

Corrosivity Laboratory Investigations of Streams Associated with Gas Compression Plants and Liquid Separation Stations

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ABSTRACT

The purpose of this laboratory study was to assess the corrosivity of fluids transported through a huge network of gas transmission lines associated with nine (9) Gas Compression Plants (GCPs) and six (6) Liquid Separation Stations (LSSs). The CO₂ content ranges from 0.94 mol% to 3.9 mol%, while the H₂S content varies from 0 to 1.9 mol%. The lines range in diameter from 20 to 36 inches. The highest gas flow rate in these lines is 757 MMscfd, and the highest estimated temperature and pressure are 140°F (60°C) and 1050 psig (72 bar), respectively. The study consisted of three parts: 1) uniform corrosion in liquid and gas phases; 2) pitting corrosion in liquid and gas phases; and 3) gas phase corrosion. The absence of dissolved solids and bacteria eliminated the need to study for scaling and microbiologically-influenced-corrosion (MIC). The study was conducted using a rotating cage assembly with low alloy carbon steel test coupons and distilled water with 0, 150, and 1000 mg/L chloride.

The obtained results show that corrosion in the liquid phase is more severe under sweet conditions than under sour conditions. In both cases, however, corrosion can be managed through the use of effective corrosion inhibition program. On the other hand, corrosion in the gas phase is more significant under sour conditions than under sweet environments. Therefore, the use of both continuous and batch corrosion inhibitor treatments is necessary under these conditions. The presence of chlorides showed an impact under sour conditions while under sweet conditions their impact was not as obvious. Pitting attacks were observed under sour test conditions in the liquid phase when left running for a period of 14 days. Pits were observed in the presence and absence of chloride ions. Coupons tested under sweet conditions didn't show any observable pits.

Gas phase corrosion was studied at low velocities to avoid water splashing. The wall shear stresses in these tests were close to 1 Pa. Similar trend was observed as in tests conducted at higher rotation speeds. Under sour conditions, the results indicated that corrosion rates were comparable in both liquid and gas phases while under sweet conditions corrosion rates in the gas phase were negligible. Based on these results, if corrosion inhibition is selected as the corrosion control method, then the applied inhibitors must be effective in protecting the whole internal circumference of the line, i.e. internal surfaces exposed to both liquid and gas phases.

Key words: corrosivity assessment, gas transmission lines, rotating cage

INTRODUCTION

The design packages are being optimized for the construction of gas transmission lines associated with nine (9) Gas Compression Plants (GCPs) and six (6) Liquid Separation Stations (LSSs). The objective of this study was to assess the service corrosivity of all gas transmission lines associated with these GCPs and LSSs. The results of the study will assist in selecting a cost-effective and efficient corrosion management program in terms of both materials and corrosion control options. To address this objective, the study involved conducting laboratory tests simulating the conditions in these lines. Three types of corrosion attacks were investigated, namely, general corrosion, pitting corrosion, and gas phase corrosion.

The proponent suggested that top-of-the-line corrosion (TLC) should be investigated as well. Knowledge of the transmission line skin temperature is required, however, to simulate TLC. Normally, TLC is driven by an abrupt drop in external temperature leading to water condensation selectively on top of the line.¹⁻³ Runs by OLGA flow modeling predict the fluid temperature to fluctuate between 140°F at the inlet of the pipeline to ~105°F at the outlet of the pipeline. The direct skin temperature was assumed to be equal to the fluid temperature. The employed heat transfer model assumes a soil temperature of 60°F.

The presence of organic acids would aggravate TLC.⁴⁻⁷ According to the field personnel, however, organic acids are not expected to be present. Since the direct skin temperature was assumed to be equal to the fluid temperature and since there are no organic acids present in the stream, the study focused on gas phase corrosion rather than TLC. The difference is that in the case of gas phase corrosion all internal surfaces exposed to the gas are considered rather than top of the line only. Therefore, we elected to use gas phase corrosion to refer to the whole surface exposed to the gas phase attack including top of the line.

The absence of dissolved solids and bacteria, which were confirmed by the proponent, eliminated the need to study for scaling and microbiologically-influenced-corrosion (MIC). The laboratory study therefore consists of three parts: 1) uniform corrosion in liquid and gas phase; 2) pitting corrosion in liquid and gas phase; and 3) gas phase corrosion.

EXPERIMENTAL PROCEDURE

A laboratory test matrix was developed which consisted of three parts: 1) general corrosion under sweet and sour simulated conditions; 2) pitting corrosion under sour simulated conditions; and 3) gas phase corrosion under sweet and sour simulated conditions. In developing the laboratory test matrix, the process data of the gas transmission lines were reviewed. The proponent proposed to develop a test matrix which considers the service conditions of two GCPs simulating one sour and one sweet systems. The Process Flow Diagrams (PFDs) and the Heat and Material Balance (H&MB) data showed the presence of a chloride level of 1,000 ppm. According to the proponent, this was based on the Detail Design Contractor Process Simulation. The proponent, however, has high uncertainty on the final geochemical contents of water on these transmission lines as the Compression Plants do not have a full liquid removal processing system. Based on the above and to ensure that all cases are covered, the proponent requested to consider the following three cases:

1. Chloride and bicarbonate @ 0 ppm
2. Chloride @ 150 ppm & 0 ppm bicarbonate
3. Chloride @ 1000 ppm & 0 ppm bicarbonate

Due to the uncertainty of the chloride level, the laboratory tests covered all three cases. The results of this study will also be used to request chemical vendors to provide the best and optimized inhibitor package. The actual contents will be determined based on geochemical analysis of collected samples once the plants are started-up.

To address the three different corrosion attacks, in total eighteen (15) laboratory test conditions were developed as given in Table 1. For gas phase corrosion, a rotation speed of 100 rpm was selected to avoid any water splashing to the gas phase.

Table 1
Laboratory Test Matrix for Gas Transmission Lines Corrosivity Assessment

Test No.	T (°F/°C)	CO ₂ (psia)	H ₂ S (psia)	Cl ⁻ (mg/L)	Speed (RPM)	Test Duration	Volume (mL)
General Corrosion							
GCP Sweet System							
HH-1	140 / 60	34	0	0	1000	18 hr	600
HH-2	140 / 60	34	0	150	1000	18 hr	600
HH-3	140 / 60	34	0	1000	1000	18 hr	600
GCP Sour System							
HH-4	140 / 60	16	14	0	1000	18 hr	600
HH-5	140 / 60	16	14	150	1000	18 hr	600
HH-6	140 / 60	16	14	1000	1000	18 hr	600
Pitting Corrosion (Long-Term)							
GCP Sour System (36")							
HH-7	140 / 60	16	14	0	500	14 days	600
HH-8	140 / 60	16	14	150	500	14 days	600
HH-9	140 / 60	16	14	1000	500	14 days	600
Gas Phase Corrosion (Condensation)							
GCP Sweet System							
HH-10	140 / 60	34	0	0	100	18 hr	500
HH-11	140 / 60	34	0	150	100	18 hr	500
HH-12	140 / 60	34	0	1000	100	18 hr	500
GCP Sour System							
HH-13	140 / 60	16	14	0	100	18 hr	500
HH-14	140 / 60	16	14	150	100	18 hr	500
HH-15	140 / 60	16	14	1000	100	18 hr	500

In these experiments, worst-case scenarios were considered along with limitations in laboratory capabilities. The volume of the solution was 600 mL except for the gas phase corrosion tests where the volume was 500 mL. The autoclave dead volume is about 1000 mL. To study both uniform and non-uniform attacks, the tests were run over relatively short and long periods of time. For uniform corrosion, the tests were run for 18 hours to avoid artificial retardation of corrosion rates due to formation of corrosion products which is attributed to the limited amount of test solution in the laboratory set-up. For non-uniform corrosion, tests were run for 14 days to allow pits to form and populate. Moreover, corrosion rates in both liquid and gas phases were measured in all tests.

To conduct these experiments, high-pressure / high-temperature (HPHT) rotating cage systems were used. One-liter autoclave reactors were used to conduct the short- and long-term corrosion tests under simulated dynamic field conditions. A typical autoclave reactor is shown in Figure 1. Also shown is a rotating cage apparatus used to generate controlled dynamic (flow) conditions inside the reactor. A typical rotating cage used to measure corrosion rates in both liquid and gas phases is shown in Figure 2. The reactors and the rotating cage assembly are constructed from Hastelloy C-276. Carbon steel coupons, CS1018, were used in these autoclave tests. Table 2 gives a typical chemical composition of these coupons. The carbon steel coupons were degreased and cleaned before and after testing in accordance with ASTM G 1⁸.

Test coupons were installed into the rotating cages after cleaning and weighting. For each test, an assembly of top and bottom rotating cages with were used. The top cage has a set of two test coupons and the bottom cage has another set of two test coupons. The whole assembly was then mounted into the autoclave. The test solution was purged with nitrogen gas for two hours to remove dissolved oxygen. The test solution was then transferred into the autoclave vessel. The vessel was closed and all necessary connections were made ready to start the test. The autoclave was heated to the desired temperature 140°F (60°C). The shaft rotation was set at the desired rotation speed. The gases were introduced to the reactor chamber. First H₂S was introduced until the required pressure was achieved followed by CO₂ to arrive at the final total pressure. The rotating cage assembly was left in the autoclave reactor for either 18 hours or 14 days and then was removed. The corrosion rates were calculated by taking the weights of the cleaned coupons before and after exposure.

A key parameter in the test conditions is the wall shear stress. The following empirical equations were used to estimate the highest average, τ_{mean} , and instantaneous, τ_{95} , wall shear stresses on the surface of the rotating coupons⁹:

$$\tau_{mean} = \alpha \times RPM^\gamma \times \eta^\lambda \quad (1)$$

$$\tau_{95} = \beta \times RPM^\gamma \times \eta^\lambda \quad (2)$$

Where,

τ_{mean}	= Maximum average wall shear stress (Pa)
τ_{95}	= Maximum instantaneous wall shear stress (Pa)
$\alpha, \beta, \gamma, \lambda$	= Empirical constants determined experimentally
RPM	= Speed of the rotating cage in revolution per minute
η	= Hydrodynamic viscosity (mPa.s)

The hydrodynamic viscosity, η , of distilled water at 140°F/60°C is equal to 466.5×10^{-6} Pa.s¹⁰. Table 3 gives the two different rotating cage wall shear stresses for the three different rotation speeds used in this study by substituting the values of η and RPM into Eq.'s 1 and 2. Due to similarities in field conditions, these rotation speeds were selected based on a previous study¹¹.



(a) 1-L Autoclave reactor



(b) Rotated cage with test coupons

Figure 1: Photographs of the autoclave setup (a) and the rotated cage with test coupons (b).

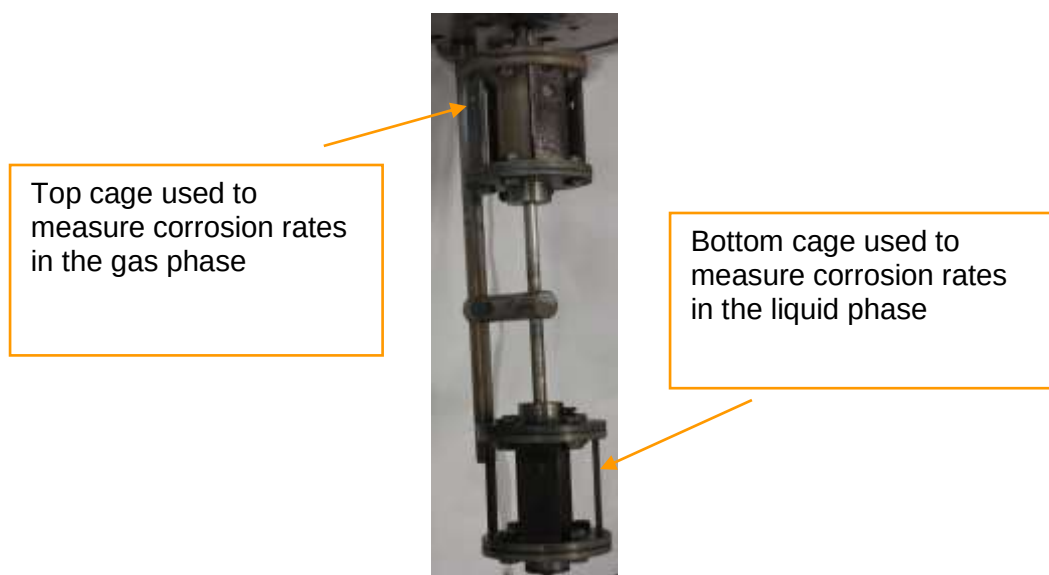


Figure 2: Photograph of a typical rotated cage assembly used to measure corrosion rates in both gas (top) and liquid (bottom) phases.

Table 2
Test Coupons CS1018 Data

UNS	G10180
Density (g/cm³)	7.87
Element	Content (%)
Manganese, Mn	0.60-0.90
Carbon, C	0.15-0.20
Sulfur, S	0.05 (max)
Phosphorous, P	0.04 (max)
Iron, Fe	Balance

Table 3
Wall Shear Stresses Calculated Using Eq.'s 1 & 2 at Different RPM Values

Cage Rotation Speed (RPM)	τ_{mean} (Pa)	τ_{95} (Pa)
100	0.92	1.64
500	10.29	18.34
1000	29.09	51.86

Upon completion of the first set of fifteen (15) experiments given in Table 1 above, additional tests were conducted, Table 4 below. These new tests were conducted based on additional data received for the transmission pipelines downstream of the GCPs.

Table 4
Additional Tests Conducted at 140°F/ 60°C to Confirm Gas Phase Corrosion Results

Operating Conditions					Minimum Pipeline Metal Temperature (Note 1)	
Test No.	CO ₂	H ₂ S	Cl ⁻ (Note 2)	Max Estimated Free-Water Volume	Summer Case	Winter Case
	(psia)	(psia)	(mg/L)	vol %	(°F/°C)	(°F/°C)
GCP Sweet						
GP-1	34	0	0	20	100 / 38	85 / 29
GP-2	34	0	150	20	100 / 38	85 / 29
GP-3	34	0	1000	20	100 / 38	85 / 29
GCP Sour						
GP-4	16	14	0	20	100 / 38	85 / 29
GP-5	16	14	150	20	100 / 38	85 / 29
GP-6	16	14	1000	20	100 / 38	85 / 29

Note 1: The soil temperature was measured to be 60°F (16°C) and 90°F (32°C) in the winter and in the summer, respectively. The pipeline minimum metal temperatures were estimated based on OLGA Dynamic Multiphase Flow Simulator.

Note 2: Additional testing with chlorides level of 150ppm and 1000ppm was requested by the proponent.

Moreover, these new tests were conducted because corrosion rate values calculated by modelling didn't match the laboratory results. For sour service conditions, corrosion modeling predicted negligible corrosion in the gas phase. The lab results, however, consistently indicated significant corrosion in the gas phase. This led to the suggestion that water splashing into the gas phase was behind the higher values. Consequently, these tests were conducted to verify this assumption.