Engineering Failure Analysis 82 (2017) 16–25

Contents lists available at ScienceDirect

Engineering Failure Analysis

journal homepage: www.elsevier.com/locate/engfailanal

Pitting corrosion failure analysis of a wet gas pipeline

Hamed Mansoori[a,*], Reza Mirzaee[a], Feridun Esmaeilzadeh[b], Arash Vojood[c], Alireza Soltan Dowrani[d]

[a] National Iranian Oil Company, Iran
[b] Chemical Engineering Department, Shiraz University, Iran
[c] Young Researchers and Elite Club, Ardabil Branch, IAU, Iran
[d] Department of Material Engineering, Science and Research Branch, IAU, Iran

ARTICLE INFO

Keywords:
CO_2 pitting corrosion
Multiphase gas pipeline
Corrosion inhibitor
Corrosion product, API 5L X65
$CaCO_3$

ABSTRACT

This paper presents corrosion failure analysis of an underground natural gas pipeline. The pipeline material grade is API 5L X65 with 10-in ID. The pipeline transfers multiphase fluid (gas, condensate, and water) from a gas well to a gas gathering plant, located 4200 m away from the well site. A portion of the line failed due to pitting corrosion under unknown circumstances. Scanning electron microscopy (SEM) and X-ray diffraction (XRD) are employed to characterize the scales and/or corrosion products near the failed portion. Based on visual and microscopic analyses and reviewing the background information, the following pitting corrosion sequences were identified: the oversized pipeline changed the dominant flow regime to “stratified”. In the stratified flow regime, the accompanying water phase accumulated in the pipelines' low points. Considerable concentration of calcium ions along with high pH in CO_2 media favored precipitation of calcium carbonate. The relatively thick scales adhered to the pipe surface were partially loosened and removed by the regional turbulent flow. This exposed the fresh steel surface to the corrosive media. The uncovered areas acted as the preferential anodic sites coupled with nearby large cathodic sites which were covered by scales and/or corrosion products. Under such conditions, pits emerged on the steel surface until one of them grew faster and failed the gas pipeline.

1. Introduction

Oil and gas extraction from reservoirs are to be continued as far as fossil fuels remains the most dominate source of the world energy [1]. Corrosion is a destructive and cost-bearing phenomenon for every industry dealing with metallic structures. Oil & gas production has been suffering from corrosion since the early history of the industry. Corrosion imposes significant cost of repair and replacement of infrastructures [2]. Indeed, it forces unplanned shutdowns and causes catastrophic incidents that result in environmental contamination and human casualties. NACE has estimated the total costs associated with all types of corrosion at $276 billion in the United States [3]. Corrosion of onshore oil & gas transmission pipelines comprises $7 billion of this total [4]. However, the costs associated with corrosion can be reduced significantly if appropriate corrosion mitigation programs are applied [5,6].

Pipeline networks are the main body of all sectors of oil industry including exploration, production, treatment, and distribution. Multiphase pipelines of oil & gas gathering systems are more vulnerable to corrosion phenomena as a result of complicated water chemistry, presence of acid gasses such as CO_2 and H_2S, multiphase flow, etc. Among all types of corrosion attack, pitting corrosion is

* Corresponding author at: Institute for Corrosion & Multiphase Technology, Ohio University, USA.
E-mail address: hm419213@ohio.edu (H. Mansoori).

http://dx.doi.org/10.1016/j.engfailanal.2017.08.012
Received 21 July 2017; Received in revised form 7 August 2017; Accepted 25 August 2017
Available online 26 August 2017
1350-6307/

Table 1
Compositional analysis of the gas phase.

Component	Mole percent
Methane	85.57
Ethane	4.49
Propane	1.35
Iso-butane	0.30
N. butane	0.53
Iso-pentane	0.51
N. pentane	0.52
Hexane	0.79
Heptane	0.54
Octane	0.07
Nonane +	0.02
Nitrogen	2.10
Carbon dioxide	3.21

Sample pressure: 113 bar
Sample temperature: 46 °C
Specific gravity: 0.69
Molecular weight: 20.38

the cause of most failures, especially in wet gas pipelines. Therefore, maintaining pipeline integrity in oil & gas production and gathering systems is a real concern [4,5,7,8].

Numerous parameters influence pitting corrosion rate such as temperature, total pressure, partial pressure of acid gasses (CO_2 and H_2S), pH, concentration of dissolved ions such as Cl^- and Ca^{2+}, pipe inclination, production rate of oil/gas/water, etc. [9,10]. Moreover, the stochastic nature of pit initiation and growth cast more uncertainty on monitoring and predicting techniques applied in field [11–15].

Case studies of pitting corrosion in multiphase pipelines play an essential role in understanding, controlling and even modeling of this enemy of pipelines [9,16]. This paper discusses CO_2 pitting corrosion failure of a multiphase gas pipeline located onshore, south of Iran. It will be discussed how the pits have remained hidden from the corrosion monitoring techniques until one of them grew faster and caused the failure. Indeed, detailed failure discussion is provided.

1.1. Pipeline description

The buried API 5L X65 pipe steel has an ID of 10″. Multiphase fluid (gas, condensate and water) is transferred from a production gas well to a downstream gas gathering unit located 4.2 km away from the well. Table 1 shows the average gas composition of the field which is nominally H_2S free. Amine-type corrosion inhibitors (CI) have been applied since the operation of the pipe as the available internal corrosion mitigation program. Prior to injection, the CI is diluted in gasoline and/or stabilized gas condensates in order to increase its fluidity and adherence factors. It is worth mentioning that the external corrosion program for this underground pipeline includes applying 3-layer polyethylene coating in conjunction with impressed cathodic protection system (ICPS). Corrosion monitoring tools and evaluation of CI efficiency include a combination of the following methods:

1- Electrochemical tests in laboratory
2- Field data from corrosion coupons and electrochemical resistance (ER) probes
3- Iron ion counting at the inlet and outlet of the pipe
4- Non-destructive tests.

The pipeline experienced its failure after 2 years of continuous operation. The failure was unexpected by the operator due to two main facts. First, the design lifespan of the pipe, based on fluid characteristics and pipe's material, was at least 20 years. Second, the pipe was under tight corrosion monitoring and mitigation programs. Furthermore, what made the pipe's failure more complicated was that such incident had not been observed in other identical pipelines at the gas field.

2. Corrosion monitoring techniques

Here, corrosion monitoring techniques applied to the failed gas pipeline are evaluated. It is discussed how these techniques can be deceptive in predicting the magnitude of pitting corrosion.