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Effect of osmosis on spontaneous imbibition of fracturing fluid in shale oil formation

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The traditional theory of spontaneous imbibition is fluid displacement caused by capillary force. However, the imbibition of fracturing fluid in shale reservoir is not only related to capillary force, but also affected by osmotic pressure. Shale pores are in micro/nano scale and have high clay content. Clay is mainly distributed on the pore wall, and can act as a semi-permeable membrane when the fracturing fluid is imbibed, thus causing water molecule osmotic transport, that is, water molecule migration from low salinity fracturing fluid to high salinity formation water. For the spontaneous imbibition of fracturing fluid during well shut-in after fracturing, people often pay attention to the effect of capillary force. In addition, the existing imbibition experiments considering osmosis are multifaceted shale gas formations. Therefore, the osmosis on spontaneous imbibition of fracturing fluid in shale oil formation needs to be further studied.
The cores used in this study are shale from continental shale oil reservoirs in China, and their petrophysical properties (porosity 5%, permeability 0.002mD) are basically the same. By means of nuclear magnetic resonance (NMR) technology and high precision electronic balance measurement, spontaneous imbibition experiment of fracturing fluid with different salinities was carried out on the core. The shale oil used in the experiment contains 10% water, which is saturated by the core and forms bound water to simulate the oil-water two-phase environment in the core matrix. Fracturing fluid and bound water have different salinity. Different osmotic pressure can be formed by changing the salinity of fracturing fluid. The imbibition recovery rate of shale oil can be calculated according to the NMR T2 spectrum measured in the imbibition experiment, and the imbibition fracturing fluid content can be calculated based on the change of core weight during the experiment.
When the high salinity fracturing fluid (18 wt.% $MnCl_2 \cdot 4H_2O$) was imbibed, the core weight first increased, then decreased, then increased again, and finally stabilized. This kind of imbibition can be divided into four stages: initial imbibition stage, drainage stage, secondary imbibition stage and stationary stage. The drainage stage indicates that the core is dewatering and dominated by osmosis, while the initial and secondary imbibition stages are dominated by capillarity. The imbibition of high salinity fracturing fluid (20 wt.% KCl) appears the same phenomenon when the salt ion type is changed. For low salinity fracturing fluids (2.4 wt.% KCl), there was no core dewatering phenomenon, but a significant increase in shale oil imbibition recovery. This is because when the fracturing fluid salinity is lower than the bound water, the great salinity difference between the fracturing fluid and the bound water will form a strong osmotic pressure, driving the fracturing fluid to move deeper into the core matrix.
The major contribution is to prove that capillarity and osmosis are important imbibition mechanisms in shale oil reservoirs, distinguish the imbibition stage dominated by osmosis or capillarity, and reveal the influence law of osmotic pressure on shale oil imbibition recovery under different salinities.

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References

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