INTRODUCTION

1.1 Carbon capture from flue gas

Global warming caused by the excessive emission of greenhouse gases has become one of the most significant environmental problems currently faced by society. According to the Kyoto Protocol and the Copenhagen International Conference on environmental requirements, each country has an obligation to reduce CO₂ emissions. For the next 50 years, fossil fuels will remain as the main energy source for the world, and CO₂ from fossil fuel combustion will account for approximately 80% of the total emissions. Flue gas from steam generators and its utilization in enhanced oil recovery (EOR) can reduce CO₂ emissions into the atmosphere and improve oil recovery efficiency.
fossil fuel power plants is the greatest long-term emission source of CO₂.¹⁻⁵

Carbon capture and storage (CCS) has been widely regarded as an effective solution to reduce CO₂ in the atmosphere to mitigate global warming. However, the profit from CCS cannot compensate for its high cost. CO₂-enhanced oil recovery, which has been widely used in oil field development, can reduce CO₂ emissions and improve oil recovery efficiency. CO₂-enhanced oil recovery is the option with the most potential for carbon capture, utilization, and storage (CCUS).⁶⁻¹⁰

CO₂ capture is the first step for CCS, including CO₂ capture and separation, purification, and compression. The energy consumption of CO₂ capture accounts for more than 70% of the total energy consumed during the CCS process. The development of CO₂ capture technology that is low cost, reliable, and environmentally friendly is critical for CCS.¹¹⁻¹³ According to the combustion process of fossil fuel use; there are three types of techniques that can be used to capture CO₂ from stationary sources.¹⁴⁻¹⁷

1. Postcombustion capture refers to the use of a chemical absorbent agent to separate CO₂ from the flue gas of fossil fuel combustion.
2. Precombustion capture means the separation of CO₂ before fossil fuel combustion, which is expected to work with the integrated gasification combined cycle (IGCC) to achieve energy conversion with high efficiency and low carbon emissions.
3. Oxygen‐enriched combustion refers to the combustion of fossil fuels in the oxygen‐enriched environment, supplemented by flue gas circulation. The flue gas components for the technology are only CO₂ and water.

1.2 | Collection and utilization of flue gas for crude oil production

Crude oil production in the oilfield has provided abundant fossil fuel to the world, but it also consumes a large amount of energy. In the process of heavy oil production, approximately 10%‐15% of heavy oil that is produced is used as fuel in the boiler for heating steam, which is then injected into a reservoir for thermal recovery. Flue gas from the boiler is a stable long‐term CO₂ emission source in the oilfield. Related research and field applications prove that flue gas injected into the reservoir with steam can greatly improve heavy oil development. Flue gas collection also avoids the complex process of CO₂ separation in CCS, which is suitable for a small‐scale steam injection boiler. The collection and utilization of flue gas in a steam injection boiler will become an important method for reducing greenhouse gas emissions in oilfields.

There is a fluidized bed boiler with the capacity of 130 t/h in Xinjiang Oilfield in PetroChina. This boiler provides steam for the steam stimulation wells in the Cong 22 Block. The production of steam also produces a large amount of flue gas. Equipment has been set up to purify and compress the flue gas and inject it into the reservoir with steam. This process can decrease the heat loss and water cut of the produced fluid, therefore, improving the oil recovery.

There are usually four parts in the flue gas collection and compression system: the flue gas pretreatment unit, centrifugal compressor unit, dehydration unit, and piston compression unit. The dust content in the flue gas after treatment is less than 5 mg/m³, the SO₂ content is less than 50 ppm, and the water content is approximately 0.3 wt%. The pressure of the flue gas is approximately 8.0 MPa, and the flue gas is injected into the wellbore through a pipeline to increase the exploitation efficiency of heavy oil.

1.3 | Flue gas corrosion mechanism

The corrosion mechanism of downhole string under flue gas injection conditions is very important. N₂ is the highest composition (approximately 80%) in flue gas and is not corrosive. The corrosive gases in flue gas are CO₂, O₂, and SO₂. In addition to N₂, CO₂ has the highest content (approximately 10%‐15%) and is a strong corrosive. Under conditions of high temperature and high pressure, it shows the characteristics of CO₂ corrosion. In oil and gas field development, CO₂ corrosion is known as sweet corrosion compared to H₂S corrosion (sour corrosion). The corrosion of CO₂ on steel materials is more serious than HCl because CO₂ dissolved in water has a higher total acidity compared to HCl with the same pH value.¹⁸⁻¹⁹ The CO₂ corrosion rate on the oil tube can reach more than 7 mm/y, which greatly reduces the service life of the downhole string.²⁰

Simultaneously, SO₂ and O₂ in the flue gas will accelerate corrosion, which makes the process extremely complex. Flue gas contains O₂ because of the excessive air coefficient of the boiler, which will make the steel rust. The combustion of coal and oil will generate a small amount of SO₂, which will also cause corrosion to the steel. The flue gas has a strong corrosive effect on steel, and the corrosion mechanism is diverse and complex because it is affected by the flue gas composition.

1.4 | Study purpose

The utilization of flue gas in heavy oil recovery avoids the complex process of CO₂ separation in CCS and yields a large profit for oilfields. However, the corrosion of flue gas is more serious than that of pure CO₂. We can only find few research results of flue gas corrosion in transportation pipeline and power plant, whose conditions are much different from that for flue gas injection in wellbores.²¹⁻²³ The corrosion
mechanism of a downhole string under flue gas injection conditions requires further research.

In this study, the effects of corrosion time, temperature, pressure, velocity, O₂ content, SO₂ content, H₂O content, and NaCl content on corrosion rates of different steels used for a downhole string were investigated through physical simulation experiments. The corrosion mechanism was analyzed by component, and the morphology of the corrosion products was tested by X-ray diffraction (XRD) and scanning electron microscopy (SEM). The experimental method is an accelerated corrosion experiment according to the machinery industry standard from China “Method of laboratory immersion testing for metals materials uniform corrosion.” The experimental results can provide theoretical support for inhibiting the corrosion of flue gas in petroleum engineering.

2 | EXPERIMENTAL METHODS

2.1 | Apparatus

The steel materials of oil pipes were made into coupons, which were then each put into different corrosion environments for a specified period of time. The corrosion rates under different conditions were calculated by the weight difference before and after the corrosion experiment, thus evaluating the effects of different factors on the corrosion mechanism for the flue gas. The main experimental equipment is a reaction kettle under higher pressure and high temperature, as shown in Figure 1.

The reaction kettle in Figure 1 has an inner diameter of 12.0 cm and a height of 16.0 cm. A heating jacket and insulation jacket are located outside of the reaction kettle to enable the reaction kettle to be accurately heated to a specific high temperature with an accuracy of less than 1°C. The flue gases injected into the reaction kettle were measured by a gas mass-flow controller (Model SLA5850S, Brooks, accuracy <±1% full scale). A constant pressure and constant speed pump (Model 100DX, Teledyne Technologies, flow accuracy <0.25 μL/min, pressure accuracy <±0.5%) were used to add brine to the reaction kettle. There is a stirring motor in the reaction kettle that can stir the fluid to simulate the flow condition in the wellbore. The pressure and temperature in the reaction kettle were measured using a pressure transducer (Model 3210PD, Haian Group, full scale of 50 MPa, accuracy <0.1% full scale) and a thermocouple (Model SLK, Omega, accuracy of 0.1°C). The weights of the coupons before and after the experiment were tested by a balance (Model AB135-S, Mettler Toledo, full scale of 120 g, accuracy of 0.1 mg).

2.2 | Materials

Industrial-grade N₂, CO₂, O₂, and SO₂ were used as gases with a purity of 99.99%. Analytically pure NaOH, NaCl, HCl, CH₃CH₂OH, and hexamethylenetetramine were employed in the experiments. Distilled water served as the liquid. Petroleum ether with a boiling point range of 60-90°C was used as the cleaning agent.

2.3 | Experimental procedures

2.3.1 | Coupon handling before the experiment

Coupon handling

The materials used for coupons are N80, P110, X70, and 13Cr; these are typically used for the oil tube and casing in an oil well in addition to pipelines for oil and gas transportation. The main components for N80, P110, X70, and 13Cr are shown in Table 1. The coupons were handled according to the machinery industry standard in China with the steps described below.

Step 1: The oil on the surface of the coupon was removed by filter paper or gauze, and then, it was put into petroleum ether with a boiling point range of 60-90°C. The dirt on the surface was then removed by absorbent cotton.

Step 2: The surface of the coupon was ground by sandpaper to make it smooth and glossy. The grinding debris was removed with absorbent cotton, and it was washed again by petroleum ether to remove the oil.

Step 3: The coupon was dipped in ethanol for degreasing and further dehydration for approximately 5 minutes.

Step 4: The coupon was cleaned by a clean silk and blown with the cold wind.

Step 5: The weight of the coupon was tested by a balance and recorded as m₀. Then, the coupon was numbered, wrapped with industrial filter paper, and put into a dryer.
2.3.2 | Corrosion experiment

Step 1: Three hundred milliliters of deionized water was injected into the reaction kettle. The coupons were fixed on the holder, which was divided into two parts. The lower part was immersed in the water that was dissolved with gas under higher pressure, and the upper part was immersed in the flue gas. Then, the reaction kettle was sealed.

Step 2: The vacuum pump was used to draw the air out of the reaction kettle.

Step 3: According to the composition of the flue gas, the N₂, CO₂, O₂, and SO₂ were injected into the reaction kettle through a gas mass-flow controller. If the pressure of the gas cylinder could not reach the predetermined value, a gas booster pump was used to increase the pressure.

Step 4: The temperature controller was opened and set to the experimental temperature. The coupons were not moved out of the reaction kettle until it reached the experiment time.

2.3.3 | Coupon handling after the experiment

Step 1: The coupons were washed with water to remove the loose corrosion product on the surface.

Step 2: The coupons were put in an acidic solution with hydrochloric acid and methylamine for 5 minutes to further remove the corrosion product; then, the coupons were washed with tap water. The coupons were put into a buffer solution with NaOH and washed again with tap water.

Step 3: The coupons were dipped in ethanol for degreasing and dehydration for approximately 5 minutes and then blown with the cold wind.

Step 4: The coupons were put into a dryer for 1 hour, and then, the weights of the coupons were tested by the balance and recorded as \( m_1 \).

2.3.4 | Calculation of corrosion rate

The corrosion rate was calculated by Equation (1):

\[
R = \frac{8.76 \times 10^7 \times (m_0 - m_1)}{STD}
\]

where \( R \) is the corrosion rate, mm/y; \( m_0 \) is the weight of the coupon before the corrosion experiment, g; \( m_1 \) is the weight of the coupon after the corrosion experiment, g; \( S \) is the total surface area of the coupon, cm²; \( T \) is the corrosion time, hour; and \( D \) is the density of the coupon material, kg/m³.

### Table 1

| Element | N80 | P110 | X70 | 13Cr |
|---------|-----|------|-----|------|
| C (wt%) | 0.35| 0.29 | 0.14| 0.21 |
| Si (wt%)| 0.30| 0.25 | 0.25| 0.90 |
| Mn (wt%)| 1.45| 0.65 | 1.35| 0.75 |
| P (wt%) | 0.02| 0.02 | 0.03| 0.02 |
| S (wt%) | 0.015| 0.01 | 0.009| 0.01 |
| Cr (wt%)| 0.12| 0.95 | –   | 13.15|
| Ni (wt%)| –   | 0.10 | –   | 0.20 |
| Cu (wt%)| –   | 0.15 | –   | 0.15 |
| V (wt%) | 0.11| 0.07 | 0.065| –   |

3 | EXPERIMENTAL RESULTS AND DISCUSSION

3.1 | Influencing factors in flue gas corrosion

3.1.1 | Effect of corrosion time on the corrosion rate

The corrosion rate changes with corrosion time at the beginning of the experiment; however, it tends to become stable as the corrosion time increase further. To reduce the control variables of the experiment, it is necessary to determine the appropriate corrosion time.

The corrosion environment was N₂ + CO₂ + O₂ + SO₂ with a pressure of 3.0 MPa and a temperature of 90°C. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The SO₂ concentration was 50 ppm. The experimental materials were N80, P110, X79, and 13Cr, and the corrosion times were set at 6, 12, 24, 48, and 72 hours. The corrosion experiment was conducted in a liquid phase in the lower part of the reaction kettle to determine the relationship between the corrosion rate and corrosion time. The results are shown in Figure 2.

Figure 2 illustrates that the corrosion rates of N80, P110, and X70 are higher in the early stage of the experiment and then decrease rapidly with time and tend to level off gradually. When the corrosion time reaches 72 hours, the corrosion rates remain fairly constant over time. The corrosion time is determined to be 72 hours in the following experiments.

The experimental results also show that the corrosion rate of 13Cr is considerably lower than those of N80, P110, and X70, showing high corrosion resistance. Cr is one of the most commonly used elements to improve the corrosion resistance of CO₂ in alloys. A small amount of Cr can significantly improve the alloy corrosion resistance effect under the aqueous solution saturated CO₂ below 90°C, because Cr can be
enriched in the film of ferrous carbonate and make the film more stable.24,25

In the flue gas corrosion process, a complete corrosion product film can form in 24 hours, which is the reason for the high corrosion rate in the initial stage of the experiment. As soon as a corrosion film forms on the surface of the coupons, the reaction between the corrosion solution and metal surface will change into the reaction of the corrosion solution through the permeability channel of the corrosion product film and metal surface. The corrosion rate decreases sharply, and the corrosion reaction terminates if the corrosion film is sufficiently dense. The finer structure of the corrosion product film and the closer combination of the corrosion film and matrix can make the permeable channel obstructed, and the corrosion reaction decreases or even terminates.26

3.1.2 Effect of temperature on the corrosion rate

The corrosion experiment was conducted in the gas and liquid phases in the reaction kettle to determine the relationship between the corrosion rate and temperature. The pressure of the reaction kettle was 3.0 MPa, and the temperature was from 30°C to 120°C. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The concentration of SO₂ was 50 ppm. The results are shown in Figures 3 and 4.

Figures 3 and 4 illustrate the effect of temperature on the corrosion rate for the four steel materials. The results show that the corrosion rate of 13Cr is low, displaying good corrosion resistance performance to flue gas. However, the corrosion rates of X70, P110, and N80 are considerably higher. In the range of the experimental temperatures, corrosion rates in the gas phase increase with increasing temperature, whereas that in the liquid phase first increase and then decrease and reach the maximum value at 90°C in the liquid phase. A number of studies show that temperature is an important parameter for CO₂ corrosion.26

Temperature affects corrosion rate through the chemical reaction and corrosion product film-forming mechanism. In the gas phase of the reaction kettle, the corrosion product on the surface of the coupon cannot dissolve without liquid. The temperature mainly affects the chemical reaction process. As the temperature increases, the corrosion rate increases because of the higher chemical reaction rate; at the same time, the partial pressure of water vapor in the gas phase increases, accelerating the corrosion rate of the flue gas.

In the liquid phase of the reaction kettle, the effect of temperature on corrosion rate is analyzed from the SEM test of corrosion product films, which is similar to the corrosion of N80 steel by CO₂.27 The SEM results show that there is a small amount of corrosion product film with poor adhesion and local shedding on the coupon surface at 60°C. After the
removal of the corrosion product film, the coupon surface is relatively smooth, with a small corroded strip and pitting. There is a thin corrosion product film at 90°C with local shedding and a large gap between grains on the surface of the coupon. After the removal of the corrosion product, the coupon surface is rough and features a small corroded strip. The corrosion product with a grain shape at 120°C is extremely dense, with strong adhesion that can stop the permeation of the corrosion solution and protect the matrix. The grains are uniform with no gaps between them. The coupon surface is not smooth after the removal of corrosion products, although to a lesser degree compared to that at 90°C.

The corrosion rate is related to the conditions of the corrosion product film and the adhesion of the corrosion product film on the matrix. For example, it is difficult to remove the corrosion product film at 120°C from the coupon surface, causing a relatively low corrosion rate. For the injection of flue gas in an oilfield, the temperature range from 80°C to 100°C should be avoided for the maximum corrosion rate that can produce the downhole string.27

3.1.3 Effect of pressure on the corrosion rate

The corrosion experiment was conducted in the gas and liquid phases in the reaction kettle to determine the relationship between the corrosion rate and pressure. The temperature of the reaction kettle was 90°C, and the pressure ranged from 1.0 to 9.0 MPa. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The concentration of SO₂ was 50 ppm. The results are shown in Figures 5 and 6.

Figure 5 shows the effect of flue gas pressure on corrosion rate in the gas phase. 13Gr steel shows good corrosion resistance performance, whereas the corrosion rates of X70, P110, and N80 are high and exhibit the same trend. When the flue gas pressure increased from 1 to 3 MPa, the corrosion rates increased rapidly. The corrosion rates remain fairly stable with further increases in pressure. The partial pressures of CO₂, O₂, and SO₂ increase with rising flue gas pressure, accelerating the chemical reaction. However, the effect of pressure on corrosion rate is not clear from 3.0 to 9.0 MPa.

Figure 6 shows the effect of flue gas pressure on the corrosion rate in the liquid phase. The corrosion rates of X70, P110, and N80 are similar. With increasing flue gas pressure, the corrosion rate increases rapidly. The corrosion rates reach maximum values at 7.0 MPa. The corrosion rates remain largely stable with further increases of flue gas pressure. Compared to the three carbon steels, the corrosion rate of 13Gr steel is considerably lower, showing good corrosion resistance performance. The pressure affects the corrosion rate in a liquid phase in two ways. First, more CO₂, O₂, and SO₂ dissolve in water with flue gas pressure increases, accelerating the chemical reaction; second, the corrosion product film becomes denser, inhibiting the corrosion of the steels to a certain extent.28

3.1.4 Effect of velocity on the corrosion rate

The corrosion experiment was conducted in the liquid phase in the reaction kettle to determine the relationship between the corrosion rate and velocity. The temperature of the reaction kettle was 90°C, and the pressure was 3.0 MPa. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The concentration of SO₂ was 50 ppm. The results are shown in Figure 7.

Figure 7 shows that the corrosion rate increases with increasing flow velocity. The higher velocity improves the mass transfer of the corrosion solution to the coupon surface and makes the depolarizing agents of H₂CO₃ and H⁺ move faster to the electrode surface, enhancing the depolarization
of the cathode. Simultaneously, the produced Fe$^{2+}$ can leave the coupon surface rapidly. The flow of the corrosive medium will also produce a tangential force on the coupon surface, which can hinder the deposition of the corrosion scale or peel off the formed corrosion product film.\textsuperscript{29}

### 3.1.5 Effect of O$_2$ concentration on the corrosion rate

The corrosion experiment was conducted in the gas and liquid phases in the reaction kettle to determine the relationship between the corrosion rate and O$_2$ concentration. The temperature of the reaction kettle was 90°C, and the pressure was 3.0 MPa. The mole fraction of CO$_2$ was 17\%, and the concentration of SO$_2$ was 50 ppm. The change of O$_2$ concentration was balanced with N$_2$. The results are shown in Figures 8 and 9.

Figure 8 shows the effect of O$_2$ concentration on the corrosion rate in the gas phase. The corrosion rates of the four steels all increase with the oxygen concentration; the increase of X70 is the most notable. Oxygen has a strong corrosive effect on steel, and it plays an important role in the catalyst mechanism of CO$_2$ corrosion. When the corrosion product film has not formed on the coupon surface, the corrosion rate of carbon steel increases with O$_2$ concentration. If the corrosion product film has formed on the coupon surface, the corrosion rate is nearly not affected by the existence of O$_2$. Corrosion rate is also related to the carbon content of the steel. A higher carbon content results in a lower corrosion rate. The carbon content of X70 in the four materials is the lowest shown in Table 1; thus, the effect of O$_2$ concentration in flue gas on the corrosion rate of X70 is the most notable.

Figure 9 shows the effect of the O$_2$ concentration in the flue gas on the corrosion rate in the liquid phase. The corrosion rates all increase with an increasing O$_2$ concentration. In a water solution saturated with CO$_2$, the existence of O$_2$ increases the corrosion rate of carbon steel considerably because O$_2$ played the role of the catalyst in CO$_2$ corrosion. Compared to X70, P110, and N80, 13Gr has good corrosion resistance. The excessive air coefficient of the boiler should be kept at a reasonable value to ensure a high boiler combustion efficiency. An excessively high air coefficient can increase the oxygen concentration in the flue gas, resulting in a higher corrosion rate of the downhole string.

### 3.1.6 Effect of SO$_2$ concentration on the corrosion rate

The corrosion experiment was conducted in the liquid phase in the reaction kettle to determine the relationship between the corrosion rate and SO$_2$ concentration. The temperature of the reaction kettle was 90°C, and the pressure was 3.0 MPa.
The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The concentration of SO₂ increased from 0 to 90 ppm. The results are shown in Figure 10.

Figure 10 shows that the existence of SO₂ has a significant influence on the corrosion rates of N80, P110, and X70. The corrosion rates increase rapidly with an increasing SO₂ concentration because the increase in the SO₂ concentration reduces the pH value of the corrosion medium, resulting in a higher corrosion rate. The increase in the SO₂ concentration has a smaller effect on the corrosion rate of 13Cr.

3.1.7 | Effect of H₂O concentration on the corrosion rate

The corrosion experiment was conducted in the gas phase in the reaction kettle to determine the relationship between the corrosion rate and H₂O concentration. The temperature of the reaction kettle was 90°C, and the pressure was 3.0 MPa. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The SO₂ concentration was 50 ppm. The H₂O concentration in the flue gas was increased to make the flue gas undersaturated, saturated, and supersaturated. The results are shown in Figure 11.

Figure 11 shows the effect of H₂O concentration on the corrosion rate in the gas phase. The corrosion rates of X70, P110, and N80 are similar. The corrosion rates are relatively low when the relative humidity of flue gas is lower than 0.7, and the corrosion rates increase rapidly as the relative humidity of flue gas increases further. The corrosion rates level off when the relative humidity reaches 1.3. The increasing corrosion rate for 13Gr with relative humidity is not as clear as for the other steels.

H₂O concentration in the flue gas is one important factor affecting the corrosion rate. When the H₂O concentration in the flue gas is sufficiently high, water will condense with increasing pressure and decreasing temperature. The condensate water can wet the steel surface and increase the corrosion rate. To reduce the corrosion of steels, the H₂O concentration of the flue gas should be reduced and the temperature of the flue gas should be kept higher than the dew point to avoid water condensation.

3.1.8 | Effect of NaCl concentration on the corrosion rate

The corrosion experiment was conducted in the liquid phase in the reaction kettle to determine the relationship between the corrosion rate and NaCl concentration. The temperature of the reaction kettle was 90°C, and the pressure was 3.0 MPa. The mole fractions of N₂, CO₂, and O₂ were 80%, 17%, and 3%, respectively. The SO₂ concentration was 50 ppm. The NaCl concentration in the flue gas was increased from 0 to 48,000 mg/L. The results are shown in Figure 12.

Figure 12 shows the effect of NaCl concentration on the corrosion rate under the liquid phase. With increasing NaCl concentration in the flue gas, the corrosion rate of steels increases. To reduce the corrosion of steels, the NaCl concentration of the flue gas should be reduced.
concentration, the corrosion rates of X70, P110, and N80 all increase notably; however, the corrosion rate of 13Gr is extremely low. Relative research shows that Cl⁻ can penetrate the corrosion product film, leading to instability of the corrosion product film. NaCl can reduce the likelihood of the formation of corrosion product film. For the injection wellbore, the flue gas should not be coinjected with water with a high salt concentration to decrease the corrosion rate of flue gas on the downhole string.

3.2 | Analysis of the corrosion product film

3.2.1 | Analysis of the corrosion products

The corrosion of metals starts on the substrate surface, and the substrate surface shows a different state after corrosion with different mediums. The composition of the corrosion product for N80 under different gas conditions was analyzed by XRD, and the experimental results are shown in Table 2.

| No. | Gas composition | Temperature/°C | Pressure/MPa | XRD result | Corrosion morphology |
|-----|-----------------|----------------|--------------|-------------|---------------------|
| 1   | 83%N₂ + 17%CO₂  | 90             | 3.0          | FeCO₃       |                     |
| 2   | 97%N₂ + 3%O₂    | 90             | 3.0          | FeO(OH)     |                     |
| 3   | 100%N₂ + 50 ppm SO₂ | 90         | 3.0          | Matrix surface of Fe with some Fe₃C |                     |
| 4   | 80%N₂ + 17%CO₂ + 3%O₂ | 60       | 3.0          | 61%Fe₂O₃ + 39%FeO(OH) |                     |
| 5   | 80%N₂ + 17%CO₂ + 3%O₂ | 90       | 3.0          | 29%Fe₂O₃ + 36%Fe₃O₄ + 35% FeO(OH) |                     |
| 6   | 80%N₂ + 17%CO₂ + 3%O₂ | 120      | 3.0          | 53%FeCO₃ + 37%Fe₃O₄ + 10%FeO(OH) |                     |
| 7   | 83%N₂ + 17%CO₂ + 50 ppm SO₂ | 120     | 3.0          | Fe with a small amount of Fe₃C |                     |
| 8   | 97%N₂ + 3%O₂ + 50 ppm SO₂ | 120     | 3.0          | Fe with a small amount of Fe₃C |                     |
| 9   | 80%N₂ + 17%CO₂ + 3%O₂ + 50 ppm SO₂ | 120 | 3.0          | Fe with a small amount of Fe₃C |                     |

Experiment No. 1 demonstrated that the coupon surface with a metallic luster became black after CO₂ corrosion, and XRD analysis of the composition on the surface indicated that it is FeCO₃. A complete corrosion product film formed on the coupon surface.

Experiment No. 2 demonstrated that the coupon surface after corrosion by O₂ became brown in color. The XRD analysis indicated that the mineral composition of the surface is mainly FeO(OH).

Experiment No. 3 demonstrated that the coupon surface after corrosion by SO₂ showed gray gloss with some residual black corrosion product. The XRD analysis indicated that the smooth area is a matrix surface of Fe and that the corrosion product is Fe₃C.

Experiments No. 4-6 demonstrated that the coexistence of O₂ and CO₂ resulted in serious corrosion. The corruptions of N80 steel under the condition of N₂ + CO₂ + O₂ for different temperatures are different. At low temperatures (60 and 90°C), the coupon surface morphologies after corrosion are similar.
The brown corrosion products are uniformly distributed on the surface of the coupon, and the area with no corrosion products is a matrix surface of Fe. With a higher temperature of 120°C, the coupon surface after corrosion appears black, covered with a layer of corrosion product film. Under the temperature of 60°C, the corrosion products are 61% Fe₂O₃ and 39% FeO(OH). Under the temperature of 90°C, the corrosion products are 29% Fe₂O₃, 36% Fe₃O₄, and 35% FeO(OH). Compared with the results at 60°C, Fe₃O₄ appears to account for a larger proportion, and the fraction of Fe₂O₃ decreases. At a temperature of 120°C, the main corrosion products are 53% FeCO₃, 37% Fe₃O₄, and 10% FeO(OH). The coupon surface forms a complete corrosion product film with a large amount of FeCO₃, and the friction of FeO(OH) decreases.

Experiments No. 7-9 demonstrated that the corrosion productions of N₈₀® steel under the conditions of N₂ + CO₂ + SO₂, N₂ + O₂ + SO₂, and N₂ + CO₂ + O₂ + SO₂ are mainly Fe with small amounts of Fe₃C. The coupon surfaces under the conditions of N₂ + CO₂ + SO₂ and N₂ + O₂ + SO₂ are smooth; however, the coupon surface under the condition of N₂ + CO₂ + O₂ + SO₂ becomes uneven with severe pitting corrosion.

3.2.2 | Analysis of the corrosion product film

The corrosion products analyzed by XRD demonstrated that the coupon surface can form a layer of corrosion product film under some corrosion conditions, inhibiting further corrosion on the metal surface. The effect of corrosion product film on the corrosion rate is related to the integrity and stability of the film. There are many factors that affect the formation of a corrosion product film, including the coupon properties and corrosion environment. According to the results of SEM, the microstructure morphologies of N₈₀® steel under the conditions of N₂ + CO₂, N₂ + CO₂ + O₂, and N₂ + CO₂ + O₂ + SO₂ were analyzed and are described below.

**SEM analysis for N₈₀® corrosion product film under N₂ + CO₂**

The N₈₀® steel corrosion test was carried out under the conditions of 80% N₂ + 17% CO₂ and 90°C, and the corrosion product film was analyzed by SEM. The results are shown in Figure 13.

The XRD analysis above shows that the corrosion product on the coupon surface is mainly FeCO₃ under the condition of N₂ + CO₂. SEM analysis from Figure 13A illustrates that a relatively complete layer of FeCO₃ covers the coupon surface, and the FeCO₃ crystal is a tetrahedron. The formation of FeCO₃ film depends on thermodynamic conditions on the coupon surface. The corrosion may be inhibited by the formation of FeCO₃ film because it reduces the contact of CO₂ and the coupon surface. However, incomplete corrosion product film may accelerate the electrochemical corrosion, resulting in severe pitting.

Figure 13B displays the SEM analysis of the coupon surface after removing the corrosion product film. The originally smooth surface with a metallic luster becomes rough with small local pits under the corrosion condition of CO₂, but the surface is relatively flat. The reason for this result is that the corrosion product film of FeCO₃ has a certain protective effect and reduces the corrosion rate. The local small pits may be caused by the incompleteness of the film.

**SEM analysis for N₈₀® corrosion product film under N₂ + CO₂ + O₂**

The N₈₀® steel corrosion test was carried out under the conditions of 80% N₂ + 17% CO₂ + 3% O₂ and 90°C, and the corrosion product film was analyzed by SEM. The results are shown in Figure 14.

Figure 14A shows a different corrosion product film for N₈₀® under the condition of N₂ + CO₂ + O₂ compared with Figure 13A. XRD analysis in Table 2 shows that the corrosion products of N₈₀® under the conditions are complex and include FeCO₃, Fe₃O₄, and FeO(OH). The SEM analysis in Figure 14A illustrates that the corrosion product film is loose and incomplete. There is considerable iron oxide embedded in the triangle-shaped FeCO₃ crystal.

Figure 14B displays the SEM analysis of the coupon surface after removing the corrosion product film under the condition of N₂ + CO₂ + O₂. The coupon surface is uneven with strip corrosion grooves. Compared with Figure 13B, the corrosion under the condition of N₂ + CO₂ + O₂ is more serious.

![SEM analysis for N₈₀® corrosion product film under N₂ + CO₂](image1.png)

![SEM analysis for N₈₀® corrosion product film under N₂ + CO₂ + O₂](image2.png)
because the corrosion product film formed under the condition is with poor protection.

**SEM analysis for the corrosion product film of N80 under \( N_2 + CO_2 + O_2 + SO_2 \)**

The corrosion test of N80 steel was carried out under the conditions of 80% \( N_2 \) + 17% \( CO_2 \) + 3% \( O_2 \) + 50 ppm \( SO_2 \) and 90°C, and the corrosion product film was analyzed by SEM. The results are shown in Figure 15.

Figure 15A shows that N80 has not formed a complete corrosion product film under the condition of \( N_2 + CO_2 + O_2 + SO_2 \), and the coupon surface is mainly a matrix that also contains an amount of \( Fe_3C \). The \( Fe_3C \) is a result of the anodic dissolution of Fe in the corrosion process. The \( Fe_3C \) is crisp and loose with holes. The \( Fe_3C \) product progresses the corrosion rate by galvanic corrosion and local acidification mechanisms.  

Figure 15B displays the SEM analysis of the coupon surface after removing the corrosion product film under the condition of \( N_2 + CO_2 + O_2 + SO_2 \). It shows characteristics of mesa attack corrosion, which results in a local platform form of corrosion on the coupon surface. The mesa attack corrosion can be caused by an unstable \( FeCO_3 \) film or turbulent erosion. Compared with the corrosion under the conditions of \( N_2 + CO_2 \) and \( N_2 + CO_2 + O_2 \), the corrosion under \( N_2 + CO_2 + O_2 + SO_2 \) is the most serious. The small amounts of \( O_2 \) and \( SO_2 \) can accelerate the corrosion of the downhole string under flue gas injection conditions considerably.

If the relative humidity of the flue gas is lower than 0.7, and the temperature of the flue gas in the wellbore is lower than 80°C, the corrosion rate is from 0.1 to 0.5 mm/y for the common carbon steels. The injection time of flue gas into reservoir is from several days to one or two months, which is not long-term injection. The corrosion is almost acceptable. If the conditions are worse, some corrosion inhibitor is needed to reduce the corrosion rate and protect the downhole string.

### 4 CONCLUSIONS

1. Under the corrosion environment of the gas phase, the corrosion rates of X70, P110, and N80 increase notably with temperature and \( O_2 \) concentration. The corrosion rates first increase rapidly with pressure from 1.0 to 3.0 MPa and then remain fairly stable.
2. Under the corrosion environment of the liquid phase, the corrosion rates of X70, P110, and N80 first increase and then decrease with temperature and reach maximum values at approximately 90°C. The corrosion rates of X70, P110, and N80 increase notably with velocity and \( O_2 \), \( SO_2 \), and \( NaCl \) concentrations.
3. The corrosion rates are relatively low when the relative humidity of flue gas is lower than 0.7, and the corrosion rates increase rapidly as the relative humidity of flue gas increases further. The corrosion rates level off when the relative humidity reaches 1.3.

**FIGURE 14** SEM analysis for N80 steel under \( N_2 + CO_2 + O_2 \). A, Corrosion product film. B, Coupon surface after the removal of the corrosion product film.

**FIGURE 15** SEM analysis for N80 steel under \( N_2 + CO_2 + O_2 + SO_2 \). A, Corrosion product film. B, Coupon surface after the removal of the corrosion product film.
4. The injection parameters should be optimized to reduce the flue gas corrosion of the downhole string. The relative humidity of the flue gas should be lower than 0.7. The temperature of the flue gas in the wellbore should avoid the range from 80 to 100°C. The excess air coefficient of the boiler should be kept at a reasonable value to reduce the O₂ content in the flue gas. The flue gas should not be cocked into wellbores with brine. Steels with higher Cr content can be used for the downhole string.

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CONFLICT OF INTEREST

The authors declare no conflict of interest.

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