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Research Article

Mechanism of Using Dilute Microemulsion System (DMS) on Enhancing Hydrocarbon Production from Low Permeability Reservoirs

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Abstract:

Dilute microemulsion system (DMS) can reduce the adsorption of surfactants on the rock surface, and it has been widely used as fracturing fluid additive for low permeability reservoirs in recent years. In some cases, it can reduce the water block caused by the invaded fracturing fluid and enhance the hydrocarbon production rate; while in some cases, it cannot. Although a few theories and models have been proposed to explain this discrepancy, it is still unclear (1) when DMS can enhance the hydrocarbon production, and (2) the impact of using DMS on hydraulic fracturing, flowback, and production. In this study, the imbibition test, contact angle test, and core flooding experiment were conducted to explore the answers to the above questions. Results from imbibition cell tests and contact angle measurements indicate our DMS can alter rock wettability from oil-wet to water-wet within half a day, but it cannot alter water-wet originally rocks. In core flooding experiments, the invasion step shows that the relative permeability to water is reduced after using DMS, suggesting DMS can reduce the forced water invasion during hydraulic fracturing; the flowback step shows that 0.1wt% DMS can reduce the water block and enhance the production rate by 12% comparing to the brine.

1. Introduction

The unconventional reservoir has become the vital part of the fossil energy. Although the permeability and porosity are low, the volume is so large that the original oil in place is giant [1]. Horizontal well and staged fracturing are the main technologies to exploit the oil. However, the production decreases fast, and the oil recovery is only about 5%-10%. The reason is that the reservoir is so tight that the energy decreases quickly [2]. Besides, the wettability of the reservoir is another critical factor [3,4]. The reservoir would tend to be oil-wet, after contact with the oil for a long period, because the surfactant in the oil would adsorb onto the stone, which would alter the wettability of reservoir. For tight reservoir, the imbibition is an essential mechanism of recovery, and if fracturing fluid can alter the oil-wet reservoir into the water –wet reservoir, the imbibition would happen, then the oil recovery would be enhanced a lot [5,6]. Surfactant and nanofluid have been added into fracturing fluid, which can help change the wettability of the reservoir [7]. Although kinds of surfactant have been used in the low permeability reservoir, the effect is unsatisfactory. The reason is that the surfactant is easier to adsorb onto the stone, which would reduce the effective area [8]. As a new fracturing additive, DMS has been widely used in the low permeability reservoir, which has shown that the DMS can improve the production at different levels [9]. However, the mechanism of using DMS on enhancing production from low permeability reservoirs hasn't been figured out. In this paper, several experiments have been conducted to answer the question. Amott test and contact angle test were used to prove the wettability alteration, core flooding test can be used to justify the higher production and less water block after using the DMS.

2. Material and Procedure

Rock properties: The permeability to water is 0.7mD, the porosity is 0.135, and rock is taken at an outcrop, and its main mineral is dolomite.

Dilute Microemulsion System (DMS): The average diameter of DMS is 15 nm, the test result is listed as Fig1, the interfacial tension (IFT) of 0.1wt% DMS is 3mN/m. Adsorption is 3 mg/g. the core of DMS is oil phase, and the surfactant adsorbs on the oil phase.

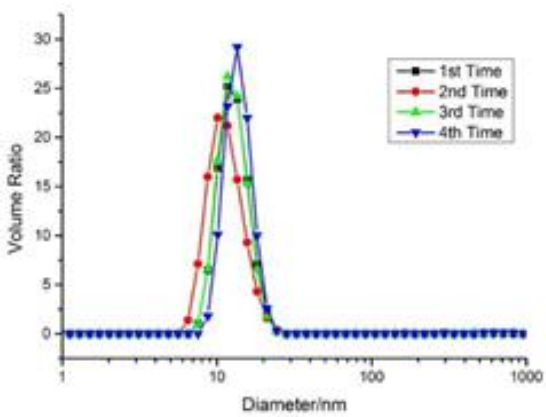

Fig 1. *Diameter distribution of DMS*

Amott cell: The cell (Fig 2) can hold a cylindrical rock core with 6cm length, the precision is 0.02ml, the maximum range is 2ml. A white cover put on the top of the cell is prevented the liquid from evaporation. A thin tube in the middle of cell can measure the variation of the oil-water boundary. The power of imbibition is the capillary force. If the stone is water wet, after putting the core into the water, the imbibition will happen, and the oil-water boundary will change, because the water would replace oil out; on the contrary, if the stone is oil wet, the capillary force is resistance, the imbibition wouldn't happen, the oil-water boundary still unchanged.

Contact angle equipment: the equipment can test the contact angle between solid surface and liquid (Fig 3).

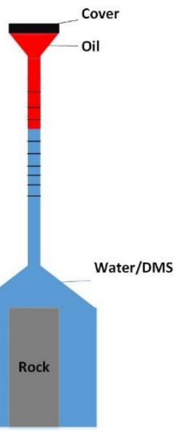

Fig 2. *Schematic diagram of Amott cell*

The test method is dropping a droplet on the solid surface, and the high precision camera can record the image of a droplet. We can adjust the camera until the droplet is clear enough. Computer screen would show the picture of a droplet. Then the contact angle between solid and surface would be tested through software. Because of different wettability, the contact angle between liquid and solid is different. If the contact angle between water and solid is larger than 105°, the solid is oil-wet; if the contact angle is between 75° to 105°, the solid is middle wet; if the contact angle is smaller than 75°, the solid is water wet.

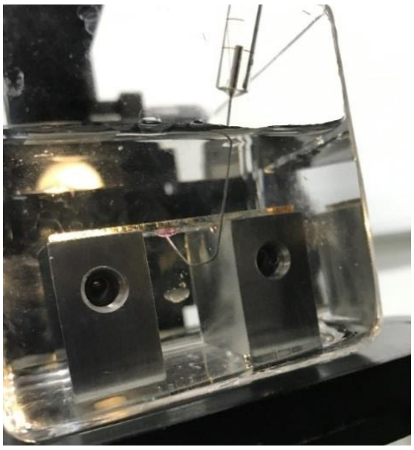

Fig 3. *Contact angle test*

Core Flooding System: The core flooding system (Fig 4) consists of 5 parts: pump system, the power system is a 100DX ISCO pump. The flow rate is from 0.00001cc/min-50ml/min, and the highest flooding pressure is 10000 psi. There are three containers which can fill in the water, DMS and kerosene. Their loading capacity is 10000psi. Five pressure transducers are loaded to monitor the pressure; the precision is 0.058psi. Core with different length is loaded in the core holder, the diameter of core is 2.54cm (1 inch). A hand pump loads confining pressure.

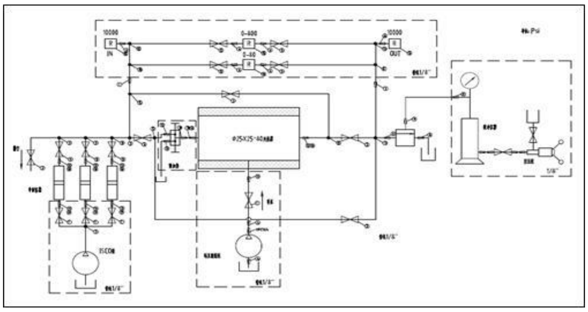

Fig 4. *Schematic diagram of the core flooding system*

Procedure:

Imbibition test:

①To change the wettability of carbonate rocks, the cores were flooded 10PV by the 1.5% oleic acid with kerosene, after that the cores were flooded with kerosene, the aim is to displace the oleic acid out in case the oleic acid influence the experiment.

②Testing the contact angle of rock, making sure the rock has become oil-wet.

③putting the core A into Amott cell and the loaded the distill water with 2wt%KCl until the water reaches the scale line of cell; putting the core B into Amott cell, and the loaded the 0.1wt% DMS until the water reaches the scale line of cell.

④recording the oil-water boundary with different time. At the start period, the interval time is 20min, after 2 hours, the interval is 1hr until the oil-water boundary doesn't change.

Core flooding experiment:

①To change the wettability of carbonate rocks, the cores were flooded 10PV by the 1.5% oleic acid with kerosene, after that the cores were flooded with kerosene, the aim is to displace the oleic acid out in case the oleic acid influence the experiment.

②0.1wt.%DMS was injected into the core reversely, which mimicked the fracturing fluid. And the fluid without the DMS was taken as the control group.

③At the end, the kerosene floods through the rock from the opposite direction. During the experiment, the pressure difference and volume of water and oil are supervised. The flow rate of the whole process is 0.05ml/min.

3. Result and Discussion

Spontaneous imbibition oil production

The imbibition test result shows that the core A immersed in the 0.1wt% DMS replace more oil than core B immersed in the fluid without the DMS. At the beginning of the imbibition test, oil-water boundary changes fast, after 1 hour, the oil-water boundary gradually unchanged (Fig 5). On the contrary, the core immersed with the core B, the oil-water boundary early keeps constant. The result proved that the DMS could alter the oil wet into water wet, because the oil was replaced by the water, and the capillary is the power. The more oil was replaced by the water; the water-wet properties are stronger. For core B, the core is oil-wet, the capillary is the resistance, and the water cannot enter the pore and replace the oil out. Therefore, the oil-water boundary in the cell is unchanged. The similar liquid called nanofluids has been proved to enhance the oil recovery through Amott cell [4].

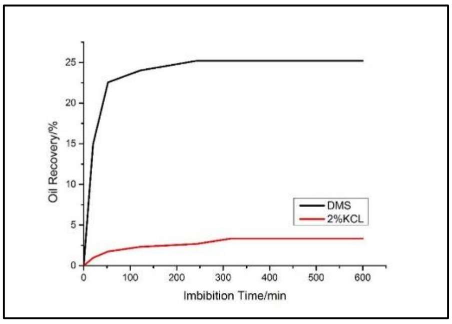

Fig 5. *The imbibition curve with two kinds of liquids*

Contact angle test

After flooded by the oleic acid, the average contact angle of core A is 145°, the average contact angle of core B is 143°. After the imbibition test, the average contact angle of core A is 65°, which proves that the core A is water-wet. This is because the DMS adsorb on the surface of a rock, and change the rock's wettability. The average contact angle of core B is 120°, which proves that the core B is still oil-wet. As shown in fig 6 and fig 7. Alvarez and Schechter has used the contact angle experiments to prove the anionic, nonionic surfactant, and complex nanofluid can alter the oil-wet to water-water at different levels [8]. Liang et al. also used the contact angle experiments to prove the liquid nanofluid can alter the oil-wet to water-water in the tight oil reservoir [5].

Core flooding test

The results show that the oil relative permeability with DMS is 12% higher than brine (Fig 8), which proves that the DMS can reduce the water invasion. The result also indicates that the core displaced with DMS has tended to water wet.

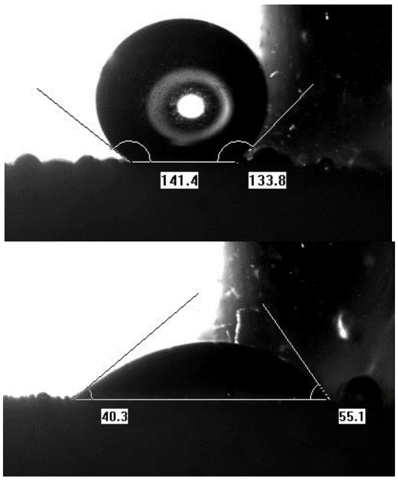

Fig 6. *Before and after submersed into the DMS*

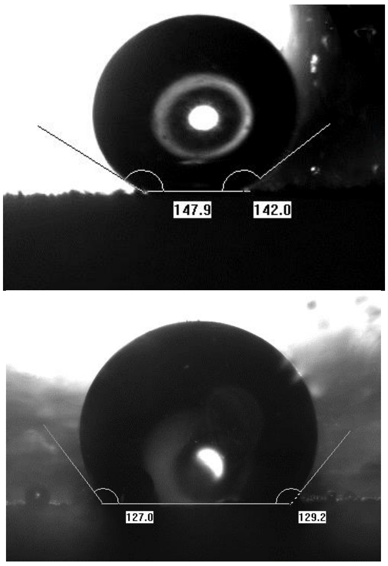

Fig 7. *Before and after submersed into the 2%KCl*

Because the relative permeability of the wetting phase is lower according to the relative permeability curve. At the third step, the pressure with DMS decreases fast, which state the core tends to water wet. On the contrary, the pressure with 2%KCl stays high, which demonstrates the core is still oil wet. The fracturing fluid loss into the reservoir can damage the reservoir and decrease the production. To asset the flow back rate, the effluent is also collected. The core displaced with DMS collected 0.15PV more water than brine at last. The result shows that the DMS can dissipate the lost fracturing fluid into the matrix and improve the flow back. Liang et al. have used the core flooding system with a surfactant to study the wettability alteration in low permeability [2].

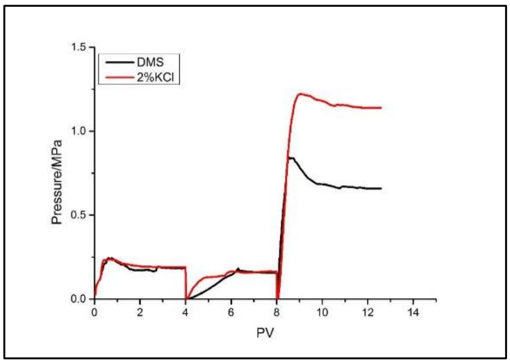

Fig 8. *Pressure variation during the flooding process*

4. Conclusion

Based on the experimental study, we propose the mechanisms of using DMS on enhancing the flowback and oil production, especially from oil-wet reservoirs. Meanwhile, we reveal the potentials of using DMS on (1) controllable altering rock wettability from oil-wet to water-wet (2) reducing water invasion and thus enlarging the fracture area. Our results also provide a criterion on screening/optimizing DMS for fracturing low permeability reservoirs.

Notes

The authors declare that they have no conflict of interests.

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