08 mm/year. The Test Separator and Electrostatic Dehydrator demonstrated even lower final corrosion rates of 0.05 mm/year and 0.06 mm/year, respectively, highlighting the effectiveness of corrosion inhibition strategies in different system environments.

The study also revealed a correlation between residual corrosion inhibitor concentration and corrosion rate reduction. Higher residual inhibitor concentrations were observed in First Stage Separator A (24.5 ppm) and First Stage Separator B (28.7 ppm), which contributed to lower corrosion rates. Conversely, the Test Separator, with the lowest residual inhibitor concentration (18.4 ppm), had the highest corrosion susceptibility.

These findings underscore the importance of optimizing corrosion inhibitor dosages based on system conditions to achieve maximum protection. Future studies should explore long-term effects, varying inhibitor formulations, and environmental factors that may influence corrosion rates. Implementing these insights can enhance asset integrity, reduce maintenance costs, and improve operational efficiency in oil and gas processing facilities.

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