Petroleum 1 (2015) 75–81

Contents lists available at ScienceDirect

Petroleum

journal homepage: www.keaipublishing.com/en/journals/petlm

Original article

An experimental study on the internal corrosion of a subsea multiphase pipeline

Shangbi Peng [a, *], Zhaoxiong Zeng [b]

[a] School of Civil Engineering and Architecture, Southwest Petroleum University, Chengdu, China
[b] PetroChina Southwest Pipeline Company, Chengdu, China

ARTICLE INFO

Article history:
Received 14 April 2015
Received in revised form
22 April 2015
Accepted 23 April 2015

Keywords:
Subsea pipeline
Internal corrosion
Experiment
Corrosion inhibitor

ABSTRACT

Based on the actual operational parameters of a subsea multiphase pipeline, an experimental study on the internal corrosion of a subsea multiphase pipeline was conducted in a dynamic, high-temperature autoclave, which had a similar environment to an actual field environment, using the partial pressure of CO_2 (P_{CO2}), velocity of the corrosion medium, temperature, corrosion time, and corrosion inhibitor as variables. The results show that CO_2 resulted in severe localized corrosion and that the corrosion rate increased as the P_{CO2} and velocity increased; the corrosion rate first increased and then decreased with increasing temperature. The corrosion rate peaked at approximately 65 °C and then decreased continuously afterwards; the corrosion rate decreased as the duration of the experimental period increased. Under the operational conditions of the selected subsea pipeline, localized corrosion caused by CO_2 was still the primary corrosion risk. Several types of corrosion inhibitors could inhibit the occurrence of localized corrosion for a short time period; however, most corrosion inhibitors could not completely inhibit localized corrosion.

1. Introduction

As the "lifeline" for the development of offshore oilfields, subsea pipelines play a vital role in the production and transpiration of offshore oil and gas [1]. However, corrosion is a major, hidden danger that threatens the normal operation of subsea pipelines. According to statistics [2], corrosion is the first cause for failure of subsea pipelines.

Between the 1940s and 1950s, many countries began conducting research related to corrosion caused by CO_2. In the 1970s, there was a second upsurge in research that focused primarily on the mechanisms and influencing factors of corrosion [3]. Since then, there has been extensive theoretical and experimental research on the corrosion of subsea pipelines, studies that have primarily focused on the mechanisms of corrosion, prediction of corrosion rates, analysis of the ultimate bearing capacities of corroded pipelines, and the use of corrosion inhibitors in retarding corrosion.

(1) Mechanisms of corrosion and corrosion rates

Based on extensive corrosion data obtained from experiments conducted in laboratories and field monitoring, many petroleum companies and research institutions have proposed a number of different corrosion prediction models, which can generally be classified into three types: empirical models, semi-empirical models, and mechanism models [4–8]. Neural network prediction methods have also been used to predict the corrosion rates of subsea pipelines.

(2) Ultimate bearing capacities of corroded pipelines

Choi et al. [9] conducted an experimental study and a numerical simulation analysis of X65 corroded gas pipelines. Netto et al. [10] studied the effects of the geometric parameters of corrosion and the properties of pipeline materials on the ultimate internal pressure of pipelines through a reduced scale

---

[*] Corresponding author.
E-mail address: 254587354@qq.com (S. Peng).
Peer review under responsibility of Southwest Petroleum University.

Production and Hosting by Elsevier on behalf of KeAi

http://dx.doi.org/10.1016/j.petlm.2015.04.003

experiment and a numerical simulation analysis. Pfennig A. [11,12] found that the presence of CO_2 at high temperatures (40–60 °C) considerably corroded steel pipe. Zhang Yucheng et al. [13] researched the relationship between fracture toughness of CO_2 corrosion scale and the corrosion rate of X65 pipeline steel under a supercritical CO_2 condition. Esmaily M. et al. [14] investigated the effect of temperature on the NaCl-induced atmospheric corrosion of Mg–Al alloy AM50 in the laboratory.

(3) Research on corrosion inhibitors

Inhibitors have been primarily applied as individual treatments for corrosion because inhibitors have been proven to be successful and cost effective [15–18]. Inhibitors can act as a surface active component and can form a protective layer on the substrate, modifying the properties of the surface [19,20].

To date, most studies have focused on understanding and quantifying the performance of either corrosion inhibitors or scale inhibitors [21]. R. Ketrane et al. [22] studied the effects of temperature and concentration of five scale inhibitors on calcium carbonate ($CaCO_3$) precipitation from hard water.

In the present study, the actual operational conditions of subsea pipelines were simulated in the laboratory, and the effects of factors such as the partial pressure of CO_2 (P_{CO2}), velocity of the corrosion medium, temperature, corrosion time, and the corrosion inhibitor on the corrosion rate were analyzed under simulated operational conditions. The results of the present study provide a reference for the safe operation of subsea pipelines.

2. Experimental methods

According to the actual operational parameters of subsea pipelines, the corrosion environment of an internal subsea pipeline was simulated in the laboratory. The P_{CO2}, velocity of the corrosion medium, temperature, corrosion time and the corrosion inhibitor were selected as variables.

2.1. Experimental materials and equipment

The failed section of a subsea pipeline that had been recovered from the sea was used as the experimental material. The failed pipeline section was made from X65 pipeline steel, which had the following chemical composition: C ≤ 0.26, Si 0.23, Mn ≤ 1.45, P ≤ 0.03, S ≤ 0.03, V + Nb + Ti ≤ 0.15, Cr ≤ 0.5, Ni ≤ 0.5, Mo ≤ 0.15, Cu ≤ 0.5, and Fe (balance). The main corrosion inhibitors used in the experiment were HYH-151B and C and TS-719B. The medium used in the experiment was the produced liquid from the subsea pipeline. Table 1 lists the composition of the medium.

2.2. Experimental process and steps

The laboratory corrosion simulation was conducted in a dynamic, high-temperature autoclave, which is similar to the actual field environment. The experimental steps were as follows:

Table 1
Composition of the aqueous medium.

Composition	NaCl	$CaCl_2$	$MgCl_2$	$NaHCO_3$
Concentration (g/L)	32.378	1.721	0.431	2.849

(1) The experimental material was machined into specimens with the same shape, which is shown in Fig. 1. The experimental surface of each specimen was polished with 800# abrasive paper. Afterwards, each specimen was degreased and dried with anhydrous ethanol.
(2) After cleaning, each specimen was weighed on an electronic analytical balance with a precision of 0.1 mg. Subsequently, the non-experimental surfaces of each specimen were sealed with 704 silica gel. Then, each specimen was fixed on an experimental fixture, and the superfluous silica gel on the experimental surface was removed with anhydrous ethanol. Each specimen was then placed in a desiccator until the silica gel solidified.
(3) The experimental solution was placed in a deaerator for 24 h to remove the oxygen content with high-purity N_2.
(4) Each specimen was secured on a fixture, which was fixed on a rotary rod inside of the high-temperature autoclave. The solution was then poured into the autoclave. After sealing the autoclave, CO_2 was pumped into the autoclave. The pressure of CO_2 was adjusted when the preset temperature was reached inside of the autoclave. The specimens were rotated at the required speed. During the experimental process, CO_2 was continuously pumped into the autoclave, and the P_{CO2} was maintained. Each group of specimens was removed from the autoclave after the specimens were corroded for 7 d and 30 d. Each specimen was then rinsed with water, degreased with anhydrous ethanol, and dried in cold air. Afterwards, the macroscopic surface morphology of the corrosion product of each specimen was photographed. The corrosion product film on each specimen was removed with acid washing, and then the specimen was rinsed and weighed. The mean corrosion rate was calculated using the weight loss method. The macroscopic corrosion morphology of each specimen, whose corrosion product was removed, was photographed after the specimen was dried in cold air.

3. Experimental results and analysis

3.1. Effect of P_{CO2} on the corrosion rate

Figs. 2 and 3 show the external morphologies and corrosion rates of the internal subsea pipeline (X65 steel) that was corroded under different P_{CO2} values for 30 d, respectively (experimental conditions: temperature, 75 °C; velocity of the corrosion medium, 1.5 m/s; corrosion medium, produced liquid from the recovered pipeline). It can be observed that severe localized corrosion occurred on the surfaces of the specimens under long (30 d) experimental conditions. When other conditions remained the same, the corrosion rate increased when the P_{CO2} increased from 0.3 MPa to 0.5 MPa, which occurred because

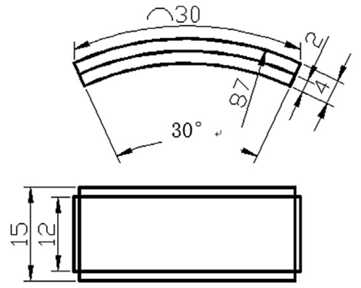

Fig. 1. Material specimen.