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Article

N_2 Foam Flooding Combined with Gel Plugging for Enhanced Oil Recovery in High-Temperature Reservoirs: Laboratory Experiments and Numerical Simulations

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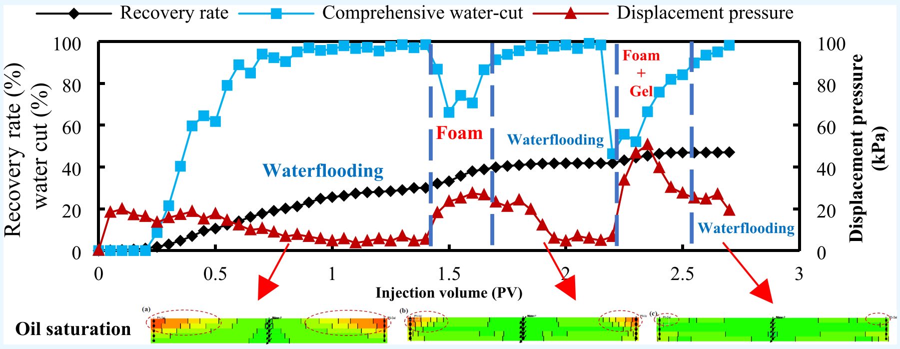

ABSTRACT: The high-temperature reservoir (105 °C) in the Liubei block of Jidong Oilfield, with severe longitudinal heterogeneity, has entered a high water-cut stage. After a preliminary profile control, the water management of the oilfield still faces serious water channeling problems. To strengthen water management, N_2 foam flooding combined with gel plugging for enhanced oil recovery was studied. In this work, considering a high-temperature reservoir of 105 °C, a composite foam system and starch graft gel system with high temperature resistance were screened out, and displacement experiments in one-dimensional heterogeneous cores were carried out. Through the three-dimensional experimental model and numerical model of a 5-spot well pattern, physical experiments and numerical simulations were carried out respectively to study water control and oil increase. The experimental results showed that the foam composite system had good temperature resistance up to 140 °C and oil resistance up to 50% oil saturation and was helpful to adjust the heterogeneous profile in a high temperature of 105 °C. The starch graft gel system had good injection performance, with a solution viscosity of 18.15 mPa·s, and its gel strength could effectively seal the high-permeability layer, with a gel viscosity of 34950.92 mPa·s. The displacement test results showed that after a preliminary implementation of N_2 foam flooding, N_2 foam flooding combined with gel plugging could still improve oil recovery by 5.26%. Compared with preliminary N_2 foam flooding, gel plugging could control the water channeling in the high-permeability zone near the production wells. The combination of foam and gel made N_2 foam flooding and subsequent waterflooding divert to flow mainly along the low-permeability layer, which was conducive to enhance water management and improve oil recovery. This method can be used as an effective technology to manage similar heterogeneous reservoirs.

1. INTRODUCTION

The reservoir in the Liubei block of Jidong Oilfield is a high-temperature reservoir, with a distribution range of 93−116 °C and an average of 105 °C. The reservoir has strong vertical heterogeneity, with permeability mainly distributed in the range of 10−600 mD. The reservoir has total recoverable reserves of 322.8×10^4 t and was brought into production for 30 years since 1990. As of now, the recovery rate is 18.2%, and the comprehensive water cut of the block is about 91.5%. Some wells have reached 96% or above. In the process of water injection development, the serious vertical heterogeneity of the reservoir leads to a rapid rise of water in the oil well. After the profile control of the water injection well, the phenomenon of injected water flowing along the thief zones was still serious. There are two challenges to take water control measures in high-temperature and vertically heterogeneous reservoirs. On the one hand, most chemical systems have poor effects in high-temperature reservoirs, and high-temperature-resistant systems

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are the key factors.[1] On the other hand, how to further tap potential oil after an early-stage profile control in vertical heterogeneous formation is also an important issue. The poor pore sweep coefficient and inner-pore displacement coefficient of subsequent waterflooding result in the decrease of displacement efficiency.[2,3]

Water plugging technologies were mainly divided into chemical and physical methods, and chemical EOR has been widely used. As for high-temperature plugging agents, there were gel, foam, particle, precipitant, resin, etc.[4] Each agent had unique water control characteristics, and high-temperature-resistant foam flooding was one of the effective methods. Field applications showed that the foam system was conductive to improving the fluidity of crude oil and helping to weaken vertical heterogeneity and was recommended for the reservoirs with a high water cut.[5−7] Foam flooding had two advantages in the profile control. For one thing, compared with low-permeability conditions, foam was easier to enter high-permeability layers and selectively block larger pores and throats from the pore-scale level. When encountering crude oil, the stability of foam became worse. After foam defoaming, a foam plugging agent could reduce reservoir damage but achieve the plugging effect.[8] For another, the system of the foam agent consisted of a surfactant and a foam stabilizer. Because of the emulsification of surfactants on oil, the foam agent had the characteristics of improving oil displacement efficiency.[9−11] However, most foam systems had good performance below 90 °C, while they were greatly weakened above 90 °C.[12] At high temperatures, the stability of foam films decreased rapidly, which led to the mobility reduction and poor swept efficiency.[13−15] Anionic surfactants had better foaming performance at normal temperatures, while nonionic surfactants and amphoteric surfactants had better stability at high temperatures.[16,17] Polymer foam of anionic surfactants had better stability, and its plugging performance was stronger than the ordinary foam, but conventional HPAM polymer molecules were easily decomposed for high-temperature conditions of higher than 90 °C.[18,19] A new fluorocarbon surfactant−polymer system was proposed, maintaining good thermal stability at 100 °C.[20] In recent years, the two different kinds of surfactants were often compounded, and the mixed system had a good temperature resistance and foaming effect.[21] The mixed system often had synergistic effects, which led to changes in dynamic absorption, reduction of the critical micelle, and reduction of the critical micelle concentration.[22] This gave scholars an inspiration to use two different types of surfactants for compounding in high-temperature reservoirs.

When it came to plugging water channeling in high-temperature reservoirs, polymer gel plugging was one of the good ways. For water management in high-temperature reservoirs, polymer gel systems were categorized into in situ cross-linked polymer gels, preformed gels, and foamed gels.[23] In terms of practical applications, in situ cross-linked polymer gels were more suitable for medium- and high-permeability formations, while preformed gels and foamed gels were more suitable for fracture and wormhole formations.[24−26] The fluidity of polymer gel solution also made it easier to enter the high-permeability layer or channel.[27] The two major challenges for the application of polymer gels at high temperatures were thermal stability and sufficient gelation time for oilfield operations. Polymer gels were formed by polymerization of monomer molecules by the cross-linking agent under the action of the initiator.[28,29] On the one hand, by changing the amount of the cross-linking agent and initiator, the strength and gelation time could be improved. On the other hand, the polymer monomer could affect the thermal stability of the gel at high temperatures. In recent years, many natural macromolecules had been used, such as starch, lignin, and so forth. Among them, the starch graft gel system not only had good injectivity but also had good thermal stability to meet the continuous plugging.[30−32] Modified starch graft gel had been widely used for water plugging in high-temperature reservoirs with a range of 60−120 °C.[33]

In view of the problem of water control in high-temperature reservoirs, foam flooding and polymer gel plugging were often used in oilfields. However, the current research on water control in high-temperature reservoirs mainly focused on the development and screening of high-temperature-resistant chemicals, ignoring the exploration of enhanced water control in combination with the reservoir and development situation.[34] In the normal-temperature reservoir, the gel−ASP system was proposed a combined technology, while the ASP was not viscous enough to control channeling.[35] Profile control through the foam system alone was not enough to effectively control the water channel. The gel and foam system for blocking wormholes in oil reservoirs was developed, while the system was not widely used in oilfields.[36] However, the study of enhanced gel−foam or gel−ASP water control technology mainly focused on the enhanced profile control of the injection well in low-temperature reservoirs of no higher than 90 °C.[37,38] In actual water management in high-temperature reservoirs, reservoir temperature, water channels near production wells, and impact of profile control in the early stage also need to be considered.

In this study, starch graft gel and foam composite systems with high temperature (105 °C) resistance were screened out and evaluated. The plugging performance and profile improvement performance were respectively evaluated through a one-dimensional (1D) artificial core. To figure out the feasibility of N_2 foam flooding combined with gel plugging for EOR, three-dimensional (3D) physical and numerical longitudinal heterogeneous models of the 5-spot injection−production unit were respectively established according to the high-temperature reservoir. Based on the displacement experiment, the recovery factor and rule were compared before and after. The characteristics of the remaining oil distribution were analyzed, and the synergistic mechanism for enhanced oil recovery was further clarified.

2. EXPERIMENTS

2.1. Materials. The experimental temperature was set as 105 °C according to the conditions of the reservoir. The oil used in the experiment was taken from the oilfield, and the viscosity was 1.73 mPa·s (105 °C). The experimental water was prepared according to the water analysis data of the reservoir, and the salinity and ion content are shown in Table 1.

At high-temperature conditions, the starch graft gel system and foam composite system were selected as water plugging agents. The starch graft gel system consisted of modified starch, acrylamide, a cross-linking agent, and an initiator. The cross-

Table 1. Salinity and Ion Content of the Simulated Formation Water

	ion concentration (mg/L)					
total salinity (mg/L)	$K^+ + Na^+$	Ca^{2+}	Mg^{2+}	Cl^-	SO_4^{2-}	HCO_3^-
1572	485.2	8.2	2.5	345.1	4.9	726.1

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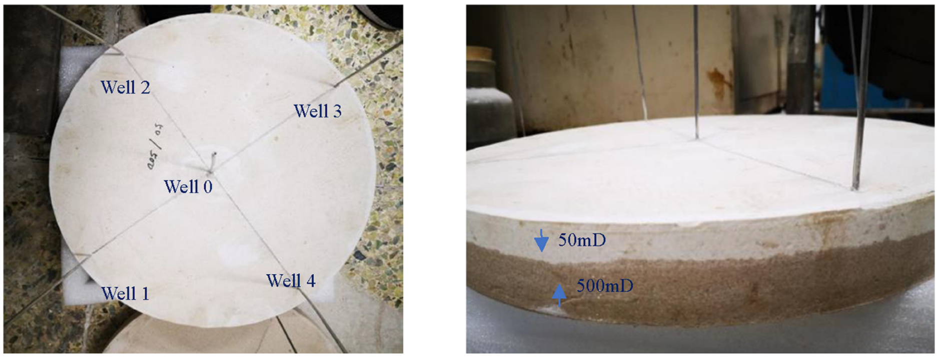

Figure 1. Physical image of the 3D heterogeneous model.

Table 2. Basic Parameters of the 3D Physical Model

gas permeability (mD)	permeability ratio	apparent volume (mL)	pore volume (mL)	porosity (%)	saturated oil volume (mL)	oil saturation (%)
500/50	10	4505	810	17.98	527	65.06

linking agent was *N*,*N*′-methylene-bis-acrylamide, and the initiator agent was potassium persulfate. The foam composite system consisted of a fluorocarbon surfactant and a hydrocarbon surfactant. The purity of nitrogen was 99.98%. The dodecyl dimethyl hydroxypropyl sulfobetaine (DDHS, Wanshan New Material Technology Co., Ltd., Henan, China) and sodium dodecyl sulfate (SDS, Aladdin Biochemical Technology Co., Ltd., Shanghai, China) were used as foaming agents.

2.2. Experimental Model Design and Fabrication. *2.2.1. 3D Longitudinal Heterogeneous Physical Model with the 5-Spot Injection−Production Unit.* The 3D physical model was designed and fabricated according to the geological characteristics of the reservoir in Jidong Oilfield. The model was an artificial core with a permeability of 50 mD in the upper layer and 500 mD in the lower layer. The size of the 3D core model had a diameter of 40 cm and a thickness of 4.5 cm. The well pattern of the experimental model adopted a 5-spot injection−production well pattern. Well 0 was the central water injection well around 4 production wells, and the 3D physical model is shown in Figure 1. The basic physical parameters of the model are shown in Table 2.

2.2.2. 3D Longitudinal Heterogeneous Numerical Model with the 5-Spot Injection−Production Unit. The model is established by CMG numerical simulation software. As shown in Figure 2, the diameter of the model is 40 cm. A total of 5 simulation layers are divided longitudinally, the thickness of the single layer is 0.9 cm, and the thickness of the model is 4.5 cm. The permeability of the 1−3 simulated layers of the heterogeneous model is 50 mD, and for the 4−5 simulated layers, it is 500 mD. The porosity of the model is 20%, and the original oil saturation is 65%.

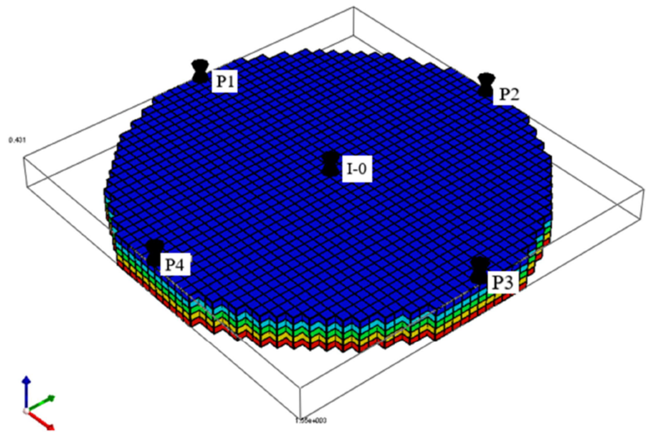

Figure 2. Equivalent numerical model of the 5-spot injection−production unit.

2.3. Experimental Methods and Procedures. *2.3.1. Static Evaluation Experiment of Foam and Gel.* The Waring blender method was used to carry out the experiment of the foam system formula. The stability and foaming ability of the system were evaluated by measuring the half-life, which meant the length of time that the volume of foam decreased and 100 mL of liquid was released, and foaming volume of the foam system. To determine the optimal ratio of SDS and DDHS, the experiment ratio of SDS/DDHS was set as 0:5, 1:4, 2:3, 3:2, 4:1, and 5:0. The total concentration of the surfactant was controlled at 0.6 wt·%. After the solution was prepared and stirred for 90 s, the foam was placed in a thermostat at 105 °C to observe its half-life, which is the length of time that the volume of liquid was released to 100 mL.

In the temperature resistance experiment, the stability of the determined foam system at different temperatures was mainly observed. To evaluate the temperature resistance of the DDHS + SDS system, the experiments of SDS and DDHS were also carried out. The volume of foam solution prepared each time was still 200 mL, and the stirred time was kept at 90 s. The temperature of the thermostat was respectively set to 60, 80, 100, 120, 140, and 160 °C. The half-life was observed at each temperature.

In the oil resistance test, the foaming volume and half-life of foam were determined to evaluate the oil resistance. Under the condition that the total volume of 200 mL of solution remained unchanged, six groups of control experiments of adding 20, 40, 60, 80, 100, and 120 mL of crude oil were set. The prepared solution was stirred for 90 s, and the foam was placed in a constant-temperature oven at 105 °C. The recorded half-life was used to mainly evaluate the oil resistance of the foam system.

In the experiment of gel formula screening, the gelation time and gel strength were used to optimize the gel system formulation. The gel strength was statutorily evaluated by the gel strength code.[34] The dosage of modified starch and acrylamide was 1:1, and the previous research showed that a total dosage of 8 wt·% was enough.[31] For the optimization

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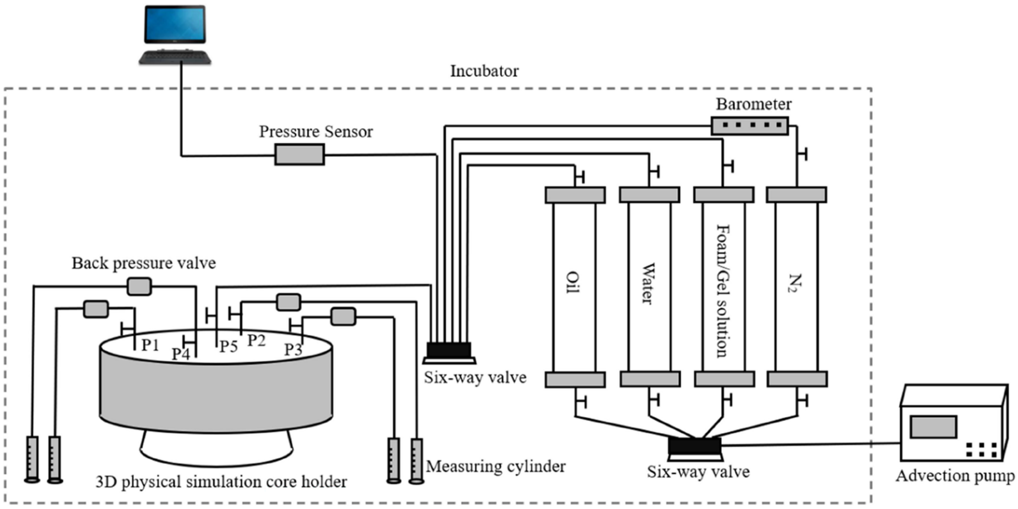

Figure 3. Schematic of the 3D experimental setup.

experiment of gel strength, the dosage of the cross-linking agent was respectively set as 0.01, 0.02, 0.03, 0.04, and 0.05 wt %. For the optimization experiment of gelation time, the dosage of the initiator was respectively set as 0.001, 0.002, 0.003, 0.004, and 0.005 wt %. To fully dissolve the solute, the solution was fully stirred for 10 min during preparation. Then, the prepared solution was poured into a glass bottle and the bottle was placed in a thermostat at 105 °C. The viscosity of solution and gel was measured by an Antonpa rheometer.

2.3.2. 1D Experiments of N_2 Foam Flooding and Gel Plugging. In the profile control experiment of N_2 foam flooding, 50−500 mD double-layer heterogeneous cores were made, and the size of the model was 30 cm × 4.5 cm × 4.5 cm. The experiment was carried out in the form of combined injection and separate production. After injection of 1.00 PV water, N_2 foam with a gas−liquid ratio of 1:1 was injected at a rate of 0.5 mL/min. The alternate injection volume of gas and liquid each time was 0.05 PV, and the total volume was 0.30 PV. Subsequently, water was injected again to carry out waterflooding. During the experiment, the liquid output of the high-permeability zone and the low-permeability zone could be recorded as L_h and L_l simultaneously. Then, the diversion rates D_h and D_l of the high-permeability zone and the low-permeability zone could be calculated using the liquid output L_h and L_l, respectively, as shown in eqs 1 and 2. The profile control effect of N_2 foam flooding could be monitored by recording the change of the diversion rate as follows:

$$D_h = \frac{L_h}{L_h + L_l} \tag{1}$$

$$D_h = \frac{L_h}{L_h + L_l} \tag{2}$$

where L_h is the liquid output of the high-permeability zone (mL), L_l is the liquid output of the low-permeability zone (mL), D_h is the diversion rate of the high-permeability zone (%), and D_l is the diversion rate of the low-permeability zone (%).

In the gel plugging experiment, artificial cores of 50 and 500 mD were made, and the size of the model was 30 cm × 4.5 cm × 4.5 cm. Gel solution (0.05 PV) was injected at a rate of 0.5 mL/min after 0.50 PV of waterflooding. Then, after 24 h of gelation, subsequent waterflooding was carried out. During the experimental process, the primary waterflooding permeability (K_{wp}) and the stable waterflooding permeability after gel plugging (K_{wg}) could be obtained. Then, the plugging rate (PR) could be calculated using K_{wp} and K_{wg}, as shown in eq 3. By calculating the PR, we could understand the effect of gel plugging:

$$PR = \frac{K_{wg} - K_{wp}}{K_{wg}} \times 100\% \tag{3}$$

where K_{wp} is the primary waterflooding permeability (mD), K_{wg} is the stable waterflooding permeability after gel plugging, and PR is the plugging rate (%).

2.3.3. 3D Physical Experiments of N_2 Foam Flooding Combined with Gel Plugging. First, the 3D heterogeneous models were ground smooth using sand paper and resin was applied to the core surface, leaving it for 3 h. Then, the 3D heterogeneous models were put into a 3D core holder. Second, the experiment devices were connected, as shown in Figure 3. The cores were vacuumed and experimental water was saturated into cores, with calculation of the pore volume. Then, oil was injected into cores to simulate the reservoir environment. Finally, the displacement experiment was carried out and the effect of N_2 foam flooding combined with gel plugging was analyzed, compared with N_2 foam flooding.

The detailed plan of the displacement experiment is as follows:

(1) Waterflooding: The outlet back pressure of 4 oil production wells was set to 15 MPa. At the waterflooding stage, water was injected from the center well at a flow rate of 0.5 mL/min to displace crude oil. When the model's comprehensive water cut reached 98%, 5 wells were closed. The recovery factor of 4 wells was calculated.

(2) N_2 foam flooding in the early stage: To simulate the profile control of N_2 foam flooding, foam with a gas−liquid ratio of 1:1 was injected from the center well into the 3D heterogeneous model at a rate of 0.5 mL/min. The injection volume was kept at 0.05 PV each time, and the total injection volume of foam was 0.30 PV. Then, subsequent waterflooding was carried out. When the comprehensive water cut of 4 wells reached 98% and remained stable, 5 wells were closed.

(3) N_2 foam flooding combined with gel plugging at a high water-cut stage for EOR: To simulate N_2 foam flooding

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combined with gel plugging, two measures were carried out respectively after (2). At first, modified starch graft gel was injected into 4 simulated oil wells and the injection volume of the single well was 5 mL, with a total of 20 mL for 4 wells. After injection, 4 wells were shut down to gelation for 24 h. Second, foam with a gas−liquid ratio of 1:1 was injected from the center well for profile control at a rate of 0.5 mL/min. The injection volume was also 0.30 PV. Finally, subsequent waterflooding was carried out. When the water cut of the model reached 98%, 4 wells were shut down. The enhanced recovery factor of the single well and the overall model was calculated.

2.3.4. 3D Numerical Simulations of N_2 Foam Flooding Combined with Gel Plugging. Based on the physical displacement experiment of 3D heterogeneous models, the specific experimental steps of numerical inversion are as follows:

(1) Waterflooding: The simulated temperature was set to 105 °C and the simulated pressure was set to 15 MPa. Water was injected from well I-0 at a rate of 0.5 mL/min. The P1, P2, P3, and P4 well was under constant back pressure at 15 MPa. When the comprehensive water cut of 4 wells reached 98%, the wells were shut down.

(2) N_2 foam flooding in the early stage: To simulate the profile control of N_2 foam flooding, foam with a gas−liquid ratio of 1:1 was injected from well I-0 at a rate of 0.5 mL/min. The P1, P2, P3, and P4 well was under constant back pressure at 15 MPa. When the foam injection volume reached 0.30 PV, foam injection was stopped. Then, waterflooding was carried out. When the comprehensive water cut of 4 wells reached 98%, the experiment ended.

(3) N_2 foam flooding combined with gel plugging at a high water-cut stage for EOR: The step of (3) was implemented after (2). To simulate gel plugging, 5 mL of gel solution was respectively injected into P1, P2, P3, and P4, and 4 wells were closed for 24 h after injection. Then, for stimulating profile control, 0.3 PV foam with a gas−liquid ratio of 1:1 was injected from I-0 well at a rate of 0.5 mL/min. At last, subsequent waterflooding was carried out, until the comprehensive water cut reached 98%.

3. RESULTS AND DISCUSSION

3.1. Static Evaluation of Foam and Gel. *3.1.1. Static Evaluation of the Foam Composite System.* The foam composite system was composed of SDS and DDHS. SDS was an anionic surfactant with good foaming performance at temperatures below 80 °C, simultaneously with an economic cost advantage.[39] DDHS was classified as an amphoteric surfactant, with good temperature resistance.[40] The screening experiment of the foam composite system was carried out at 105 °C, and the foaming volume and half-life were mainly evaluated. As shown in Figure 4, as the content of SDS increased, the foaming volume of the system gradually increased from 812 to 1180 mL, which indicated that the foaming ability was gradually improved. Simultaneously, at 105 °C, when the proportion of DDHS increased, the half-life of the foam system gradually extended from 182 to 697 s. When the ratio of SDS/DDHS was less than 2/3, the half-life of foam had better thermal stability. It indicated that with the introduction of DDHS, the surface tension of the mixed liquid gradually decreased, resulting in the gradually enhanced thermal stability of the foam system. Two

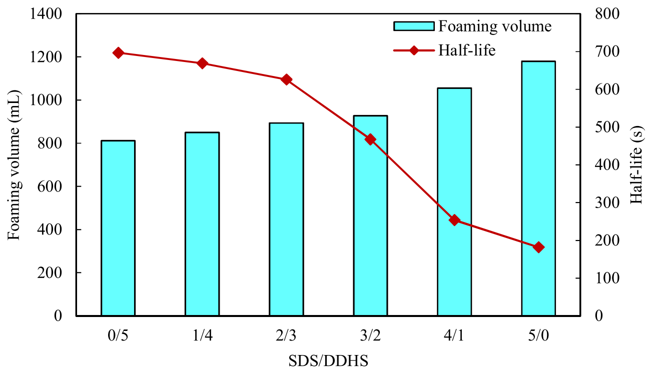

Figure 4. Screening test results of the foam composite system (at 105 °C).

different types of surfactants could be compounded to make their performance complementary under certain conditions.[22,40] When the content of DDHS was further increased, the thermal stability of foam was slightly enhanced. Considering the importance of thermal stability in N_2 foam flooding, a 2/3 ratio of SDS/DDHS was relatively enough.

The foam composite system was a combination of DDHS and SDS. To compare the performance of the foam composite system, the experimental results of DDHS + SDS, SDS, and DDHS are shown in Figure 5. The combination of DDHS and

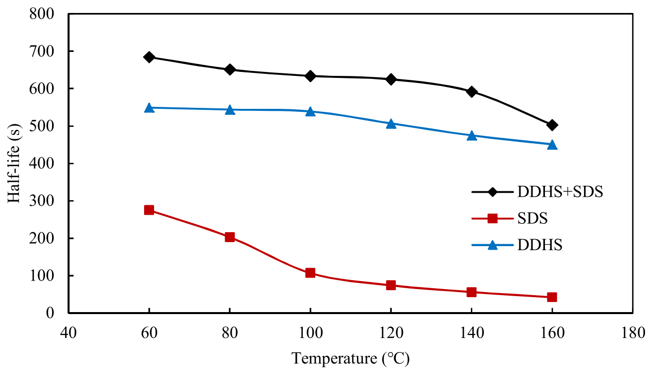

Figure 5. Half-life time results of the foam composite system at different temperatures.

SDS had an obvious synergistic effect.[22] The foam composite system integrated the temperature resistance characteristics of SDS and DDHS, and the half-life of the composite system was longer than both. As shown in Figure 6, the half-life of the foam composite system decreased slowly with the increase of temperature. When the temperature was higher than 140 °C, the decline rate increased obviously and the decay of foam accelerated. As the temperature raised, the molecular motion was strengthened, resulting in an increased adsorption of the surfactant molecule. In the process of temperature rise, the elasticity and strength of the foam film gradually weakened, which led to a faster gas−liquid exchange rate and an increased pressure difference between bubbles.[41−43] The balance between the formation and disappearance of foam was gradually broken, and the thermal stability of foam decreased. It was concluded that the SDS/DDHS mixed system with a 2/3 ratio had good temperature resistance and could maintain good stability in the range of temperatures less than 140 °C.

The experimental results of oil resistance are shown in Figure 7. With the increase of oil saturation, the foaming ability of the

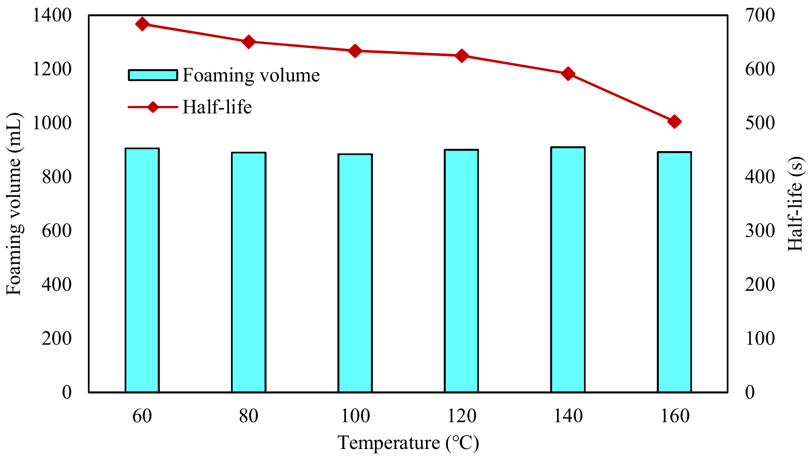

Figure 6. Foaming volume results of the foam composite system at different temperatures.

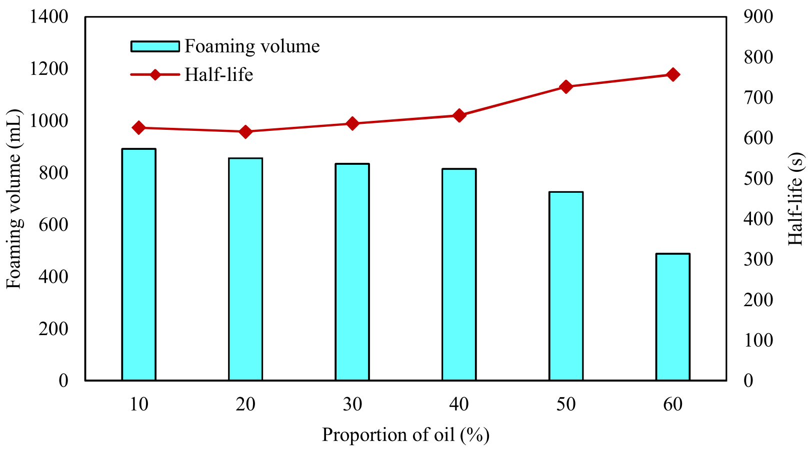

Figure 7. Oil resistance test results of the foam composite system (at 105 °C).

system decreased slowly. When the oil saturation was greater than 50%, the performance of the foam composite system became weak, and the foaming volume decreased significantly from 726 to 489 mL. The emulsification of foam on crude oil produced small oil droplets, which entered the bubble film under the action of external force and interfacial force. When the crude oil content was higher than 50%, the integrity of the bubble film was destroyed and the stability of foam was reduced. The light hydrocarbons of the crude oil could make foam properties degenerated significantly.[44] The result showed that the mixed system of SDS and DDHS with a ratio of 2/3 could maintain good oil resistance in the range of oil saturation less than 50%.

3.1.2. Static Evaluation of the Starch Graft Gel System. The application of the gel system was mainly affected by the gelation time and gel strength,[45] which were mainly affected by the amount of the cross-linking agent and initiator, and we then evaluated the dosage of two agents in the starch gel system. *N*,*N*′-Methylene-bis-acrylamide and potassium persulfate were selected respectively as the cross-linking agent and the initiator agent. The potassium persulfate could stimulate the emergence of free radicals in the starch skeletons, and the amount of free radicals would affect the polymerization reaction time of monomer molecules.[33] As shown in Table 3, when the amount of potassium persulfate was increased from 0.001 to 0.005 wt %, the gelation time of the system was reduced from 10 to 1.2 h, and there was no obvious effect on the strength of the gel. The potassium persulfate could induce the polymerization of monomer molecules, and the higher the concentration, the faster the intermolecular polymerization reaction. On the contrary, *N*,*N*′-methylene-bis-acrylamide, which was mainly used in the field of drilling fluids, was conductive to the gel strength and the thermal stability.[46] When the amount of *N*,*N*′-methylene-bis-acrylamide was increased from 0.01 to 0.05 wt %, the gel strength was increased from H to I, and there was no obvious effect on the gelation time. It indicated that the higher the concentration, the more tightly the monomer molecules were bound and the stronger the gel was. It was concluded that at 105 °C, 0.02 wt % *N*,*N*′-methylene-bis-acrylamide and 0.002 wt % potassium persulfate could make the starch graft gel system achieve better performance.

Table 3. Results of the Gel System Screening Experiment

			gelation time (h)		
no.	cross-linking agent (wt %)	initiator (wt %)	G	H	I
1	0.02	0.001		10	
2	0.02	0.002		8	
3	0.02	0.003		5.4	
4	0.02	0.004		3	
5	0.02	0.005		2	
6	0.01	0.002			7.8
7	0.03	0.002			8.1
8	0.04	0.002			8
9	0.05	0.002			7.9

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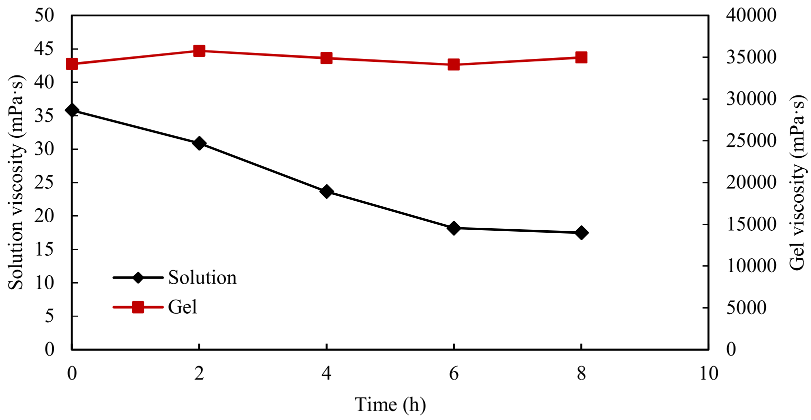

Figure 8. Viscosity solution and gel of the modified starch gel system.

The gelation time of the system under static conditions reached 8 h, not too fast, which was very conducive to the actual injection construction in the oilfield.[47] In addition, as shown in the viscosity test results in Figure 8, the viscosity of the starch graft gel solution was 18.15 mPa·s, and from the static parameters, the system was easy to inject. However, after gelation, the gel viscosity was an order of magnitude difference from that before gelation, with a maximum of 34950.92 mPa·s. It was concluded that the starch gel system solution had good injectivity, and the gel strength was high, which could be used for plugging.

3.2. Performance of Foam Flooding and Gel Plugging. There was a higher mobility in the high-permeability core, which made the injection water tend to flow mainly along the channels. In the profile control experiment, the diversion rate (D_h) of the high-permeability layer reached 98.1% before profile control. Also, in the process of foam flooding, foam first tended to flow into the layer with good mobility control. Via multiple mechanisms of snap-off, lamella division, and leave-behind, foam could be regenerated in situ and blocked the channels with a high water cut effectively and continuously, which made plenty of water divert to the low-permeability layer.[13−15,43,48] After N_2 foam flooding, the maximum diversion rate (D_l) of the low-permeability layer reached 24.06% at 105 °C, as shown in Figure 9, which is about three times that of the D_l value before foam injection. Foam selectively blocked the high-permeability layer, and the sweep area of the low-permeability layer was expanded. It was concluded that N_2 foam flooding had good profile control performance and could be used as a temporary plugging agent in water injection wells.

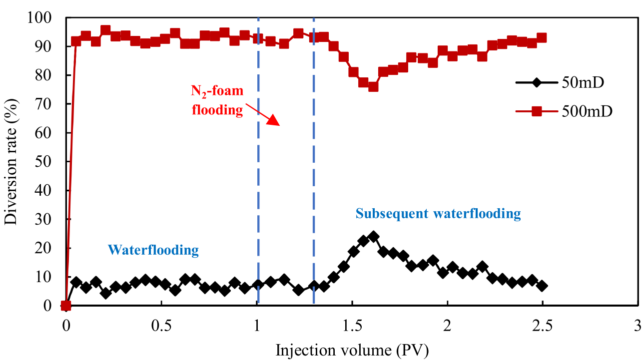

Figure 9. Profile improvement performance of the foam composite system.

The starch graft gel system is the in situ cross-linked polymer gels. The injected gelling solution could be easily pumped into target zones and penetrate into pores and throats to ensure sufficiently deep placement.[49] In the gel plugging experiment, the viscosity of modified starch graft gel solution was 18.15 mPa·s at 105 °C and it was easy to inject into the cores. After the aging period, the 3D network structures were formed in porous media and the maximum viscosity of the gel could be 34950.92 mPa·s, which could act as plugging agents.[23] The experimental results showed that the plugging rates (PR) of 50, 500, and 1000 mD cores by starch graft gel respectively reached 99.52, 99.27, and 99.08% calculated from Figure 10. The result showed that starch graft gel had strong plugging ability and could be used in production wells to block channels or high-permeability layers.

3.3. N_2 Foam Flooding Combined with Gel Plugging in the 3D Physical Core. In the 3D longitudinal heterogeneous core, the water control and enhanced oil recovery characteristics of N_2 foam flooding combined with gel plugging were studied. A comparative experiment of N_2 foam flooding was set before the combination, and the results are shown in Figure 11 and Table 4. In the process of N_2 foam flooding, the comprehensive water cut of the model decreased from 98.54% to the lowest 66.14%, and the displacement differential pressure increased from 5.36 kPa to the highest 27.42 kPa. In the process of N_2 foam flooding combined with gel plugging, the comprehensive water cut of the model decreased from 97.67% to the lowest 46.37%, and the displacement differential pressure increased from 5.35 kPa to the highest 50.64 kPa. In comparison, the water control and the sweep area on the low-permeability layer of foam combined with gel was better. Gel plugging could effectively adjust the liquid production profile of production wells, and N_2 foam flooding could improve the water injection profile of the injection well. Based on the study of micro synergy, the sweep area of the low-permeability layer was significantly enhanced with N_2 foam flooding combined with gel plugging. In the subsequent waterflooding stage, affected by the stability of foam, the profile control of N_2 foam flooding was time-dependent, and the problem of water channeling reappeared. However, due to N_2 foam flooding combined with gel plugging, the gel continued to effectively block the high-permeability layer, and the water channeling problem had been alleviated.

The model mainly considered longitudinal heterogeneity, but during core compaction, due to the uneven distribution of sand body and cement, the permeability between injection and production wells was slightly different, resulting in plane heterogeneity. This slight plane heterogeneity led to different

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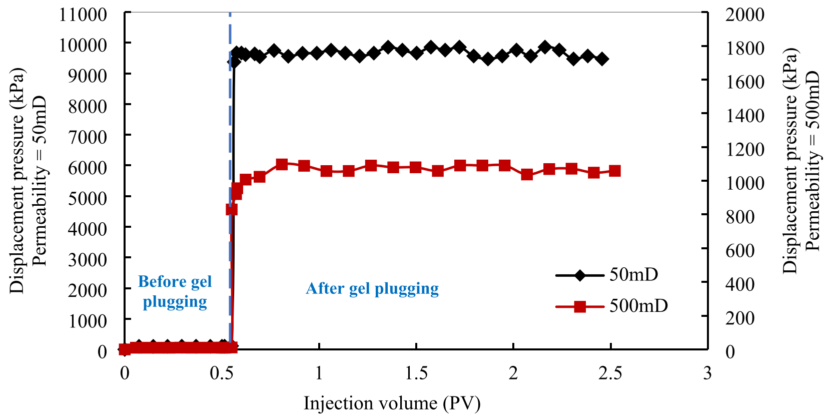

Figure 10. Experimental results of the plugging performance of the gel system.

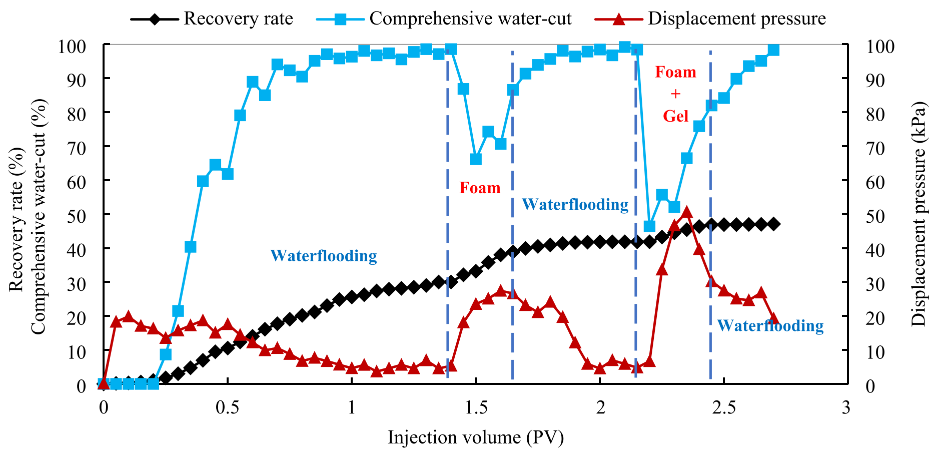

Figure 11. Relations between comprehensive water cut, displacement pressure, recovery rate, and injection volume.

Table 4. Recovery Rate Statistics of Well Groups

measures	recovery factor (%) P1	P2	P3	P4	overall recovery (%)
waterflooding	8.57	6.32	6.05	9.07	30.01
N_2 foam flooding + subsequent waterflooding	2.82	3.01	3.05	2.93	11.81
N_2 foam flooding combined with gel plugging + subsequent waterflooding	1.31	1.36	1.62	0.97	5.26
total	12.7	10.69	10.72	12.97	47.08

performances of each production well, but it could more truly reflect the production performance characteristics of the field. After waterflooding, the recovery efficiency of P1 and P4 was significantly higher than that of P2 and P3, which indicated that there was a plane difference in the degree of waterflooding. After N_2 foam flooding, the recovery rate of the model increased by 11.81% and the well recovery rate increased by 2.95% on average. The EOR of P2 and P3 was higher than that of P1 and P4, and N_2 foam flooding also weakened the influence of plane heterogeneity. After N_2 foam flooding combined with gel plugging, the recovery rate of the model increased by 5.26% and the well recovery rate increased by 1.32% on average (Table 4). After N_2 foam flooding only, more crude oil could be produced through enhanced water control with N_2 foam flooding combined with gel plugging. The method could further weaken the water channeling caused by longitudinal and plane heterogeneity and expand the sweep range of the low-permeability layer to enhance oil recovery.

3.4. Numerical Simulation Analysis of N_2 Foam Flooding Combined with Gel Plugging.

To study the synergy EOR mechanisms of N_2 foam flooding combined with gel plugging, the 3D longitudinal heterogeneous numerical model was established for numerical simulations. Compared with N_2 foam flooding, the variation characteristics of oil saturation were studied. Before starting the study, the accuracy of the numerical model was verified, and the result is shown in Table 5. In numerical simulations, the EOR of N_2 foam flooding was 10.76%, 1.05% lower than the physical experiment, and the EOR of N_2 foam flooding combined with gel plugging was 5.9%, 0.64% higher than the experimental model. The result of numerical simulation was similar to the result of the 3D physical

Table 5. Comparison of Fitting Results of the Longitudinal Heterogeneity Model

recovery factor (%)	physical	numerical
waterflooding	30.01	31.58
N_2 foam flooding + subsequent waterflooding	11.81	10.76
N_2 foam flooding combined with gel plugging + subsequent waterflooding	5.26	5.9
cumulative recovery factor	47.08	48.24

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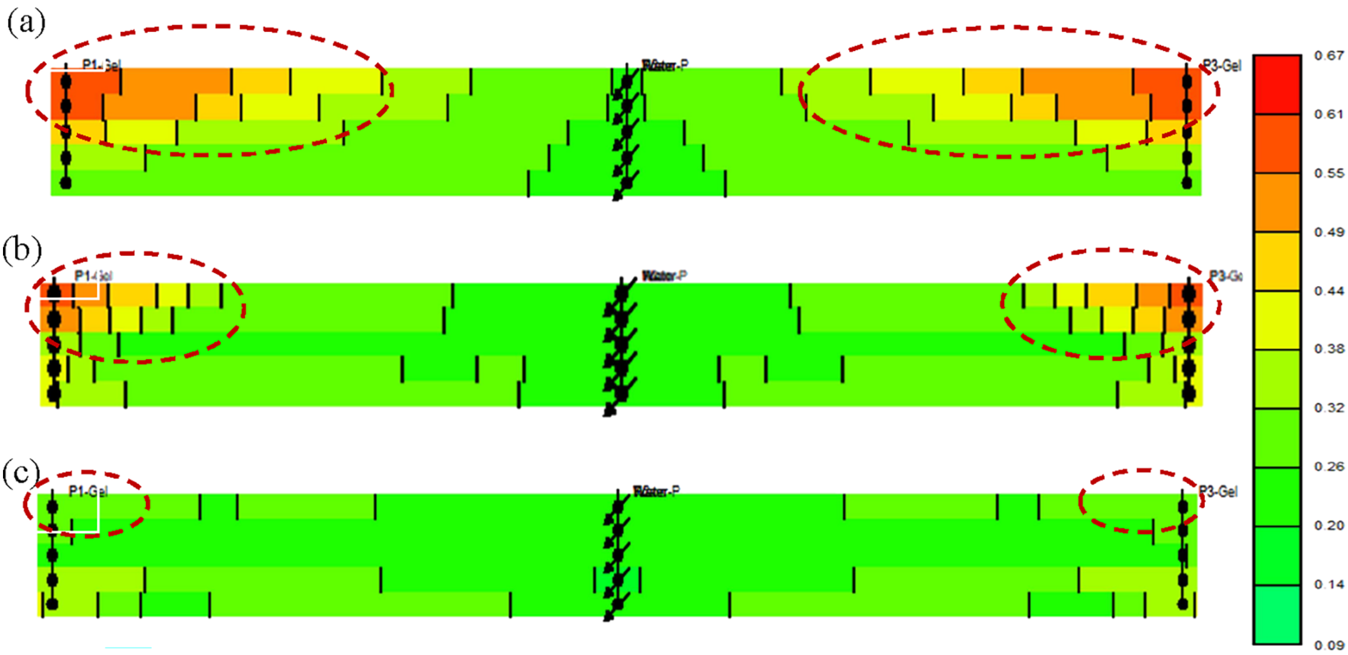

Figure 12. Comparison of longitudinal remaining oil saturation after different production enhancement measures ((a) waterflooding, (b) N_2 foam flooding, and (c) N_2 foam flooding combined with gel plugging).

experiment, and the numerical model established better fitted the physical core.

3.4.1. Variation Characteristics of Longitudinal Oil Saturation. In this study, longitudinal heterogeneity was the main contradiction in this numerical model and the high-permeability zone at the bottom was the main reason for high water content. In the process of numerical simulation, we successively simulated the effect of waterflooding, N_2 foam flooding, and N_2 foam flooding combined with gel plugging on oil displacement. As shown in Figure 12a, the oil saturation in most high-permeability zones and a few low-permeability zones had decreased from 67% to below 38% after waterflooding, while the oil saturation near the top area of the production well was especially as high as 49−61%. Affected by longitudinal heterogeneity, the vertical effective area was mainly concentrated in the low-permeability layer near the water injection well, and the sweep range of waterflooding was limited. The high conductivity of the high-permeability layer led to water channeling, and the displacement efficiency of the low-permeability layer was poor. As shown in Figure 12b, the profile with oil saturation between injection and production wells at 49−61% was further reduced after N_2 foam flooding. The foam weakened the mobility of fluid in high-permeability layers. Under the profile control of N_2 foam flooding, the sweep range of the longitudinal low-permeability layer was expanded. In addition, N_2 foam flooding also improved the oil displacement efficiency of the high-permeability zone, and the oil saturation in about 1/2 of the area had decreased from 38% to below 26%.

At the stage of N_2 foam flooding combined with gel plugging, the displacement efficiency of N_2 foam flooding was better in the low-permeability layer and the fluids mainly flowed through the low-permeability layer. From the longitudinal section, the oil saturation in the low-permeability layer was reduced to less than 26%, and the gel plugging enlarged the profile control efficiency of N_2 foam flooding (Figure 12c). At the stage of subsequent waterflooding, the gel plugging had restrained the channeling in the high-permeability layer, which was conducive to tapping the potential oil at the top of the production well in the low-permeability layer. Compared with N_2 foam flooding before, gel plugging obviously weakened the mobility control of high-permeability parts near production wells, which was worse than the upper low-permeability layer. The fluids tended to flow back to the upper low-permeability layer to achieve the purpose of displacing more crude oil. The combination of two water control measures had attained to enhancing water management, which was better than the effect of only implementing foam flooding. In general, N_2 foam flooding combined with gel plugging could weaken water channeling near production wells, improve the efficiency of profile control, and then expand the displacement range vertically.

3.4.2. Variation Characteristics of Planar Oil Saturation. In the interior of the zones, there were also planar sweep differences due to the influence of fingering. After waterflooding, most of the oil in the high-permeability layer was displaced, while most of the oil in the low-permeability layer was not swept. As shown in Figure 13a,b, the oil saturation in more than 70% of the area was less than 32% and oil was mainly immovable residual oil of waterflooding. In the low-permeability layer, water mainly flowed between the water injection well and the production well, which showed the obvious characteristics of water channeling. The oil saturation between production wells decreased slightly, and the oil displacement in most areas was poor.

After N_2 foam flooding, the area where oil saturation decreased was larger in the low-permeability layer, which indicated that the displacement effect was improved under the profile control of N_2 foam flooding. The remaining oil between production wells was activated partially, and the area with oil saturation below 26% was expanded nearly three times. To some extent, N_2 foam flooding effectively weakened channeling in high-permeability layers, and some oil not affected by waterflooding in low-permeability layers was displaced (Figure 13c,d). At the same time, the oil saturation in most areas of the high-permeability layer decreased to less than 26%, which

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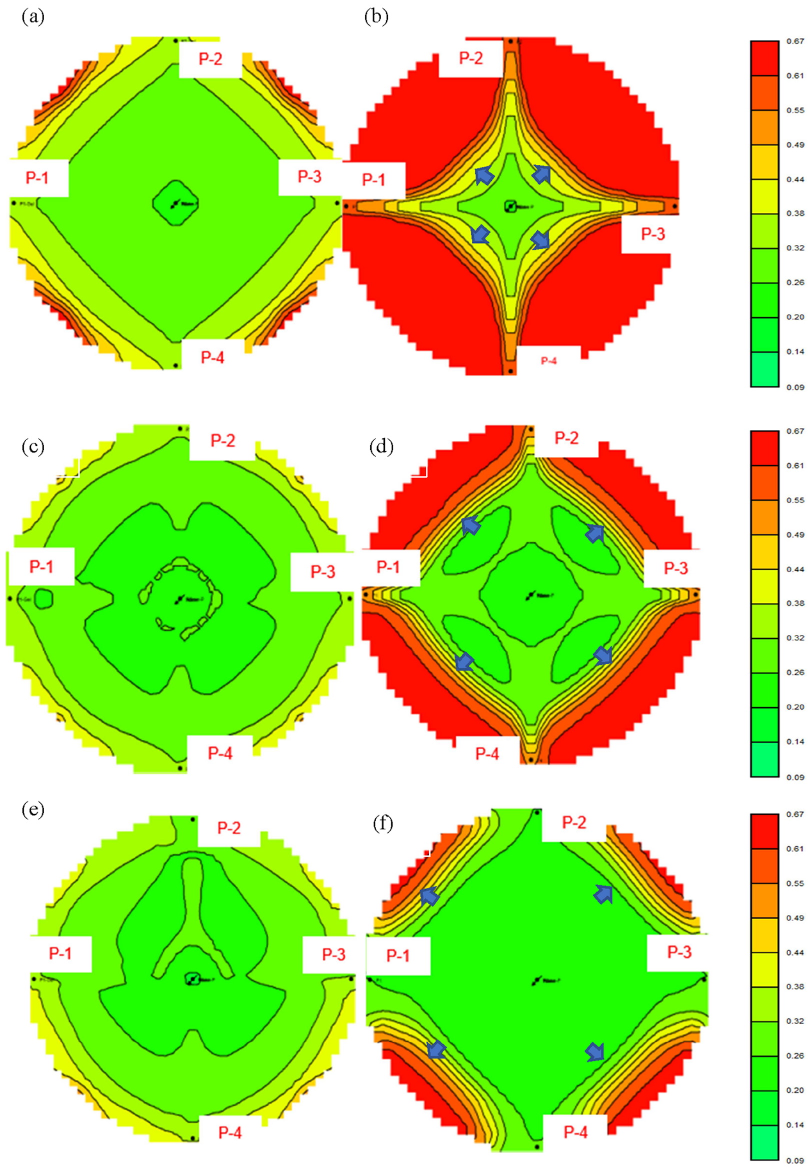

Figure 13. Plane distribution of remaining oil saturation ((a) high-permeability layer (500 mD) of waterflooding, (b) low-permeability layer (50 mD) of waterflooding, (c) high-permeability layer (500 mD) of N_2 foam flooding, (d) low-permeability layer (50 mD) of N_2 foam flooding, (e) high-permeability layer (500 mD) of foam and gel, and (f) low-permeability layer (50 mD) of foam and gel).

indicated that N_2 foam flooding also improved the displacement efficiency of oil in the high-permeability layer.

After gel plugging, the sweep range of N_2 foam flooding and subsequent waterflooding in the low-permeability layer was further expanded and the combination had a good displacement effect especially on attic oil. In the low-permeability layer, the oil saturation of large areas in the middle decreased to less than 20%, and the area of remaining oil not activated was greatly reduced (Figure 13e,f). The oil saturation between the production wells in the low-permeability layer was reduced to below 26%. N_2 foam flooding can expand the sweep range in the low-permeability layer near the injection well, and gel plugging can make the mobility of fluids in the high-permeability layer near the production well become poor. N_2 foam flooding combined with gel plugging could better delay the coning of injected water by enhanced water control and could still improve oil recovery at a deeper level after N_2 foam flooding.

4. CONCLUSIONS

After N_2 foam flooding in the early stage of high-temperature reservoirs, the difficulty of enhanced oil recovery is obviously increased. Meanwhile, the combination of N_2 foam flooding and gel plugging could be used as a choice for deeply enhanced oil recovery. The experimental results are as follows:

(1) The 2/3 ratio of SDS/DDHS can ensure the temperature resistance to 140 °C at a concentration of 0.6 wt % and maintain good performance at a 50% oil saturation. In the heterogeneous core of 50/500 mD, the foam composite system has good profile improvement efficiency.

(2) At the dosage of 0.02 wt % cross-linking agent and 0.002 wt % initiator, the gelation time of the starch graft gel system reached 8 h and the gel strength reached I at 105 °C. The PR of the starch graft gel system can reach almost 99% for cores 50 and 500 mD.

(3) In the 3D longitudinal heterogeneous core, N_2 foam flooding combined with gel plugging could improve the

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oil recovery by 5.26% after primary N_2 foam flooding. In the 5-spot injection−production unit, the recovery factor of a single well could reach 0.97−1.62%, and gel and foam can be used as an effective measure to enhance water control and oil increase.

(4) Numerical simulations showed that under the combination of N_2 foam flooding and gel plugging, more fluids divert and flow along the low-permeability layer for enhanced oil recovery, resulting in the expansion of the sweep range. After preliminary N_2 foam flooding, the combination can further reduce the oil saturation in the sweep blind zone between production wells on the plane, as well as the attic oil in the top low-permeability layer on the vertical direction, which can provide guidance for further enhanced oil recovery in similar oil reservoirs.

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Notes

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