

The Performance of HPHT Corrosion Inhibitor at Offshore Downhole Sour Conditions

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ABSTRACT

High pressure, high temperature (HPHT) corrosion in sour conditions is a major concern in oil and gas production. Here, the selection of corrosion inhibitor is a significant challenge in oil and gas industry. This paper presents the results using HPHT Hastelloy RC autoclave for the performance study of corrosion inhibitor with high H₂S/CO₂ environments and high shear stress of 25 Pa in 80 % water cut. The sour corrosion testing conditions were the combination of 16.8 bar H₂S concentration and 12 bar CO₂ concentration with the temperature of 121 °C. Triplicate API 5L X65 weight-loss coupons were used in the test. Some important standard tests (e.g. thermal stability, emulsification tendency, foaming tendency, and solubility) with material compatibility test (Alloy 825) were also presented. The test results show that the average corrosion rates using weight-loss coupons are less than 0.1 mm/yr with low corrosion inhibitor concentration. No pitting corrosion was observed.

Key words: HPHT, sour conditions, corrosion inhibitor

INTRODUCTION

As traditional reserves deplete onshore and offshore, the oil industry is moving into increasingly deeper waters and harsh environments in the pursuit of hydrocarbons. As the industry drills deeper, the challenges that face infrastructure increase markedly with the longstanding issues of corrosion. One of the major challenges to corrosion management is the extreme pressure and temperature. In addition to these operating conditions, a sour condition makes even more challenging to manage the fluid handling equipment such as well production tubing and flowlines that are carrying the produced fluid. Sour fields consist of approximately one-third of oil

and gas fields globally¹ and this sour condition leads to the localized corrosion that causes a threat to the integrity of mild steel pipelines and equipment in the oil and gas industry.²

In oil field production, carbon steel is the most commonly used material due to its relatively low capital cost coupled with good mechanical properties. However, carbon steel is susceptible to corrosion in the oil field operating environment. In a sour environment, the most common form of corrosion damage found on carbon steel is localized pitting corrosion.³

In order to mitigate the HPHT corrosion in sour condition, corrosion inhibitors have been used for some time.⁴ However, the efficiency of corrosion inhibitor is not well documented at a high temperature above 90 °C.⁵ This makes a challenge to the use of carbon steel when developing fields with higher temperatures. Typically, the dosage of traditional corrosion inhibitor used for the temperature that is higher than 120 °C is between 400 ppm and 1,500 ppm. Even with a higher dosage of corrosion inhibitor, traditional corrosion inhibitors may lose their chemical integrity at higher temperatures which can lead to non-performing degradation products or even precipitation which can block chemical injection systems and consequently lose economic advantage of chemical inhibition.⁶ For such reasons, the selection of adequate corrosion inhibitor for HPHT sour conditions is very challenging.

This paper presents the laboratory test results on the performance of a low dosage of a newly developed inhibitor based on a HPHT sour field simulated test conditions in the Middle East downhole sour oil field. Besides the inhibition performance, physical and secondary properties such as thermal stability, emulsification tendency, foaming tendency, and solubility were evaluated and the efficacy of the newly developed corrosion inhibitor is discussed.

EXPERIMENTAL PROCEDURE

Rotating Cage Test

All tests were conducted using 8 liter Hastelloy autoclaves equipped with a rotating cage (RC) assembly, Figure 1. Each vessel was fitted with gas in and out ports, a pressure gauge, a pressure transducer, a dip tube (for gas purging and solution sampling), a pressure relief valve and a chemical injection port. The autoclaves were also equipped with a drain valve for solution replenishment/sampling. A magnetic drive with an integrated, digital variable speed motor and tachometer was fitted to the lid of the autoclaves to provide rotation.

RC testing was conducted in the following sequence and in accordance with ASTM G184⁷ guidelines.

The coupons, 16 mm x 50 mm x 5 mm thick, were cut from API 5L X65 pipe material and identified. They were degreased in an ultrasonic bath with acetone before polishing to P500 surface finish. They were then measured and weighed to 0.01 mm and 0.1 mg accuracy, respectively.

The samples were photographed to assist with the post-test examination and positioned onto the RC carousel.

The solution was prepared using analar grade chemicals and deionized water inside a glass aspirator and sparged CP grade CO₂ gas to remove dissolved oxygen to ≤ 10 ppb; the corrosion inhibitor was added thereafter. The required amount of solution (7 liters) was then transferred, under positive, CO₂ pressure, into the test vessel. The solution was then sparged with the sour gas mixture for 30 minutes at room temperature. The fluids were heated to the test temperature, pressurized to the required partial pressure of acid gases, using an H₂S/CO₂ sour gas mixture, and the motor speed was adjusted to the required wall shear stress level.

On completion of each test, the vessel was allowed to cool to 40-50 °C before venting the acid gases through the catalytic oxidation unit. The test solution was then transferred to a separate autoclave for further treatment before disposal. The test vessel was sparged with N₂ to remove residual H₂S before retrieving the sample.

The exposed coupons were photographed and cleaned with soapy water to remove loose corrosion products. The coupons were cleaned with an inhibited acid solution in accordance to ASTM G1⁸ before photographing again.

The post exposure weight was determined and the annualized, average corrosion rates were calculated in accordance with ASTM G1 as follows:

$$\text{corrosion rate (mm/yr)} = (K \cdot \Delta W) / (A \cdot T \cdot D) \quad \text{Eq. 1}$$

where:

K = a constant (8.76×10^4) for units of mm/yr

ΔW = mass change (in g)

A = surface area (in cm²)

T = exposure period (in hours)

D = density of material (in g/cm³)

Surface analysis was conducted using a 3D profilometry microscope at various magnifications. The general surface of the exposed coupons together with any evidence of the localized attack was photographed and the depth of attack was recorded.

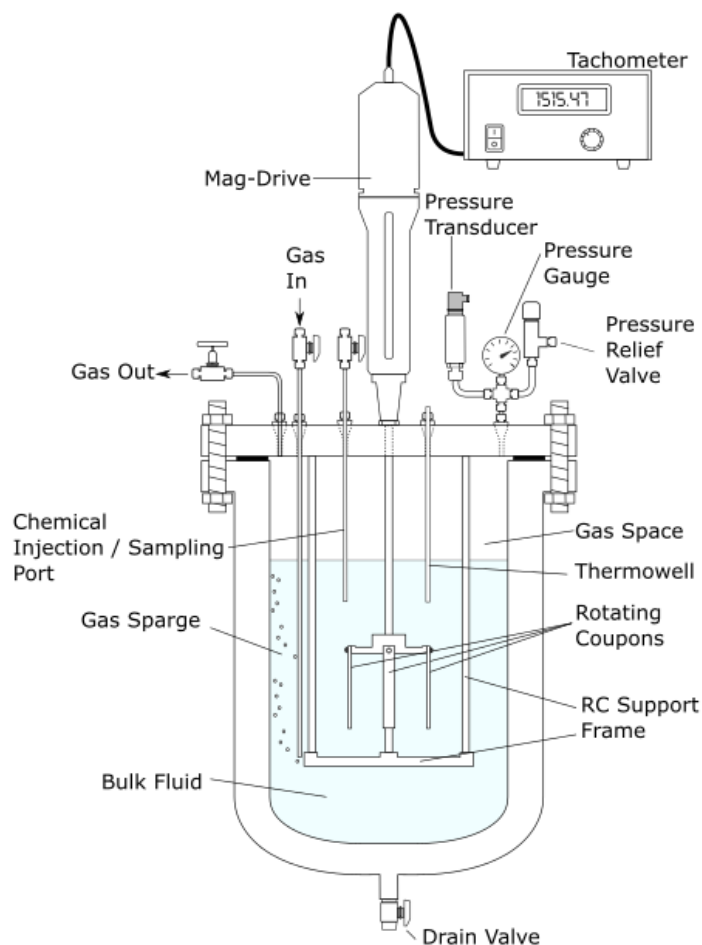


Figure 1: RC test assembly

The following conditions were used in the RC test:

Table 1
Autoclave Corrosion Test Conditions

Temperature (°C)	120
Shear Stress (Pa)	25
pH ₂ S (bar)	11.9
pCO ₂ (bar)	16.8
Water Chemistry	Table 2
Water Cut (%)	80
Hydrocarbon	LAWS/Balance
Inhibitor	U
Concentration (ppm)	60, 100
Test Duration (days)	4

Table 2
Simulated Brine Compositions

Ion	Concentration (mg/L)
Chloride	80,000
Sulphate	316
Barium	4
Calcium	1,250
Strontium	889
Magnesium	3,278
Sodium	46,132
Bicarbonate	928

Thermal stability/FTIR

The thermal stability of the corrosion inhibitor was assessed by subjecting the chemical to a 10 day thermal exposure at 120 °C in a sealed glass temperature resistant bottle (Schott Duran bottle, high temperature tolerance to 180 °C). The sample was degassed and covered with a nitrogen blanket prior to aging. Differences between the thermally exposed sample and the as-supplied product were measured by comparing their infrared spectra in a double beam FTIR infrared spectrometer.

Emulsification tendency

A mixture of 30 % brine and 70 % Low Aromatic White Spirit (LAWS) containing an excess dosage of corrosion inhibitor, based on the brine phase, was prepared and vigorously agitated at a temperature to simulate operational temperature and then allowed to stand. The respective volumes of hydrocarbon, brine and any emulsified phase present were observed, measured and recorded after ceasing agitation as a function of time at 0, 5, 15, 30, 60 minutes and final stability.

Foaming tendency

In the processing system, there are several areas where there is potential for direct interaction or carryover between applied chemicals and the fluid matrix. To ensure that the candidate inhibitor would not promote excessive foaming in these areas, a test was conducted to assess the foaming tendency in brine/synthetic hydrocarbon, LAWS as a substitute for actual field