

Paper No.
16672



Corrosion Failure Analysis and Corrosion Prevention Practice Of Water Injection Pipeline In Middle East Carbonate Oilfield

Zhengrong Ye, Xiang Zhou, Weidong Jiang, Zhichao Qiu, Xiaodong Cui, Guohao Chen
PetroChina Research Institute of Petroleum Exploration and Development
Beijing 100083
P. R. China

Huachang Chi
Al-Waha petroleum Co., Ltd
Kut 52001
Iraq

Weixiao Li, Zhiwen Yang, Maomao Wang
Safetech Research Institute (Beijing) Co., Ltd
Beijing 100083
P. R. China

ABSTRACT

In order to build up formation pressure and maintain oil production, a carbonate oilfield in the Middle East adopted water injection technology, then in less than two years, a number of corrosion perforation failures were seen in the water injection pipeline. In this paper, several methods are used to find out the pipeline failure mechanism, such as the corrosion simulation experiment, bacteria testing, scanning electron microscopy (SEM) and X-ray diffractometer (XRD). The results show that the composition of corrosion products was FeS, Fe₃O₄, FeCO₃ and CaCO₃, which created the possibility of under-deposit corrosion. The localized corrosion was more serious under the condition of coexistence of 100 mg/L S²⁻ and bacteria than the condition of 100 mg/L S²⁻ in the injected water. Deposition of scale and bacteria in the injected water are the important factors for the pipelines' fast corrosion and leakage. The corrosion prevention strategies of water quality modification and HDPE lining technology were proposed and achieved obvious result.

Key words: Water Injection Pipeline; Under-deposit Corrosion; Microbiologically Influenced Corrosion; Failure Analysis; Water Quality Modification; HDPE Lining Technology

INTRODUCTION

In order to build up formation pressure and maintain oil production, a carbonate oilfield in the Middle East adopted water injection technology. However, injected water introduced serious corrosion risks to the water injection strings and pipelines, such as dissolved oxygen corrosion, microbiologically

influenced corrosion, under-deposited corrosion and the combination of above corrosion, which were different with the production systems corrosion risks¹⁻⁴. In this paper, the injected water was a mixture of production water and Tigris river water with a mixing ratio of approximately 5:1. It had high salinity, bacteria and high content of S^{2-} which was mainly derived from the electrolytic dissociation of H_2S . Then in less than two years, a number of corrosion perforation failures had been seen in the water injection pipeline since its commission, and the localized corrosion rate was up to 5mm/y, which seriously affected the normal water injection and production of the oilfield.

Take the case of a water injection pipeline. It was put into service in August 2014. In October 2017, Corrosion perforation occurred and the perforation position was located at 6 o'clock and near the weld of the pipeline. Also, the internal wall was covered by the unequally distributed corrosion product or scale. The diameter of the pipeline was 152.4mm and the wall thickness was 9.53mm, the perforation rate was about 3.01mm/y. The material was API 5L X52N, and the service temperature was 40°C, the flow rate was 0.2m/s. And the longest stopping time before perforation was 30 days, the flow rate was 0m/s. The total sulfur content of the injected water exceeded the standard and reached 80mg/L. The dissolved oxygen content ranged from 0.05 to 0.10 mg/L. The injection salinity reached 13.5×10^4 mg/L, which was a high-salinity water quality, and the chloride ion content reached 8.2×10^4 mg/L.

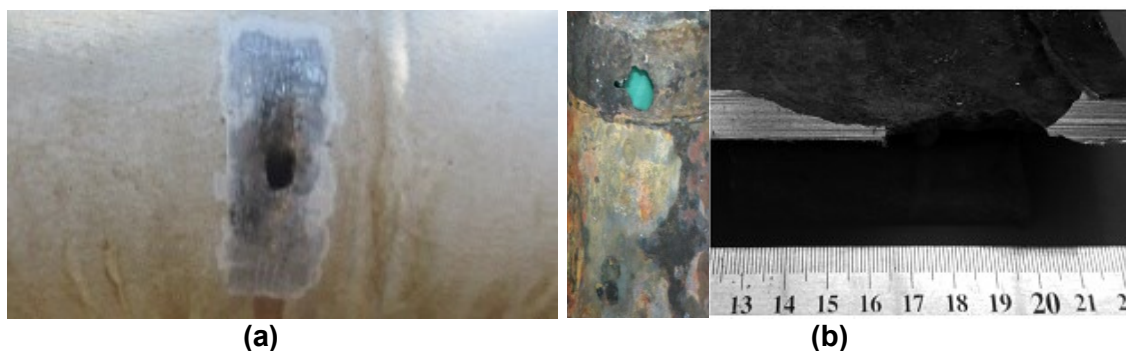


Figure 1: Appearance of corrosion perforation failed pipeline (a) Outer surface, (b) Internal surface

For the water injection pipeline, optical metallographic microscopy, scanning electron microscopy (SEM), energy dispersive spectrometer (EDS), and X-ray diffraction (XRD), combined with the weight loss and bacteria tests were used to find the main causes of the failure.

EXPERIMENTAL PROCEDURE

Firstly, in order to determine the material properties of the injection water pipeline, chemical composition and metallographic structure were analyzed. Secondly, XRD and SEM-EDS were used for further analysis on the corrosion products on the inner wall surface of the pipeline. The bacterial tests were performed with the on-site injection water according to the method recommended in GB/T 5239-2012. Finally, the immersion corrosion testing was conducted to verify the analysis results.

Three types of bacteria in the injected water were tested including sulfate reducing bacterial (SRB), saprophytic bacteria (TGB) and iron-oxidizing bacteria (IOB). TGB were aerobic bacteria that could produce organic and inorganic acids by microbial metabolism, such as lactic acid and carbonic acid, which could cause corrosion. The bacteria test of the injected water was carried out with three kinds of bacteria test bottles (SRB test bottle, TGB test bottle and IOB test bottle). The most possible number (MPN) method was used and the test procedure followed the standard of SY/T 5329-2012.⁵ During the testing, the bottles were placed in bacteriological incubator for 7 days at 311 K (99.5 °F). After 7 days, the amount of bacteria would be found out by inspecting the bacteria test bottles' color.

The laboratory corrosion immersion test was conducted in a high temperature and high pressure autoclave (as shown in Fig.2). The X52N pipeline steel used in the oilfield was selected as the test material. According to the standard ASTM G111-1997 (2013)⁶, the sample size was 50mm*13mm*3mm. Before the test, the samples were prepared by grinding smooth with SiC paper up to 800grit. Then the samples were cleaned with absolute ethyl alcohol and quickly dried using cold air to remove organic contaminations and avoid oxidation. The test temperature was 313K (101.5°F), the flow rate was 0.2m/s. The test solutions were a simulated solution of injected water, and the compositions were shown in Table 1. The dissolved oxygen content was 0.10 ppm. The samples were placed in a high temperature and high pressure reactor, after passing O₂. When the temperature and pressure reached the preset value, the test started, the test period was 120h. After the test, the chemical detergent (500mL HCl+500mL deionized water+3.5g hexamethylenetriamine) was used to remove all corrosion products from the sample surface, the surface corrosion morphology of the sample was observed with an optical microscope, and the uniform corrosion rate was calculated by weight loss. If pits occurred, pit depths should be measured, and the local corrosion rate was calculated.

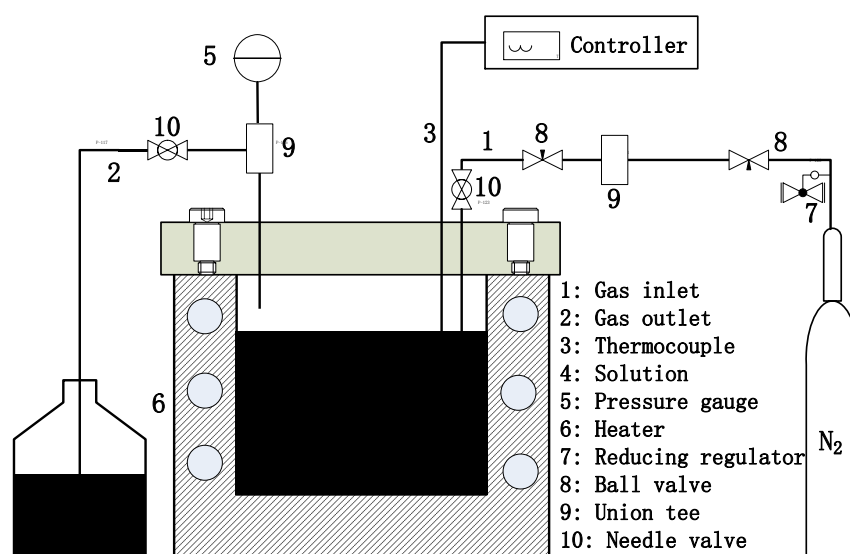


Figure 2: Schematic diagram of C276 autoclave.

Table 1
Simulated solution for immersion test

Water type	Ca ²⁺ (mg/L)	Mg ²⁺ (mg/L)	HCO ₃ ⁻ (mg/L)	Cl ⁻ (mg/L)	SO ₄ ²⁻ (mg/L)	S ²⁻ (mg/L)	K ⁺ &Na ⁺ (mg/L)	Dissolved oxygen (mg/L)	Bacteria content (cells/mL)
Injected water	6839	1050	269	82474	587	50	44055	0.10	existence
Simulated solution 1#	6839	1050	269	82474	587	50	44055	0.10	nonexistence
Simulated solution 2#	6839	1050	269	82474	587	100	44055	0.10	nonexistence