CORROSION UNDER WET GAS CONDITIONS

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ABSTRACT

CO_2 wet gas corrosion rates at the top and bottom of a high pressure 10-cm diameter system have been measured under different pressures up to 1.82MPa at a temperature of 40°C. The flow patterns at test conditions are determined at gas velocities up to 11m/s and liquid velocities up to 0.2m/s. The liquid was de-ionized water and carbon dioxide was used as the gas phase.

The flow patterns at test conditions are annular flow or near the stratified-annular flow transition zone. The corrosion rate becomes stable after 3 hours. It was found that the corrosion rate increases with the increase in gas velocity, liquid velocity, and CO_2 partial pressure.

INTRODUCTION

Carbon dioxide corrosion of low alloy steels such as carbon steel is a well recognized phenomena in oil and gas production, transportation and processing. The type of corrosion caused by dissolved CO_2 varies considerably depending on the precise environment conditions[1,2,3,4]. In natural gas pipelines,

reduction in temperature results in condensation of water and hydrocarbon along the length of the pipe. The produced fluids may contain significant levels of CO_2, H_2S, and organic acids, which in combination with free water make the pipeline environment potentially very corrosive[5]. In these multiphase flow conditions, various types of flow regimes exist, each of which contributes differently to the corrosion rate[6].

The flow patterns that are encountered in wet gas systems are mist flow, annular mist flow, and stratified flow. Figure 1 shows the various flow patterns observed[7]. In annular flow, the liquid phase contacts all of the pipewall's perimeter with a gas core in the middle. This flow usually occurs when the gas velocity is high[8]. 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 liquid is transported as droplets that are entrained in the vapor phase. These 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[9].

Corrosion studies have not been carried out systematically in flow conditions similar to those observed in wet gas systems. In this work, the flow patterns are determined , the effect of time and the effect of different liquid and gas velocities on corrosion rates at the top and bottom of the pipe are also discussed for different pressures.

EXPERIMENTAL SETUP AND PROCEDURE

The flow loop is a unique 18-m long, 10-cm diameter, high pressure, high temperature, inclinable system. A schematic diagram of this system is shown in Figure 2. The entire flow loop is manufactured from 316 stainless steel. A predetermined oil-water mixture is stored in a $1.4m^3$ tank which serves as a storage tank as well as a separation unit for the multiphase gas-oil-water mixture. The tank has a heating jacket around it. Heater oil is heated in a separate heating tank using four 15KW heaters and pumped to the heating jacket, to heat the contents of the storage tank. Liquid is moved through this system by a variable speed centrifugal pump. The liquid flow is then controlled within a range of 0 to $100m^3/hr$ with the variable speed pump in conjunction with a recycle stream. Liquid flow rate is metered with an inline turbine meter.

A fresh gas feed line at 2MPa pressure supplies carbon dioxide gas from a 20,000kg storage tank. This line is used initially to pressurize the system and 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, driven by a variable speed motor through a reduction gear system. An exhaust line with a knock out drum is used to vent gas from the system when required.

Before the experiment, the solution was deoxygenated with carbon dioxide and the levels of dissolved oxygen and dissolved iron were controlled below 20ppb and 10ppm respectively. The oxygen and iron levels were periodically monitored and samples were taken and tested using CHEMets dissolved oxygen and iron test kits. Before the test, the surfaces of the electrodes were wet-polished by grid sandpaper up to 600 grit, then rinsed with acetone 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 then fed to the recirculating pump.

Description of the Test Section

The test section is a 0.10m diameter, 2m long schedule 80 stainless steel pipe. A schematic of the section is given in Figure 3. The two pairs of ports at the top and at the 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

De-mineralized water is used as the liquid phase and CO_2 is used as the gas phase. Table 1 shows the test matrix.

RESULTS

Flow Regime Determination

Figures 4 and 5 show the flow regime maps for 100% water at carbon dioxide partial pressures of 0.45MPa and 1.82MPa at a temperature of 40°C respectively. It is seen that at superficial liquid velocities below 0.2m/s, the flow pattern is in either the stratified flow or annular flow regime. It is also observed that the stratified-annular flow transition line in the map shifts slightly to the left when the pressure increases from 0.45MPa to 1.82MPa at the given gas and liquid velocities. For example, at the superficial liquid velocity of 0.1m/s and gas velocity of 7m/s, the flow pattern is in the stratified-annular

flow transition zone at 0.45MPa while it shifts to annular flow regime at 1.82MPa. Hence, the gas velocity to obtain annular flow decreases with an increase in pressure[10, 11, 12].

Over the gas and liquid velocities studied, the flow patterns are in annular flow or stratified-annular flow transition zone. The test conditions represent the wet gas conditions and the corresponding research can be applied to these conditions for getting corrosion information in wet gas pipelines.

Effect of Time

Figure 6 shows the effect of time on corrosion rate at the top and bottom of the pipe for gas and liquid velocities of 7 m/s and 0.1 m/s at a carbon dioxide partial pressure of 0.79MPa. It is seen that for both the top and bottom in 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 mm/y to 3.7 mm/y in the first 2 hours. Within a few hours, it becomes stable at 3.4mm/y. The corresponding value for the top of the pipe decreases from 0.7mm/y to 0.3mm/y after 1.5 hours and then remains constant. A similar trend was observed for all other test conditions.

It is seen that the corrosion rate at the top of the pipe is lower than that at the bottom of the pipe.

Effect of Superficial Gas Velocity

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 are shown in Figures 7 and 8. In Figure 7, at a carbon dioxide partial pressure of 0.45MPa, it is seen that the corrosion rate increases approximately linearly. At the bottom of the pipe, the corrosion rate increases from 2.7mm/y to 3.1mm/y and then to 3.9mm/y as the gas velocity is increased from 7 to 9 and then to 11 m/s respectively. The corresponding corrosion rates at the top of the pipe is 0.1mm/y ,0.5mm/y and 0.8mm/y respectively. A similar trend are obtained at the carbon dioxide partial pressure of 0.79MPa as shown in Figure 8, 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 is because the mass transfer rate increases due to the enhanced turbulence generated by the increased gas velocity[7]. Figures 7 and 8 show that the corrosion rate at the top of the pipe is much lower than that at the bottom of the pipe. This is because at this low superficial liquid velocity of 0.1 m/s, there is insufficient liquid to spread the liquid film completely around the pipe. It is expected that the corrosion rate will increase at the top of the pipe when the superficial liquid velocity is increased.

Effect of Superficial Liquid Velocity

The effect of superficial liquid velocity on corrosion rate at the top and bottom of the pipe, at a carbon dioxide partial pressure of 0.45MPa and 0.79MPa are shown in Figures 9 and 10. It can be seen from Figure 9 that the corrosion rate increases with increase in liquid flow rate. This is even more apparent at 0.79MPa, Figure 10. For example, at a superficial gas velocity of 11m/s, increasing the liquid velocity from 0.1 m/s to 0.2 m/s gives an increase in corrosion rate from 0.8mm/y to 1.7mm/y at 0.45MPa, whilst at 0.79MPa, the corrosion rate increases from 1.1 mm/y to 7.7mm/y.

Increasing the liquid flow rate causes more water to be present in the pipe. Since the flow is annular flow, the liquid spreads around the perimeter of the pipe. The higher pressure causes more CO_2 dissolve into the water, making the solution more acidic. Thus the corrosion rate at the top of the pipe increases more at 0.79MPa than at 0.45MPa at each flow condition.

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

CONCLUSIONS

The following conclusions are made:

- The gas velocity required to obtain annular flow decreases with an increase in pressure. At superficial liquid velocities below 0.2m/s, gas velocities between 7 and 11m/s, a temperature of 40°C and 100% water cut, the flow patterns are in annular flow or stratified-annular flow transition zone.

- The corrosion rate becomes stable after ~3 hours exposure to the test environment.

- The corrosion rate increases with an increase in gas velocity both along the top and bottom of the pipe because of the enhanced turbulence generated by the increased gas velocity.

- An increase in the liquid velocity increases the corrosion rate both at the top and bottom of the pipe because of the higher mass transfer rate introduced by the increased liquid velocity.

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Table 1   Test Matrix

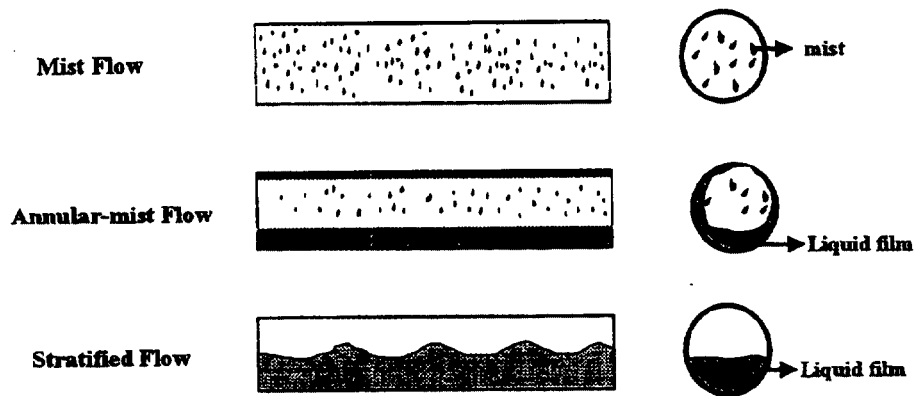| PARAMETER	CONDITIONS
Water cut	100%
Temperature	40°C
Pressure	0.45, 0.79, 1.13, 1.48, 1.82MPa
Superficial liquid velocity	0.1 and 0.2m/s
Superficial gas velocity	7, 9, 11 m/s
Liquid loading, bbl/mmscf d	105,140,170,200,250,310, 350,400,480,580,700,850

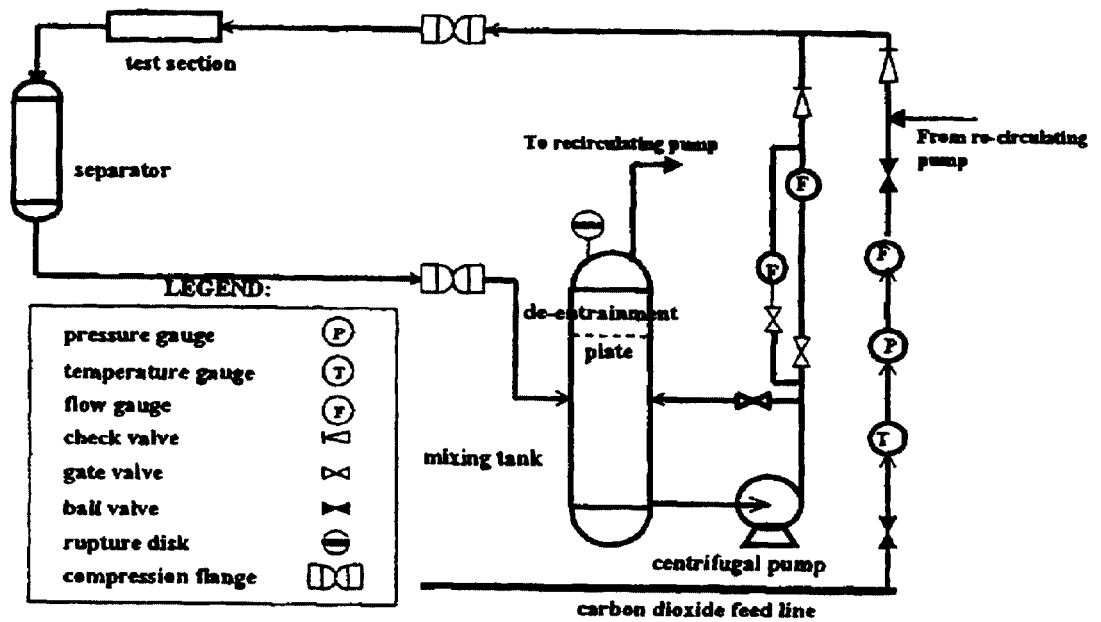**Figure 1. Flow patterns observed in wet gas pipelines**

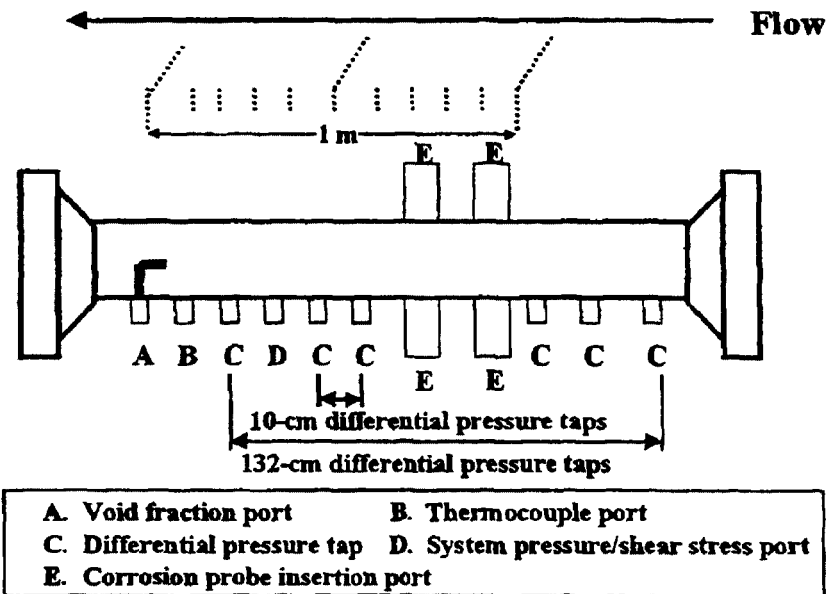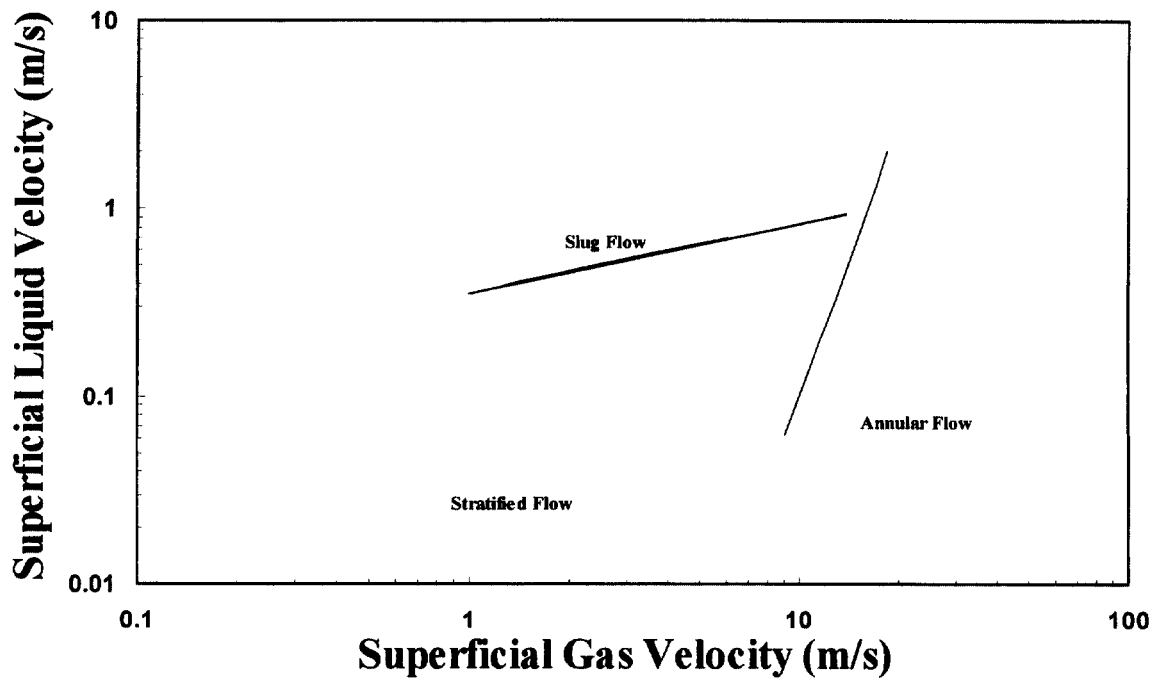**Figure 2. Schematic of the high pressure inclinable flow loop system**

A. Void fraction port   **B.** Thermocouple port
C. Differential pressure tap   **D.** System pressure/shear stress port
E. Corrosion probe insertion port

Figure 3. Schematic of the test section

Pipe Diameter =10 cm Inclination =0 Degree Water Cut =100% Gas Density =7.81 kg/m^3

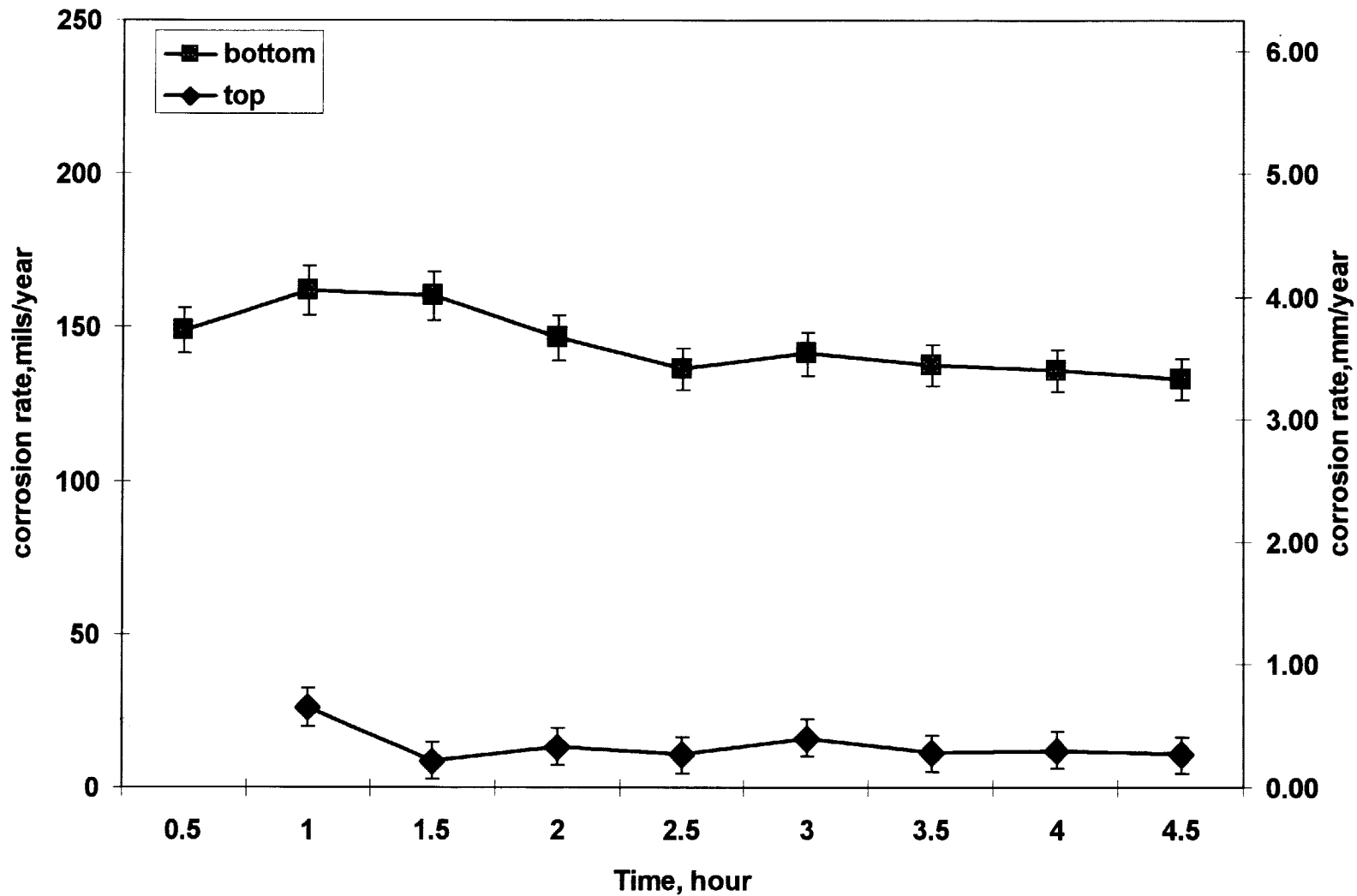**Figure4. Flow Regime Map at P=0.45 MPa (50psig) and T=40C**
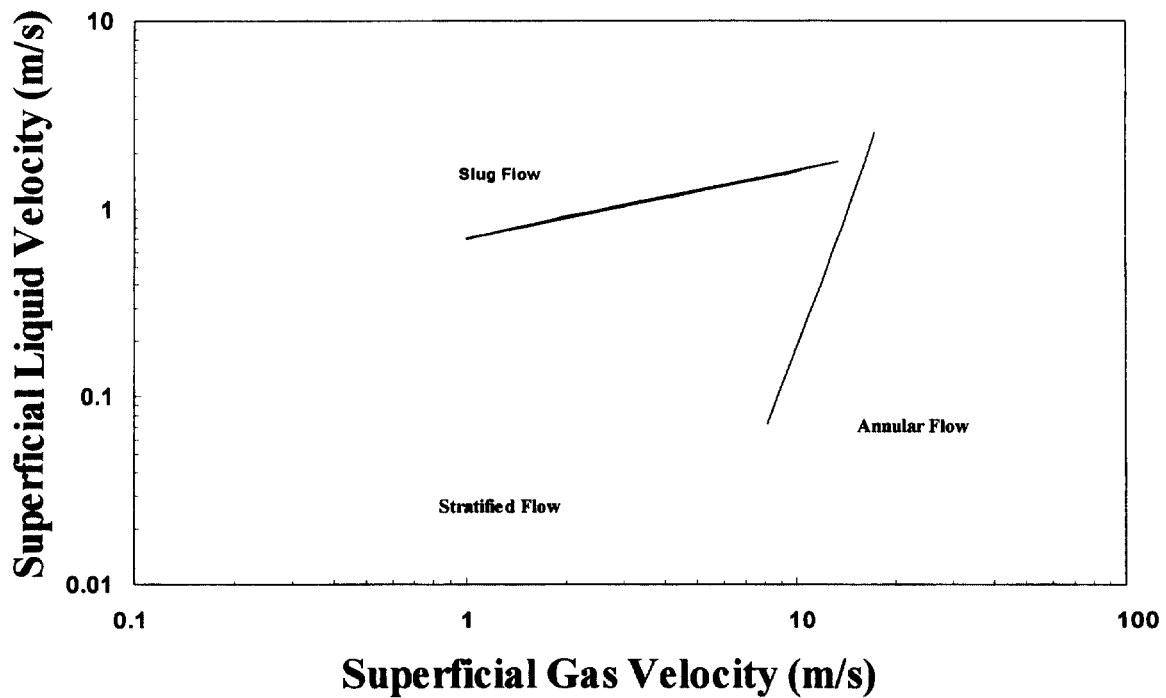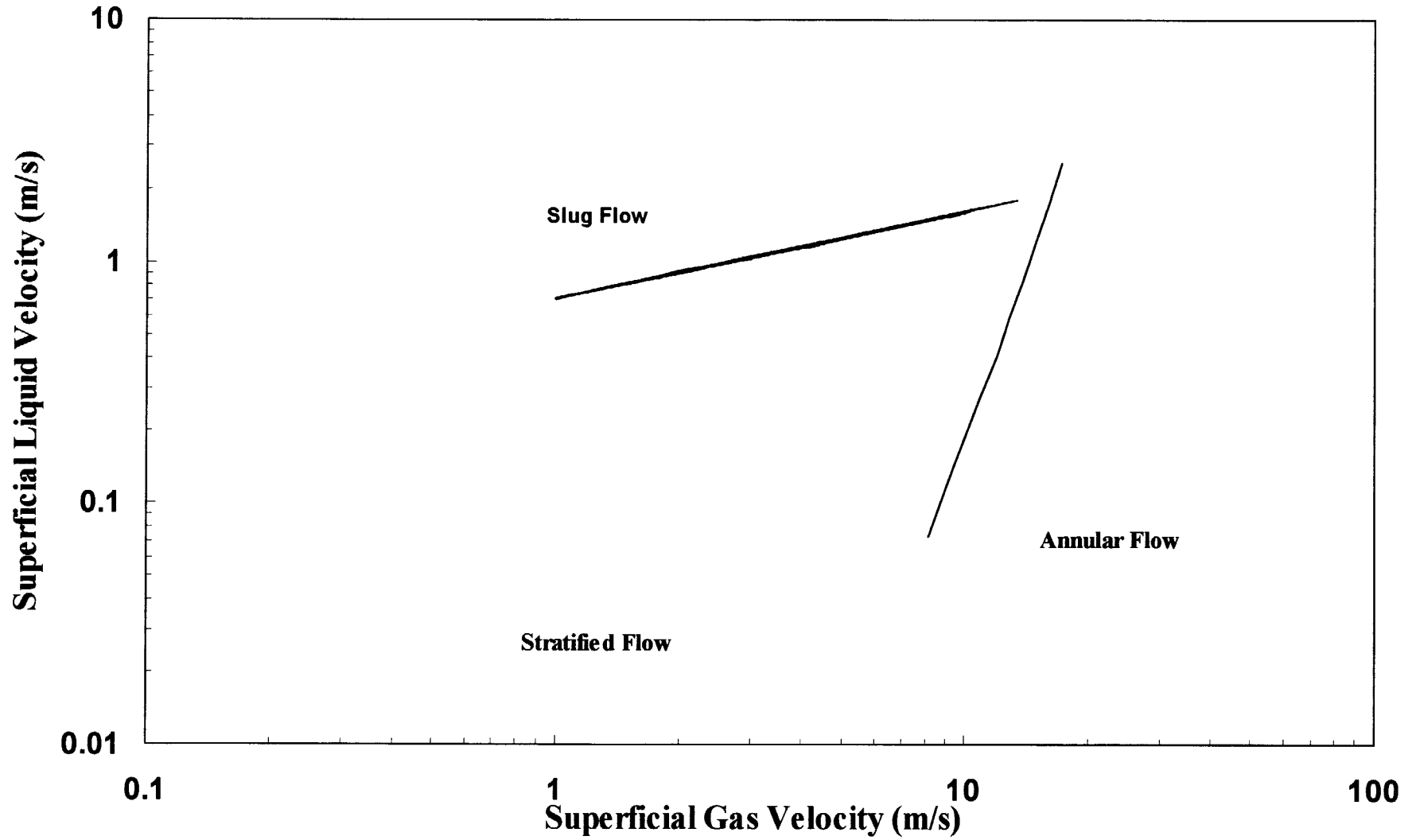
Pipe Diameter =10 cm Inclination =0 Degree Water Cut =100% Gas Density =31.96 kg/m^3

Figure 5. Flow Regime Map at P=1.82MPa(250psig) and T=40C

Figure4. Flow Regime Map at P=0.45 MPa (50psig) and T=40C

Figure 5. Flow Regime Map at P=1.82MPa(250psig) and T=40C

Figure6. The effect of time on corrosion rate at the top and bottom of the pipe at 0.79MPa, Vsg=7m/s, Vsl=0.1m/s, T=40C, 100% water cut
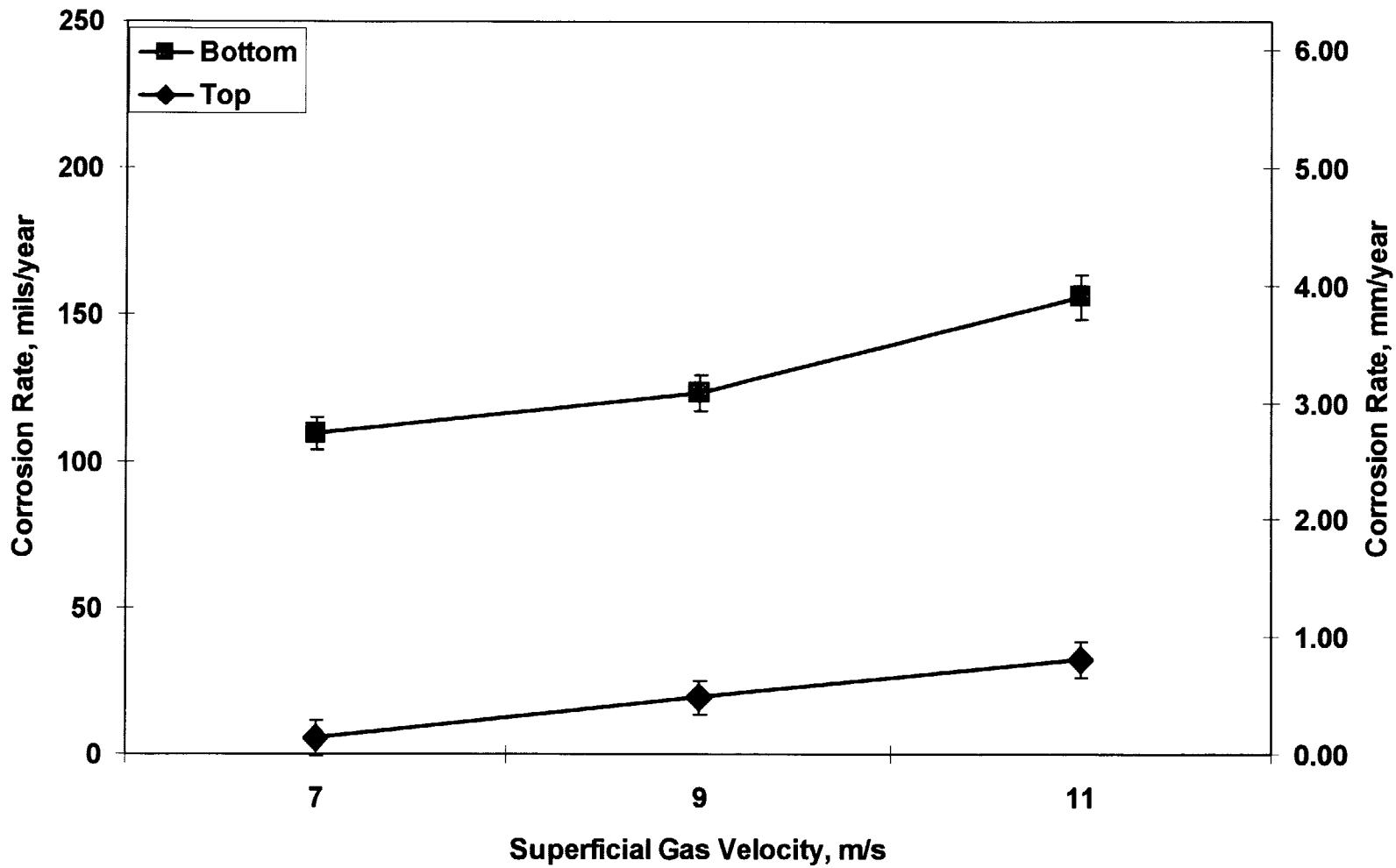
Figure7. The effect of superficial gas velocity on corrosion rate at the top and bottom of the pipe for a superficial liquid velocity of 0.1m/s at 0.45MPa, 40C and 100% water cut
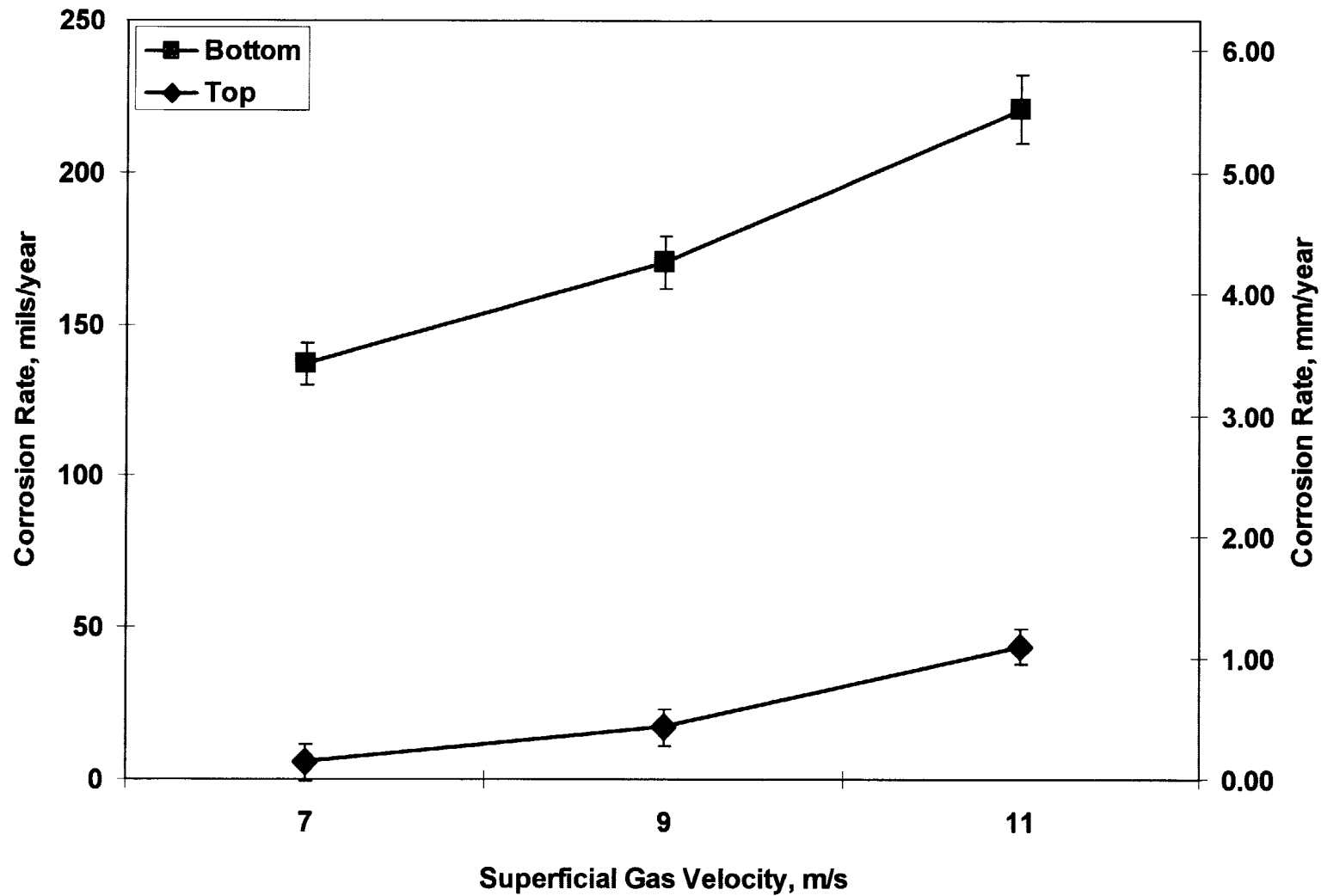
Figure8. The effect of superficial gas velocity on corrosion rate at the top and bottom of the pipe for a superfical liquid velocity of 0.1m/s at 0.79MPa, 40C and 100% water cut
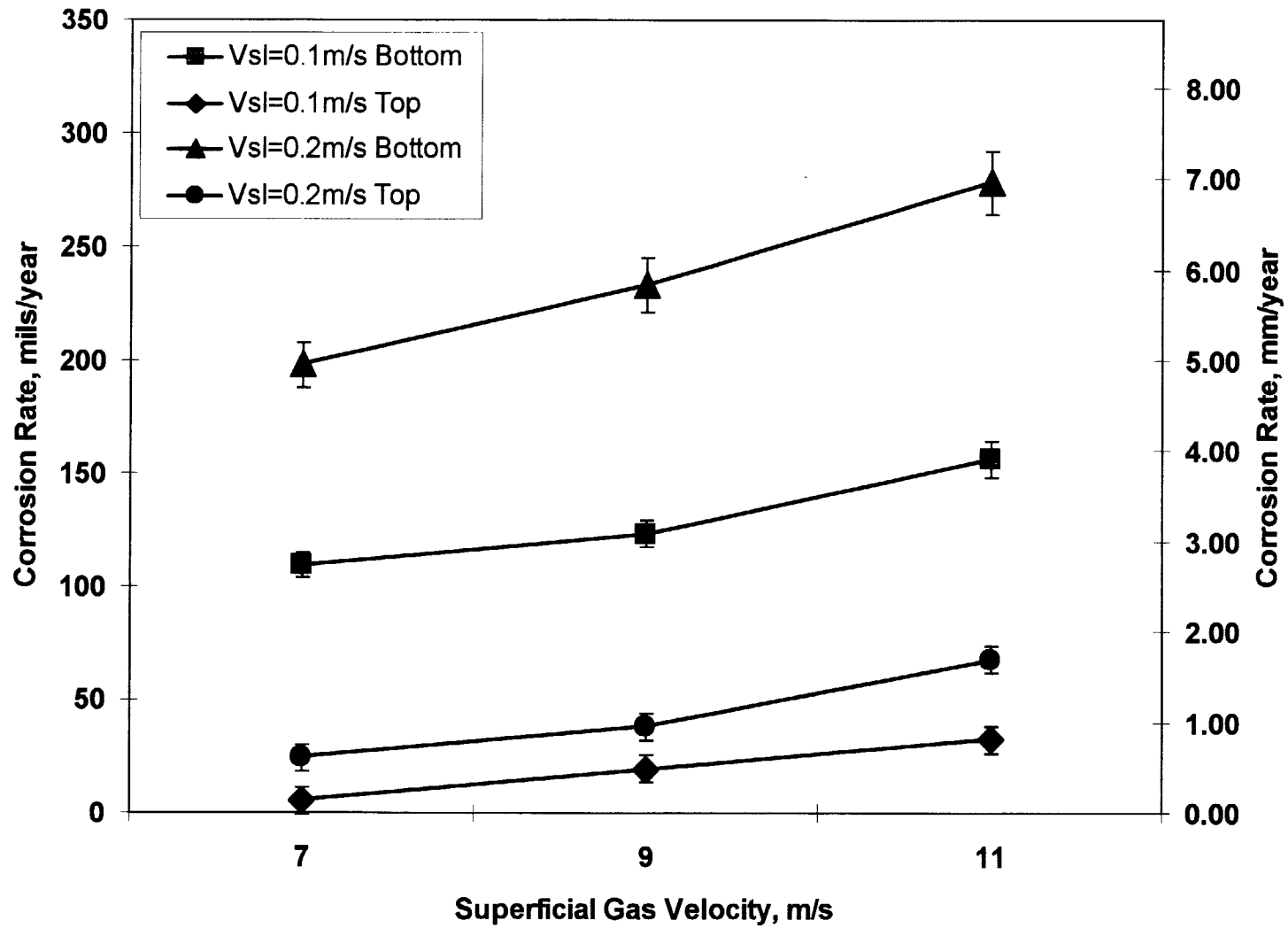
Figure9. The effect of superficial liquid velocity on corrosion rate at the top and bottom of the pipe at 0.45MPa, 40C and 100% water cut
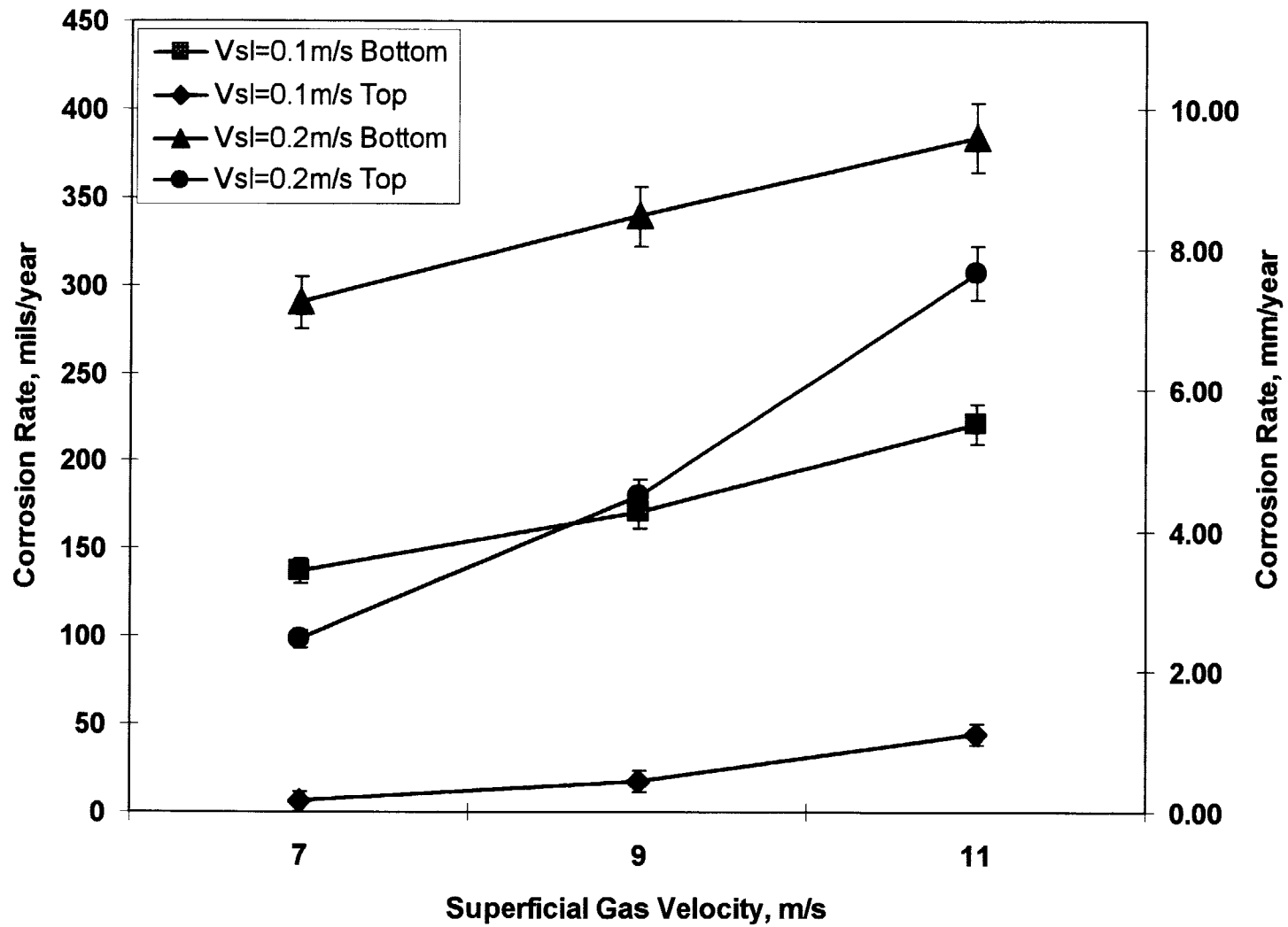
Figure10. The effect of superficial liquid velocity on corrosion rate at the top and bottom of the
pipe at 0.79MPa, 40C and 100% water cut