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Qiang Fu

Southwest Petroleum University

Cheng Jin

jincheng1986@126.com

Southwest Petroleum University

Rusen Feng

Southwest Petroleum University

Yongjun Guo

Southwest Petroleum University

Guoyu Liu

Southwest Petroleum University

Qian Wu

Southwest Petroleum University

Ruijie He

Southwest Petroleum University

Wei Zhang

Sichuan Guangya Polymer Chemical Co., Ltd

Di Pu

Xinjiang Guangya Oil and Gas New Technology Development Co., Ltd

Chuan Wang

Southwest Petroleum University

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Reservoir Adaptability of Alkali-Free Flooding Systems in Medium- and Low-Permeability Reservoirs: An Integrated Evaluation Based on Multipoint Pressure Measurements and Microscopic Visualization

Qiang Fu^b, Cheng Jin^{a*}, Rusen Feng^{b*}, Yongjun Guo^{a,b,c*}, Guoyu Liu^b, Qian Wu^a, Ruijie He^a, Wei Zhang^d, Di Pu^c, Chuan Wang^a

(a. School of New Energy and Materials, Southwest Petroleum University, Chengdu 610500, Sichuan, China)

(b. School of Chemistry and Chemical Engineering, Southwest Petroleum University, Chengdu 610500, Sichuan, China)

(c. State Key Laboratory of Oil & Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, Sichuan, China)

(d. Sichuan Guangya Polymer Chemical Co., Ltd., Chengdu 610500, Sichuan, China)

(e. Xinjiang Guangya Oil and Gas New Technology Development Co., Ltd., Karamay 834000, Xinjiang, China)

Corresponding Author: Cheng Jin, jincheng1986@126.com

Second Corresponding Author: Rusen Feng, gs_frs@163.com

Abstract: Alkali/surfactant/polymer (ASP) ternary flooding systems, which are applied in medium- and high-permeability reservoirs, are associated with severe corrosion, leading to increasing attention to alkali-free chemical flooding systems. Reservoir development targets, however, have gradually shifted from medium- and high-permeability reservoirs to medium- and low-permeability reservoirs characterized by strong intralayer heterogeneity, low permeability, and complex pore structures. The reservoir adaptability and oil-displacement performance of alkali-free chemical flooding systems currently used in medium- and high-permeability reservoirs remain unclear under medium- and low-permeability conditions. In this study, two alkali-free chemical flooding systems were formulated: a surfactant/polymer binary system (SP) and a surfactant/salt/polymer ternary system (SSP), with partially hydrolyzed polyacrylamide (HPAM) used as a reference. Their physicochemical properties were characterized by measurements of interfacial tension and viscosity, together with static adsorption and emulsification tests. Reservoir adaptability was evaluated by combining multipoint pressure-measurement experiments using 50, 100, and 150 mD cores with 100 mD microscopic visualization displacement experiments; oil-displacement performance was subsequently determined by 100 mD Berea core flooding experiments. The physicochemical-property tests showed that, compared with the SP system, the SSP system exhibited lower interfacial tension and greater emulsion stability. Multipoint pressure measurements indicated that the SSP system exhibited good injectivity in 100-150 mD cores, but upstream-section plugging occurred at 50 mD; by contrast, the SP system showed relatively poor injectivity at all tested permeabilities. Microscopic visualization at 100 mD showed that the SSP system formed a more continuous oil-water displacement front and produced a more uniform sweep pattern, without the pronounced inlet emulsification plugging observed for the SP system. In the Berea core flooding experiments, the SSP system achieved the highest total oil recovery factor of 55%, compared with 48% for the SP system and 47% for the HPAM system. The combined use of multipoint pressure measurements and microscopic visualization provides an experimental basis for screening alkali-free flooding systems, identifying injection-related plugging, and evaluating reservoir adaptability in medium- and low-permeability reservoirs.

Keywords: Alkali-free chemical flooding system; medium- and low-permeability reservoirs; reservoir adaptability; injectivity; emulsification behavior; microscopic visualization

1. Introduction

At present, chemical flooding remains an important enhanced oil recovery (EOR) strategy for mature oilfields. Among chemical EOR methods, ASP ternary flooding has been applied at field scale in medium- and high-permeability reservoirs and has yielded favorable results^[1-2]. Polymers increase aqueous-phase viscosity and improve mobility control; surfactants reduce oil-water interfacial tension; and alkalis react with acidic components in crude oil to generate in situ surface-active species. These effects collectively enhance sweep efficiency and microscopic displacement efficiency. However, the use of alkali can also induce dissolution of formation minerals, fines migration, scale deposition, equipment corrosion, and more severe emulsification of produced fluids^[3-4]. Consequently, developing alkali-free chemical flooding systems that retain the recovery benefits of chemical flooding while mitigating alkali-related engineering risks has become an important research direction.

Research on alkali-free chemical flooding has focused primarily on surfactant/polymer binary systems and surfactant/salt/polymer ternary systems, with particular emphasis on interfacial-tension control, optimization of rheological properties, emulsification behavior, and EOR mechanisms^[5-7]. Representative studies include the work of Wang et al.^[8], who optimized and evaluated a surfactant/polymer binary flooding system, elucidated its microscopic oil-displacement mechanism, and demonstrated its ability to mobilize residual oil. Chen et al.^[9] developed a polymer/surfactant/salt ternary flooding system based on a middle-phase microemulsion. In Berea core-flooding experiments, this chemical flooding system increased oil recovery by 45%; however, the surfactant concentration was as high as 0.5 wt%, which may limit its field-scale application.

Despite progress in alkali-free chemical flooding, most evaluation methods have been developed for medium- and high-permeability reservoirs with favorable petrophysical properties and well-connected flow pathways. For example, Su et al.^[10] used long-distance sand-pack experiments to determine the resistance factor and residual resistance factor of polymer solutions at different migration distances. They also evaluated the potential of these solutions to improve the injection profile. Yu et al.^[11] screened 15 polymers for Class III reservoirs in Daqing, with permeabilities of 100-200 mD, and assessed their physicochemical properties, injectivity, and EOR performance. Conventional core flooding experiments generally rely on inlet and outlet pressures to assess overall flow resistance, making it difficult to determine whether plugging occurs at the core inlet or in deeper sections; they also make it difficult to directly correlate macroscopic pressure responses with pore-scale displacement behavior^[12]. Accordingly, a systematic understanding is lacking of flooding-system injectivity across different permeability regimes, pressure-transmission characteristics, and the locations of emulsion-induced plugging in medium- and low-permeability reservoirs^[13]. Such reservoirs commonly exhibit complex pore structures and pronounced intralayer heterogeneity. To support the development of these reservoirs, both the injectivity of flooding formulations and emulsion-induced plugging must be addressed. The formulations may require optimized injection conditions, whereas emulsions generated upon contact with crude oil may be retained in porous media. Their retention can raise injection pressure and obstruct flow

channels^[14]. Further work is therefore needed to characterize the pressure response and flow behavior of emulsions in porous media.

Overall, the injectivity and emulsion-induced plugging behavior of alkali-free chemical flooding systems in medium- and low-permeability reservoirs remain insufficiently understood. In particular, comprehensive methods for localizing plugging sites are lacking. This study therefore prepared two alkali-free chemical flooding formulations, SP and SSP, with HPAM as a reference. Physicochemical-property tests, multipoint pressure monitoring during core flooding, microscopic visualization, and Berea core-flooding experiments were combined to evaluate the injectivity, emulsion-induced plugging behavior, and EOR performance of the three formulations. The results provide an experimental basis for screening and optimizing alkali-free flooding systems for medium- and low-permeability reservoirs.

2. Materials and Methods

2.1 Experimental Materials and Equipment

The main experimental materials were partially HPAM ($M_w=8.0 \times 10^6 \text{ g} \cdot \text{mol}^{-1}$) and the surfactant S1 and S2. S1 was a fatty alcohol polyoxyethylene-polyoxypropylene carboxylate with an active-material content of 40% and was used to formulate the SP; S2 was a fatty alcohol polyoxyethylene-polyoxypropylene sulfonate with an active-material content of 50% and was used to formulate the SSP. S1, S2, and HPAM were all supplied by Daqing Oilfield. The model oil was prepared by mixing dehydrated crude oil from Daqing Oilfield with kerosene at a mass ratio of 4:1. Its viscosity was 10 mPa·s at 45 °C. The synthetic brine had a total salinity of 6783.17 mg·L⁻¹, and its ionic composition is listed in Table 1. A 20 wt% solution containing NaCl and NaOH at a mass ratio of 11:1 was used to formulate the SSP system. Berea sandstone cores supplied by Daqing Oilfield were used for the core-flooding experiments. Microscopic visualization experiments were conducted using a laboratory-fabricated planar sand-pack visualization model.

Table 1. Ionic composition of the experimental water

Ionic composition	CO ₃ ²⁻	HCO ₃ ⁻	Cl ⁻	Ca ²⁺	Mg ²⁺	SO ₄ ²⁻	Na ⁺	Total salinity
Concentration (mg·L ⁻¹)	294.1	3065.7	1188.7	55.4	20.8	73.9	2084.6	6783.17

The principal instruments used in the experiments were a DV-III rotational viscometer (Brookfield, USA), a TX-500C spinning-drop tensiometer (Shanghai Zhongchen Digital Technology Equipment Co., Ltd., China), a UV-2365 ultraviolet-visible spectrophotometer (Unico Shanghai Instruments Co., Ltd., China), and a CPK-II ultrapure water purification system (Chengdu Youpu Ultrapure Technology Co., Ltd., China).

2.2 Preparation of the Flooding Systems

In accordance with the Chinese petroleum and natural gas industry standard SY/T 5862-2020 and conditions representative of field application, synthetic brine was used to prepare the HPAM stock solution and the working solutions of the three flooding systems. HPAM powder was slowly added to synthetic brine and stirred continuously at 400 rpm for 2 h, yielding an HPAM stock solution with a mass concentration of 5000 mg·L⁻¹. The stock solution was then aged for at least 12 h before use. The HPAM

working solution was prepared by diluting an aliquot of the aged HPAM stock solution with synthetic brine to the prescribed concentration. The SP working solution was prepared by mixing the aged HPAM stock solution with a specified amount of S1, followed by dilution with synthetic brine to the target concentration. The SSP working solution was prepared by sequentially mixing the aged HPAM stock solution, a specified amount of S2, and the salt solution in that order, followed by dilution with synthetic brine to the target concentration. After dilution, each working solution was stirred at 400 rpm for 30 min and maintained at 45 °C until use.

2.3 Experimental Methods

2.3.1 Viscosity Measurement

In accordance with China's petroleum and natural gas industry standard SY/T 5862-2020, the HPAM, SP, and SSP systems were prepared. Their apparent viscosities were measured at 45 °C and a shear rate of 7.34 s^{-1} using a DV-III rotational viscometer.

2.3.2 Oil/Water Interfacial Tension Measurement

The oil/water interfacial tension between the model oil and each flooding system was measured using a TX-500C spinning-drop interfacial tensiometer. The oil phase was the model oil, whereas the aqueous phases were the single-component, binary, and ternary systems, respectively. Measurements were performed at 45 °C and a rotational speed of 5000 rpm.

2.3.3 Static Adsorption Test

Static adsorption experiments were conducted according to Ref.^[15]. Quartz sand with a particle size of 60–80 mesh was washed with ultrapure water and dried in a forced-air oven at 75 °C for 24 h. Each flooding system was then mixed with the treated quartz sand at a mass ratio of 5:1 and incubated in a forced-air oven at 45 °C. Samples were collected at 0, 12, 24, 36, 48, and 72 h. The apparent viscosity of each sample was measured, and the polyacrylamide concentration was determined using the starch–cadmium iodide spectrophotometric method. The adsorption amount at each contact time was then calculated.

2.3.4 Emulsion Stability Test

Emulsification performance and emulsion stability were evaluated in accordance with China's petroleum and natural gas industry standard SY/T 6424-2014. SP and SSP working solutions were prepared, and a series of oil/water mixtures was prepared at different oil-to-water ratios. The oil-to-water ratio ranged from 1:9 to 9:1, while the total liquid volume was kept constant. Model oil and kerosene were used separately as the oil phase, and the corresponding flooding system was used as the aqueous phase. The prepared mixtures were transferred to stoppered graduated cylinders and shaken in a thermostatic shaker at 45 °C for 24 h. The resulting emulsions were then placed in a thermostatic water bath at 45 °C. Their phase-separation behavior and emulsion volume were recorded after 1–6 h and 24 h of standing.

2.3.5 Core Injectivity and Pressure-Transmission Test

The apparatus used for the core-injectivity and pressure-transmission experiments is shown in Fig. 1. Berea sandstone cores were used, and their geometric dimensions, permeability, and porosity are listed in Table 2. After core preparation, synthetic formation brine was injected at a velocity of $3 \text{ m} \cdot \text{d}^{-1}$ until

the pressure stabilized. Subsequently, 10 pore volumes (PV) of the flooding system were injected continuously at the same velocity. A post-flush with synthetic formation brine was then performed until the pressure was essentially stable, after which an additional 2 PV was injected. During the experiment, pressures at the inlet and at points located 10 and 20 cm downstream of the inlet were continuously recorded and denoted as P₁, P₂, and P₃, respectively. The pressure-drop ratio was calculated using Eq. (1).

$$R = \frac{P_1 - P_2}{P_2 - P_3} \quad \text{Eq. (1)}$$

Here, R denotes the pressure-drop ratio, whereas P₁, P₂, and P₃ denote the pressures measured at the core inlet and at points 10 and 20 cm downstream of the inlet, respectively.

When R is close to 1, the pressure drops across the upstream and downstream monitored sections are similar, indicating a relatively uniform distribution of flow resistance. When R > 1, the pressure drop is concentrated primarily in the upstream section, suggesting higher flow resistance and possible retention or plugging in that region. When R < 1, the pressure drop is concentrated primarily in the downstream section, indicating increased flow resistance in that region.

Table 2. Core parameters for the injectivity experiments

Core number	Diameter (mm)	Height (mm)	Length (mm)	Permeability (mD)	Porosity (%)
1#	21.6	45.1	45.2	302.4	49
2#	20.5	45.1	45.0	299.7	49
3#	21.6	44.8	45.1	301.6	53
4#	21.3	45.3	45.2	300.5	105
5#	19.7	45.1	45.2	301.3	104
6#	19.9	45.2	45.1	300.4	105
7#	21.5	45.1	45.3	299.8	153
8#	22.9	45.3	45.1	300.7	148
9#	19.4	45.1	45.2	301.3	147

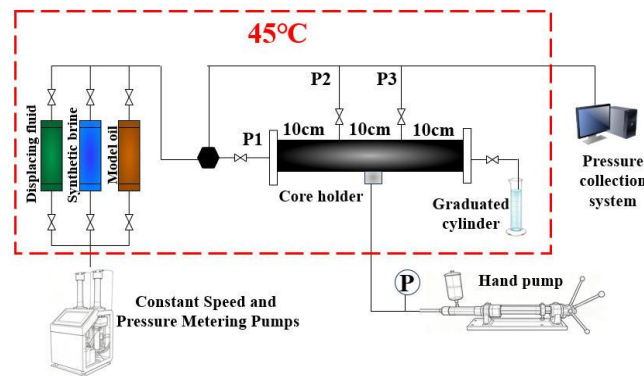


Fig. 1. Schematic of the injectivity and multipoint pressure-measurement apparatus

2.3.6 Microscopic Visualization Experiment

The microscopic visualization setup is shown in Fig. 2. A planar sand-pack model with a permeability of approximately 100 mD was used. The injection rate was set to 0.05 mL·min⁻¹, and the injection behavior of the HPAM, SP, and SSP systems in the porous medium was recorded in real time.

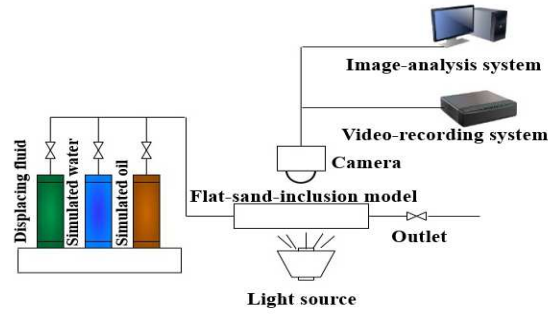


Fig. 2. Schematic of the microscopic flooding visualization platform

2.3.7 Berea Core Flooding Experiment

The Berea core-flooding apparatus is shown in Fig. 3. Berea sandstone cores were used, and their dimensions, permeability, and porosity are listed in Table 3. After core preparation, each core was flooded with model oil at 45 °C until no water was produced and was then aged for 24 h. Synthetic formation brine was subsequently injected at an injection velocity of $3 \text{ m} \cdot \text{d}^{-1}$ until the water cut of the produced fluids exceeded 97%. Subsequently, 0.8 pore volumes (PV) of the selected flooding system were injected, comprising a 0.35 PV primary slug, a 0.25 PV secondary slug, and a 0.20 PV HPAM polymer slug. After injection of the flooding system, post-flush with synthetic formation brine was continued until the water cut of the produced fluids reached 97%. Oil production, water production, and injection pressure were continuously recorded throughout the experiment. Changes in oil recovery were calculated from the oil produced during the different flooding stages.

Table 3. Core parameters for the flooding experiments

Core number	Diameter (mm)	Height (mm)	Length (mm)	Permeability (mD)	Porosity (%)
10#	45.1	45.2	302.4	103	21.3
11#	45.1	45.0	299.7	98	21.5
12#	44.8	45.1	301.6	104	21.5

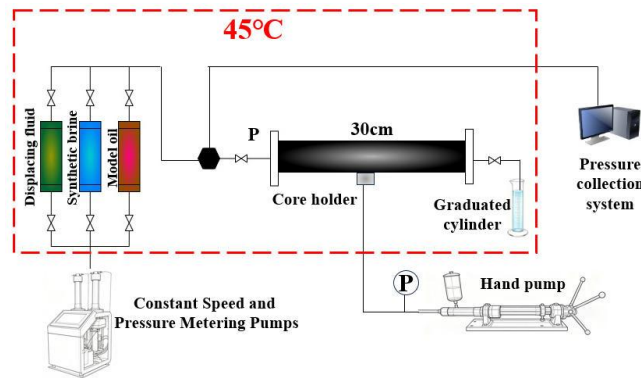


Fig. 3. Schematic of the core flooding apparatus

3. Results and Discussion

3.1 Performance Evaluation of the Flooding Systems

3.1.1 System Formulation and Basic Properties

Surfactants can reduce oil/water interfacial tension by adsorbing at the oil/water interface, thereby increasing the capillary number. When the displacement velocity and displacing-fluid viscosity remain approximately constant, lower interfacial tension weakens capillary trapping and promotes the deformation, migration, and mobilization of residual oil in the pore space after water flooding, thereby improving microscopic displacement efficiency^[16]. Oil/water interfacial tension is therefore an important indicator of the interfacial performance and oil-displacement potential of a flooding system. The effects of surfactant, NaCl, and HPAM concentrations on the oil/water interfacial tension of the systems were investigated. As shown in Fig. 4a, the interfacial tensions of S1 and S2 decreased rapidly with increasing surfactant concentration and then approached a plateau. Increasing the S1 concentration from 0.1 wt% to 0.3 wt% decreased the interfacial tension from $5.2 \times 10^{-2} \text{ mN}\cdot\text{m}^{-1}$ to $6.1 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$, whereas further increases in concentration produced only a slight additional decrease. Increasing the S2 concentration from 0.1 wt% to 0.3 wt% decreased the interfacial tension from $8.7 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$ to $2.7 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$, after which the interfacial tension also approached a plateau. Across the tested concentration range, S2 produced lower interfacial tensions than S1, indicating a stronger interfacial-tension-reducing ability under the present experimental conditions. Because increasing either surfactant concentration beyond 0.3 wt% produced only limited additional improvement, 0.3 wt% was selected as the S1 and S2 concentration for subsequent experiments, considering both interfacial-tension reduction and surfactant dosage.

The effect of NaCl concentration on the oil/water interfacial tension of the SSP system is shown in Fig. 4b. The interfacial tension first decreased and then increased as the NaCl concentration increased. Increasing the NaCl concentration from 0.8 wt% to 1.2 wt% decreased the interfacial tension from $1.3 \times 10^{-2} \text{ mN}\cdot\text{m}^{-1}$ to $3.6 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$, whereas a further increase to 1.6 wt% increased the interfacial tension to $5.5 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$. These results indicate that an NaCl concentration of approximately 1.2 wt% favors a relatively low interfacial tension in the SSP system. This trend may be associated with the effects of salt ions on surfactant adsorption at the interface. At relatively low salt concentrations, salt ions may compress the electrostatic repulsion between the hydrophilic groups of surfactant molecules, promote closer packing at the oil/water interface, and thereby reduce the interfacial tension^[17]. At higher salt concentrations, excessive ionic strength may alter surfactant solubility, interfacial adsorption equilibrium, and partitioning between the oil and aqueous phases. These changes may reduce interfacial adsorption efficiency and increase the interfacial tension^[18]. On the basis of the overall trend, an NaCl concentration of 1.2 wt% was selected for the SSP system in subsequent experiments.

The effect of HPAM concentration on the interfacial tension of the SP and SSP systems is shown in Fig. 4c. Increasing the HPAM concentration from 500 to 2500 $\text{mg}\cdot\text{L}^{-1}$ gradually increased the interfacial tension of both systems. For the SP system, the interfacial tension increased from $1.5 \times 10^{-2} \text{ mN}\cdot\text{m}^{-1}$ to $1.4 \times 10^{-1} \text{ mN}\cdot\text{m}^{-1}$, whereas for the SSP system it increased from $8.1 \times 10^{-3} \text{ mN}\cdot\text{m}^{-1}$ to $4.9 \times 10^{-2} \text{ mN}\cdot\text{m}^{-1}$. At a given polymer concentration, the SSP system consistently exhibited a lower interfacial tension than the SP system. Increasing HPAM concentration may alter the interfacial arrangement of surfactant molecules through interfacial adsorption, intermolecular interactions, or increased solution viscosity. This may reduce the effective interfacial coverage of the surfactant and increase the interfacial tension^[19].

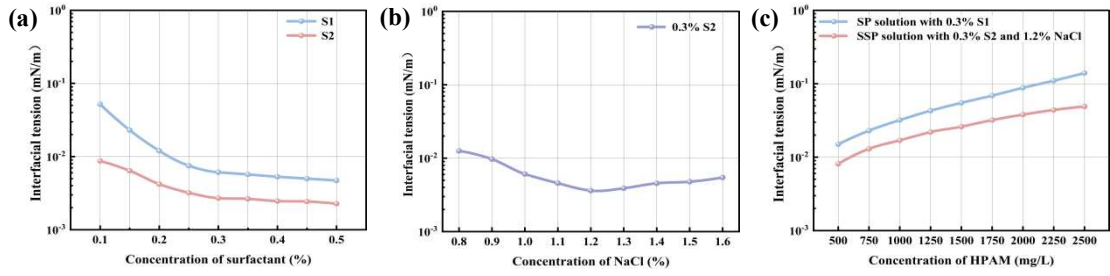


Fig. 4. Oil-water interfacial tension of the systems under different compositional conditions. (a) Oil-water interfacial tension of S1 and S2 at different concentrations; (b) effect of NaCl concentration on the oil-water interfacial tension of the system at an S2 concentration of 0.3%; (c) effect of HPAM concentration on the oil-water interfacial tension of the SP and SSP systems when the concentrations of S1 and S2 were both 0.3% and the NaCl concentration in the SSP system was 1.2%

Introducing polymer into the displacing fluid increases the aqueous-phase viscosity and reduces the mobility ratio between the displacing fluid and crude oil. This can suppress viscous fingering and tonguing, thereby increasing the macroscopic sweep volume in the reservoir^[20]. As shown in Fig. 5, at a given HPAM concentration, the viscosities of the three systems followed the order SP > HPAM > SSP. The viscosity of the HPAM solution increased approximately linearly with HPAM concentration. Increasing the HPAM concentration from 500 to 2500 mg·L⁻¹ increased the solution viscosity from 17.83 to 42.67 mPa·s, indicating a relatively stable thickening response. The viscosity of the SP system also increased continuously with HPAM concentration and reached 59.73 mPa·s at 2500 mg·L⁻¹, exceeding that of the HPAM system at the same polymer concentration. This result suggests that intermolecular interactions between S1 and HPAM may contribute to the higher apparent viscosity of the SP system. Because S1 is an anionic–nonionic surfactant, this effect may be associated with hydrogen bonding or physical entanglement between molecules^[21]. The viscosity of the SSP system increased more slowly and reached only 40.53 mPa·s at 2500 mg·L⁻¹, lower than those of the SP and HPAM systems. This lower viscosity may be related to the increase in ionic strength caused by NaCl. Salt ions may screen electrostatic repulsion between HPAM chains, causing the chains to adopt a more contracted conformation. The resulting decrease in effective hydrodynamic volume may reduce the solution viscosity^[22].

To minimize the effect of viscosity differences on subsequent comparisons of injectivity and oil-displacement performance, the target viscosity of all three systems was set to 25 mPa·s according to Ref.^[23]. The working compositions were then determined under identical temperature and shear-rate conditions, and the detailed compositions are listed in Table 4. Based on the interfacial-tension and viscosity results, the S1 and S2 concentrations were both set to 0.3 wt%, and the NaCl concentration in the SSP system was set to 1.2 wt%.

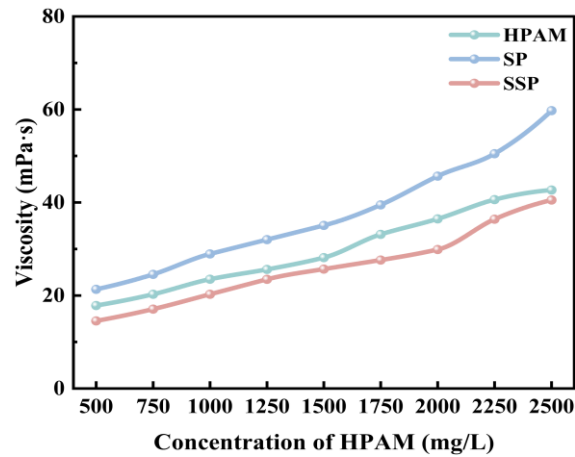


Fig. 5. Apparent viscosity of the three flooding systems at different HPAM concentrations

Table 4. Formulations of the three experimental systems at a target viscosity of 25 mPa·s

Flooding system	Flooding-system formulation	Interfacial tension (mN·m ⁻¹)
HPAM	1200 ppm HPAM	/
SP	0.3% S1+750 ppm HPAM	1.6×10 ⁻¹
SSP	0.3% S2+1500 ppm HPAM+1.2% NaCl	5×10 ⁻²

3.1.2 Emulsion Viscosity and Emulsion Stability

Depending on the identities of the dispersed and continuous phases, emulsions are commonly classified as oil-in-water (O/W) or water-in-oil (W/O) emulsions^[24]. In an O/W emulsion, water forms the continuous phase and oil is dispersed as droplets. This structure may facilitate the dispersion and transport of residual oil, thereby improving microscopic displacement efficiency under appropriate pore-scale conditions^[25]. In a W/O emulsion, oil forms the continuous phase and water is dispersed as droplets. Such emulsions generally exhibit higher viscosities and can increase flow resistance in preferential channels through droplet retention, deformation, and the Jamin effect, thereby increasing the sweep volume^[26]. It is therefore necessary to compare the viscosity characteristics and stability of emulsions generated by the SP and SSP systems to determine how their distinct emulsification behaviors affect flow regulation and adaptability to reservoir conditions.

Because the HPAM system contained no surfactant, it did not form a stable emulsion with the model oil. Therefore, only the SP and SSP systems were evaluated in this section. As shown in Fig. 6, the emulsion viscosity of both systems initially increased and subsequently decreased with increasing oil volume fraction, whereas the SSP system generally produced higher viscosities. For the SP system, the emulsion viscosity remained close to the viscosity of the corresponding bulk flooding system at oil volume fractions of 10–50%. When the oil volume fraction increased to 70%, the emulsion viscosity reached 43.33 mPa·s and then decreased slightly to 37.73 mPa·s at higher oil volume fractions. For the SSP system, the emulsion viscosity increased continuously as the oil volume fraction increased from 10% to 70% and reached 155.6 mPa·s at 70%. It then decreased markedly to 33.07 mPa·s at higher oil volume fractions. Overall, the SSP system produced a stronger emulsion-induced viscosity increase over a broader range of oil volume fractions.

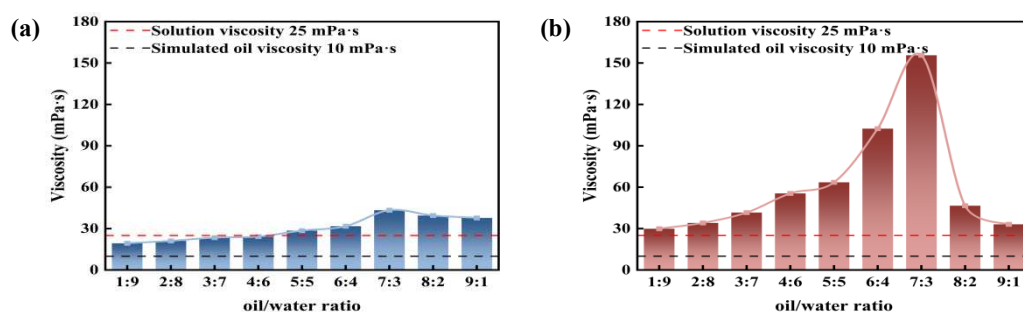


Fig. 6. Apparent emulsion viscosities of the SP and SSP systems at different oil/water ratios (a) SP system; (b) SSP system

The emulsion-stability results are shown in Figs. 7 and 8. Overall, the SSP system exhibited greater emulsion stability than the SP system. The SP system maintained an emulsified state for a limited period at high oil volume fractions but underwent phase separation or demulsification more readily at low oil volume fractions. By contrast, the SSP system maintained a relatively stable emulsified state over an oil volume fraction range of 10–70%. The pronounced turbidity of the lower liquid layer was consistent with the presence of dispersed droplets and suggested greater emulsion stability. These results indicate that, under the present experimental conditions, the SSP system was more favorable for forming relatively stable emulsions.

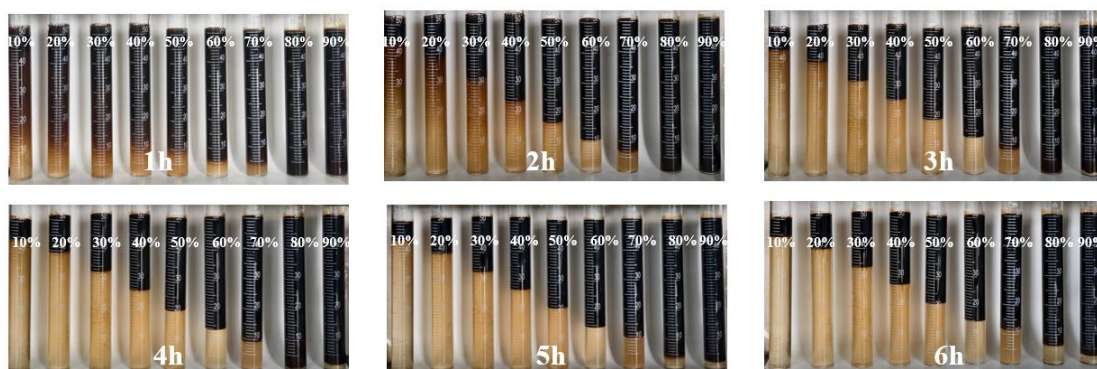


Fig. 7. Emulsion states of the SP system after standing for 1-6 h at different oil/water ratios (the numbers on the colorimetric tubes indicate the oil fraction)

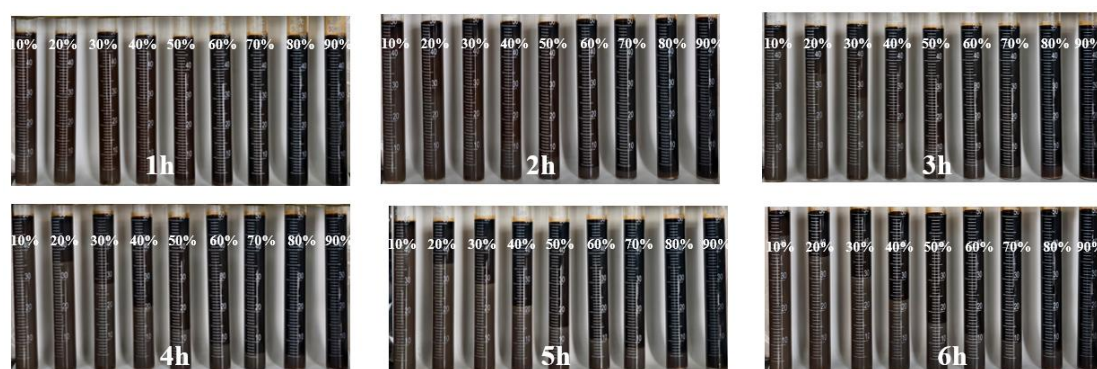


Fig. 8. Emulsion states of the SSP system after standing for 1-6 h at different oil/water ratios (the numbers on the colorimetric tubes indicate the oil fraction)

To further characterize the emulsification behavior, the states of the kerosene- and model-oil-based systems after 24 h of standing were examined, as shown in Fig. 9. In kerosene, the SP system formed relatively stable W/O emulsions at oil volume fractions of 10–60%. When the oil volume fraction increased to 70–90%, emulsion stability decreased and local demulsification occurred. In model oil, the

SP emulsions were more susceptible to phase separation, indicating limited adaptability to different oil phases. Thus, although S1 promoted emulsification under certain conditions, its emulsifying performance was strongly affected by the oil-to-water ratio.

In comparison, the SSP system exhibited more stable emulsification in both kerosene and model oil. In kerosene, the SSP system formed W/O emulsions across the entire tested oil volume-fraction range, with no obvious demulsification even at high oil volume fractions. In model oil, the emulsions were generally more homogeneous, and the lower liquid layer remained turbid, indicating good interfacial stability. These results suggest that S2 was more effective in maintaining emulsion structural stability, possibly because it adsorbed more effectively at the oil/water interface. Overall, the emulsifying performance of the SP system was strongly dependent on the oil volume fraction, whereas the SSP system maintained good emulsion stability over a broader range of oil-to-water ratios.

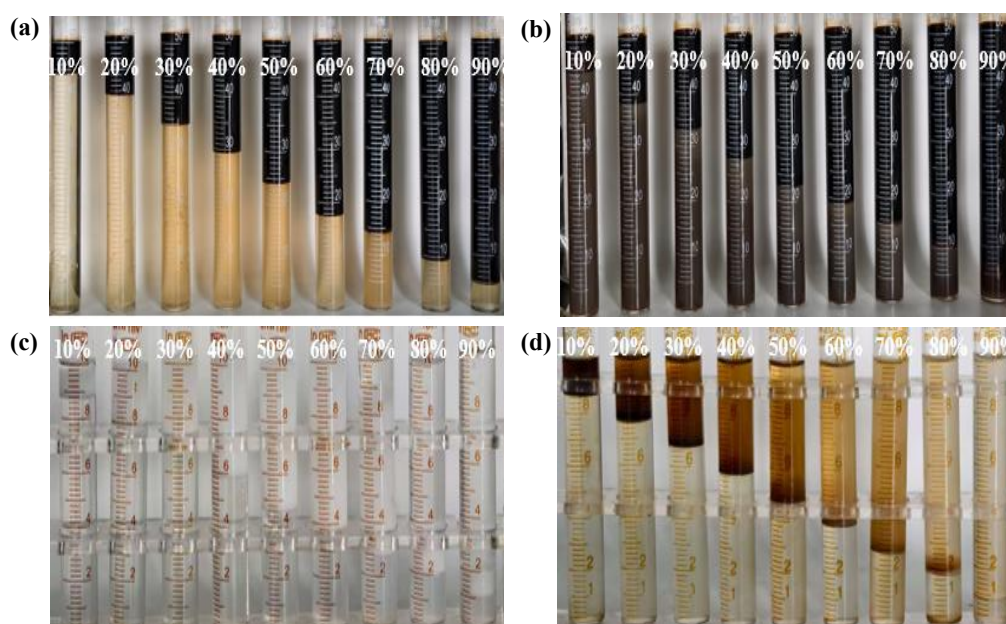


Fig. 9. Emulsion states after standing for 24 h under different oil-phase conditions. (a) SP system with simulated oil; (b) SSP system with simulated oil; (c) SP system with kerosene; (d) SSP system with kerosene (the numbers on the colorimetric tubes indicate the oil fraction)

3.1.3 Static Adsorption Performance

To evaluate the viscosity-retention capability and adsorption-loss characteristics of different flooding systems after contact with quartz sand, changes in the apparent viscosity and polymer adsorption amount of the three systems were investigated over 0–72 h. Viscosity retention reflects the performance stability of a flooding system during interactions with solid surfaces^[27], whereas the adsorption amount characterizes the loss of effective polymer components from the flooding system in porous media^[28].

As shown in Fig. 10a, the initial viscosity of each system was 25 mPa·s, and none of the systems exhibited a sustained or substantial decrease after contact with quartz sand. The viscosity of the HPAM system remained between 24 and 27 mPa·s throughout the test. The SP system showed a transient increase after 12 h, reaching a maximum of approximately 30 mPa·s, before gradually returning to a value close to the initial level. The viscosity of the SSP system temporarily decreased to 22 mPa·s after 24 h, recovered to nearly the initial value after 36 h, and remained between 24 and 26 mPa·s at 72 h. Overall, all three systems showed good apparent-viscosity retention after contact with quartz sand,

indicating that adsorption did not markedly deteriorate their thickening performance under the present experimental conditions^[29]. As shown in Fig. 10b, the adsorption amount of each system increased with contact time, indicating that adsorption had not reached equilibrium within 72 h. According to the data shown in the figure, the adsorption amount of the HPAM system increased from approximately 130 to 340 $\mu\text{g}\cdot\text{g}^{-1}$, that of the SSP system increased from approximately 200 to 450 $\mu\text{g}\cdot\text{g}^{-1}$, and that of the SP system increased from approximately 20 to 200 $\mu\text{g}\cdot\text{g}^{-1}$. The adsorption amounts followed the order $\text{SSP} > \text{HPAM} > \text{SP}$, suggesting that the surfactants and ionic environment in the SP and SSP systems may alter the interfacial interactions between HPAM and quartz sand.

The lower adsorption amount of the SP system may be associated with competitive adsorption between S1 and HPAM. S1 is a carboxylate-type anionic–nonionic surfactant and may preferentially accumulate on the quartz-sand surface or at the solid–liquid interface. It may therefore act as a sacrificial adsorbate by occupying some surface adsorption sites and altering the interfacial properties of the quartz sand. This could reduce direct contact between HPAM and the sand surface and thereby decrease polymer adsorption^[30]. Consequently, the SP system exhibited lower polymer adsorption loss.

The higher adsorption amount of the SSP system may result from the combined effects of the salt-ion environment and the interfacial behavior of S2. S2 is a sulfonate-type anionic–nonionic surfactant and may exhibit relatively strong adsorption resistance under the present experimental conditions. It may therefore be less effective at occupying adsorption sites on the quartz-sand surface, providing only limited suppression of HPAM adsorption^[31]. At the same time, NaCl can compress the electrical double layer between charged groups, weaken electrostatic repulsion between HPAM chains and the quartz-sand surface, and alter the conformation of the polymer chains. These effects may allow the chains to approach and adsorb onto the solid surface more readily, thereby increasing HPAM adsorption in the SSP system^[32]. In addition, the HPAM concentrations were not identical among the three systems, and the differences in adsorption amount may also have been affected by the initial polymer concentrations.

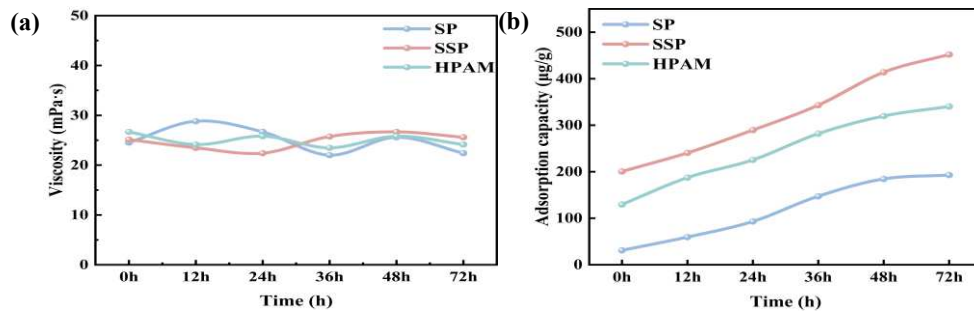


Fig. 10. Static adsorption performance of the different flooding systems. (a) Apparent viscosity of the different systems after adsorption treatment; (b) static adsorption amount of the different systems

3.2 Injectivity of Flooding Systems under Different Permeability Conditions

Injectivity reflects the pressure response, flow resistance, and transport stability of a flooding system in porous media and is an important indicator of reservoir adaptability^[33]. In this study, cores with permeabilities of 50, 100, and 150 mD were selected. A multipoint pressure-measurement apparatus was used to record pressure variations at the core inlet and at points located 10 and 20 cm downstream of the inlet. The injection behavior of the three systems was compared using the pressure-drop distribution between the upstream and downstream sections. When the pressure drop in the upstream

section exceeds that in the downstream section, flow resistance is concentrated primarily in the upstream portion of the core^[34].

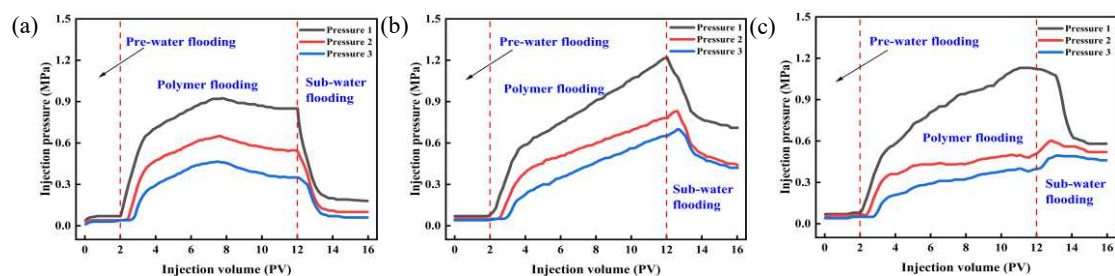
As shown in Fig. 11, the three systems exhibited markedly different pressure responses at 50 mD. During the initial stage of HPAM injection, the pressure increased rapidly, then gradually decreased and approached a stable level. The peak pressures at the inlet and at 10 and 20 cm downstream of the inlet were approximately 1.0, 0.7, and 0.5 MPa, respectively, whereas the peak pressure drops in the upstream and downstream sections were approximately 0.32 and 0.20 MPa, respectively. These results indicate that HPAM encountered a certain degree of upstream flow resistance during the initial stage of injection into the low-permeability core. However, the pressure gradually stabilized as injection proceeded, suggesting that a relatively stable flow regime was eventually established. The pressure of the SP system continued to increase without reaching a clear plateau. The peak pressure drops in the upstream and downstream sections were approximately 0.44 and 0.18 MPa, respectively. The substantially higher upstream pressure drop indicates that flow resistance was concentrated primarily in the upstream portion of the core, suggesting possible inlet retention or upstream plugging. When considered together with the static adsorption results, the relatively low static adsorption amount of the SP system did not translate into better dynamic injectivity. This finding suggests that the upstream flow resistance was not attributable solely to adsorption on the solid surface and may also have been affected by local retention of polymer molecules within the pore throats. Therefore, the SP system still exhibited pronounced upstream flow resistance at 50 mD. The SSP system likewise showed a continuous pressure increase without reaching a stable plateau. Its peak pressure drops in the upstream and downstream sections were approximately 0.68 and 0.14 MPa, respectively, and the difference between the two sections was greater than that observed for the SP system. In conjunction with the adsorption results, these findings suggest that although S2 may exert a regulatory effect on adsorption behavior, pore-throat constraints and polymer retention remained the principal factors affecting SSP injectivity at 50 mD. Thus, under the 50 mD condition, HPAM established a relatively stable flow regime after an initial pressure-adjustment period, whereas both the SP and SSP systems exhibited sustained pressure buildup and increased upstream flow resistance.

As shown in Fig. 12, at 100 mD, the pressures of the HPAM and SSP systems stabilized relatively rapidly, whereas the SP system continued to show a pressure-increase trend. The peak pressure drops in the upstream and downstream sections of the HPAM system were approximately 0.16 and 0.13 MPa, respectively. Their similar values indicate a relatively uniform pressure-drop distribution along the core, with no obvious local plugging. Compared with the 50 mD condition, the higher permeability reduced the flow resistance encountered by HPAM during passage through the core. The slope of the pressure curve for the SP system was lower than that at 50 mD, but a fully stable plateau was still not established. Its peak pressure drops in the upstream and downstream sections were approximately 0.28 and 0.14 MPa, respectively. The higher upstream pressure drop indicates that appreciable flow resistance remained in the upstream portion of the core. Although S1 may reduce HPAM adsorption on the quartz-sand surface through competitive adsorption, this effect was insufficient to eliminate dynamic retention of the SP system within the pore throats. Consequently, its injection pressure continued to increase. The pressure of the SSP system stabilized relatively rapidly, with peak upstream and downstream pressure drops of

approximately 0.22 and 0.17 MPa, respectively. The small difference between these values indicates a relatively uniform distribution of flow resistance along the 100 mD core. Under this condition, the NaCl-induced reduction in the hydrodynamic volume of HPAM molecules, together with the larger pore-throat space, reduced the tendency for polymer bridging and inlet retention, thereby improving the dynamic injectivity of the SSP system.

As shown in Fig. 13, at 150 mD, the overall injection pressures of the three systems were lower than those observed under the lower-permeability conditions, indicating that higher permeability reduced the flow resistance encountered by the flooding systems during passage through the core. The peak inlet pressure of the HPAM system was approximately 0.5 MPa, and the peak pressure drops in the upstream and downstream sections were approximately 0.11 and 0.09 MPa, respectively. The similarity between these values indicates that HPAM was less prone to localized upstream retention under this condition and that the pressure drop was distributed relatively uniformly along the core. The pressure of the SP system increased relatively slowly but still did not fully reach a stable plateau. Its upstream pressure drop was higher than its downstream pressure drop, indicating that a certain degree of upstream flow resistance remained. Compared with the 50 and 100 mD conditions, the pressure increase of the SP system was smaller at 150 mD, suggesting that the larger pore-throat space may have reduced inlet retention. The pressure of the SSP system stabilized relatively rapidly, with peak pressure drops of approximately 0.15 and 0.13 MPa in the upstream and downstream sections, respectively. The two values were similar, indicating good along-core flow uniformity and injection stability in the 150 mD core. When considered together with the adsorption results, the higher static adsorption amount of the SSP system did not result in obvious dynamic upstream plugging at 150 mD. This finding indicates that static adsorption loss and dynamic injection resistance are not simply correlated, and that pore-throat size and the hydrodynamic size of polymer molecules may have a more direct influence on injectivity.

Overall, the pressure responses under different permeability conditions indicate that core permeability and flooding-system composition jointly affect injectivity. HPAM was able to establish flow at 50, 100, and 150 mD. Although a pronounced initial pressure increase occurred at 50 mD, the pressure subsequently approached a stable level. The SP system exhibited either sustained pressure buildup or an elevated upstream pressure drop across the 50–150 mD range, indicating a greater tendency toward upstream plugging in narrow pore throats. The pressure of the SSP system stabilized relatively rapidly at 100 and 150 mD but continued to increase at 50 mD, indicating a clear dependence of its injectivity on core permeability. Therefore, under the experimental conditions of this study, HPAM exhibited a relatively broad injectivity range; the SP system presented a certain injection risk across the 50–150 mD range; and the SSP system showed good injection stability at 100–150 mD but may undergo pronounced upstream plugging at 50 mD.



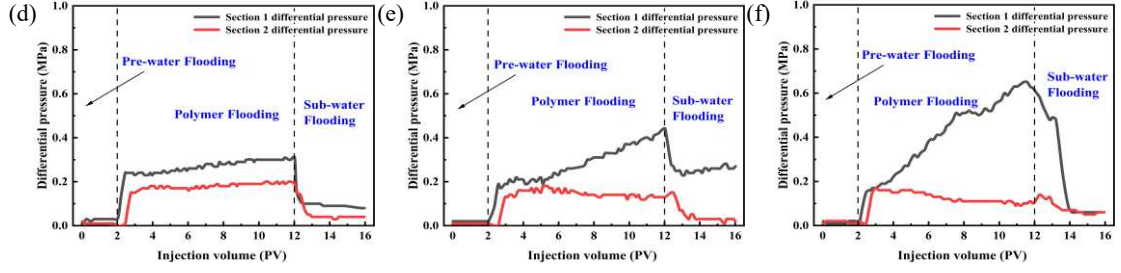


Fig. 11. Injection-pressure and sectional pressure-drop curves of different flooding systems in 50 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

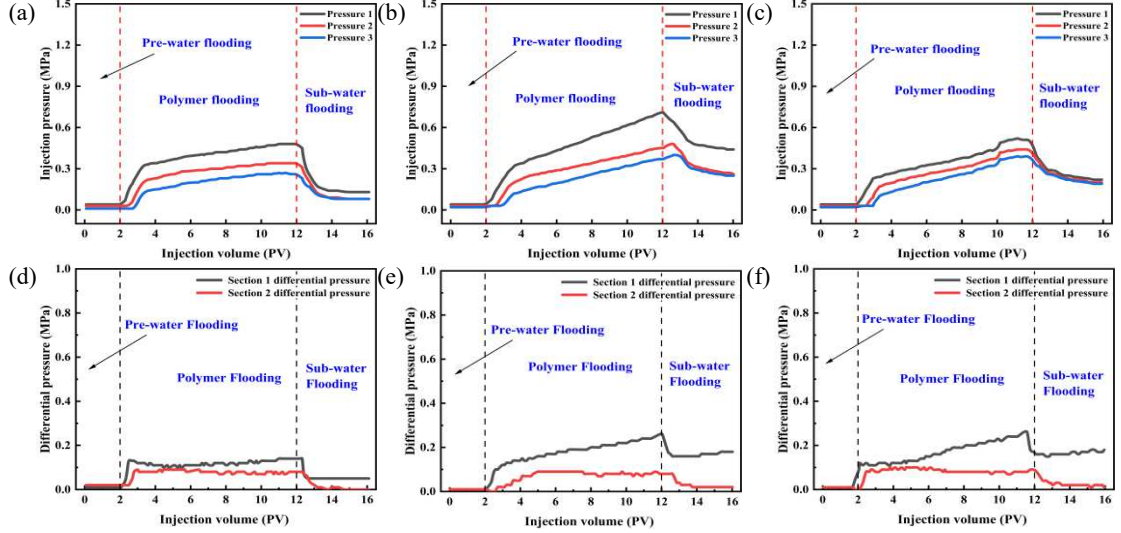


Fig. 12. Injection-pressure and sectional pressure-drop curves of different flooding systems in 100 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

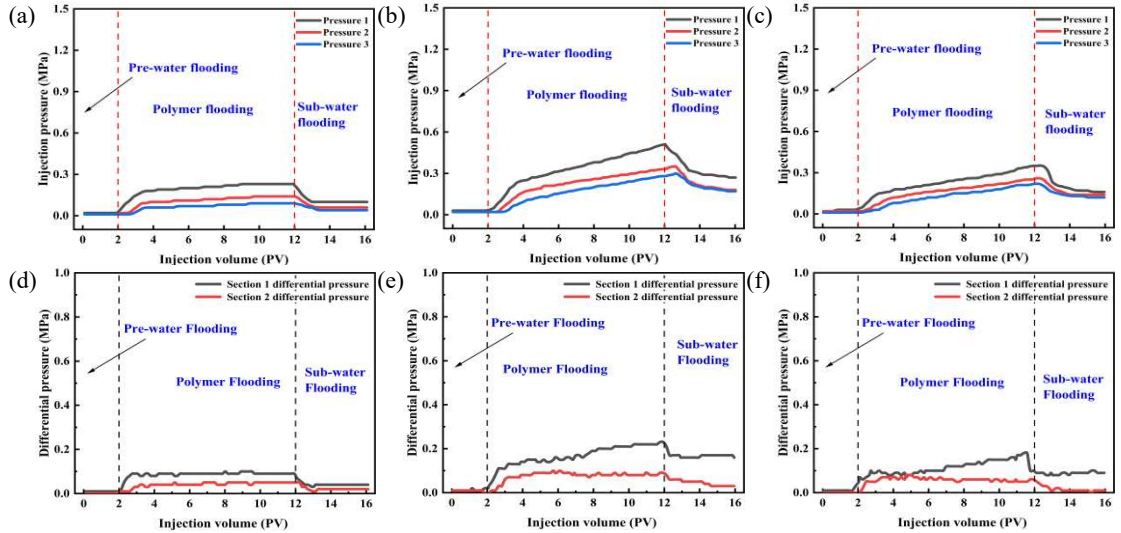


Fig. 13. Injection-pressure and sectional pressure-drop curves of different flooding systems in 150 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

3.3 Microscopic Visualization Experiments

Microscopic visualization images can directly characterize the formation and dynamic evolution of emulsion layers generated by flooding systems in the presence of oil^[35]. In this experiment, a planar sand-pack microscopic visualization model was used to observe the emulsification behavior and changes

in swept area of the HPAM, SP, and SSP systems at different injection stages under the same injection rate. In the images, lighter-colored regions represent areas swept by the displacing fluid, whereas darker regions represent areas that remained unswept or contained higher amounts of residual crude oil. Changes in the swept area within the model were therefore assessed based on image contrast.

After pre-water flooding, all three systems exhibited fingering to varying degrees, and darker oil-bearing regions remained near the downstream end of the model. This observation indicates that some crude oil was not effectively swept during the initial waterflood. Subsequent injection of the different flooding systems produced marked differences in swept area, oil–water displacement-front morphology, and fluid distribution near the inlet. After 0.5 PV of HPAM had been injected, only a small portion of the model was swept, and an oil bank began to form at the oil–water displacement front. When the injected volume reached 1.0 PV, the swept regions became lighter and the oil bank at the displacement front became more pronounced. During the subsequent waterflood, most of the model area was gradually swept, although small unswept regions remained along both lateral edges. Overall, HPAM gradually expanded the swept area, but the displacement front remained somewhat nonuniform. After 0.5 PV of the SP system had been injected, no obvious change in swept area was observed. When the injected volume reached 1.0 PV, pronounced emulsion-induced plugging appeared in the inlet region. During the subsequent waterflood, the inlet emulsion layer continued to thicken and remained in place for an extended period, while some darker oil-bearing regions persisted within the model. This behavior indicates that the emulsified products generated by the SP system did not migrate uniformly through the model but instead accumulated and were retained in the inlet and near-inlet regions. Retention of the emulsified products increased local flow resistance, reduced the effective permeability of the inlet region, and limited the migration of subsequently injected fluid into deeper regions of the model^[36]. Together with the continuously increasing upstream flow resistance observed in the multipoint pressure-measurement experiments, these results suggest that local plugging by the SP system in oil-bearing porous media may result from the combined effects of polymer retention and emulsified-product accumulation.

For the SSP system, the swept area in the inlet region was slightly greater than that observed for HPAM after 0.5 PV had been injected. Emulsification occurred in localized regions, and a relatively distinct oil bank also formed at the oil–water displacement front. As the injected volume increased to 1.0 PV, the lighter-colored regions within the model gradually expanded. During the subsequent waterflood, a relatively continuous displacement front was maintained, and the swept regions were distributed comparatively uniformly. Most of the model was effectively swept, with only small darker unswept regions remaining near the edges. Compared with the SP system, although emulsification also occurred in the SSP system, no obvious expansion of an inlet emulsion-retention zone was observed. The more balanced transport behavior of the SSP system may be attributable to the greater stability of the emulsions formed with the model oil. In the SSP system, HPAM-associated emulsification mainly occurred at the oil–water interface, which may have reduced HPAM adsorption on the quartz-sand surface and thereby mitigated plugging. In addition, the higher viscosity and greater stability of the SSP emulsions allowed them to increase resistance in preferential flow channels through viscosity enhancement, droplet retention, and the Jamin effect. This behavior may have diverted the fluid toward unswept regions and

expanded the swept area.

In summary, the swept area of the HPAM system gradually expanded during injection, but the uniformity of the oil–water displacement front remained limited. The most prominent feature of the SP system was the continuous formation and retention of an inlet emulsion layer, which resulted in pronounced emulsion-induced plugging. By contrast, the SSP system exhibited a relatively continuous displacement front and a more uniform sweep pattern.

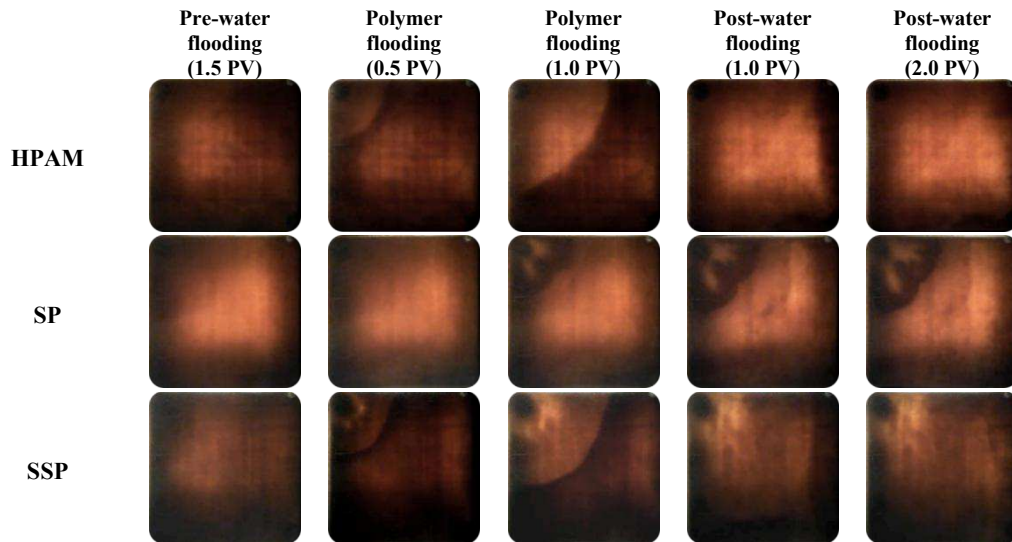


Fig. 14. Microscopic visualization experiments of the three systems in a 100 mD model at an injection rate of 0.05 mL·min⁻¹

3.4 Berea Core Flooding Performance

Based on the preceding evaluation of the reservoir adaptability of the flooding systems, Berea sandstone cores with a permeability of approximately 100 mD were selected for the core-flooding experiments. Composite-slug designs were applied to the SP and SSP systems. The detailed compositions of the three systems are listed in Table 5, and the experimental results are shown in Fig. 15.

The final recovery factors ranked in descending order as SSP, SP, and HPAM, with values of 55%, 48%, and 47%, respectively. Because the recovery factors of the three systems differed only slightly during the pre-water-flooding and post-water-flooding stages, the differences in final recovery factor arose mainly during the polymer-flooding stage. Accordingly, the recovery-factor increment during polymer flooding was used as the primary indicator of oil-displacement performance. The recovery-factor increments were 13% for the SSP system, 8% for the SP system, and 6% for the HPAM system. The relatively small recovery-factor increment of the HPAM system was mainly attributable to its limited ability to reduce oil/water interfacial tension and mobilize residual oil, which resulted in insufficient sweep of some regions. The relatively low recovery-factor increment of the SP system during polymer injection may be related to its poor macroscopic injectivity. Although emulsification can improve microscopic displacement efficiency, the microscopic visualization results showed that the SP system formed an emulsion-induced plugging zone near the inlet, thereby limiting further recovery enhancement. The higher recovery factor of the SSP system mainly resulted from the synergistic effects of interfacial activity, mobility control, emulsion-induced viscosity enhancement, favorable injectivity, and deep transport. Lower interfacial tension reduces the resistance to residual-oil mobilization, whereas the lower adsorption of S2 on solid surfaces may reduce the loss of interfacially active components. NaCl may also promote emulsion stability by altering the ionic strength of the aqueous phase and interfacial

partitioning behavior^[37-39]. Meanwhile, the high-salinity environment reduces the hydrodynamic volume of HPAM molecular chains, thereby decreasing their retention and plugging in narrow pore throats^[40]. These effects are consistent with the multipoint pressure-measurement results, which showed that the pressure of the SSP system stabilized relatively rapidly and that flow resistance was distributed comparatively uniformly along the core. Stable emulsions can expand the swept volume through viscosity enhancement and the Jamin effect. In the microscopic visualization experiments, this behavior was manifested as a relatively continuous oil/water displacement front and a more uniform sweep pattern, without the pronounced inlet emulsion-retention layer observed for the SP system. Therefore, the SSP system can simultaneously promote residual-oil mobilization, provide mobility control, and maintain deep transport, ultimately resulting in a higher chemical-flooding recovery factor.

Table 5. Formulations of the flooding systems

Flooding system	Primary slug (0.35 PV)	Secondary slug (0.25 PV)	Polymer slug (0.2 PV)
HPAM	1200 ppm HPAM	1200 ppm HPAM	1200 ppm HPAM
SP	0.3% S1+750 ppm HPAM	0.2% S1+900 ppm HPAM	1200 ppm HPAM
SSP	0.3% S2+1500 ppm HPAM+1.2% NaCl	0.2% S2+1350 ppm HPAM+1% NaCl	1200 ppm HPAM

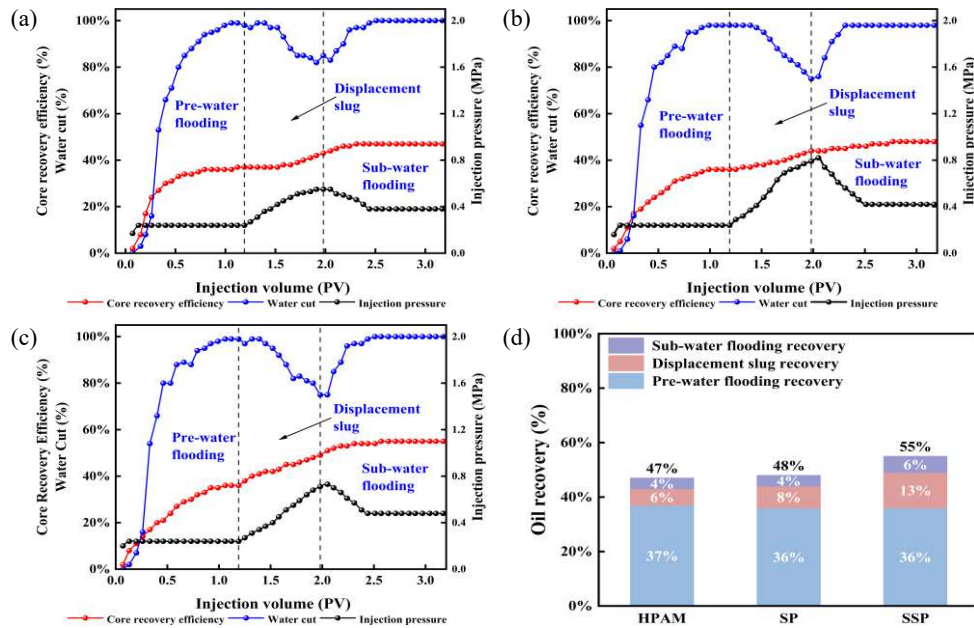


Fig. 15. Flooding results of different flooding systems in 100 mD Berea cores. (a) HPAM system; (b) SP system; (c) SSP system; (d) recovery factor

4. Conclusion

The combined core-flooding multipoint pressure-measurement and microscopic visualization method established in this study enabled macroscopic pressure responses to be correlated with directly visualized emulsion-induced plugging behavior. This approach therefore facilitated the identification of plugging locations and the analysis of transport characteristics. Based on a detailed evaluation of the reservoir adaptability of the SP and SSP alkali-free flooding systems in medium- and low-permeability reservoirs, the following conclusions were drawn:

(1) The SP binary system and SSP ternary system differed substantially in their physicochemical properties. The static adsorption results showed that the polymer adsorption amount of both systems increased with contact time. The SSP system exhibited the highest adsorption amount, whereas the SP system exhibited the lowest. Nevertheless, neither system showed a pronounced and sustained decrease in apparent viscosity after contact with quartz sand. Compared with the SP system, the SSP system exhibited lower oil/water interfacial tension, greater emulsion stability, and more pronounced emulsion-induced viscosity enhancement at high oil volume fractions.

(2) The three systems exhibited distinct injectivity behaviors. HPAM showed good injectivity across the 50–150 mD range. In the 100 mD microscopic model, the swept area of HPAM gradually expanded during injection, although the oil/water displacement front remained somewhat nonuniform. The SP system exhibited poor injectivity across the entire tested permeability range. In the 100 mD microscopic model, an inlet emulsion layer continuously formed and was retained, indicating a pronounced tendency toward inlet emulsion-induced plugging. The SSP system exhibited good pressure stability at 100–150 mD but still showed obvious upstream retention at 50 mD. In the 100 mD microscopic model, it exhibited a relatively continuous oil/water displacement front and a more uniform sweep pattern.

(3) In the 100 mD Berea core-flooding experiments, the final recovery factors of the SSP, SP, and HPAM systems were 55%, 48%, and 47%, respectively. The corresponding recovery-factor increments during the polymer-flooding stage were 13%, 8%, and 6%, respectively.

For lower-permeability reservoirs, future research will focus on two aspects to further clarify the applicability of the combined multipoint pressure-measurement and microscopic visualization method to reservoir-adaptability evaluation and to improve the systematic nature and reliability of the evaluation results:

(1) The microscopic visualization experiments in this study were conducted only at 100 mD. Plugging characteristics under other permeability conditions were inferred primarily from macroscopic pressure responses, and the applicability of the pressure-drop-ratio criterion requires further verification. Future work should conduct microscopic visualization experiments across a range of permeabilities, particularly at lower permeabilities, and combine these results with multipoint pressure measurements to systematically verify plugging locations, formation mechanisms, and the applicable range of the pressure-drop-ratio criterion.

(2) To address the restricted transport of flooding systems in lower-permeability reservoirs, the polymer molecular weight could be reduced, or salt-resistant and adsorption-resistant functional polymers could be introduced to decrease the hydrodynamic size of the molecular chains and reduce their retention in pore throats. In parallel, the proportions of polymer, surfactant, and NaCl, together with the injection parameters, should be optimized in a coordinated manner. This optimization should improve pore-throat transportability while maintaining viscosity and mobility-control capability. Future studies should combine multipoint pressure measurements, microscopic visualization, and core-flooding experiments to systematically evaluate the injectivity, transport stability, and EOR performance of the improved systems.

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Declaration of interest statement

We declare that we have no financial and personal relationships with other people or organizations that can inappropriately influence our work. There is no professional or other personal interest of any nature or kind in any product, service and company that could be construed as influencing the position presented in, or the review of, the manuscript entitled.

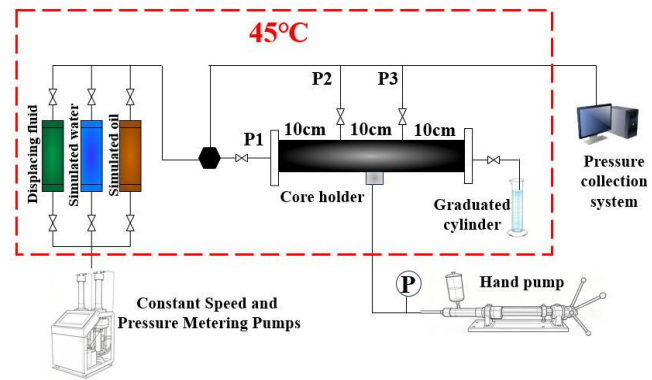


Fig. 1. Schematic of the injectivity and multipoint pressure-measurement apparatus

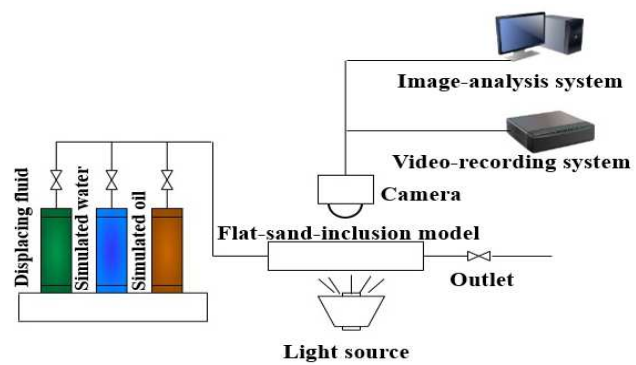


Fig. 2. Schematic of the microscopic flooding visualization platform

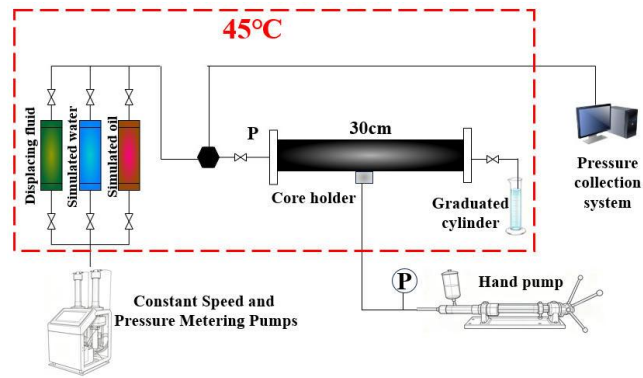


Fig. 3. Schematic of the core flooding apparatus

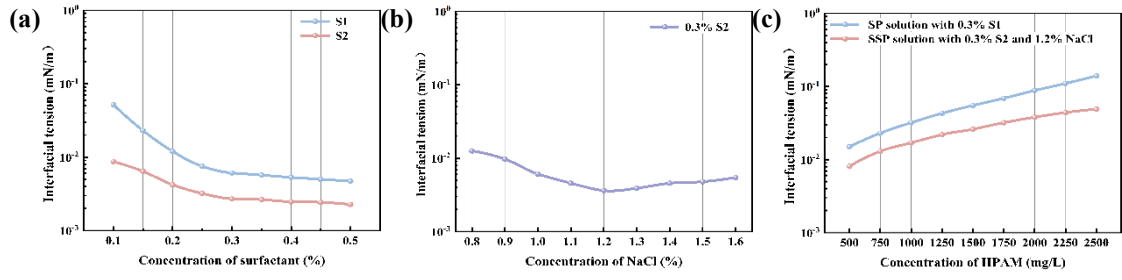


Fig. 4. Oil-water interfacial tension of the systems under different compositional conditions. (a) Oil-water interfacial tension of S1 and S2 at different concentrations; (b) effect of NaCl concentration on the oil-water interfacial tension of the system at an S2 concentration of 0.3%; (c) effect of HPAM concentration on the oil-water interfacial tension of the SP and SSP systems when the concentrations of S1 and S2 were both 0.3% and the NaCl concentration in the SSP system was 1.2%

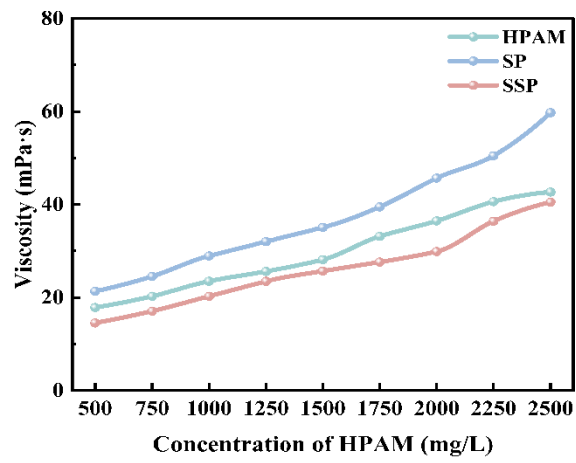


Fig. 5. Apparent viscosity of the three flooding systems at different HPAM concentrations

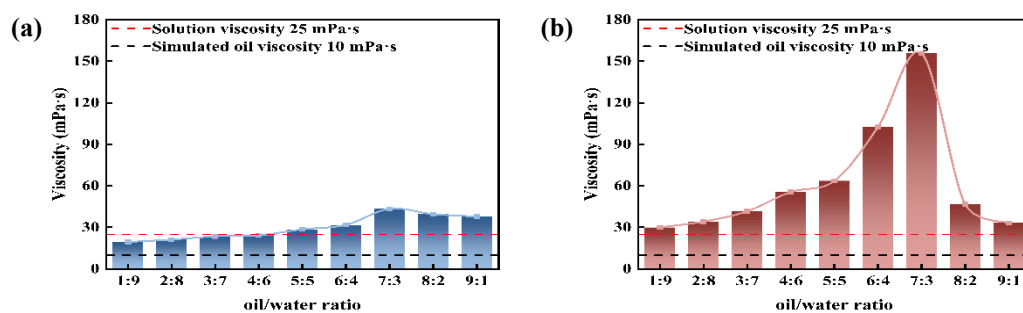


Fig. 6. Apparent emulsion viscosities of the SP and SSP systems at different oil/water ratios (a) SP system; (b) SSP system

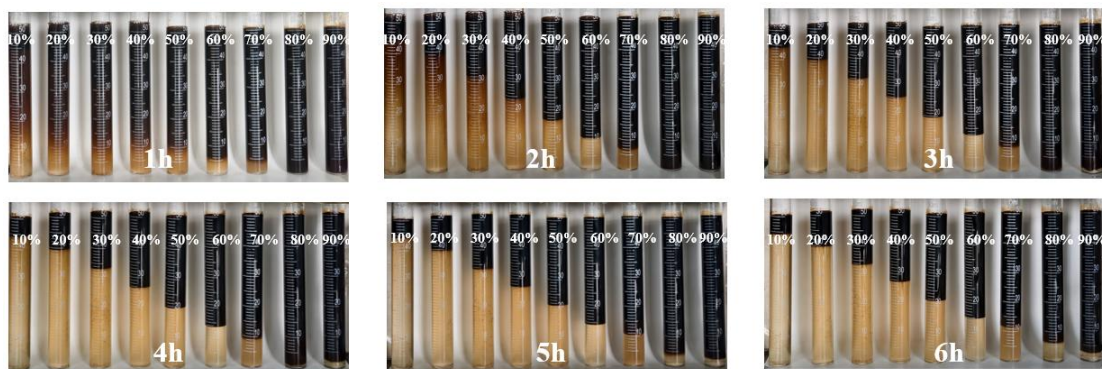


Fig. 7. Emulsion states of the SP system after standing for 1-6 h at different oil/water ratios (the numbers on the colorimetric tubes indicate the oil fraction)

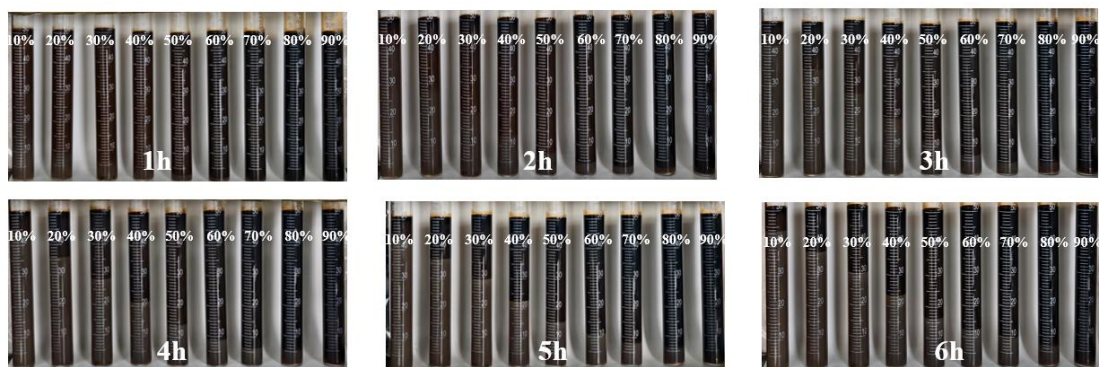


Fig. 8. Emulsion states of the SSP system after standing for 1-6 h at different oil/water ratios (the numbers on the colorimetric tubes indicate the oil fraction)

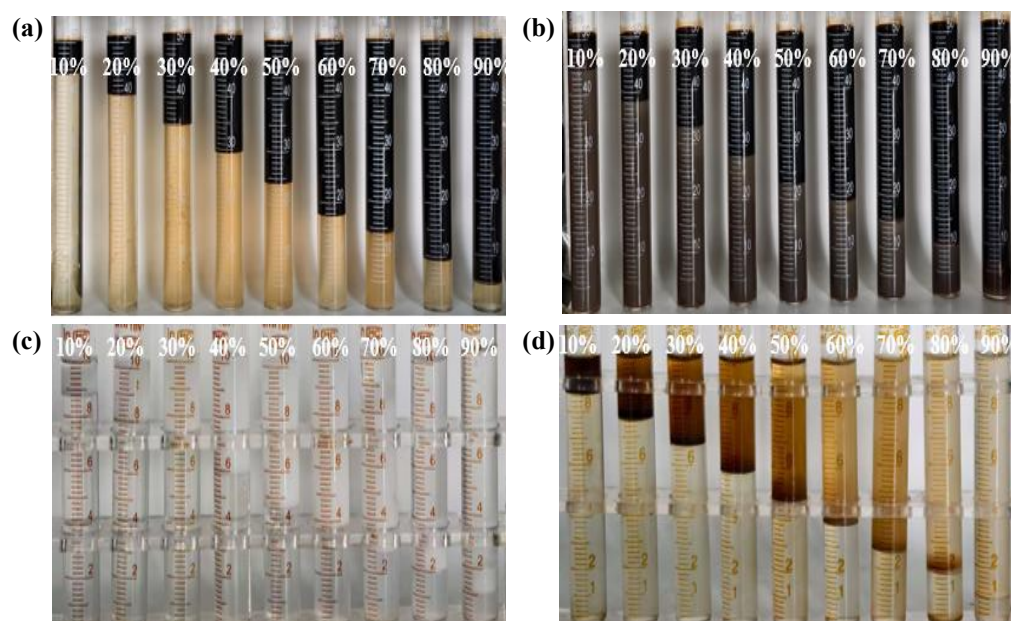


Fig. 9. Emulsion states after standing for 24 h under different oil-phase conditions. (a) SP system with simulated oil; (b) SSP system with simulated oil; (c) SP system with kerosene; (d) SSP system with kerosene (the numbers on the colorimetric tubes indicate the oil fraction)

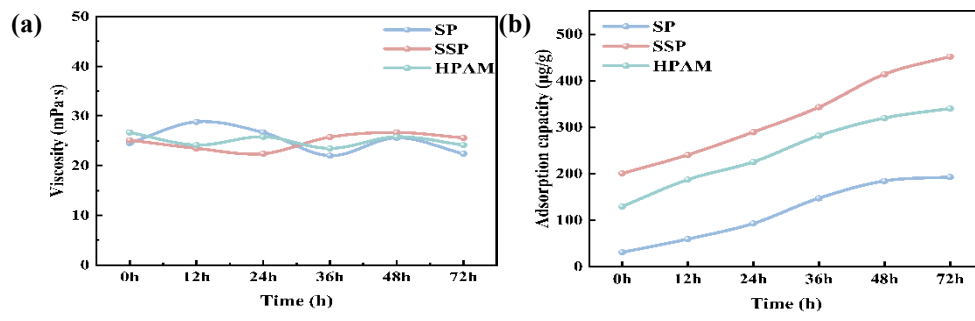


Fig. 10. Static adsorption performance of the different flooding systems. (a) Apparent viscosity of the different systems after adsorption treatment; (b) static adsorption amount of the different systems

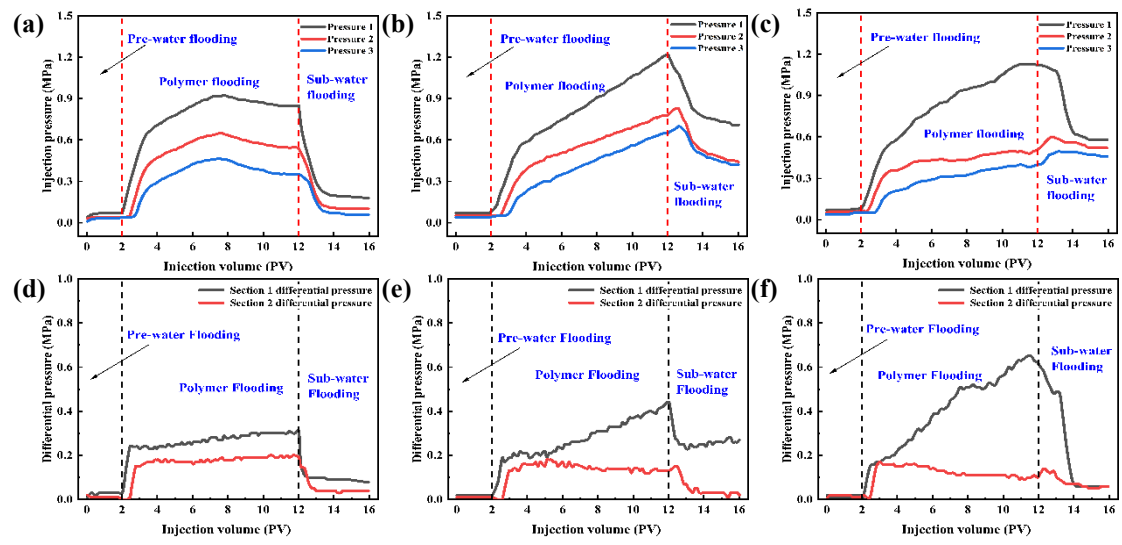


Fig. 11. Injection-pressure and sectional pressure-drop curves of different flooding systems in 50 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

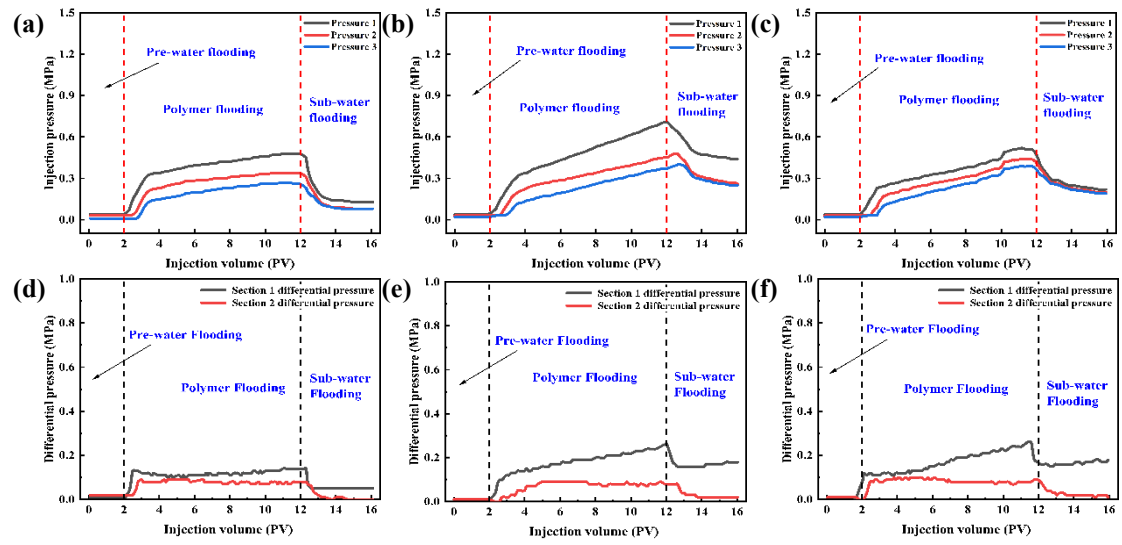


Fig. 12. Injection-pressure and sectional pressure-drop curves of different flooding systems in 100 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

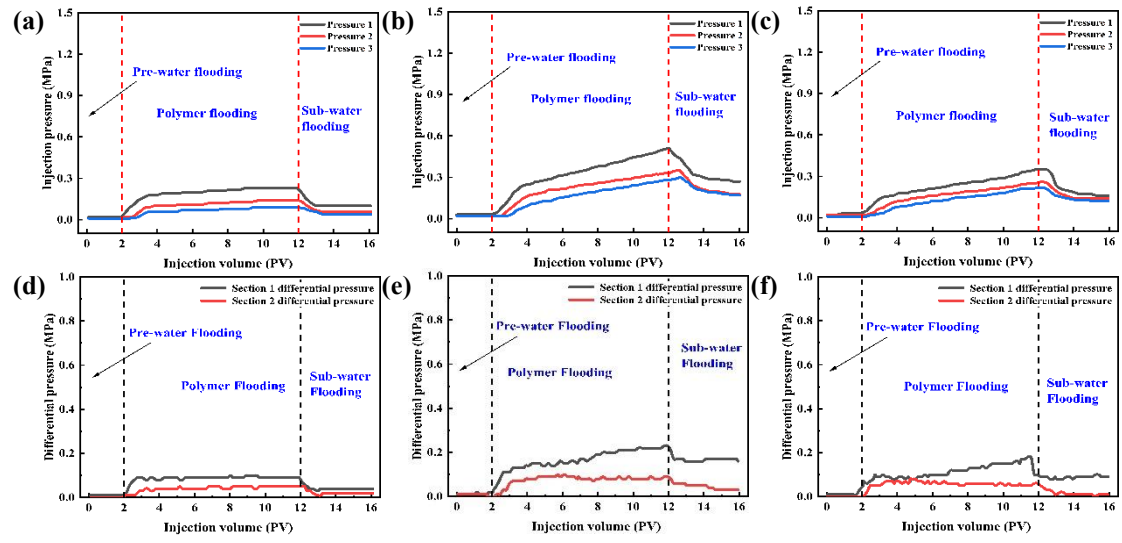


Fig. 13. Injection-pressure and sectional pressure-drop curves of different flooding systems in 150 mD cores. (a) HPAM injection pressure; (b) SP-system injection pressure; (c) SSP-system injection pressure; (d) HPAM sectional pressure drop; (e) SP-system sectional pressure drop; (f) SSP-system sectional pressure drop

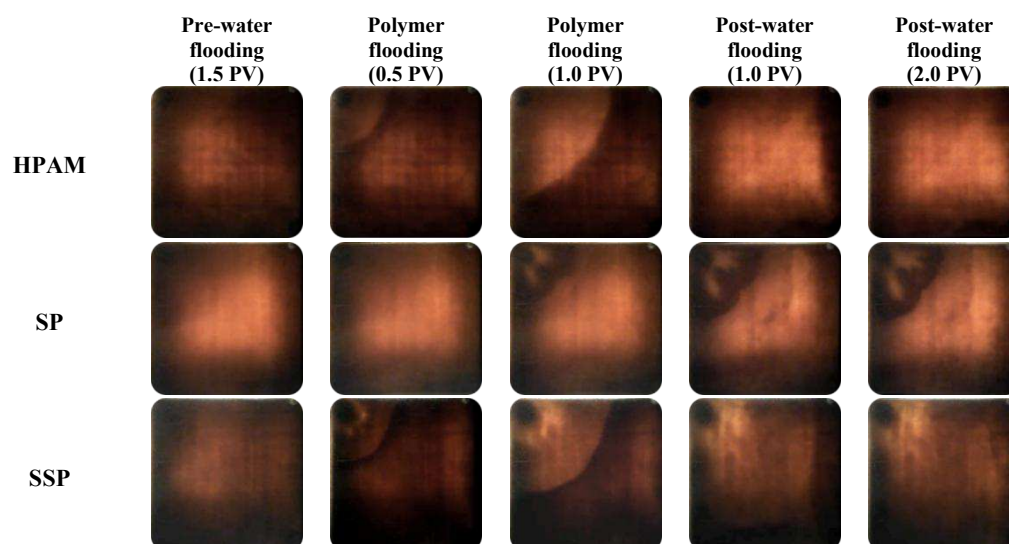


Fig. 14. Microscopic visualization experiments of the three systems in a 100 mD model at an injection rate of $0.05 \text{ mL} \cdot \text{min}^{-1}$

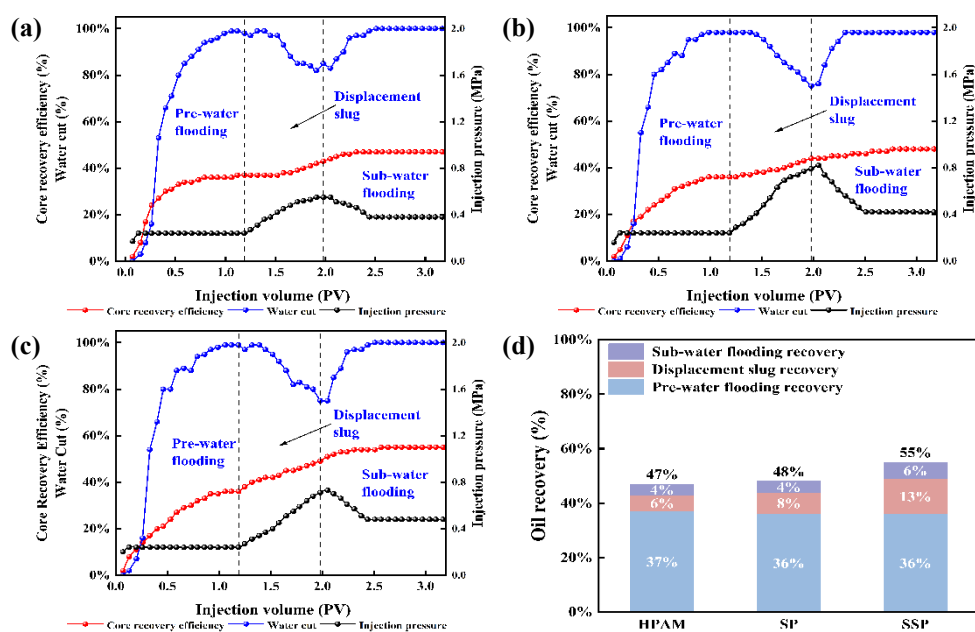


Fig. 15. Flooding results of different flooding systems in 100 mD Berea cores. (a) HPAM system; (b) SP system; (c) SSP system; (d) recovery factor

Table 1. Ionic composition of the experimental wate

Ionic composition	CO ₃ ²⁻	HCO ₃ ⁻	Cl ⁻	Ca ²⁺	Mg ²⁺	SO ₄ ²⁻	Na ⁺	Total salinity
Concentration (mg·L ⁻¹)	294.1	3065.7	1188.7	55.4	20.8	73.9	2084.6	6783.17

Table 2. Core parameters for the injectivity experiments

Core number	Diameter (mm)	Height (mm)	Length (mm)	Permeability (mD)	Porosity (%)
1#	21.6	45.1	45.2	302.4	49
2#	20.5	45.1	45.0	299.7	49
3#	21.6	44.8	45.1	301.6	53
4#	21.3	45.3	45.2	300.5	105
5#	19.7	45.1	45.2	301.3	104
6#	19.9	45.2	45.1	300.4	105
7#	21.5	45.1	45.3	299.8	153
8#	22.9	45.3	45.1	300.7	148
9#	19.4	45.1	45.2	301.3	147

Table 3. Core parameters for the flooding experiments

Core number	Diameter (mm)	Height (mm)	Length (mm)	Permeability (mD)	Porosity (%)
10#	45.1	45.2	302.4	103	21.3
11#	45.1	45.0	299.7	98	21.5
12#	44.8	45.1	301.6	104	21.5

Table 4. Formulations of the three experimental systems at a target viscosity of 25 mPa·s

Flooding system	Flooding-system formulation	Interfacial tension (mN·m ⁻¹)
HPAM	1200 ppm HPAM	/
SP	0.3% S1+750 ppm HPAM	1.6×10 ⁻¹
SSP	0.3% S2+1500 ppm HPAM+1.2% NaCl	5×10 ⁻²

Table 5. Formulations of the flooding systems

Flooding system	Primary slug (0.35 PV)	Secondary slug (0.25 PV)	Polymer slug (0.2 PV)
HPAM	1200 ppm HPAM	1200 ppm HPAM	1200 ppm HPAM
SP	0.3% S1+750 ppm HPAM	0.2% S1+900 ppm HPAM	1200 ppm HPAM
SSP	0.3% S2+1500 ppm HPAM+1.2% NaCl	0.2% S2+1350 ppm HPAM+1% NaCl	1200 ppm HPAM