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Experimental Study of Foam Flooding in Low Permeability Sandstones: Effects of Rock Permeability and Microscopic Heterogeneity

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ABSTRACT

Foam flooding (or injection of foam) is a common technology to enhance oil recovery. Although the effects of permeability on foam flooding were well studied in many laboratory experiments, little research has been focused on the specificity of low permeability. In this paper, a series of constant-quality nitrogen foam flow experiments were conducted to investigate the effects of permeability on the foam performance and oil displacement efficiency. Moreover, the results indicated that foam can be generated in low permeability porous media. With uniform experimental conditions, the higher permeability core has a bigger recovery amplification and greater decreasing range of water cut decline. Furthermore, the effect of microscopic heterogeneities of low permeability reservoir on foam displacement is considered. Moreover, experimental comparative analysis with different microscopic heterogeneity cores showed that, in low permeability condition, homogeneous porous media has a better prospects of oil-displacement. Finally, in this work, the results of the permeability effects on the foam performance and oil displacement efficiency exemplify a potential to apply the technology to low permeability reservoir.

Keywords: Foam flooding, Low permeability, Heterogeneities.

INTRODUCTION

For the past few decades, gas injection has received much attention as an important method of enhanced oil recovery (EOR). With favorable mobility, gas can be more easily injected than water to enhance oil recovery in low permeability reservoirs. Nevertheless, early breakthrough and poor sweep efficiency are common problems in gas flooding which results from the large viscosity contrast between the displaced and injected fluids [1-2]. The evidence shows that the presence of an aqueous surfactant solution can produce a foam with gas which reduces the gas mobility across the regions of different permeability [3].

The study of using foam to reduce gas mobility was initially patented in 1958 [4]. In two references [5-6], it is shown that residual unrecoverable oil by conventional water or gas drives can be displaced by foam from porous structures. In addition, foams are dealt as a conception that agglomerations of gas

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bubbles separated from each other by thin liquid films [7]. Moreover, the foams are used to improve the volumetric sweep efficiency of gas and liquid floods by either reducing gas mobility in depth or by plugging thief zones near the injector. Therefore, foam technology, for example, N_2-foam, has been successfully applied to enhance oil recovery in a relatively high permeability reservoir [8]. As more investigations of foam flooding have been made on low permeability, there is a potential and tendency to apply the technology to low permeability reservoir, recently.

The permeability is a decisive parameter in the control of foam generation and stability in heterogeneous porous media [9]. The published data [10] indicate that foam strength is affected by the permeability of porous media. It is found by Kibodeaux [11] that foam mobility decreases when the permeability increases. This shows that foam is stronger in high permeability rocks than in low permeability ones. Moreover, the influences of core permeability on foam flooding are reflected in several aspects. For one thing, foam properties and foam-oil interactions are influential to foam effectiveness in the presence of residual oil. It is argued by some researchers that foam cannot be generated at relatively high oil saturations, but it is shown by other researchers that it is possible to generate foams on this occasion [12-15]. It is shown by Mannhardt. [16] that foam can be generated at 42% oil saturation. Also, for another, foam texture is also governed by capillary pressure. As the capillary pressure is raised, the work required to break the foam film decreases [17]. At a sufficiently high capillary pressure, this work may become so small that mechanical disturbances or even thermal fluctuations may rupture the film [18].

Quite a few studies about foam behavior on homogeneous and heterogeneous porous media have been done [1,19-24]. The view has held by some investigators that the heterogeneity of porous media is favorable to generate strong foam. The generation of foam lamellae by snap-off for flow across an abrupt increase in permeability is shown to be dependent on the degree of permeability contrast and the gas fractional flow [20]. However, it is drawn a different conclusion. It is indicated by Jonas. [24] that the strong foam can be generated in the low permeability core with more homogeneity in some ways. However, the study into low permeability (about 9 mD) core without the presence of oil has been done by some researchers. Hence, it is essential to make more researches about foam effect on EOR with the homogeneous and heterogeneous porous media in the presence of oil.

In this paper, two main parts are covered. First, it is a controversy that foam can be generated in low permeability core in the presence of oil. The effects of permeability on foam flooding performance in low permeability natural cores experiments must be considered. Second, the influence of microscopic heterogeneities on low permeability cores based on foam displacement experiments is investigated.

EXPERIMENTAL PROCEDURES

Experimental Materials

The experimental cores were prepared for the single-core experiment. Moreover, Table 1 gives the summary of the physical properties of the different core used.

Table 1: Physical properties of core material.

Core No.	Length [cm]	Diam [cm]	Cross section area [cm^2]	Porosity [%]	K(measured with water) [mD]	K(measured with gas) [mD]	Core type
1	8.552	2.503	4.918	12.80	9.66	46.58	core from Mo Bei field
2	8.668	2.521	4.989	12.91	24.13	94.71	
3	8.577	2.563	5.157	13.02	32.20	116.26	
4	7.57	2.520	4.985	15.69	156.86	428.37	
5	10.142	2.553	5.157	13.31	24.97	98.69	artificial core

Cores samples were dried at 90 °C for 12 hours. Afterward, cores were proceeded vacuum deoxygenation, then synthetic formation water was added to saturation point in the vacuum vessel. The gas (nitrogen) used in this study was supplied by Xinju Ltd (China), with a purity of 99.9 wt.%. In addition, Mo Bei light crude was used in this study. The viscosity of the oil is 9.44 mPa·s at 90 °C, and its density is 0.8439 g/cm^3.

A composite surfactant SDS was used in this study, and the solution in this study was prepared by mixing composite surfactant with brine. The main component of surfactant is sodium dodecyl sulfate. The composite surfactant concentration was 0.15 wt.% in all. In addition, the Critical Micellar Concentration (CMC) is 0.21 wt.% experiments. The SDS was delivered as a power with a molecular weight of 288.38 g/mol. The interfacial tension between the oil and the surfactant solution was 1.586 mN/m, and the interfacial tension of the oil-water interface was 127.635 mN/m at 90 °C measured by Spinning Drop Video Tensiometer. Moreover, the interfacial tension of the solution is significantly reduced after the addition of the surfactant. Table 2 gives the composition of the formation water used in the experiments.

Table 2: Synthetic formation water composition.

Total salinity (mg/L)	C_{anion} (mg/L)			C_{cation} (mg/L)		
	K^++Na^+	Ca^{+2}	Mg^{+2}	Cl^-	SO_4^{-2}	CO_3^{-2}
12944.74	4716.94	91.22	11.61	6265.32	762.23	1097.42

Experimental Setup

The N_2-foam flow experiments were conducted at 20 MPa and 90 °C with a unit. A schematic of the experimental setup is given in Figure 1.

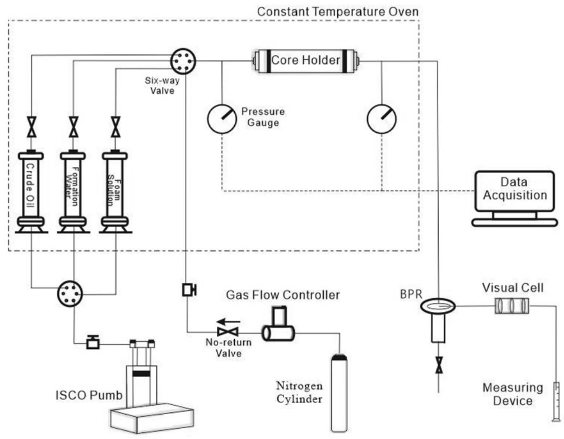


Figure 1: Schematic of the experimental setup.

Experimental Method

Five cores were prepared in advance, four of which were natural cores, one of which was an artificial core, all cores were water-wet. The pore distribution of core No. 2 and core No. 5 were measured by mercury intrusion before the experiment. Their distribution of pores is shown in Figure 2, and core No. 2 is heterogeneous because the size of pores is concentrating approximately on 7 um. In addition, core No. 5 is homogeneous as there is its uniform pore size distribution.

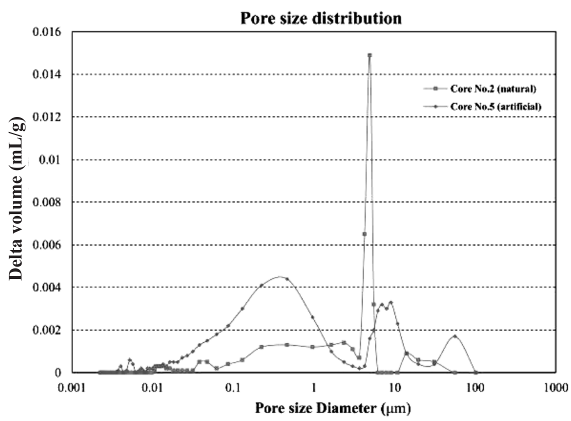


Figure 2: The pore size distribution of core No.2 and core No.5.

The absolute permeability of the core with formation water is calculated. In addition, the formation of the oil reservoir is simulated by injecting MoBei oil to the core until the core oleaginousness reaching the peak. Moreover, formation water has been injected to displace the oil in core until the water cut approached or was about 95%. Also, the recovery by the liquid production is calculated.

Simultaneously, surfactant solution and N_2 from separate reservoirs are injected. In addition, the foam quality of simultaneous injection of all single-core foam experiments in the study is 66.7% of pore volume. Similarly, the recovery by the liquid production is calculated.

At the moment of subsequent water flooding, formation water is injected to measure the effectiveness of foam flooding by counting the recovery in this stage. After the water cut has approached or has been about 99% (or 98%), the injection is stopped. Afterward, the ultimate recovery is calculated.

There is a parameter relating to the evaluation of N2-foam flooding. Also, foam breakthrough time is defined as the total injection volume of surfactant and gas, when the sharp pressure drops, and a mass of foams which breaks through is observed in the outlet of the back pressure regulator (BPR).

RESULTS AND DISCUSSIONS

Effect of Core Permeability

Four N_2-foam flooding experiments were conducted with different cores' permeability. Table 1 -(Core No. 1-4) gives the summary of the physical properties of the cores used.

The significant difference between low and high permeability core foam experiments is obviously reflected on water cut and recovery. In addition, the water cut and recovery curves are presented in Figure 3.

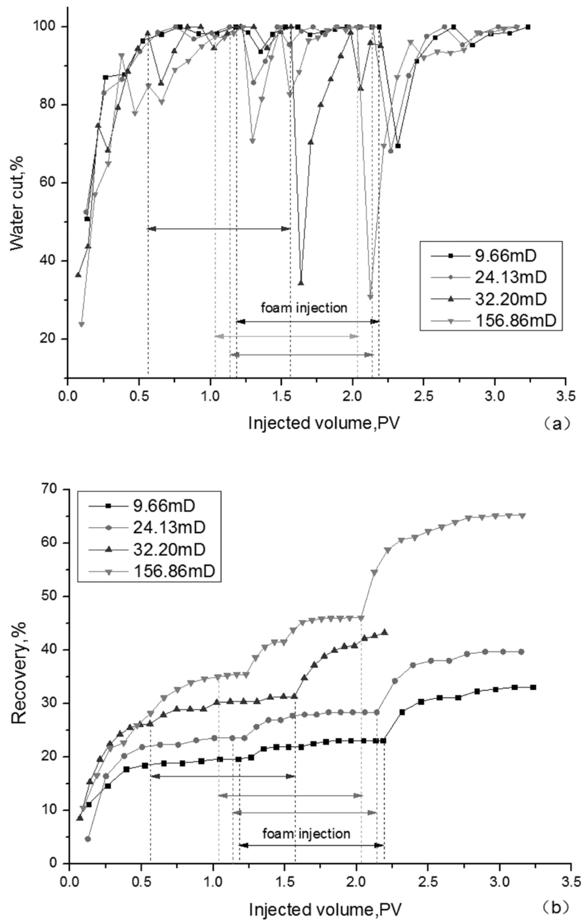


Figure 3: Water cut (a) and (b) oil recovery as a function of injected volume at different permeability.

Based on Figure 3, it can be seen that the water cut has declined sharply in all experiments after subsequent water flooding, because the resistance and pressure gradient set up an inner space of core by the foam performance. It can be seen from Figure 4 that the pressure at the inlet and outlet of cores is significantly increased after the injection of the surfactant and N_2, and the pressure of subsequent water flooding is also higher than its first water flooding.

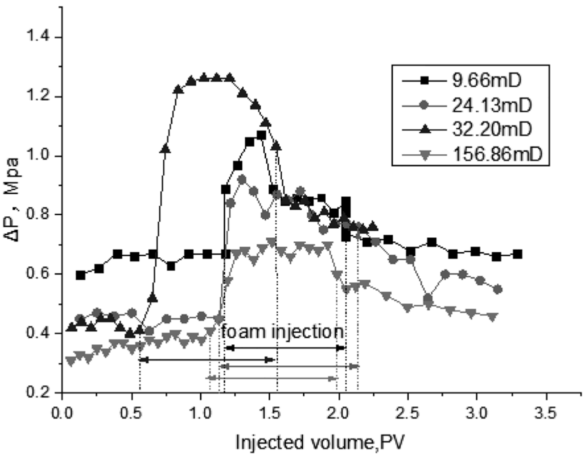


Figure 4: The pressure of injected volume at different permeability.

The decreasing range of water cut has increased with the rising permeability. In addition, the water cut has a more significant decline in relatively higher permeability (156.86 mD). For the three low-permeability cores with the same experimental conditions, the higher the permeability core has a bigger recovery amplification.

As a decisive parameter in the control of foam generation and stability, permeability affects the foam displacement efficiency in detrimental ways. It can be shown that low permeability media often leads to a relatively high level of residual oil saturation which is 40.43%. As a foam depressant, oil has negative effects on foam effectiveness and slows down the net rate of foam development. When the oil is present in the porous media, once foam front comes in contact with oil, some non-uniform fingering pattern due to foam-oil interaction is found first in the frontal region [25]. Surfactant loss owing to partitioning into the oil phase and the change of foam properties upon contact with oil (foam coalescence) also affect foam flow in the porous medium. Moreover, the above-mentioned behaviors can influence the effectiveness of foam displacement further.

Capillary effect is also a critical influence factor on foam effectiveness. Theory prediction assumes that the capillary pressure at which foam breaks increases with decreasing permeability. Finally, the capillary pressure scales following the model,

$$P_c = \frac{2\sigma\cos\theta}{r}$$

where σ=the interfacial tension, θ=the contact angle, and r=the average curvature radius of pore throats. In normal conditions, core permeability (k) increases with the average curvature radius. There is a negative correlation between permeability and capillary pressure. In low permeability cores, high capillary pressure has a negative effect on foam propagation. Effective viscosity of foam has influences on foam mobility, which impacts on foam displacement efficiency further. It is argued by Veeningen [9] that the decline of foam mobility with increasing permeability is due to the dominant increase of foam effective viscosity, showing that foam is stronger in high permeability rocks than in low permeability ones.

On the other side, high permeability is usually associated with large pore size, which influences the foam propagation. Large pore size means that bubbles population could be easily created with the result of a great increase in foam resistance capacity [26]. Besides, fluid in small pores is hard to start flowing, and it needs higher displacement pressure to make pore fluid flexible. It usually means that it is needed by us to inject more gas and surfactant to build up the pressure gradient, resulting in less effective action volume of foam system.

Effect of Microscopic Heterogeneities

Core No. 2 and No. 5 which have different microscopic heterogeneities are used in this part of experiments. Table 1 gives the summary of the physical properties of the cores used.

Breakthrough times of two experiments are presented in Figure 5. For the homogeneous core, the breakthrough time is longer than natural core which is more heterogeneous. At the same time, the stronger foam can be observed by the sight-glass at the core outlet.

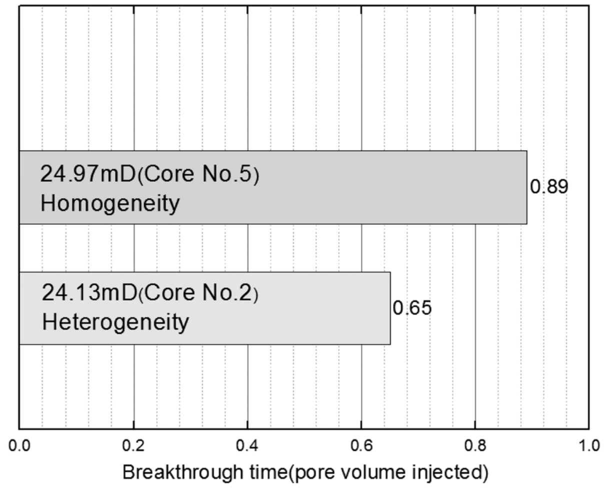
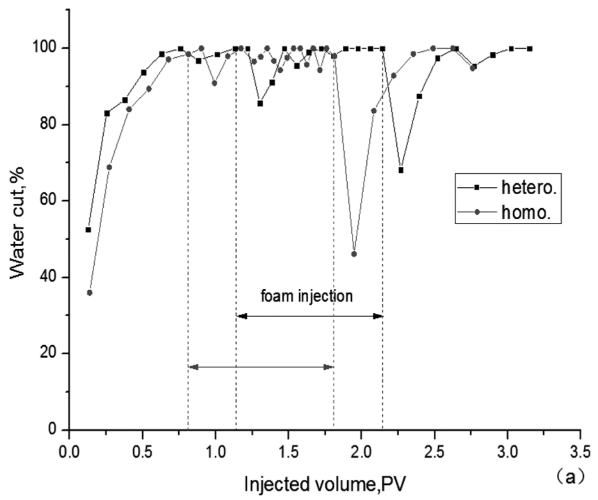


Figure 5: Comparison of foam breakthrough times in different local heterogeneities.

The water cut curves of two experiments with different foam injected volume is shown in Figure 6(a). It shows that a sharp decrease in water cut occurred in the artificial core experiment. In addition, Figure 6(b) gives the recovery curves of different local heterogeneities.



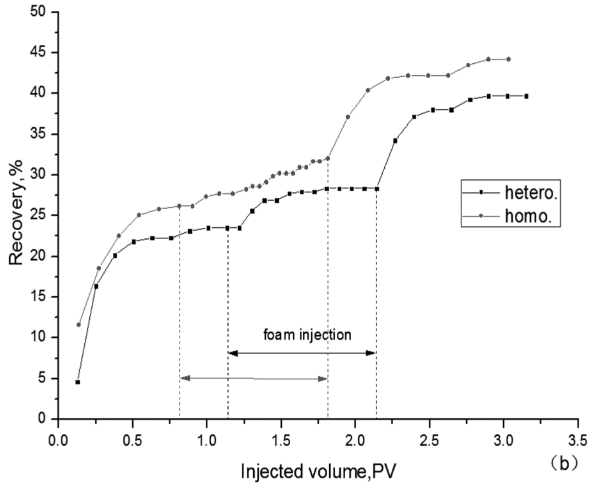
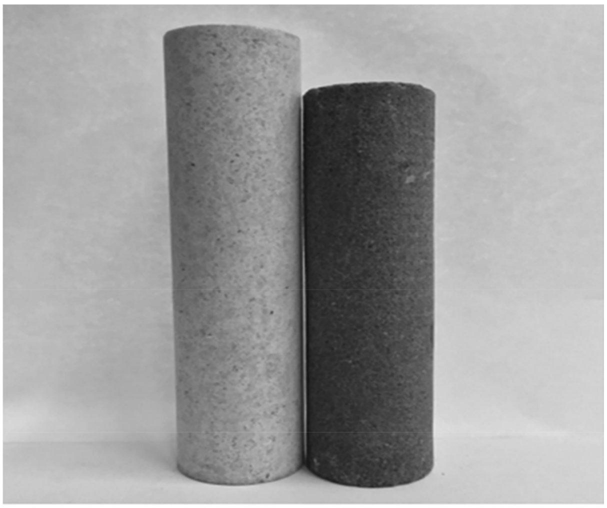


Figure 6: water cut (a) and (b) oil recovery as a function of injected volume at different permeabilities.

Experimental comparative analysis with different microscopic heterogeneities cores shows that homogeneous media has the better prospects of oil-displacement. This result is mainly reflected in the following aspects. On the other hand, as the degree of pore heterogeneities rises, the residual oil saturation decreases, which induces the defoaming phenomenon. In addition, high oil saturation leads to the collapse of foam displacement front, which has a negative effect on displacement efficiency.

On the other hand, permeability and porosity variation in heterogeneity core tend to foam gas channeling and early foam breakthrough, which induce less action time and lower action effects of foam. While the displacement process in N_2- foam flooding with homogeneous media is closer to Darcy flow, resulting in a longer duration of foam action in porous media and prolonging production duration. However, contrary to the above-mentioned roles, microscopic heterogeneities have a positive effect on foam propagation because of the generation of foam lamellae by snap-off for flow across an abrupt increase in permeability. Therefore, several aspects common influence the experimental results. Among them, the effect of snap-off may play only a minor role in low permeability core foam flooding, as the relatively low permeability contrasts in comparison to high permeability media. Generally, microscopic heterogeneities of porous media have an essential effect on duration of foam action, it can also further affect the final oil recovery. In addition, it can be seen from Figure 7 that core No. 2 and core No. 5 flooded by nitrogen foam have a clear indication that the homogeneous core has a higher oil recovery than the heterogeneous.



(a) (b)

Figure 7: Experimental cores with microscopic heterogeneities: (a) core No.5 and (b) core No.2.

CONCLUSIONS

Preliminary conclusions of the N_2-foam flooding experimental investigation are as follows:

(1) Experiment results showed that permeability can significantly affect the foam breakthrough time as well as displacement efficiency.

(2) In the presence of Mo Bei oil, an increase in core permeability in simultaneous injection of N_2 and surfactant solutions resulted in improved sweep efficiency.

(3) The water cut declined sharply in all experiments after foam injected as well as subsequent water flooding, and it has a more significant decline in relatively higher permeability.

(4) Experimental comparative analysis showed that microscopic heterogeneities of porous media have an essential effect on duration of foam action; moreover, it can further affect the final oil recovery. At the low permeability (approximately 24 mD), homogeneous media has the better prospects of oil-displacement.

NOMENCLATURE

BPR : Back Pressure Regulator

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