Wellbore Corrosion Control Technology Research for H field in Iraq

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Abstract. Simulating the corrosive environment of H field, the corrosion rate of L80 steel is tested and corrosion rate is high. So the suitable corrosion inhibitors are selected. Through the simulated experiment, two types of corrosion inhibitors are screened and these two inhibitors are suitable for CO₂ and CO₂/H₂S co-existed corrosive environment respectively. Moveover the corrosion monitor system for H field is designed.

1. Introduction
For H field in Iraq, 0.03mol%-2.24mol% dissolved CO₂ exist in each formation water, while only 0.5mol% H₂S in formation Mishrif. As for salinity, all formation water is CaCl₂ water type that salinity rang from 152568ppm to 220104ppm and density is 1.12g/cm³-1.17g/cm³. The salinity of formation Sadi, Nahr Umr, Mishrif is higher than 150000ppm. As for concentration of Cl⁻ in the formation water, formation Nahr Umr is 100000ppm and formation Mishrif has reached 130000ppm. As for concentration of cation in all formation water, Na⁺ is over 60000mg/L, Ca²⁺ is over 80000mg/L, while Mg²⁺ of formation MB1 is over 2000mg/L. It is a conclusion that salinity and concentration of Cl⁻ of all formation water are too higher to cause a severe corrosion. The existence of massive Cl⁻, Ca²⁺ and Mg²⁺ would lead to a severe damage called localized corrosion [1-5].

2. Corrosion Test with Experiment Research
L80 steel made tubing has been used in H field. A series of lab corrosion tests have been conducted and the test results show that at WC=30%, corrosion rate of L80 is relatively high, normally, as the corrosion rate >0.125mm/a, it is under serious corrosion condition, corrosion control measures shall be taken. L80 steel lab corrosion test results are summarized in Table 1.

| No. | T/°C | P₁₂₅/ MPa | P₉₀₀/ MPa | Cl⁻/ ppm | H₂O/% | Corrosion Rate/mm·a⁻¹ |
|-----|------|------------|------------|-----------|------|-----------------------|
| 1   | 85   | 0          | 0.4        | 80000     | 30   | 0.1914                |
| 2   | 90   | 0.1        | 0.5        | 130000    | 30   | 0.8482                |

From the result of corrosion experiment, in the simulated corrosive environment of H oil field, the corrosion rate of L80 steel is high. To support the security of development of H oil field, the corrosion inhibitor suitable for oil field should be researched.
3. Corrosion Inhibitors Research

To keep oil field produce regularly, corrosion inhibitor plays an important role in reducing corrosion damage to metallic materials. Thus, a suitable and feasible corrosion inhibitor should be screened and selected. According to the experience before, two corrosion inhibitors which is named HGY-9B and MHS-2 have been selected to test the anti-corrosion ability. The major components of HGY-9B are imidazole amide and organic amine. HGY-9B suits for high CO₂ and high salinity corrosive environment. The major components of MHS-2 are imidazole cationic surfactant and long chain heterocyclic amide. MHS-2 suits for low pH, high salinity and CO₂/H₂S co-existed corrosive environment.

3.1. Experiment Result of HGY-9B Corrosion Inhibitor

Hanging the specimens on the bracket, each group has three specimens, the experiment temperature is 85°C, partial pressure of CO₂ is 0.4 MPa, the water cut is 30%, the flow rate is 2.5 m/s, experimental time is 5 days (120 h), use the autoclave to study the corrosion mitigation of HGY-9B, when the concentration is 100ppm and 200ppm, the results are listed as follow (Table 2.)

| Corrosion Inhibitor | Concentration/ppm | Corrosion Rate/mm·a⁻¹ | Efficiency/% |
|---------------------|-------------------|------------------------|--------------|
| Blank               | -                 | 0.1914                 | -            |
| HGY-9B              | 100               | 0.0412                 | 78.47        |
| HGY-9B              | 200               | 0.323                  | 83.12        |

Adding 100 ppm HGY-9B, L80 corrosion rate drop to 0.041mm/a, from the morphology of corroded test coupon, the surface of specimen covers with a thin black protective film. After remove the corrosion product, most of the area on the surface is bright and clean as the original standard specimen, the localized corrosion is presented in some local area, which indicates HGY-9B can inhibit the general corrosion. After concentration of HGY-9B reaching 200ppm, corrosion rate changed little compared with 100ppm, corrosion rate dropped to 0.0323 mm/a. But view from samples after the removal of corrosion products on the surface, localized corrosion decreased sharply. Most of the sample surface is bright and clean as the original one before the corrosion experiment, only in a very small area micro shallow pit appears.

3.2. Experiment Result of MHS-2 Corrosion Inhibitor

Using the high pressure and temperature autoclave, the corrosion mitigation efficiency of MHS-2 in the concentration of 100, 200ppm under the simulated Mishrif operating condition is tested. Hanging the L80 corrosion specimen on the bracket, each group has three specimens, the experiment temperature is 90°C, the medium is Mishrif simulated formation water, partial pressure of CO₂ is 0.5MPa, partial pressure of H₂S is 0.1MPa, the water cut is 30%, all corrosion experiments are carried out in a rotation system to mix the oil and water to be a homogenous phase at the flow rate 2.5m/s. The test results show in the Table 3.

| Corrosion Inhibitor | Concentration/ppm | Corrosion Rate/mm·a⁻¹ | Efficiency/% |
|---------------------|-------------------|------------------------|--------------|
| Blank               | -                 | 0.8482                 | -            |
| MHS-2               | 100               | 0.1903                 | 77.56        |
| MHS-2               | 200               | 0.0929                 | 89.05        |

As shown in Table 3 the corrosion rate for L80 specimen without inhibitors in simulated Mishrif operating condition is much larger than the standard 0.125mm/a, has reached to 0.8482mm/a, which
indicates a serious corrosion under this condition. From the experiment MHS-2 corrosion inhibitor shows good anti-corrosion ability in CO₂/H₂S co-existed corrosive environment.

According to the experiment result, HGY-9B and MHS-2 are suitable for the corrosive environment of H field. HGY-9B plays good anti-corrosion ability in CO₂ environment and MHS-2 is suitable for CO₂/H₂S co-existed environment, such as Mishrif formation.

4. Corrosion Monitor System Design

4.1. Produced Water Quality Analysis
Analyzing the ion concentration of produced water. Focus on the concentration of Fe²⁺, Ca²⁺, Mg²⁺, HCO₃⁻, SO₄²⁻, Cl⁻. Especially the concentration of Cl⁻ and Fe²⁺ should be concerned. The concentration of Cl⁻ can be used to judge the possibility of localized corrosion. The concentration of Fe²⁺ can be applied to estimate the inclination of wellbore corrosion. Analyzing the produced water frequently can help to understand the corrosive medium of wellbore and help to predict the inclination of corrosion.

4.2. Corrosion Inhibitor Concentration Monitor
When the corrosion inhibitors are applied in the H oilfield, the corrosion inhibitor concentration monitor should be applied. Test the concentration of corrosion inhibitor in produced water and compared with the order concentration. This method can be used to adjust the corrosion inhibitor injection rule.

4.3. Corrosion Inhibitor Concentration Monitor
This corrosion monitor method had been widely applied in the oilfield. One of the advantages of this method is that this method can be easily managed and operated. The field engineer who is easily trained can satisfy the requirement. The other advantage is that according to the difference of production wells, the material of coupon can be adjusted. The corrosion rate of the coupon can stand for the corrosion rate of production well. This corrosion monitor system should be established in H oilfield.

4.4. Corrosion Logging should be applied frequently
If the corrosion logging is ran every year. The corrosion logging result can be compared strongly and easily. Through the compare of the corrosion results, the corrosive situation of tubing and casing can be well known. Corrosion rate of tubing and casing wall can be calculated through the corrosion logging result. Moreover because the corrosion logging can show the real situation of wellbore clearly, logging result can support the adjustment of anti-corrosion method.

5. Conclusion
Through the experiment which simulating the corrosive environment of H field, the corrosion rate of L80 steel is tested and the corrosion rate is high when water cut over 30%. So the corrosion inhibitors which are suitable for corrosive environment of H field should be selected. Through the experiment two types of corrosion inhibitor are screened. HGY-9B plays good anti-corrosion ability in CO₂ environment and MHS-2 is suitable for CO₂/H₂S co-existed environment, such as Mishrif formation.

To understand the corrosion situation deeply, corrosion monitor system which cover the wellbore and wellhead parts is designed and would be established.

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