

# Pipeline Corrosion Under Wet Gas Conditions

Y.H. SUN, T. HONG, AND W.P. JEPSON,  
*Corrosion in Multiphase Systems Center, Ohio University*

**Carbon dioxide (CO<sub>2</sub>) wet gas corrosion rates at the top and bottom of a high-pressure, 10-cm-diameter pipe were measured at pressures  $\leq 1.82$  MPa at a temperature of 40°C. The flow patterns were determined at gas velocities  $\leq 1$  m/s and liquid velocities  $\leq 0.2$  m/s. The liquid was deionized water and the gas was CO<sub>2</sub>. Flow patterns at test conditions were annular or near the stratified-annular flow transition zone. The corrosion rate became stable after 3 h and increased along with gas velocity, liquid velocity, and CO<sub>2</sub> partial pressure. The test results can be applied to actual field conditions.**

**C**arbon dioxide (CO<sub>2</sub>) corrosion of low-alloy steels such as carbon steel is a well recognized phenomenon in oil and gas production, transportation, and processing. The type of corrosion caused by dissolved CO<sub>2</sub> varies considerably according to precise environmental conditions.<sup>1-4</sup> In natural gas pipelines, temperature reduction causes condensation of water and hydrocarbon along the length of the pipe. The produced fluids may contain significant levels of CO<sub>2</sub>, hydrogen sulfide (H<sub>2</sub>S), and organic acids that, combined with free water, make the pipeline environment potentially very corrosive.<sup>5</sup> In these multiphase flow conditions, various types of flow re-

gimes exist, each of which contributes differently to the corrosion rate.<sup>6</sup>

The flow patterns encountered in wet gas systems are mist flow, annular mist flow, and stratified flow (Figure 1).<sup>7</sup> In annular flow, the liquid phase contacts all of the pipe wall's perimeter with a gas core in the middle. This flow usually occurs when the gas velocity is high.<sup>8</sup> At very high gas velocities and low liquid contents, a mist flow can be achieved. The stratified flow regime is common in wet gas pipelines at low gas velocities. Typically, the gas phase flows in the upper portion of the pipe and the liquid phase is transported in a film covering the bottom portion of the pipe. Some of the liquid is transported as droplets that are entrained in the vapor phase and can deposit on the top of the pipe. Consequently, corrosion can occur at both the top and bottom of the pipe. Top-of-the-line corrosion (TLC) is specific to wet gas lines.<sup>9</sup>

Corrosion studies have not been carried out systematically in flow conditions similar to those observed in wet gas systems. This work determines the flow patterns and discusses the effect of time and different liquid and gas velocities on corrosion rates at the top and bottom of the pipe for different pressures.

## Experimental Setup and Procedure

### FLOW LOOP

The flow loop is an 18-m (46-cm)-long, 10-cm-diameter, high-pressure, high-temperature, inclinable system. Figure 2 shows a schematic diagram of this system. The entire flow loop is manufactured from type 316 stainless steel (SS) (UNS S31600). A predetermined oil-water mixture is stored in a 1.4-m<sup>3</sup> tank that serves as a storage tank and a separation unit for the multiphase gas-oil-water mixture. A heating jacket surrounds the tank. Heater oil, heated in a separate heating tank that uses four 15-kW heaters, is pumped to the heating jacket to heat the contents of the storage tank. A variable-speed

centrifugal pump moves liquid through the system. The liquid flow is then controlled within a range of 0 to 100 m<sup>3</sup>/h with the variable speed pump in conjunction with a recycle stream. An inline turbine meter regulates the liquid flow rate.

A fresh gas feed line at 2 MPa pressure supplies CO<sub>2</sub> gas from a 20,000-kg storage tank. This line is used initially to pressurize the system and then for calibration purposes when the system is run with once-through gas. In normal operation, gas is continuously circulated through the system at desired speeds by a multiphase progressing cavity pump, which is driven by a variable-speed motor through a reduction gear system. An exhaust line with a knockout drum is used to vent gas from the system when required.

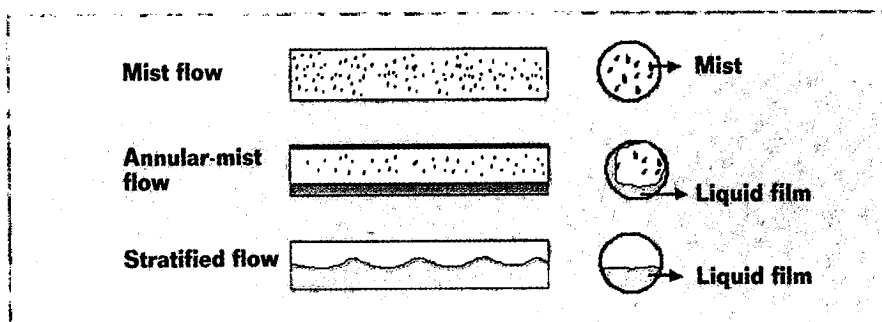
Before the experiment, the solution was deoxygenated with CO<sub>2</sub> and the levels of dissolved oxygen and dissolved iron were controlled below 20 ppb and 10 ppm, respectively. The oxygen and iron levels were periodically monitored, and samples were taken and tested using CHEMets<sup>†</sup> dissolved oxygen and iron test kits. Before the test, the surfaces of the electrodes were wet-polished by grid sandpaper up to 600 grit and then rinsed with acetone (CH<sub>3</sub>COCH<sub>3</sub>) and distilled water.

At the start of the experiments, the system is pressurized to the required level. The liquid pump is turned on and a required liquid flow rate is set. The recirculating gas pump is then turned on and the required gas flow rate is set. The gas-liquid mixture enters the test section, where corrosion measurements are made, and is then returned to the storage tank, where the mixture is separated. After separation, the gas is fed to the recirculating pump.

### TEST SECTION

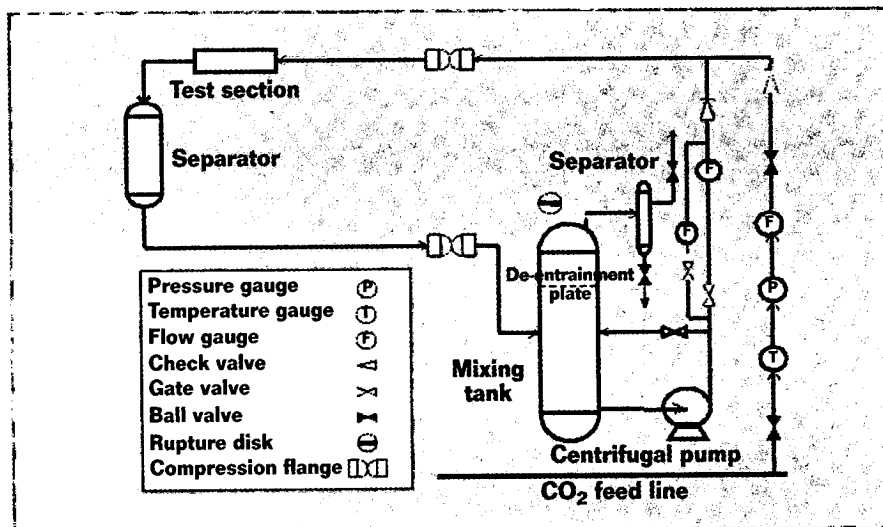
The test section is a 0.10-m-diameter, 2-m-long schedule 80 SS pipe. Fig-

FIGURE 1



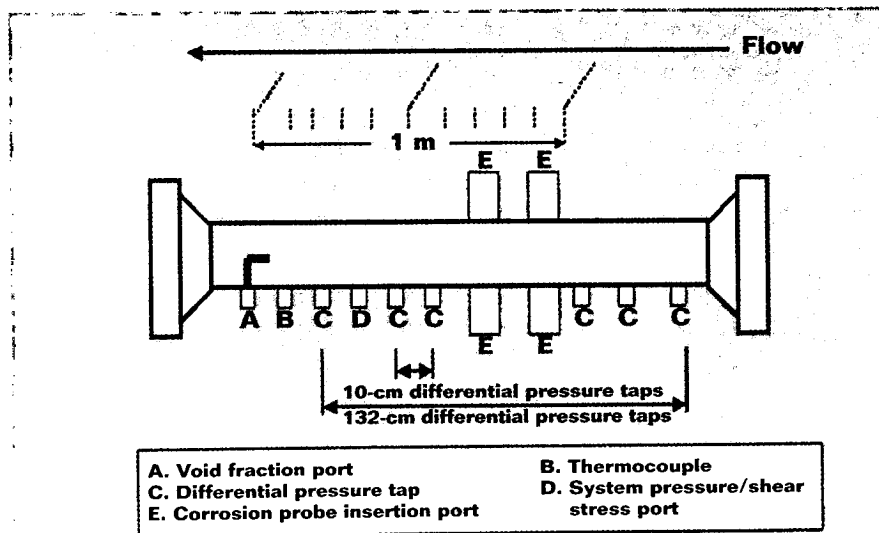
Flow patterns observed in wet gas pipelines.

FIGURE 2



Schematic of the high-pressure inclinable flow loop system.

FIGURE 3



Schematic of the test section.

<sup>†</sup>Trade name.

TABLE 1

## TEST MATRIX

Parameter	Conditions
Water cut	100%
Temperature	40°C
Pressure	0.45, 0.79, 1.13, 1.48, 1.82 MPa
Superficial liquid velocity	0.1 and 0.2 m/s
Superficial gas velocity	7, 9, and 11 m/s
Liquid loading, bbl/mmscf d	105, 140, 170, 200, 250, 310, 350, 400, 480, 580, 700, 850

Figure 3 shows a schematic of the section. The two pairs of ports at the top and bottom are used to insert flush-mountable electrical resistance (ER) probes for corrosion rate measurements. ER probes are used with an automatic data logging system. The pressure tappings are connected to a pressure transducer to measure the pressure drop through the test section. These are used to determine the flow pattern. There are ports for inserting the pH probe and the thermocouple.

### TEST MATRIX

Demineralized water is used as the liquid phase and CO<sub>2</sub> is used as the gas phase. Table 1 shows the test matrix.

## Results

### FLOW REGIME DETERMINATION

At superficial liquid velocities <0.2 m/s, the flow pattern is in either the stratified flow or annular flow regime. The stratified-annular flow transition line shifts slightly to the left when the pressure increases from 0.45 to 1.82 MPa at given gas and liquid velocities. For example, at the superficial liquid velocity of 0.1 m/s and gas velocity of 7 m/s, the flow pattern is in the stratified-annular flow transition zone at 0.45 MPa and shifts to annular flow at 1.82 MPa. Hence, the gas velocity to obtain annular flow decreases with an increase in pressure.<sup>10-12</sup>

Among the gas and liquid velocities studied, the flow patterns are in annular flow or the stratified-annular flow transition zone. The test conditions represent the wet gas conditions, and the test results can apply to these conditions for obtaining corrosion information in wet gas pipelines.

### EFFECT OF TIME

Figure 4 shows the effect of time on corrosion rate at the top and bottom of the pipe for gas and liquid velocities of 7 and 0.1 m/s at a CO<sub>2</sub> partial pressure of 0.79 MPa. For both the top and bottom of the pipe, the corrosion rate decreases with time until it reaches a stable value after a given time. For example, the corrosion rate at the bottom of the pipe decreases from 4.0 to 3.7 mm/y in the first 2 h. Within a few hours, it becomes stable at 3.4 mm/y. The corresponding value for the top of the pipe decreases from 0.7 to 0.3 mm/y after 1.5 h and then remains constant. A similar trend was observed for all other test conditions. The corrosion rate at the top of the pipe is lower than that at the bottom of the pipe.

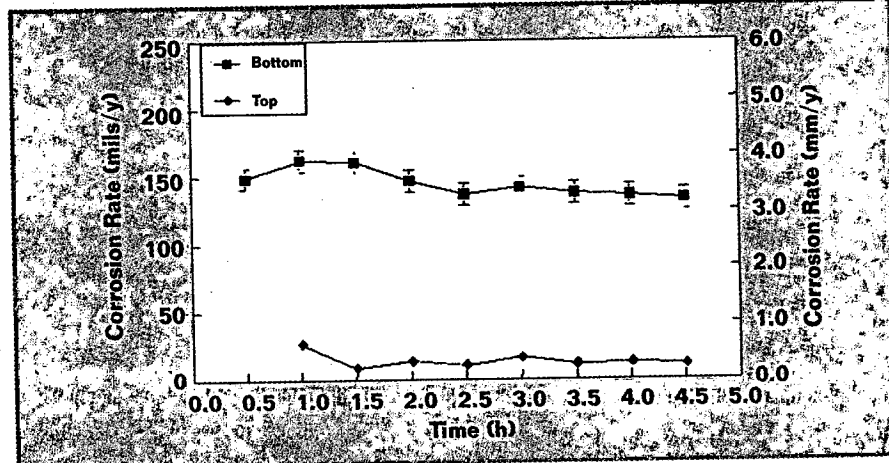
### EFFECT OF SUPERFICIAL GAS VELOCITY

Figures 5 and 6 show the effects of superficial gas velocity on corrosion rate

at the top and bottom of the pipe at a superficial liquid velocity of 0.1 m/s. In Figure 5, at a CO<sub>2</sub> partial pressure of 0.45 MPa, the corrosion rate increases approximately linearly. At the bottom of the pipe, the corrosion rate increases from 2.7 to 3.1 mm/y and then to 3.9 mm/y as the gas velocity is increased from 7 to 9 and then to 0.8 mm/s, respectively. The corresponding corrosion rates at the top of the pipe are 0.1, 0.5, and 0.8 mm/y, respectively. A similar trend is obtained at the CO<sub>2</sub> partial pressure of 0.79 MPa, as shown in Figure 6, but the corrosion rates are higher in each case.

The results indicate that the increase in gas velocity causes an increase in the corrosion rate at both the top and bottom of the pipe. This occurs because the mass transfer rate increases as a result of the enhanced turbulence generated by the increased gas velocity.<sup>7</sup> Figures 5 and 6 show that the corrosion rate at the top of the pipe is much lower than that at the bottom of the pipe. At this low superficial liquid velocity of 0.1 m/s, there is insufficient liquid to spread the liquid film completely around the pipe. One would expect the corrosion rate to increase at the top of the pipe when the superficial liquid velocity increases.

FIGURE 4



The effect of time on corrosion rate at the top and bottom of the pipe at 0.79 MPa. V<sub>sg</sub> = 7 m/s, V<sub>sl</sub> = 0.1 m/s, T = 40°C, 100% water cut.

### EFFECT OF SUPERFICIAL LIQUID VELOCITY

Figures 5 and 6 also show the effects of superficial liquid velocity on corrosion rate at the top and bottom of the pipe at CO<sub>2</sub> partial pressures of 0.45 and 0.79 MPa. The corrosion rate increases as the liquid flow rate increases; this becomes even more apparent at 0.79 MPa than at 0.45 MPa. For example, at a superficial gas velocity of 11 m/s, increasing the liquid velocity from 0.1 to 0.2 m/s increases the corrosion rate at the top of the pipe from 0.8 to 1.7 mm/y at 0.45 MPa; however, at 0.79 MPa, the corrosion rate goes from 1.1 to 7.7 mm/y.

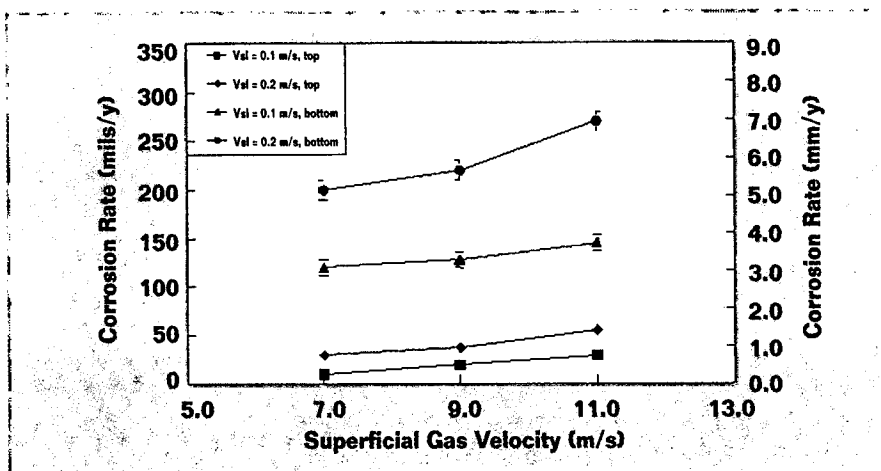
Increasing the liquid flow rate causes more water to be present in the pipe. Because the flow is annular, the liquid spreads around the perimeter of the pipe. The higher pressure causes more CO<sub>2</sub> to dissolve into the water, making the solution more acidic; thus, the corrosion rate at the top of the pipe increases more at 0.79 MPa than at 0.45 MPa at each flow condition.

Observations of the gas velocities studied reveal that the liquid velocity has a greater effect on the corrosion rate at the bottom of the pipe for both 0.45 and 0.79 MPa. For example, at a superficial gas velocity of 9 m/s, the corrosion rate at 0.45 MPa increases from 3.1 to 5.8 mm/y with the superficial liquid velocity increasing from 0.1 to 0.2 m/s. The corrosion rate at 0.79 MPa at the same conditions increases from 4.3 to 8.5 mm/y.

### Conclusions

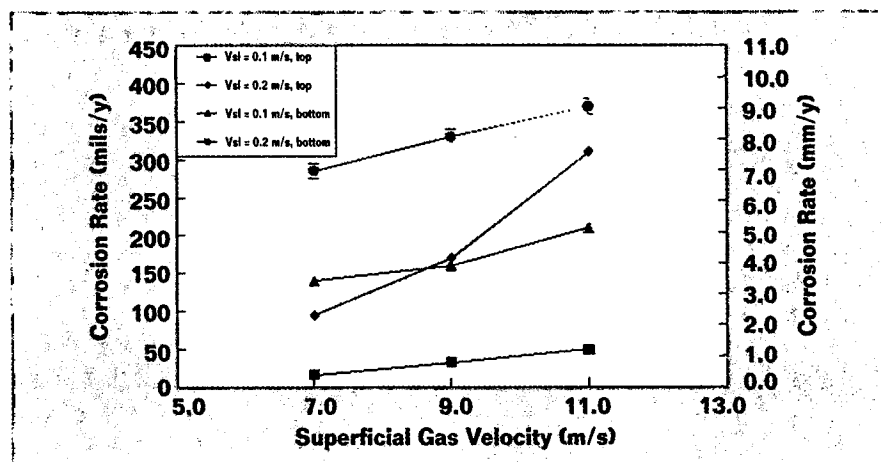
- The gas velocity required to obtain annular flow decreases as pressure increases. At superficial liquid velocities <0.2 m/s, gas velocities between 7 and 11 m/s, a temperature of 40°C, and 100% water cut, the flow patterns are in annular flow or the stratified-annular flow transition zone.
- The corrosion rate becomes stable after ~3 h of exposure to the test environment.

FIGURE 5



The effect of superficial liquid velocity on corrosion rate at the top and bottom of the pipe at 0.45 MPa, 40°C, and 100% water cut.

FIGURE 6



The effect of superficial liquid velocity on corrosion rate at the top and bottom of the pipe at 0.79 MPa, 40°C, and 100% water cut.

- The corrosion rate increases with an increase in gas velocity—along both the top and bottom of the pipe—because the enhanced turbulence generated by the increased gas velocity increases the mass transfer rate.
- The corrosion rate increases with an increase in the liquid velocity—along both the top and bottom of the pipe—because of the increase of water, the annular flow, and the higher concentration of CO<sub>2</sub> in the water introduced by the increased liquid velocity.

### References

1. X. Zhou, W.P. Jepson, "Corrosion in Three-Phase Oil/Water/Gas Slug in Horizontal Pipes," CORROSION/94, paper no. 26 (Houston, TX: NACE, 1994).
2. A.K. Vuppu, W.P. Jepson, "Study of Sweet Corrosion in Horizontal Multiphase Carbon Steel Pipelines," Proceedings of the 4th Annual Offshore and Polar Engineering Conference, paper no. OTC-7494 (Houston, TX: 1994).
3. J.-Y. Sun, W.P. Jepson, "Slug Flow Characteristics and Their Effect on Corrosion Rates in Horizontal Oil and Gas Pipelines," SPE paper no. 24787, 1992.
4. L. Jiang, M. Gopal, "Multiphase Flow Enhanced Corrosion Mechanisms in Horizontal Pipelines," Journal of Energy Resources and Technology 120, 1 (1998).
5. S.D. Kapusta, B.F.M. Pots, R.A. Connell, CORROSION/99, paper no. 45 (Houston, TX: NACE, 1999).

Unbreakable. Unbeatable. Unbelievable.

**LIDA**



**ELECTRODE Corporation**  
**LIDA Products Group**

Houston, Texas  
1-800-442-5432

## Chemical Treatment

6. T. Sydberger, "Flow Dependent Corrosion Mechanism, Damage Characteristics and Control," *British Corrosion Journal* 22, 2 (1986): pp. 83-89.

7. D. Vedapuri, C. Kang, D. Dhanabalan, M. Gopal, "Inhibition of Multiphase Wet Gas Corrosion," *CORROSION/2000*, paper no. 43 (Houston, TX: NACE, 2000).

8. Y.M. Gunaltun, D. Larrey, "Correlation of Cases of Top of Line Corrosion with Calculated Water Condensation Rates," *CORROSION/2000*, paper no. 71 (Houston, TX: NACE, 2000).

9. M. Estavoyer, "Corrosion Problems at Lack Sour Gas Field," in *H<sub>2</sub>S Corrosion in Oil and Gas Production* (Houston, TX: NACE, 1981), pp. 905.

10. W.P. Jepson, A.H. Lee, J.-Y. Sun, "Study of Flow Regime Transitions of Oil-Water-Gas Mixtures in Horizontal Pipelines," *Proceedings of the International Society of Offshore and Polar Engineers (ISOPE)*, paper no. JSC-052 (Singapore: ISOPE, June 1993).

11. J.Y. Cai, M. Gopal, W.P. Jepson, "The Investigation of Flow Regime Transitions in Large Diameter Inclined Pipes," *The Journal of Energy Resources and Technology* 121 (1999): pp. 91-95.

12. M. Gopal, W.P. Jepson, R. Wilkens, "Flow Regimes, Their Transitions, and Slug Flow Characteristics in High Pressure, Inclined Pipelines," *Energy*

*Sources Technology Conference and Exhibition* (Houston, TX: 1998).

*This article is based on CORROSION/2001 paper no. 34, presented in Houston, Texas.*

W.P. JEPSON, previously a Russ Professor, Chemical Engineering, at Ohio University, is currently with Control Center, LLC, 4301 Metric Drive, Winter Park, FL 32792. He has lead technical and managerial responsibility for all activities in flow and corrosion, including testing, studies, experiments, field trials, and product development. He has a Ph.D. from the Department of Chemical and Process Engineering at Heriot-Watt University (Scotland) and has authored more than 100 papers. *MP*

Next Month in *MP*

**CORROSION/2002**  
Advance Program

gill8.com

Voulez-vous un Potentiostat haut de gamme?

Car...

**ACM est devenu Francophone !**

(Monitoring de Corrosion Appliqué)

- Experts dans le dessin d'instrumentation de haute qualité à l'avant garde de la technologie depuis 1985
- Un savoir-faire étendu dans le secteur industriel partout au monde
- Instruments personnalisés suivant votre besoin

Jetez un oeil sur: [www.gill8.com](http://www.gill8.com)  
Contactez nous au: [ventes@gill8.com](mailto:ventes@gill8.com)  
Appelez-nous au: +44 15395 59185  
Faxez-nous au: +44 15395 58562

