The Pressure Sensitivity Test and Plugging Mechanism Analysis in Salt-out Reservoir

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Abstract. With the decrease of formation pressure, high temperature and high salinity reservoirs are prone to salting out, which leads to the blockage of reservoir pore throat and the decrease of oil recovery. The gas-liquid two-phase seepage mechanism when the formation pressure is lower than the saturation pressure is simulated by changing gas-liquid injection volume ratio, and metallographic microscope and probabilistic statistical method were used to analyze the degree of plugging caused by salting out in displaced cores. The research shows that when the reservoir pressure is slightly lower than the saturation pressure, it is beneficial to improve the reservoir recovery, but when the reservoir pressure is too low, the salting out phenomenon is serious, the reservoir pore throat is blocked, and the reservoir permeability and recovery are significantly reduced. The reservoir blockage mainly occurs at the end of production, and the regularity of blockage degree is in line with the characteristics of exponential variation.

1. Introduction
For high temperature and high salinity reservoirs, the reservoir pressure system changes constantly with the development of oilfield[1-3]. When the reservoir pressure is lower than the saturation pressure, a large amount of gas is precipitated[4-7]. Many domestic and foreign scholars believe that the gas precipitated in the high temperature environment of the reservoir, accompanied by a large amount of steam quickly flows to the bottom of the well[8-10]. At the same time, the high salinity formation water with excessive water loss will cause salting out and block the reservoir pore throat[11-15]. However, the degree to which the phenomenon of salting out affects the reservoir is unclear, and the plugging law and seepage characteristics of salt-out reservoirs need further study. By means of gas-liquid co-injection experiment in the laboratory, the gas-liquid two-phase seepage law at the pressure lower than the formation saturation pressure is simulated and studied, and the plugging degree of displaced core caused by salting out phenomenon is analyzed by metallographic microscope and probability statistics method, so that the influence of the process and extent of salting out effect on the reservoir can be obtained.

2. Experiment preparation

2.1. Experimental material
The experimental materials include: the formation water from the studied block, with a salinity of about 155682mg/L; Natural columnar core, specifications Φ25mm×10cm, and the average gas
permeability is $56 \times 10^{-3} \mu m^2$; CO$_2$ gas, which is used to simulate the gas precipitated when the pressure of the formation is lower than the saturation pressure.

2.2. Experimental apparatus
The experimental apparatus includes: KD-II thermostat, ISCO Displacement Pump with constant rate and pressure, Metallographic Microscope, Precision Flowmeter, Precision Pressure Gauge, Core Gripper, Cooling Device, Back-Pressure Valve and so on.

2.3. Experimental method
The constant injection rate method was applied in the experiment. The injection rate was 0.1mL/min. The experimental temperature was 85℃.

There are four schemes for experimental design: in scheme I, the injection pressure is higher than the formation saturation pressure, and gas injection is not carried out; in scheme II, III and IV, the injection pressure simulated is lower than the formation saturation pressure, and the gas-liquid volume ratio maintained for injection is 5:1, 10:1 and 15:1, respectively.

The displacement test was carried out until the pressure of inlet and outlet was stable, and the water permeability of unsaturated crude oil core was calculated. The recovery was calculated when the outlet water content was 90%.

3. Pressure sensitivity experiment

3.1. Flow experiment
According to the experimental results obtained from the flow experiment, Darcy formula was used to calculate the water-measured permeability of the cores in 4 schemes respectively. The experimental results are shown in Table 1.

| experiment scheme | gas liquid ratio | gas-measured permeability ($\times 10^{-3} \mu m^2$) | water-measured permeability ($\times 10^{-3} \mu m^2$) |
|-------------------|----------------|---------------------------------|---------------------------------|
| scheme 1          | gas liquid ratio 0:1 | 57.28                           | 21.73                           |
| scheme 2          | gas liquid ratio 5:1 | 55.19                           | 23.36                           |
| scheme 3          | gas liquid ratio 10:1 | 56.32                           | 17.04                           |
| scheme 4          | gas liquid ratio 15:1 | 55.71                           | 14.43                           |

As can be seen from table 1, with the increase of gas-liquid injected volume ratio, the water-measured permeability of the core first increases and then decreases. When the gas-liquid injected volume ratio is 5:1, the water-measured permeability of the core reaches the maximum. The above experimental results show that when the reservoir pressure is slightly lower than the saturation pressure, gas precipitation occurs in the reservoir, and a small amount of gas precipitated rapidly flows to the core outlet end, resulting in a decrease in the pressure difference at the core inlet and outlet end and an increase in the water permeability of the core. However, for salting out reservoir, when the injected gas-liquid volume ratio is higher than 5:1, since the gas seepage rate is higher than the liquid, the formation water in the reservoir evaporates under the condition of high temperature, and rapidly flow with the large amount of gas to the core outlet, leading to further water loss of formation water with high salinity. When the formation water loss reaches a certain degree, salting-out phenomenon appears in the supersaturated formation water, which causes the blockage of formation pore, and the water-measured permeability of the core decreases.
3.2. Displacement experiment

For the core with vacuum pumping, saturated water and saturated oil, four schemes are adopted to conduct oil displacement experiments respectively. The water content at the outlet end in the oil displacement experiment is up to 98%. The experimental data are recorded. The experimental results are shown in figure 1.

As can be seen from figure 1, with the increase of injected gas-liquid volume ratio, the recovery increases and then decreases, and the change law is consistent with that of the permeability change in the flow experiment. When the reservoir pressure is slightly lower than the saturation pressure, a small amount of gas is precipitated out of the reservoir, and the gas precipitated can form favorable effect for gas oil displacement to a certain extent. However, when the reservoir pressure is too low, with the precipitation of a large amount of gas, the phenomenon of salt out is serious, the reservoir pore throat is blocked, the permeability is reduced, and the reservoir recovery is reduced.

4. Microscopic experiments of metallographic microscope

On the basis of previous studies, microscopic experiments of metallographic microscope were carried out to study the distribution of core blockage and the blockage degree of each part, so as to clarify the variation of the blockage degree of salt out core. Metallographic micrograph of salt out core is shown in Figure 2.
The cores after gas-liquid injection oil displacement were cut into thin slices every 1cm and observed under metallographic microscope. According to the principle of mirroring anti-optics, the reflected light of the rock skeleton is weaker than that of the crystal. Therefore, under the metallographic microscope, the precipitated crystal aggregation location becomes brighter and brighter, as shown in Figure 2.

According to the image morphology observed by metallographic microscope, probability statistics method was used to calculate the degree of the pore throat blockage in each section. The calculation results are shown in Figure 3.

As can be seen from figure 3, from the injection end to the production end, the degree of core blockage first increases and then decreases. At the location 8cm away from the injection end and 2cm away from the production end, the degree of blockage reaches the maximum, and the blockage mainly occurs at the outlet end. The process of core plugging can be basically divided into two stages. The first stage blockage increases with time, and the latter stage of blockage decreases with time, which is mainly caused by the gas-liquid seepage erosion. In addition, the degree of blockage change in the two stages conforms to the characteristics of exponential change.
5. Conclusion
(1) When the reservoir pressure is slightly lower than the saturation pressure, a small amount of gas is precipitated out of the reservoir, forming a favorable effect for gas flooding. However, when the reservoir pressure is too low, with the precipitation of a large amount of gas, the phenomenon of salting out is serious, the reservoir pore throat is blocked, the permeability is decreased, and the reservoir recovery is reduced.

(2) From the injection end to the production end, the blockage degree of the reservoir increases first and then decreases. The blockage phenomenon mainly occurs at the production end. The change law of the blockage degree of the reservoir conforms to the characteristics of exponential change.

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