Study on Water Displacing Gas Relative Permeability Curves in Fractured Tight Sandstone Reservoirs Under High Pressure and High Temperature

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ABSTRACT: Water–gas relative permeability is an important parameter for the rational development of gas fields. Conventional measurement methods are carried out at normal temperature and pressure without considering the actual conditions of high temperature and high pressure. The water displacing gas process in fractured tight sandstone reservoirs, under formation condition (116 MPa and 160 °C), was simulated by the self-manufactured displacing apparatus. The results show that cores under formation condition have the larger residual gas saturation, the smaller two-phase coexisting area, the lower water/gas relative permeability, and the lower displacement efficiency than that under normal conditions. The relative permeability declines slowly and the residual gas saturation is high, making the process of replacing the gas more difficult. The number and the interconnection quality of fractures affect the shape and the position of the displacing curves. It provides a reference for the rational development and further research of fractured tight sandstone reservoir.

1. INTRODUCTION

Fractures are of great importance to gas reservoirs, which are either storage spaces or main flowing channels of natural gas. Therefore, it is critical for enhancing gas recovery to study fractures and flowing characteristics in tight sandstone reservoirs. Commonly, measuring permeability curves is the most useful method to reveal the flowing mechanism and predict petroleum recovery in fracture media. However, at present, it is under normal pressure and normal temperature that the measurement of gas–water permeability curves is carried out at home and abroad. However, because of the complicated structure of fractured reservoirs, the gas–water permeability curves measured under normal pressure and normal temperature, which do not get influenced by high pressure and high temperature, cannot accurately reflect real gas–water flowing character in fractured tight reservoirs. Therefore, it is necessary to measure gas–water permeability curves in actual fractured tight reservoirs. Presently, there are few studies available on high temperature and high pressure gas–water relative permeability at home and abroad that can satisfy both high temperature and high pressure stratum conditions. Even the experimental pressure is much lower than the real pressure of the gas reservoir. A theoretical conversion model was established by Guo to transfer gas–water relative permeability from experimental conditions to reservoir conditions. A high-pressure and high-temperature well was taken as an example to simulate and calculate the effects of different temperatures and pressures on gas–water relative permeability. The results indicated that experimental temperature and pressure exert an effect on gas relative permeability instead of water relative permeability, particularly when gas relative permeability at experimental room temperature and lower pressure is 10 times higher than that at high temperature and high pressure. Wang simulated the development of reservoir cores by means of artificial fracture and hole formation, then the gas–water relative permeability curve is tested under room temperature with normal pressure and high temperature with high pressure (160 °C and 56 MPa). The difference between the relative permeability curves obtained by several methods is huge for gas–water two phase flow characteristic between horizontal connection and vertical connection because of the influence of gravity differentiation.

The K–S gasfield is one which is typical of fractured tight sandstone reservoirs in China. In this study, the gas–water permeability curves of 9 full-diameter cores collected from the K–S gasfield were obtained under formation conditions (116
MPa and 160 °C) and under normal conditions, and the results obtained by the methods were compared and analyzed. First, the cores were dried and saturated with water. Then, appropriate displacement pressure was selected to measure the effective gas relative permeability under the condition of confined water in the core gripper, so as to obtain the gas–water relative

Figure 1. Comparison of water displacing gas relative permeability curves under different conditions.
permeability curve. It was the first time that a method for measuring water displacing gas relative permeability curves had been established considering the interaction of gas and water under high pressure and temperature in fractured tight sandstone reservoirs, according to the China National Standard GB/T 28912-2012 (“test method for two phase relative permeability in rock”).

2. RESULTS AND DISCUSSION

The data obtained under normal pressure and temperature were processed according to GB/T 28912-2012. Because a large amount of gas was dissolved in water and the volume of gas and water changed with pressure and temperature increased. The data obtained under high pressure and temperature need to be revised. Comparison of water displacing gas under different conditions is shown in Figure 1 and Table 1 (where NPNT is normal pressure and normal temperature and HPHT is high pressure and high temperature).

As shown in Table 1 and Figure 1, samples no. 1 and no. 2 have the highest value for $K_f / K_b$ ratio (where $K_f$ refers to the fracture permeability and $K_b$ refers to the bedrock permeability) in which fractures are the absolutely dominant flowing channels, and the bedrocks are hardly useful, resulting in low sweep efficiency. In addition, gas relative permeability under normal pressure and normal temperature has a slower declination than that under high pressure and high temperature with increase in water saturation. Samples no. 3, no. 4, no. 5, and no. 6 have low values for $K_f$ to $K_b$ ratio, causing high sweep efficiency. The relative permeability curve under high pressure and high temperature is on the left of that under normal pressure and normal temperature. Samples no. 8 and no. 9 are equal to bedrocks because fractures are not interconnected; therefore, they have relatively high sweep efficiency. Under high pressure and high temperature, samples with interconnected fractures have larger residual gas saturation and smaller two-phase coexisting area. On the whole, rarely the physical properties had the same effect on the position and shape of the curves as the number and the interconnection quality of the fractures.

As shown in Figure 2, samples have the smaller $K_g (S_{wi})$ and $K_w (S_{rg})$ under high pressure and high temperature. That is because the viscosity of water/gas declined, and the viscosity ratio of water to gas is about 13 times lower than that under normal pressure and normal temperature, which indicates a harder process of water displacing gas under high pressure and high temperature.

Figure 3 shows that displacement efficiency ($R$) under high pressure and high temperature (17−45%) is lower than that under normal pressure and normal temperature (20−64%), and the higher fracture the permeability is, the lower the displacement efficiency is. With the flowing of a large amount of water, permeable capacity of water improves quickly, indicating that plenty of water could be out of samples, as they are lowly permeable. Moreover, we found the bedrock contributed hardly a portion of flowing in the process of water displacing gas in the sample whose permeability was more than 6.98 mD, and the flowing depended on the fractures completely, only to bring about the lower displacement efficiency.

There exists great difference in the physical property of cores and fluids from formation to the surface. On one hand, in rocks, high temperature of formation resulted in the thermal expansion of mineral particles. The volume change of the thermal expansion is small, which will not give rise to a significant

Table 1. Comparison of Character Values Under Different Conditions

|   | NPNT |   |   |
|---|------|---|---|
|   | $S_{wi}$ (%) | $K_g (S_{wi})$ mD | $S_{rg}$ (%) | $K_w (S_{rg})$ mD |
| 1 | 40.38 | 473.41 | 49.41 | 58.65 |
| 2 | 39.75 | 8.06 | 46.77 | 2.61 |
| 3 | 39.88 | 3.79 | 42.22 | 1.04 |
| 4 | 40.29 | 1.01 | 40.47 | 0.2 |
| 5 | 40.2 | 2.65 | 38.03 | 0.98 |
| 6 | 40.29 | 1.05 | 46.32 | 0.21 |
| 7 | 40.28 | 0.583 | 46.64 | 0.09 |
| 8 | 38.74 | 0.196 | 44.95 | 0.06 |
| 9 | 39.99 | 0.115 | 32.47 | 0.03 |
|   | HPHT |   |   |
| 1 | 38.78 | 508.65 | 49.18 | 64.35 |
| 2 | 40.41 | 10.28 | 44.71 | 3.1 |
| 3 | 38.32 | 4.05 | 38.73 | 1.17 |
| 4 | 40.16 | 1.22 | 38.71 | 0.24 |
| 5 | 38.87 | 3.22 | 29.92 | 1.07 |
| 6 | 40.51 | 1.11 | 38.77 | 0.24 |
| 7 | 38.86 | 0.606 | 46.15 | 0.16 |
| 8 | 39.83 | 0.342 | 35.55 | 0.08 |
| 9 | 40.09 | 0.189 | 21.43 | 0.03 |
change of the total porosity. But the slight change of the thermal expansion caused by temperature had an obvious effect on pore throat of the rock, which will make the pore structure change. New fracture will not form before temperature reached the threshold so as to worsen the porosity and permeability of the rock. Meanwhile, under high pressure and temperature, reservoir rocks, the minute pore and the fracture are compressed greatly, leading to the reduction of the porosity and the permeability. That is, in contrast with surface, high pressure and temperature will change the pore structure of the reservoir rock, furthermore, resulting in poor physical property of the rock and the reduction of gas–water permeability. On the other hand, under high pressure and temperature, the viscosity of water and gas will decrease, but the viscosity of water decreases much more than that of gas, and the viscosity ratio from water to gas is much lower than that under normal condition. Two parts working together cause different water–gas relative permeability curves between formation and the surface.

![Figure 3. Comparison of displacement efficiency under different conditions.](https://dx.doi.org/10.1021/acsomega.0c00139)

### Table 2. Selected Samples Properties

| No. | Length (cm) | Diameter (cm) | Porosity (%) | Permeability (mD) | Bedrock permeability (mD) | Fracture $K_r$ ($P_{bedrock} K_o$) | Fracture characteristics |
|-----|-------------|---------------|--------------|------------------|--------------------------|------------------------------------|--------------------------|
| 1   | 8.753       | 6.461         | 6.83         | 612.9            | 0.00717                  | 85481                              |                          |
| 2   | 8.967       | 6.485         | 7.52         | 25.18            | 0.00528                  | 4768                               |                          |
| 3   | 8.785       | 6.486         | 8.09         | 6.98             | 0.00691                  | 1010                               |                          |
| 4   | 6.913       | 6.576         | 6.6          | 5.86             | 0.00252                  | 2325                               |                          |
| 5   | 6.947       | 6.332         | 5.88         | 3.66             | 0.0855                   | 66                                 |                          |
| 6   | 8.913       | 6.534         | 5.7          | 3.57             | 0.00377                  | 946                                |                          |
| 7   | 8.924       | 6.521         | 5.44         | 2.54             | 0.00745                  | 340                                |                          |
| 8   | 8.819       | 6.551         | 6.5          | 1.51             | 0.00352                  | 993                                |                          |
| 9   | 8.875       | 6.373         | 5.02         | 0.381            | 0.00229                  | 166                                |                          |
3. EXPERIMENTAL PROCEDURES

3.1. Samples. The samples were collected from the well K-S-1-2 where fractures were well developed. The physical characteristics of the samples are shown in Table 2. Commercial nitrogen was used as the displaced phase and distillated water was used as the displacing phase.

3.2. Experimental Procedures. The water displacing gas experiment under normal pressure and normal temperature was conducted in a type 103 gas−water relative test instrument, according to the China National Standard GB/T 28912-2012. The water displacing gas experiment under high pressure and high temperature was conducted in the self-manufactured displacing apparatus, as shown in Figure 4, as follows:

(1) Experimental preparation: A drying sample was weighed and saturated with water under 41.38 MPa and 20 °C. The sample was weighed again after 24−36 h to confirm quality of the saturated water. Then, the sample was placed in the core holder and displaced by N2 injected from the inlet of the core holder until no flowing water was out of the outlet of the core holder. The sample saturated water was acquired.

(2) Experimental parameters and operation: Pressure and temperature were lifted to 116 MPa and 160 °C, respectively, keeping confining pressure 2 MPa at least higher than the inlet pressure of the core holder. Then, stable temperature and pressure were expected. Other operations were complied with GB/T 28912-2012.

In conclusion, compared with the test results at normal temperature and pressure, the water−gas relative permeability curve under high pressure and high temperature is affected by the combined effect of temperature, pressure, pore structure, and fluid, and has the following characteristics:

(1) With the increase of water saturation, water−gas relative permeability decreases slowly.

(2) The viscosity ratio of water to gas is about 13 times lower than that under normal pressure and normal temperature.

(3) High temperature and high pressure will change the pore structure of reservoir rocks, resulting in poor physical properties of rocks.

4. SUMMARY AND CONCLUSIONS

We have compared the water displacing gas relative permeability curves under different conditions. Such conclusions can be drawn:

(1) The number and the interconnection quality of fractures affect the shape and the position of the curves in fractured reservoirs under high pressure and high temperature.

(2) Cores have the larger residual gas saturation, the smaller two-phase coexisting area, and the lower water/gas relative permeability of endpoints in the displacement of gas by water in fractured tight sandstone reservoirs under high pressure and high temperature.

(3) There is the lower displacement efficiency when gas is displaced by water in fractured tight sandstone reservoirs under high pressure and high temperature.

(4) The curves measured under formation condition are recommended in order to reveal real flowing characteristics in displacement of gas by water.

It was the first time that a method for measuring water displacing gas relative permeability curves had been established considering the interaction of gas and water under high pressure and temperature in fractured tight sandstone reservoirs because of the difficulty of the experiment and the numerous factors affecting the gas−water permeability, the test results are quite different from those obtained by conventional methods; therefore, further research is needed.

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Figure 4. Experimental procedure of water−gas relative permeability under high pressure and temperature.
The authors declare no competing financial interest.

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