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Evaluation of the Performances of Foam System as an Agent of Enhancing Oil Recovery

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Abstract: Foam has been used in petroleum engineering to enhance oil recovery for many years. It is a very complicated dispersion system, and the performances are affected by many factors. In order to understand the influence rules and mechanisms of such factors, the performances and mechanisms of foam systems are investigated by static and core flooding experiments with Sodium Dodecyl Sulfate. It is found that a polymer may reduce the foaming ability, but significantly enhance the foam stability in both oil-free and oil-bearing environments, while the optimal concentration is around 1500 mg/L in this case. NaCl may reduce the stability, but the capability of enhancing the foaming ability and oil tolerance gradually increases and stabilizes when the concentration reaches to 7000 mg/L. Oil can reduce the foam stability, and the stability decreases as the oil saturation increases to 0.15. Moreover, the foam stability is worse in light oil conditions than in heavy oil conditions. In the sand-pack tests, the resistance factors of foam are much higher than that of a polymer solution. The maximum resistance factor of the foam tested reaches about 230. The residual resistance factor of polymer-enhanced foam (PEF) is generally larger than that of pure foam and salt enhanced foam (SEF) in an oil-free environment. The maximum value of resistance factor of PEF and SEF is only about 60, and that of pure foam is less than 40 in an oil-bearing environment. In the parallel sand-pack tests, both ultimate oil recovery and incremental oil recovery are the best when using PEF, with SEF the second, and pure foam the worst.

Keywords: foam; enhanced foam; oil-bearing capacity; foam stability; resistance factor

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1. Introduction

In the production of oil from reservoirs, more than 65% of original oil in place (OOIP) is still left in the reservoir after natural depletion and water flooding. This remaining oil is a target for enhanced oil recovery (EOR) methods, which currently include gas or solvent flooding, chemical flooding, thermal recovery, and combinations of these techniques [1,2]. Immiscible or miscible gas flooding can potentially recover a large fraction of the remaining oil after primary depletion and water flooding. However, such potential has barely ever been realized due to the poor sweep efficiency. Gas overlap and channeling through high permeability zones are inherent in most gas flooding process due to its much higher mobility and much lower density contrast to those of oil and water [3,4].

Since 1958, foam has been introduced by Bond and Holbrook to the field of petroleum engineering as an agent of EOR [5]. It is used to improve the reservoir sweep efficiency in gas and steam flooding scenario due to its ability to reduce gas mobility [6–9]. Recently, foam has been widely used in many oil fields [10–12]. Most experts are concerned about the performance of foam system, and the impact on the process from factors such as foaming agent concentration, liquid saturation, foam quality, flow rate, pore structure, gas diffusion, temperature, oil, temperature, salinity, solid particles, etc. [13–17]. Firstly, most of these studies mainly focused on the macroscopic performances of a foam system,

and paid less attention to the microscopic mechanisms. Secondly, most studies were conducted in such environments far away from the actual field environment of foam flooding. Thirdly, few studies have yet been conducted on the PEF or SEF systems which could obtain a higher viscosity of the injectant and better blocking effect in such floods. In recent years, the micro-mechanisms have attracted experts' attention. Majeed et al. found that there was another critical concentration of surfactant, and when the critical concentration was lower than that, adding NaCl would reduce the foam stability, while when the concentration was higher, adding NaCl would improve the foam stability [18]. Wang et al. divided foam film destruction for oil into three types: "hole", "attraction", and "budding" through coarse-grained molecular dynamics (CGMD) [19]. Wang et al. studied the impact of hydrocarbon gas on the foam stability by molecular dynamic method with the sandwich simulation system of gas–surfactant/polymer-aqueous phase inorganic salt ions [20]. Wang et al. found that anionic surfactants were least affected by temperature, and the ideal temperature of foaming was concentrated in the range of 20~30° [21].

In this paper, the micro-mechanisms of the different factors affecting the macroscopic performance were first studied based on the static experiments and chemistry theories. Then, the blocking ability in both oil-free and oil-bearing environments in the porous media were tested by single-tube sand-pack experiment. Lastly, the EOR effects of pure foam, PEF system, and SEF system were tested by parallel sand-pack with heterogeneity. The knowledge of micro-mechanisms could help us to recognize the foam characteristics, determine suitable working conditions, and choose the best type of foam system. The core-flood test results provided experimental evidence that PEF and SEF not only have a better oil tolerance to form effective blocking in oil-bearing conditions, but also significantly enhance oil recovery and effectively reduce the water-cut in heterogeneous reservoirs by blocking the channeling zones.

2. Materials and Methods

2.1. Materials

Two kinds of anionic surfactants, Sodium Dodecyl Sulfate (K12) and Sodium Dodecyl Sulfonate (SDS), were selected as foaming agents. NaCl was used as the electrolyte. The polyacrylamide (BH7-30149660) with a molecular weight of 3.0 million Daltons, 25.0% Hydrolyzed (HPAM), was chosen as the polymer used in this study. Light oil from Changqing Oilfield, heavy oil from Henan Oilfield, and paraffin oil were used in the study. Their properties are listed in Table 1. Nitrogen with the purity of 99% was used as the gas phase.

Table 1. Properties of oil sample.

Oil Sample	Viscosity /mPa·s @50 °C	Density /(kg/m^3) @50 °C	Composition/wt% (Weight Percent)		
			Saturated Hydrocarbon	Aromatic Hydrocarbon	Asphaltenes +Colloids
Light oil	7.6	843	>60	<30	<10
Heavy oil	2109	940	<20	<50	>30
Paraffin oil	2.6	822	>95 (mainly C16~C31)	<5	≈0

2.2. Surface Tension (SFT) and Interfacial Tension (IFT) Measurements

The SFT of foaming agent solution and IFT between oil and foaming agent solution were measured by the Ring method with JZ-200A (Chengde Jingmi Ltd. COM., Chengde, China) in the range of 0–180 mN/m. The SFT of K12 and SDS for different concentrations were measured at 25 °C. The influences of temperature, concentration of HPAM, and concentration of NaCl on SFT, plus the impact of the concentration of NaCl on IFT between oil and foaming agent solution were measured using K12 with the concentration of 0.4 wt% at 50 °C.

2.3. Foaming Ability and Stability Tests

Foaming ability is usually characterized by the foaming volume, and stability is usually characterized by draining half-life time and foam half-life time. The foaming volume is defined as the maximum foam volume of a certain volume of foaming agent solution (100 mL with predetermined concentration) at a fixed shear rate for 1 min. The draining half-life time is defined as the time taken by the drained liquid to increase to 50 mL. The foam half-life time is defined as the time taken by the foaming volume to decrease to the half size of the maximum foam volume [22].

The foaming volume was measured by Waring-blender method:

① Heat the water in the hohlraum of the metering tube and keep the predetermined value by the heated water bath, which is shown in Figure 1. Unless specified, the concentration of foaming agent equals 0.4 wt%, and temperature is constant at 50 °C;

② Pour 100 mL of predetermined foaming agent solution into the Waring blender, and stir for 1 min at the rotate speed of 2000 r/min;

③ Pour the foam into the metering tube, record the foaming volume (V_{max}) and the variation of foam volume as time goes by.

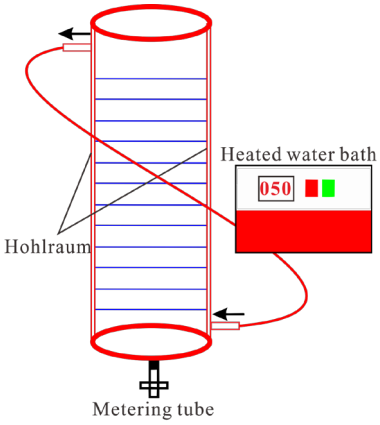


Figure 1. Flowchart of foam stability testing system.

When the oil is present in the system, the volume of foaming agent solution and oil is first calculated based on the predetermined oil saturation calculated by Equation (1). We then pour the oil into the preformed foam, which is similar to the process of foam flooding. Unless specified, the oil saturation equals 0.15.

$$S_o = \frac{V_{oil}}{V_{oil} + V_{as}} \quad (1)$$

where S_o is the oil saturation. V_{oil} is the oil volume in ml. V_{as} is the foaming agent solution in mL.

2.4. Sand-Pack Core Tests

The singular sand-pack core-flood tests were performed to evaluate the block ability of polymer solution, pure foam, SEF, and PEF systems in both oil-free environment and oil-bearing environment by measuring the pressure differences between the sand-pack. Figure 2 shows the sketch of the sand-pack core-flooding system used in this study (e.g., only one sand-pack is used in these tests). The diameter and length of the sand-pack are 3.8 cm and 60 cm, respectively. It was filled with quartz sand produced by Lingshou County Huixin Mining Processing Plant. The particle size of 20 Meshes and 80 Meshes were used, and their surfaces of quartz sand show water wet.

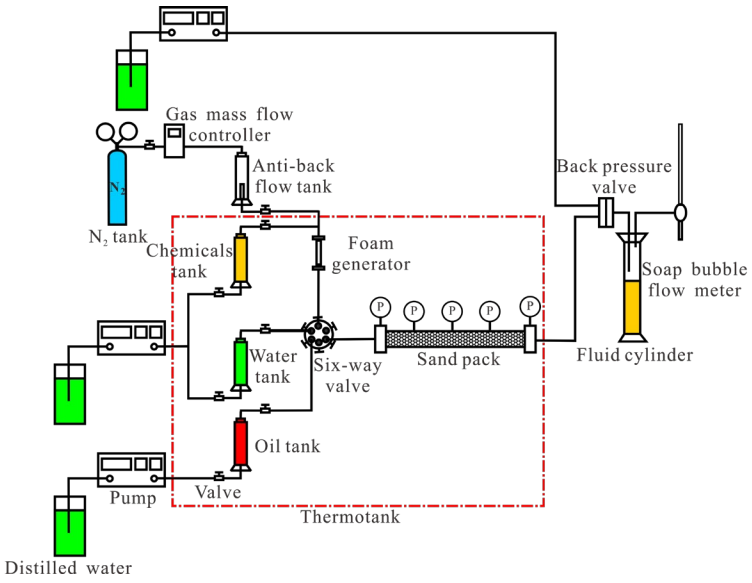


Figure 2. Schematic diagram of sand-pack core-flooding system.

In the oil-free environment experiments, firstly, the distilled water is injected to measure the pore volume and permeability. Secondly, 1 pore volume (PV) of HPAM solution with the concentration of 1500 mg/L is injected at the speed of 2 mL/min. Thirdly, 0.7 PV distilled water was injected at the speed of 5 mL/min and the pressure was monitored. After that, the sand-pack was washed with a higher injection speed. On the next steps, repeat the experiments with pure foam, SEF, and PEF systems instead of the polymer solution, respectively. The injection speed of foaming agent solution was 2 mL/min, and the speed of nitrogen was 30 mL/min at the standard condition.

In the oil-bearing environment tests, the same sand-pack was used. Firstly, about 3 PV paraffin oil was injected into the previously water-saturated sand-pack with the connate water saturation and initial oil saturation, of 0.227 and 0.773, respectively. Secondly, the distilled water was injected at the speed of 2 mL/min until 85 mL oil flows out from the exit. At this moment, the oil saturation equals 0.4. Thirdly, 1 PV of HPAM solution with a concentration of 1500 mg/L was injected at the speed of 2 mL/min. Finally, 0.7 PV distilled water was injected at the speed of 5 mL/min and the pressure was monitored. After that, the sand-pack was washed with a higher injection speed. On the next steps, repeat the experiments with pure foam, SEF, and PEF systems instead of the polymer solution, respectively. The injection speed of foaming agent solution was 2 mL/min, and that of nitrogen was 30 mL/min at standard condition.

Resistance factor is usually used to evaluate the blocking capability of polymer solution or foam systems, which can be defined as follows:

$$R = \frac{\Delta p_{\mathrm{i}}}{\Delta p_{\mathrm{w}}} \tag{2}$$

where R is the resistance factor. Δp_{i} is the pressure difference for i-the test in kPa. i represents polymer, pure foam, PEF, and SEF, respectively. Δp_{w} is the pressure difference for water flooding in kPa.

The parallel sand-pack core-flood tests were also performed to study the EOR effects of different foams. The permeability of high permeable tube is 5.92 μm^2, and that of low permeable tube is 0.91 μm^2. Paraffin oil-46# was used as the simulated oil. The distilled water was injected into sand-pack at a constant rate firstly. Then, about 5.0 PV of oil was injected into the sand-pack at a constant rate, and the connate water saturation and initial oil saturations were calculated. After that, the distilled water was injected at the speed of 3 mL/min until the water-cut reaches 90%. Next, 0.23 PV of foam was injected into the

sand-pack and the oil recovery and flow rate fraction of the two tubes were recorded. At last, the distilled water was injected until the water-cut reached 100%.

3. Results and Discussion

3.1. SFT and IFT

The SFT of foaming agent solution decides the foaming ability, and a lower SFT means a better foaming ability. K12 and SDS are the most commonly used foaming agents, both of which are anionic surfactants. Therefore, they are regarded as the optional samples. The SFT of them for different concentrations are shown in Figure 3. It can be seen that the SFT of K12 is lower than that of SDS, and the concentration at the minimum is smaller, which means the critical micelle concentration (CMC) of K12 is lower and the foaming ability is better. Therefore, the K12 is selected to carry out the following experiments.

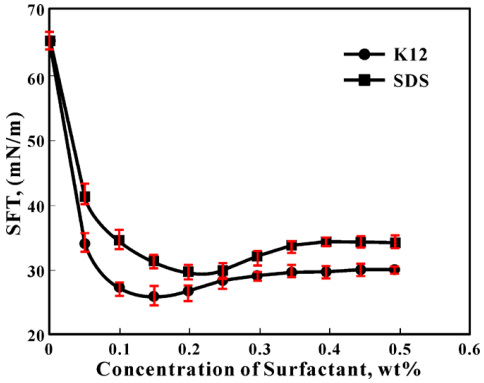
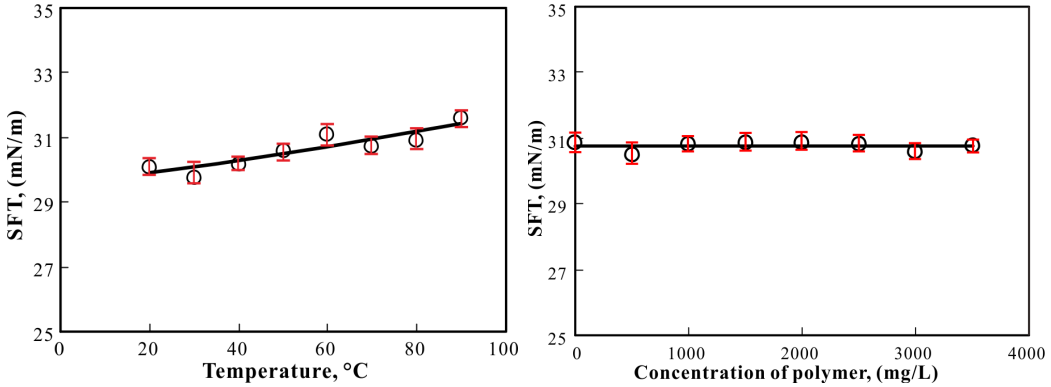


Figure 3. SFT of K12 and SDS for different concentrations (Red is the error bars).

In order to analyze the micro-mechanisms of different factors affecting the macroscopic performances of the foam system, the influences of temperature and HPAM on the SFT of K12 are measured and shown in Figure 4. The influences of concentration of NaCl on SFT and IFT between oil and K12 are measured and shown in Figure 5. It is clear that the SFT slightly increases as the temperature increases, and the concentration of HPAM has almost no effect on the change in SFT. Both SFT and IFT decrease as the concentration of NaCl increases.



(**a**) Temperature (**b**) Concentration.

Figure 4. Influences of temperature and HPAM on the SFT of K12 (**a**) Temperature and (**b**) Concentration (Red is the error bars).

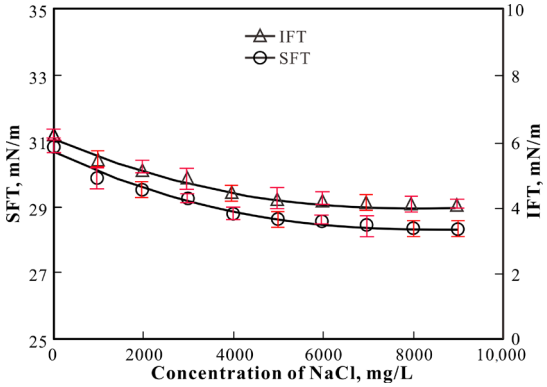


Figure 5. Influences of NaCl on SFT and IFT (Red is the error bars).

3.2. Foaming Ability and Stability

The foaming volume, draining half-life time ($T_{d1/2}$), and foam half-life time ($T_{f1/2}$) for different concentrations of foaming agent are shown in Figure 6. It can be seen from these figures that when the concentration is lower than 0.2, the foaming volume increases as the concentration increases. And then, it keeps stable as concentration further increases. Both the draining half-life time and foam half-life time increase at first, and then decrease as the concentration increases. The potential reason is that the foaming ability is related to the SFT of the foaming agent solution. When the concentration is lower, fewer active molecules are adsorbed on the gas–liquid interface. Thus, the SFT is greater and the foaming ability is poorer. As the concentration increases, more active molecules will be adsorbed onto the gas–liquid interface. The SFT will decrease and the foaming ability is improved accordingly. On the other hand, when the concentration reaches the CMC, micelles will be formed in the liquid phase, and the SFT is no longer decreasing, with the foaming ability basically remaining stable. From the draining half-life time and the foam half-life time, we can find that when the concentration is near the *CMC*, the foam system has a good stability. If the concentration exceeds the *CMC*, the stability will deteriorate, which has also been proved by Zhu et al. [23]. The reason is that the stability is decided by the elasticity of the liquid film. Based on Gibbs's theory, the elasticity of the liquid film is as follows,

$$E = 4\frac{(\Gamma_2^1)^2}{H_b c_2} \tag{3}$$

where E is the elastic modulus of the liquid film; H_b is the thickness of the liquid film; c_2 is the surfactant concentration in bulk solution. Γ_2^1 is the surface excess concentration of component 2 in 1, and it is modeled as

$$\Gamma_2^1 = -\frac{1}{RT}\left(\frac{\partial\sigma}{\partial \ln c}\right)_T \tag{4}$$

where R is the conventional gas constant; T is the temperature; σ is the surface tension; c is the surfactant concentration. Thus, for surfactant, Γ_2^1 first increases with the concentration increases when the concentration is smaller than *CMC*, and then becomes stable when the concentration exceeds *CMC*. Therefore, when the concentration exceeds *CMC*, E decreases with the concentration increases for c_2 increases.

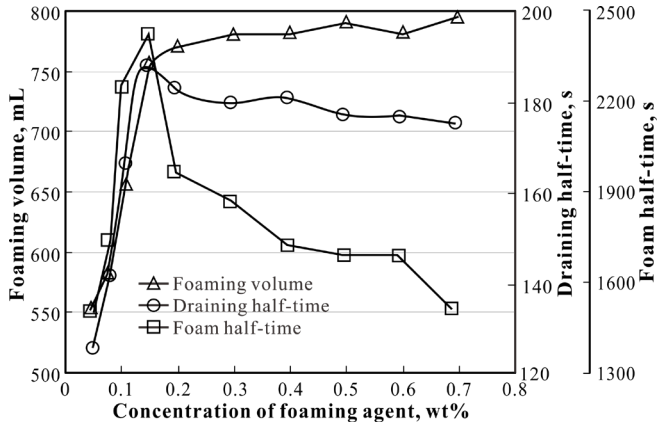


Figure 6. Foaming ability and stability of K12 for different concentrations of foaming agent.

An oil reservoir is an oil-bearing environment. Although, the foam flooding is used to block the high permeability layers in high water-cut stage, there exists some remaining oil in these layers. The presence of oil has large influence on the performance of foam. The foaming volume, draining half-life time, and foam half-life time of different oil saturations are shown in Figure 7. It can be seen that the foaming volume, draining half-life time, and foam half-life time all decrease as the oil saturation increases, especially when $S_o < 0.15$. Consequently, oil reduces the foaming ability and stability significantly. The reason is that the higher the oil saturation is, the lower the water phase is. As a result, less liquid can form liquid films. Also, active molecules tend to enter the oil when encountering the oil. Thus, the SFT of foam agent solution increases, and the bubble will be much easier to collapse and coalescence.

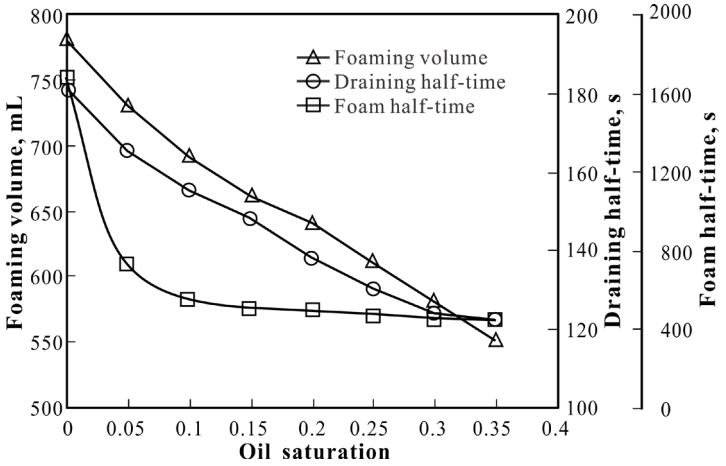
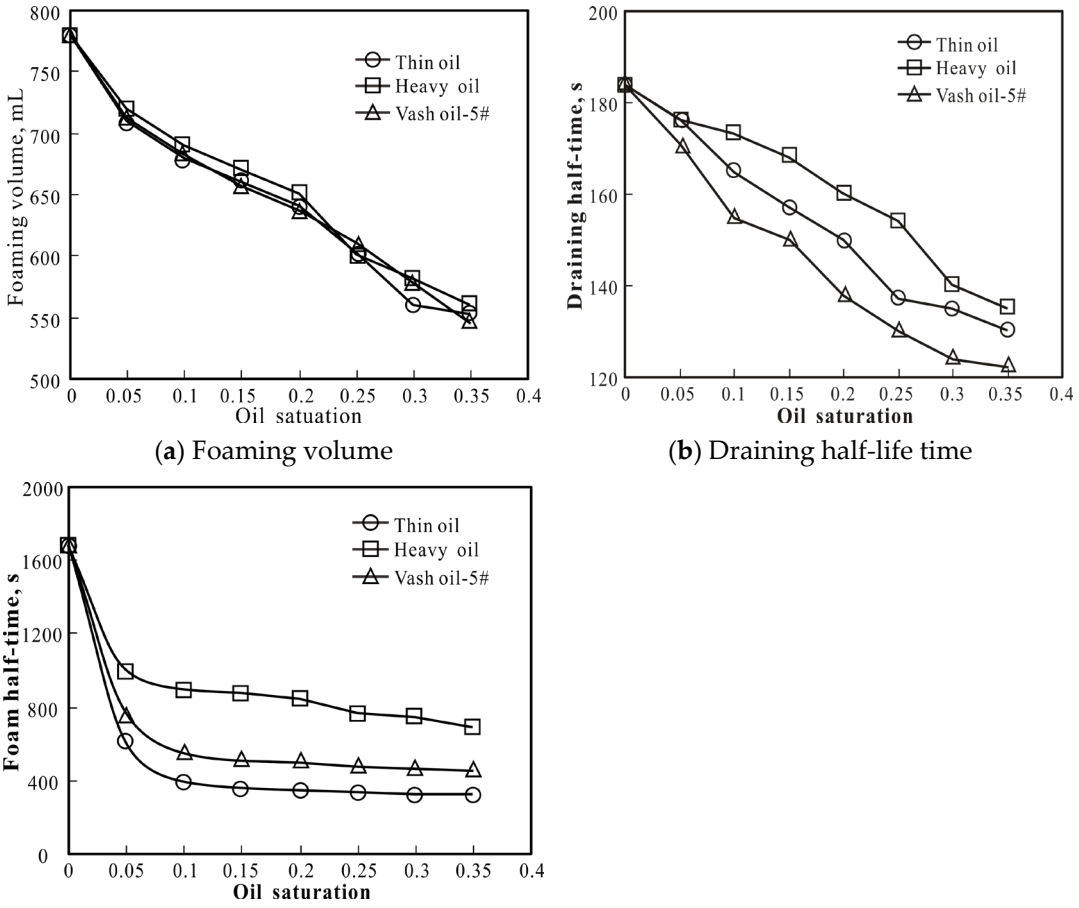


Figure 7. Foaming ability and stability of K12 for different oil saturation.

The influence of oil on foam stability originates from the interaction between lipophilic groups and active molecules [24]. The number of lipophilic groups is different in different types of oil. The foaming volume, draining half-life time, and foam half-life time for different types of oil are shown in Figure 8. It can be seen from these figures that the foaming volume, draining half-life time, and foam half-life time all decrease as the oil saturation increases for all types of oil in these tests. The falling speed of draining half-life time is: heavy oil < light oil < paraffin oil. And the falling speed of foam half-life time is: heavy oil < paraffin oil < light oil. The driving force of draining is the gravity force and the pressure difference between the plateau border and the planar film, and the resistance is the viscous force of liquid. Generally, the oil enters the lamella to form emulsion, and the larger the oil viscosity, the larger the particle size of the emulsion formed and the greater the resistance to drainage [25]. From Table 1, the viscosity of the oil is: heavy oil > light oil > paraffin oil. So, the emulsion formed by heavy oil is the strongest

in resisting draining, and that of paraffin oil is the weakest. Moreover, as the oil density increases, its viscosity and surface tension increase, and the influence on foam stability decreases. The increased surface tension means that it is difficult for crude oil to enter and spread on the surface of the film [26]. Although the viscosity of light oil is a little greater than paraffin oil, the paraffin oil is mainly composed by normal iso-alkanes which has little effect on foam stability. However, the short-chain alkanes in light oil have a worse effect on foam ability by reducing the repulsive force between micelles to inhibit the stratification of liquid film [27]. Therefore, the foam half-life time is shortest for light oil, and longest for heavy oil.



(**a**) Foaming volume

(**b**) Draining half-life time

(**c**) Foam half-life time

Figure 8. Foaming ability and stability of K12 for different types of oil (**a**) Foaming volume, (**b**) Draining half-life time, and (**c**) Foam half-life time.

A polymer can enhance the stability of foam [28]. The foaming volume, draining half-life time, and foam half-life time for different concentrations of polymer are shown in Figure 9. It can be seen that the foaming volume decreases as the concentration increases, while the draining half-life time and foam half-life time increase as the concentration increases. These indicate that the polymer reduces the foaming ability, however, enhancing the foam stability. The reason is that polymer molecules enhance the viscosity of foaming agent solution, which results in the much harder draining of foam films. Therefore, the draining half-life time always increases as the concentration increases. The major mechanism of increasing foam half-life time using a polymer is that the polymer molecules adsorbed on the gas–liquid interface enhance its elasticity, which resist the film to collapse and coalescence caused by the gas diffusion. However, the adsorption of polymer molecules is limited, instead of always increasing, as the concentration of polymer increases. Therefore, the foam half-life time will start keeping stable when the concentration reaches

about 1500 mg/L. In order to obtain both well foaming ability and stability, the optimal concentration of polymer should be 1500 mg/L in this case.

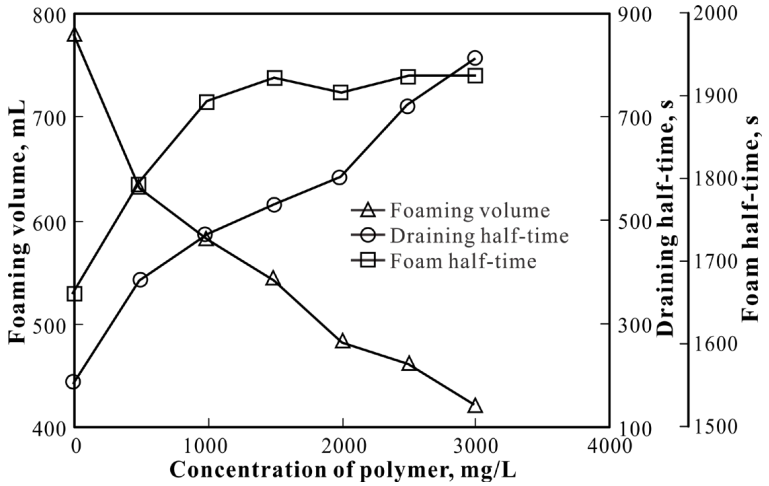


Figure 9. Foaming ability and stability of K12 for different concentrations of polymer.

Temperature is another factor of affecting foaming ability and stability. The foaming volume, draining half-life time, and foam half-life time at different temperatures are shown in Figure 10. It can be seen that as the temperature increases, the foaming volume gradually increases, and the draining half-life time and foam half-life time gradually decrease. This seems to be counter to the observations in the earlier test results of SFT for different temperatures. In fact, a higher temperature will strengthen gas expansion effect, which is the dominant factor of leading to the increase in foaming volume. The reasons of temperature reducing the foaming stability include:

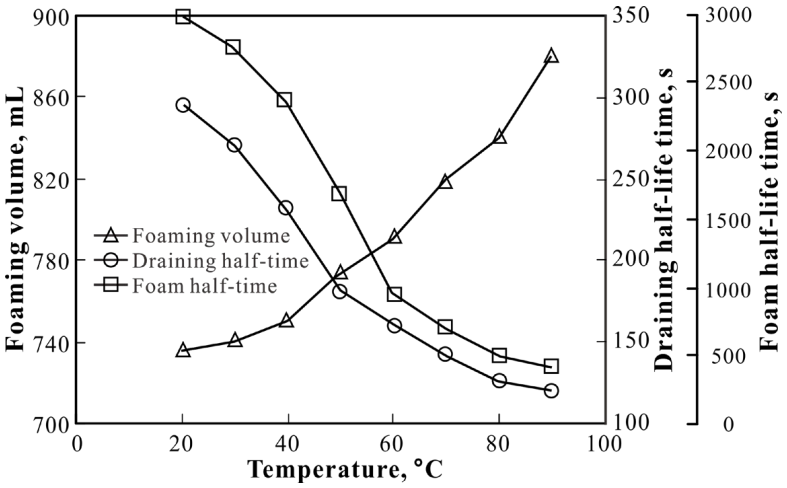


Figure 10. Foaming ability and stability of K12 for different temperatures.

① The solubility of foaming agent is larger in high temperature, which leads to more active molecules dispersed in the liquid and less active molecules adsorbed on the gas–liquid interface. Therefore, the strength of the liquid film is weaker;

② The viscosity of the liquid phase is lower in high temperature, which accelerates the draining of liquid film and makes it thinner;

③ Higher temperature accelerates the gas diffusion, which fastens the coalescence of gas bubble;

④ Higher temperature also accelerates the degradation of active molecules to some extent.

Salt also has an important effect on the foaming ability and stability. The foaming volume, draining half-life time, and foam half-life time for different concentrations of

NaCl are shown in Figure 11. It can be seen that the foaming volume increases as the concentration increases, the foam half-life time decreases as the concentration increases, and the salt has almost no impact on the draining half-life time. On one hand, NaCl can decrease the SFT of foaming agent; on the other hand, it can decrease the CMC of ionic surfactant as well. Thus, the foaming ability is improved. Due to the fact that K12 is an anionic surfactant, the like charges arrange on both sides of the liquid film to resist the double layers thinning by their repulsion forces. The repulsion force, however, weakens when the concentration of electrolyte increases. As a result, the strength of the liquid film decreases.

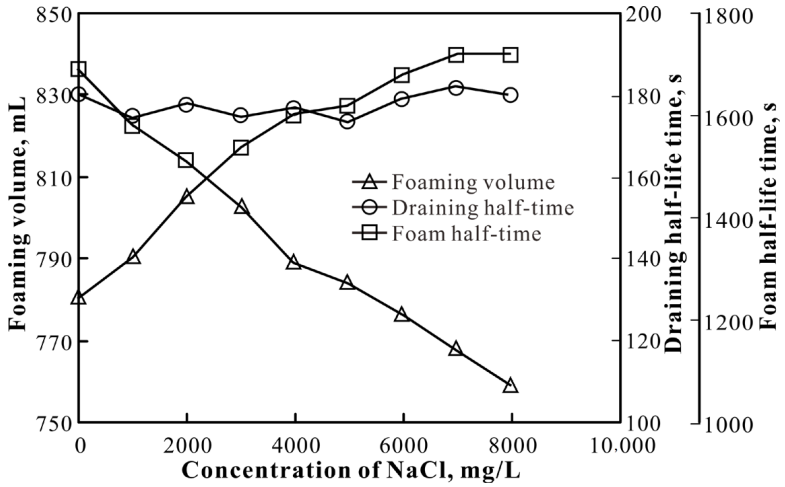


Figure 11. Foaming ability and stability of K12 for different concentrations of NaCl.

In order to enhance the foam stability during foam flooding, the polymer is usually mixed into the foaming agent. However, the working condition of foam flooding is an oil-bearing environment. The foaming ability and stability of PEF in an oil-bearing environment are shown in Figure 12. It can be seen that the variations of foaming volume, draining half-life time, and foam half-life time with the increase in polymer concentration in the oil-bearing environment is similar to the observations in the oil-free environment. Consequently, the polymer can improve the oil tolerance of foam by increasing the stability. The mechanism of improving oil tolerance is similar to that in an oil-free environment.

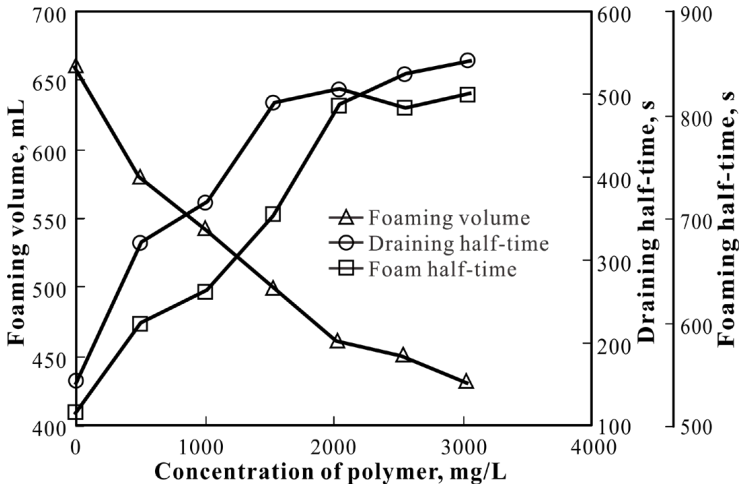


Figure 12. Foaming ability and stability of PEF in an oil-bearing environment.

Bergeron, et al. found that salt can also improve the oil tolerance of foam [29]. The foaming ability and stability of SEF in an oil-bearing environment are shown in Figure 13. It can be found that the variations of foaming volume and draining half-time with the

increase in NaCl concentrations are similar to that in the oil-free environment. But the variation of foam half-life time is different from that of the oil-free environment. The foam half-life time first increases as the concentration of NaCl increases. Then it tends to stabilize. The mechanism can be interpreted by the classical definitions of spreading and entering coefficients presented by Harkins and Feldman [30] and Robinson and Woods [31]:

$$\text{Spreading coefficient}: S_{o/w} = \sigma_{wg} - \sigma_{ow} - \sigma_{og} \quad (5)$$

$$\text{Entering coefficient}: E_{o/w} = \sigma_{wg} + \sigma_{ow} - \sigma_{og} \quad (6)$$

where σ_{wg} is the interfacial tension between water and gas; σ_{ow} is the interfacial tension between water and oil; σ_{og} is the interfacial tension between gas and oil.

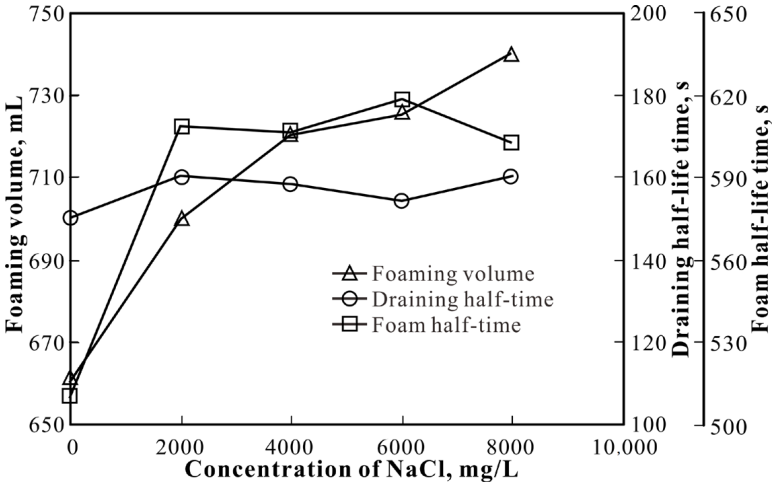


Figure 13. Foaming ability and stability of SEF in an oil-bearing environment.

Based on the above two parameters, the relationship between oil and foam stability can be predicted. If $E_{o/w} < 0$ and $S_{o/w} < 0$, the oil neither enters the liquid film, nor spreads in it. And the oil has no effect on the foam stability. If $E_{o/w} > 0$ and $S_{o/w} < 0$, the oil can enter the liquid film, but cannot spread in it. And the effect of the oil on the foam stability can be evaluated by the value of $E_{o/w}$ and $S_{o/w}$. If $E_{o/w} > 0$ and $S_{o/w} > 0$, the oil can enter the gas–water film and spread in it, which will generate a strong influence on the foam stability [29]. The corresponding surface and interfacial tensions are presented in Table 2. It can be seen from the table, $E_{o/w}$ = 10.52 mN/m and $S_{o/w} < -1.92$ mN/m for the system of K12/Paraffin oil (5#). Visibly, the oil can easily enter the liquid film to a great extent, but cannot spread in it. The influences of NaCl on classical entering and spreading coefficients are shown in Figure 14. Both the entering and spreading coefficients decrease as the concentration of NaCl increases. The decreasing of entering coefficient is obvious, and the decrease in entering coefficient is small. It is clear that in this scenario, the difficulty for oil entering the liquid film increases, and the spreading tends to be highly non-spreading.

Table 2. Interfacial tensions and entering/spreading coefficients at 50 °C.

System	σ_{wg}/ (mN/m)	σ_{ow}/ (mN/m)	σ_{og}/ (mN/m)	$E_{o/w}$/ (mN/m)	$S_{o/w}$/ (mN/m)
K12/Paraffin oil (5#)	30.83	6.22	26.53	10.52	−1.92
K12 + NaCl/Paraffin oil (5#)	<29.83	<5.34	26.53	<8.64	<−2.04

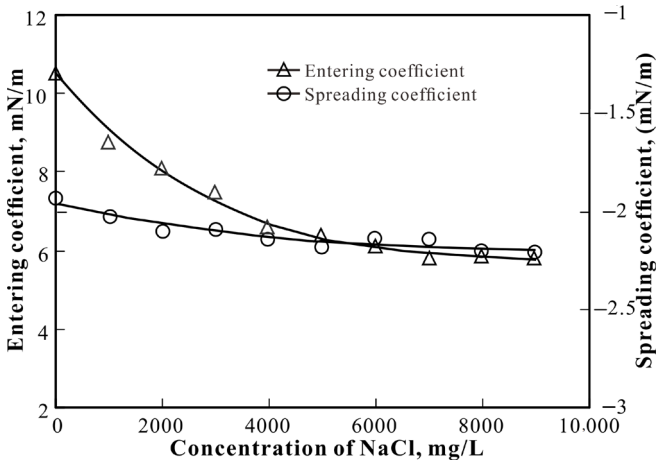


Figure 14. Influences of NaCl on classical entering and spreading coefficients.

3.3. Blocking Ability in Sand-Pack Core

The foaming ability and foam stability dictates the blocking effects of foam in porous media. To evaluate the blocking effects of the polymer solution, pure foam, PEF, and salt-enhanced foam, the resistance factors are benchmarked and tested. The concentration of polymer solution is 1500 mg/L, with the viscosity of 4.9 mPa·s. The concentration of polymer in the PEF is 1500 mg/L, and the concentration of NaCl in the SEF is 5000 mg/L.

The resistance factors of different systems in different stages in an oil-free environment are shown in Figure 15. It is clear that all the resistance factors of foam are much higher than that of a polymer solution. The maximum resistance factor of all the foam systems reaches about 230. The rising velocity of PEF and SEF is faster than that of pure foam. The reason is that the foaming ability of SEF is better than that of pure foam. However, the foaming ability of PEF is poorer, the viscosity of the PEF is higher, and the formed-foam quality is better than that of the pure foam. In the stage of continued water flooding, the resistance factors of all the foam systems decrease sharply. But the resistance factor of PEF is still higher than 100 after 0.7 PV continued water flooding. The resistance factors of pure foam and SEF are, however, less than 20. And the resistance factor of SEF decreases a little faster than that of pure foam does. This indicates that the PEF has a larger residual resistance factor once it is formed. And the residual resistance factors of pure foam and salt enhanced foam are lower.

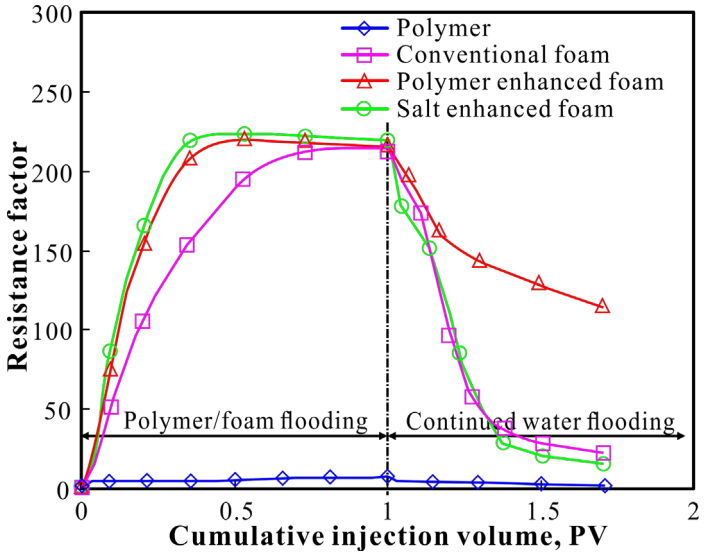


Figure 15. The blocking ability of different systems in an oil-free environment.

The resistance factors of different systems in different stages in an oil-bearing environment are shown in Figure 16. It is clear that all the resistance factors of foam systems are still much higher than that of polymer solution. But the maximum value is only about 60 for PEF and SEF, which is much larger than that in an oil-free environment. The resistance factor of pure foam is less than 40, which indicates that the oil tolerance is poorer than that of the PEF and SEF. In the stage of continued water flooding, the resistance factor of PEF is about 30 after 0.7 PV continued water flooding. However, the resistance factors of pure foam and SEF are less than 10. But the resistance factor of SEF decreases a little slower than that of the pure foam does in the oil-bearing environment. This indicates that the oil tolerance of PEF is the best, with SEF being the second, and pure foam being the worst.

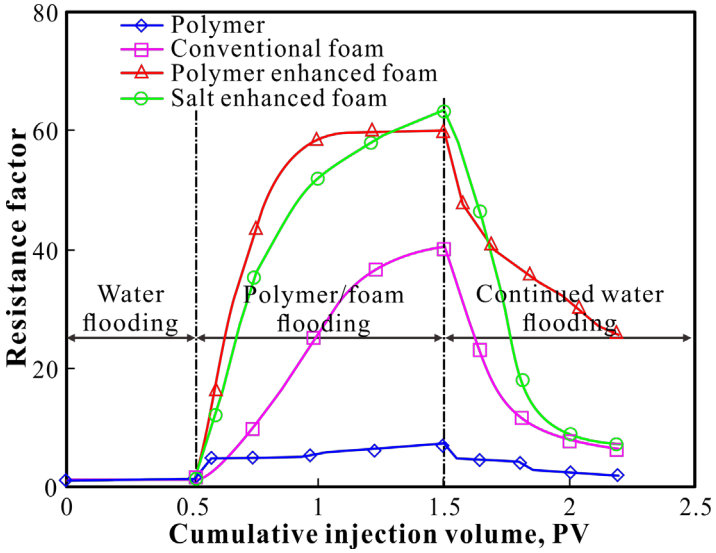


Figure 16. The blocking ability of different systems in an oil-bearing environment.

3.4. EOR Effect Using Parallel Sand-Pack

Foam flooding is used to enhance oil recovery by blocking the high permeable layers. After a long time of production, most oil in the high permeable layers was swept out. But there is much of remaining oil in the low permeable layers. The foam system is injected to block the high permeable layers, which diverts the injection water into the low permeable layers to drive out the remaining oil. Therefore, the performances of foam systems decide the EOR effect. The oil recovery and incremental recovery for different systems are shown in Table 3.

Table 3. Oil recovery (R_o) and incremental recovery (I_r) for different systems.

System	High Permeable Tube		Low Permeable Tube		Total	
	R_o	I_r	R_o	I_r	R_o	I_r
Water	22.73		2.37		12.71	
Pure foam	35.04	12.31	6.64	4.27	21.11	8.4
SEF	37.56	14.83	13.03	10.66	25.62	12.91
PEF	42.18	19.45	20.61	18.24	31.78	19.07

It can be seen that the R_o of water flooding is only 12.71%, and the I_r of pure foam flooding is about 8.4%, which is not very good. The I_r of SEF and PEF are 12.91% and 19.07%, respectively, which are much better than that of the pure foam flooding. The R_o and I_r in both low and high permeability tubes are the highest for PEF, and the lowest for pure foam. The reason is that there is much remaining oil when the water-cut reaches 90%. The foam preferentially flows into the high permeable tube to block the water flow. However, the stability is much worse due to the high oil saturation in it. The oil tolerance of PEF is the best, and that of the pure foam being the worst. The blocking ability of PEF is

the best, which makes much injected fluid flow into the low permeable tube. The injection pressure is shown in Figure 17. And the flow fractions of low and high permeable tubes for different systems are shown in Figure 18. It can be seen that the largest value of injection pressure for pure foam flooding is only 40 kPa; however, that of SEF and PEF are 75 kPa and 130 kPa, respectively. As for the fractional flow, the fractional flow of water decreases to 75% in higher permeable tube for PEF flooding, but it is still much higher than 90% for pure foam flooding. In addition, the residual blocking ability is the best for PEF due to its great stability.

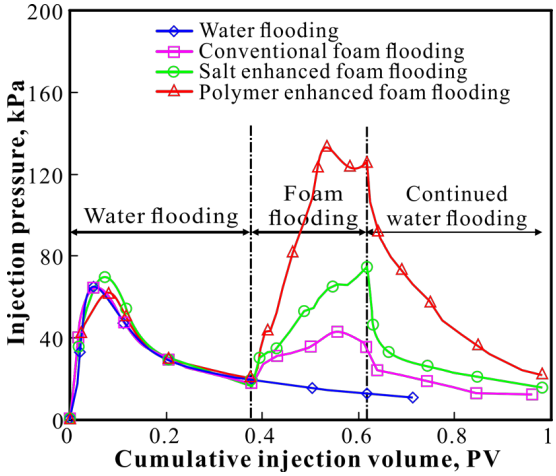


Figure 17. Injection pressure of the double-tube for different systems.

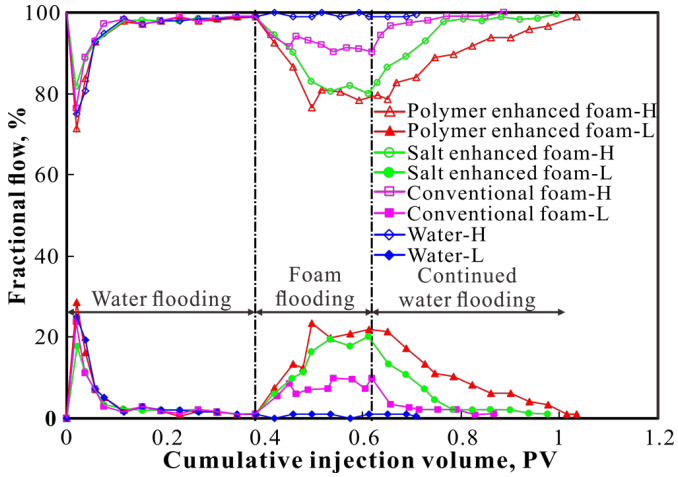


Figure 18. Fractional flow of low and high permeability tubes for different systems.

4. Conclusions

In this paper, the micro-mechanisms of different factors affecting the macroscopic performances of foam flooding were studied using Sodium Dodecyl Sulfate. The foaming ability increases with the increasing of foam agent concentration, temperature, and concentrations of NaCl, and decreases with the increase in the concentration of polymer. The foam stability increases with the increasing of concentrations of polymer, and decreases with the increasing of temperature, concentrations of NaCl and the oil saturation. Moreover, the foam stability is better in heavy oil environment than that in light oil. The presence of a polymer and NaCl can increase the oil tolerance of foam system.

With comprehensive consideration of foaming capacity and stability, the optimal polymer concentration is around 1500 mg/L, and the optimal NaCl concentration is about 7000 mg/L. In an oil-bearing environment, when the oil saturation is lower than 15%, the foam stability decreases rapidly with the increase in oil saturation, and then becomes stable.

In the single-tube sand-pack tests, the resistance factors of foam systems are much higher than that with polymer solution. The maximum resistance factor of all the foam systems reaches about 230. The residual resistance factor of PEF foam is larger than that of pure foam and SEF in an oil-free environment. The maximum value is only about 60 for PEF and SEF, and that of pure foam is less than 40 in the oil-bearing environment.

In the parallel sand-pack tests, both the oil recovery and incremental oil recovery using the PEF are the best, the SEF being second, and the pure foam being the worst. The injection pressures of PEF flooding, SEF flooding, and pure foam flooding reach about 130 kPa, 75 kPa, and 40 kPa, respectively. The fraction flow of water of the high permeability tube decreases from 98% to 75% due to the blocking effect of PEF. And that of the SEF and pure foam are 80% and 90%, respectively. In general, it is difficult to achieve an ideal EOR effect by pure foam flooding when the remaining oil saturation is high. On the other hand, the PEF and SEF are found to achieve a better EOR effect.

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