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Research on the Oil Displacement Effect of Binary Composite System on High Water Content Heavy Oil Reservoirs

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Abstract: The development of water injection in heavy oil reservoirs often progresses to a late stage characterized by high water content. During this phase, more than 70% of the remaining oil is retained within the reservoir, making its recovery challenging. Consequently, there is an urgent need to identify suitable displacement systems to enhance recovery efficiency. This study examines a specific heavy oil field located offshore China, focusing on the effects of mobility control and low interfacial tension on the oil displacement efficacy during chemical flooding. The findings reveal that the oil displacement performance of a binary composite system surpasses that of a single system. The synergistic effects of the composite system are advantageous for extracting residual oil from low-permeability layers. Notably, the contribution of mobility control within the composite system (54.88%) is greater than that of low interfacial tension (45.12%). Only effective mobility control through the use of polymers can enhance the efficacy of surfactants. Furthermore, variations in the solution properties of composite systems can significantly influence the oil displacement outcomes. The binary composite system, which primarily employs mobility control and appropriately reduces interfacial tension, is more effective for enhancing the recovery rate of water-flooded high-permeability heavy oil reservoirs in the later stages.

Keywords: Heavy oil reservoir; Polymer flooding; Binary composite drive; Oil displacement efficiency.

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1. Introduction

Water injection development is the primary secondary recovery method employed in most oil fields in China, with the majority of water-drive reservoirs having already entered the high water cut stage [1-3]. In heavy oil reservoirs characterized by significant heterogeneity, unfavorable mobility ratios [4,5] can easily result in the injection water breaking through along high-permeability layers. This phenomenon creates preferential water flow channels and establishes an injection-production balance that adversely affects the medium and low-permeability layers. Consequently, this leads to a rapid transition of the reservoir into the high water cut stage following water injection development, leaving a substantial volume of remaining oil trapped in the medium and low-permeability layers. Continuing with water drive development is unlikely to effectively enhance the recovery rate.

To effectively enhance the crude oil recovery rate in high water cut heavy oil reservoirs, the oilfield has implemented processes such as adjusting the injection-production well network [6], optimizing production layers [7], and employing profile control and water plugging technologies [8,9] to improve the mobility ratio. However, these processes provide only a temporary solution and do not fundamentally address the adverse mobility ratio encountered during the water flooding process. In contrast, the development of chemical flooding technology [10-14] can effectively improve the mobility ratio at its core, thereby enhancing both displacement efficiency and sweep efficiency. Among these methods, polymer flooding primarily focuses on mobility control, while binary and ternary composite flooding techniques address both mobility control and interfacial tension. Different composite systems exhibit varying effects and are suited to different reservoir conditions and requirements.

Considering the feasibility of composite flooding technology and its anticipated enhancement of oil recovery, numerous petroleum engineers, both domestic and international, have conducted extensive laboratory and field experiments. Their dual objectives are to maximize the oil recovery rate and to minimize the usage of surfactants and additives in polymer/surfactant binary composite flooding, thereby increasing its economic viability. The pilot test of polymer/surfactant binary composite flooding conducted by Oryx Energy Company in the Mccleskey sand layer of Ranger Oilfield [15,16], located in Eastland County, Texas, was implemented in a water-flooded area with a well spacing of 16.2 km^2. The reservoir conditions in this block were as follows: permeability ranging from 0.2 to 0.5 μm^2, a permeability coefficient of variation between 0.7 and 0.83, and a porosity of approximately 15%. When utilizing polymer flooding, the increased oil recovery rate does not sufficiently offset the cost of polymer input. However, by adding a certain amount of surfactant that is well compatible with the polymer, the interfacial tension between oil and water can be significantly reduced. This leads to a more substantial decrease in residual oil saturation compared to polymer flooding alone. The enhanced recovery rate can reach up to 25%, yielding considerable economic benefits. Xia Huifen [17,18] and colleagues utilized self-synthesized betaine-based amphoteric surfactants to investigate the mechanism of polymer/surfactant binary composite systems on residual oil in oil reservoirs post-water flooding. They employed glass etching technology to fabricate a simulated rock micromodel, allowing them to study the effects of polymer/surfactant binary composite flooding. The research further analyzed how the solution's viscoelasticity and interfacial activity influenced the improvement of oil displacement efficiency. The experimental results demonstrate that the formation of an ultra-low interfacial tension polymer/surfactant binary composite system can simultaneously utilize the viscoelastic properties of the polymer and the surfactants' ability to reduce oil-water interfacial tension. This combination facilitates the mobilization and displacement of various types of residual oil (columnar, film, and cluster) in the micromodel of water-flooded reservoirs, occurring in the form of "oil filaments" and "emulsions." Consequently, polymer/betaine surfactants significantly enhance the oil displacement efficiency following water flooding. Cui Maolei [19] conducted laboratory displacement experiments on heterogeneous rock cores with low to medium permeability using a betaine-type surfactant binary composite system, aimed at the development of low to medium permeability reservoirs. The study analyzed the effects of the core's coefficient of variation, permeability, injection timing, and displacement fluid viscosity on the recovery rate. The experimental results revealed that the binary composite system yielded a higher recovery rate compared to both strong alkali and weak alkali ternary composite flooding methods. Wang Lili [20] addressed the challenge of poor water drive performance in Jurassic low-permeability reservoirs in Longdong, which have entered the middle to high water cut stage. Initially, she investigated the matching relationship between the polymer fluid mechanics radius and the reservoir throat radius and evaluated the adaptability of the binary system in the Longdong reservoir. The results demonstrated that the polymer/surfactant binary system exhibited excellent injectability and viscosity enhancement, capable of reducing the oil-water interfacial tension to ultra-low levels. Laboratory physical modeling experiments showed that this system increased the recovery rate by more than 15%, indicating its feasibility for application in low-permeability reservoirs.

Therefore, it is essential to optimize the binary composite displacement system by utilizing typical conditions of high-permeability heavy oil reservoirs as a reference. This optimization will clarify the contributions of performance parameters of the displacement system to the displacement of high water cut heavy oil reservoirs, ultimately providing both data and theoretical support for the design of efficient production and development plans for these reservoirs.

2. Experimental Conditions

2.1. Experimental Materials

1) **Surfactants:** (1) Cocoyl propyl dimethyl betaine (HYCAB); (2) Alkylphenol polyoxyethylene ether (OP-10); (3) Sulfate anionic surfactant (KHD959a); (4) Hydroxysulfobetaine-type amphoteric surfactant (HSB-16).

2) **Polymer Solution:** Laboratory-synthesized comb-shaped polymer solution HMPAM and branched polymer DHAP [21, 22].

Hydrophobically modified partially hydrolysed polyacrylamide (HMPAM) with a hydrophobic group content of 1.2 mol% and molecular weight of 12 million. The synthetic steps are as follows. The first step involves weighing 12 g of acrylamide (AM), 3 g of acrylic acid (AA), 0.369 g of two methyl allyl pair of sixteen alkyl benzyl ammonium chloride, 35 g of distilled water, respectively, to a beaker, stirring and dissolving evenly. Then, the pH is adjusted to 5-6 by using sodium carbonate. After heating for 45 minutes in a water bath at a temperature of 45 degrees, adding 4.8 mg initiator sodium bisulfited and 4.8 mg ammonium persulfate, and reacting for 6-10 hours, the hydrophobically modified partially hydrolysed polyacrylamide polymer could be obtained.

The DHAP has a relative molecular weight of 6 million and a hydrophobic group content of 0.6 mol%. The specific synthetic steps for this polymer can be found in Ref. 14. Synthesis steps are as follows. First, the two generations of the polyamide amine tree, including 2.619 g macromolecular skeleton monomer and 1.437 g maleic anhydride, were added to different beakers. Then, 20.16 g and 8.09 g of two methylene sulfoxide are added, and the solution is evenly stirred. Using a molar ratio of 1:8, the two methylene sulfoxide solutions of skeleton monomer are slowly dripped into the two methylene sulfoxide solutions of maleic anhydride, and the nitrogen is added via a dropping process. The system is placed into an ice salt bath. After adding the skeleton monomer solution, the solution is stirred until the temperature of the reaction liquid system no longer increases (temperature is less than 50 degrees). The functional skeleton monomer ($C_{94}H_{144}O_{36}N_{26}$) is obtained by repeated precipitation with chloroform. Then, 20 g acrylamide (AM), 5 g acrylic acid (AA), 0.025 g functionalized skeleton monomer, 0.8 g two methyl allyl -N- alkyl ammonium chloride, and 74 g distilled water are weighed. The components are placed into the beaker to stir and dissolve. Sodium hydroxide is used to adjust pH to 5-6, and the solution is incubated at 35 °C to preheat for 30 minutes. Then, 0.26 g solvent urea, 0.26 g sodium sulfate, 0.052 g chain transfer agent sodium methoxide, 4.8 mg oxidation-reduction initiator sodium bisulfite and 4.8 mg ammonium persulfate are added. The reaction proceeds for 8 hours, yielding DHAP polymer.

3) **Experimental Oil:** Degassed and dehydrated crude oil with a viscosity of 70 mPa·s at a reservoir temperature of 65 °C [23].

4) **Experimental Water:** The ion content and composition are detailed in **Table 1** [24].

Table 1. Mineralized composition of experimental water.

Inject water	component	Na^+, K^+	Ca^{2+}	Mg^{2+}	CO_3^{2-}	HCO_3^-	SO_4^{2-}	Cl^-	TDS
	mg/L	3091.96	276.17	158.68	14.21	311.48	85.29	5436.34	9374.12

5) **Equipment:** Mechanical mixer (IKA, Germany); Texas-500c full-range rotary droplet interfacial tension meter (USA); Brookfield DV-III viscometer (USA). The dimensions

of the sand filling model are φ 25×500 mm, with an average permeability of 2000 mD and a porosity of 31%.

2.2. Experimental Steps

2.2.1. Interface tension testing steps

Inject the external surfactant solution into the centrifuge tube using a syringe, followed by the careful introduction of oil droplets of appropriate size into the tube containing the surfactant solution [25]. During the insertion of the oil droplets, precautions should be taken to prevent the formation of bubbles. Finally, seal the centrifuge tube with a plug. The centrifuge tube is then placed in a Texas-500c rotating droplet interfacial tension meter for temperature rise testing. The parameters are set to a rotation speed of 6000 r/min, an oil-water density difference of 0.20 g/cm^3, and a temperature of 65 °C.

2.2.2. Viscosity testing steps

The viscosity of the solution was determined [26]. The concentrations of the prepared solutions are 20, 40, 60, 80, 1000, 1250, 1500, 1750, 2000, 2500, and 3000 mg·L^{-1}. The 0$^{\#}$ or 34$^{\#}$ rotor of the Brookfield viscometer was used to measure the viscosity at a rate of 7.34 s^{-1}.

2.2.3. Experimental steps for seepage characteristics

1) Water Permeability Measurement: Simulate the injection of water at a rate of 3 mL/min to displace a one-dimensional sand filling model. Measure the pore volume of the sand filling model and determine the stable pressure during water flooding. Calculate the permeability using Darcy's law, and employ the weighing method to ascertain the pore volume of the sand filling model and calculate its porosity.

2) Chemical Flooding: Utilize a sand filling tube with water permeability that meets the specified requirements. Replace the sand filling model with an oil displacement system solution at a rate of 1 mL/min until the displacement pressure at the measurement point stabilizes. Record the stable displacement pressure at the final measurement point and calculate the resistance coefficient (RF) [27].

3) Subsequent Water Flooding: Following the completion of polymer injection, continue to inject simulated water into the one-dimensional sand filling model at a rate of 1 mL/min until the displacement pressure stabilizes. Record the final stable displacement pressure at the inlet and calculate the residual resistance coefficient (RRF) [28].

2.2.4. Oil displacement experiment steps

1) Water Permeability Measurement: Simulate the injection of water into the sand filling model at a rate of 3 mL/min until the water drive stabilizes the pressure, and subsequently calculate its permeability.

2) Saturation with Oil: Employ a method of gradually increasing the flow rate of saturated oil. Initially, saturate the simulated crude oil at a flow rate of 0.1 mL/min for 12 hours in a reservoir maintained at the target temperature. Following this, increase the flow rate to 0.2 mL/min for 6 hours, and finally, saturate at a flow rate of 0.5 mL/min for 4 hours. After saturation, seal the system and age it at 65 °C for 2 days.

3) Water Flooding: Utilize simulated water to displace crude oil at an injection rate of 1 mL/min. Cease the injection of simulated water when the water content exceeds 95% after three consecutive measurements, and then switch the valve to inject a chemical solution.

4) Chemical Flooding: Inject the oil displacement system solution at a rate of 1 mL/min to replace the sand filling model. Stop the injection when the total injection volume reaches 0.3 pore volumes (PV), then replace the valve and proceed with subsequent water flooding.

5) Subsequent Water Flooding: Following polymer flooding, continue to replace the sand filling model with experimental water flooding as outlined in Table 1, at an injection

rate of 1 mL/min, until the water content of the produced fluid reaches 98% or higher for three consecutive measurements, at which point the injection should be halted [29].

3. Results and Discussion

3.1. Optimal Evaluation of Solution Performance for Different Systems

3.1.1. Optimal selection of interfacial tension

The experimental results regarding the interfacial tension of four different types of surfactants are presented in **Figure 1**.

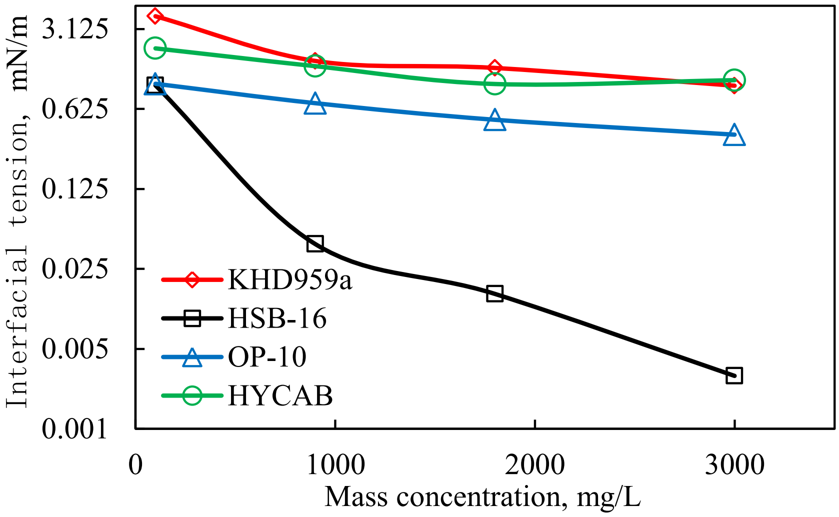


Figure 1. The ability of different surfactants to reduce interfacial tension of crude oil

From **Figure 1**, it can be seen that the interfacial tension between various types of surfactants and crude oil gradually decreases with increasing mass concentration. Among them, HSB-16 can reduce the interfacial tension between oil and water to the order of 10^{-3}, while other surfactants reduce it by around 10^{-1}. Therefore, it is preferable to use hydroxysulfobetaine type amphoteric surfactant (HSB-16) as a single surfactant system for research.

3.1.2. Performance of polymer system

The experimental results of the permeability characteristics of polymers are shown in **Table 2**:

Table 2. Mobility control ability of different polymers.

System code - Solution concentration mg/L	Experimental core permeability, mD	System viscosity, mPa·s	*RF*	*RRF*
DHAP-1750	1965	231.2	484.29	202.50
HMPAM-1750	1995	102.2	183.55	43.10

Table 2 illustrates that the mobility control capabilities of polymers with varying solution structural characteristics in porous media differ significantly. The drag coefficient and residual drag coefficient established by DHAP are notably higher than those of HMPAM. A greater resistance coefficient facilitates the establishment of flow resistance in the high-permeability layer of the injected fluid during the displacement process, thereby enhancing sweep efficiency. Additionally, a higher residual resistance coefficient aids in the subsequent redirection of fluid. Consequently, DHAP was selected as the single polymer displacement agent for further research.

3.1.3. Performance of binary composite system

By combining polymers with effective mobility control and surfactants that exhibit favorable interfacial tension properties, the viscosity and interfacial tension under various concentration conditions were investigated, leading to the determination of the optimal formulation for the system.

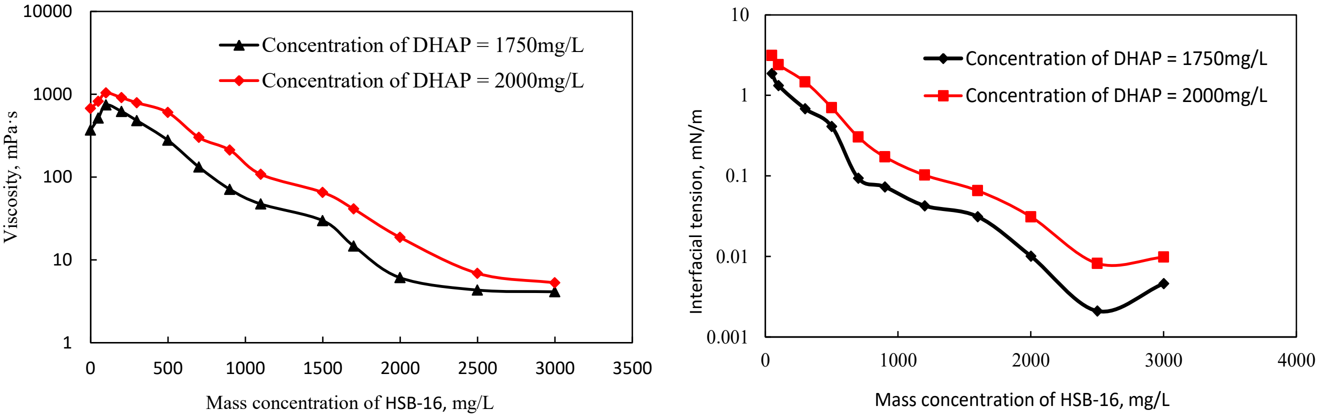


Figure 2. Effect of HSB-16 on apparent viscosity / interfacial tension of composite system.

Figure 2 demonstrates that the effect of HSB-16 on the apparent viscosity of polymer solutions at varying concentrations is consistent. As the concentration of the HSB-16 solution increases, the viscosity of the composite system initially rises, then decreases, and ultimately levels off. The interfacial tension of the composite system with different polymer concentrations continuously decreases with increasing surfactant concentration, subsequently recovering to a certain extent upon reaching its minimum value. An increase in polymer concentration is not conducive to reducing interfacial tension.

Therefore, based on the criteria of apparent viscosity and interfacial tension, a composite system of DHAP-HSB-16 was preliminarily identified that can effectively reduce interfacial tension while maintaining an acceptable level of apparent viscosity. Considering the viscosity and interfacial tension values of the composite system, the solution formulation is presented in Table 3.

Table 3. Compound formulation.

Code	Polymer Concentration, mg/L	Surfactant concentration, mg/L	Solution Viscosity, mPa·s	Interfacial tension, mN/m
DH-1	1750	500	112.4	0.5283
DH-2	1750	700	42.2	0.104
DH-3	1750	900	15.8	0.0745
DH-4	2000	1000	75.3	0.149
DH-5	2000	2500	4.1	0.0098

3.2. Analysis of the Effect of Oil Displacement System Performance on Oil Displacement Efficiency

3.2.1. Oil displacement effect analysis of different action systems

Three distinct oil displacement systems with varying effects were compared: the binary composite system DH-3, which exhibits flowability control and reduced interfacial tension; DHAP, which provides flowability control at a concentration of 1750 mg/L; and HSB-16, which reduces interfacial tension at a concentration of 2000 mg/L. The experimental results regarding the oil displacement efficacy are presented in **Figure 3**.

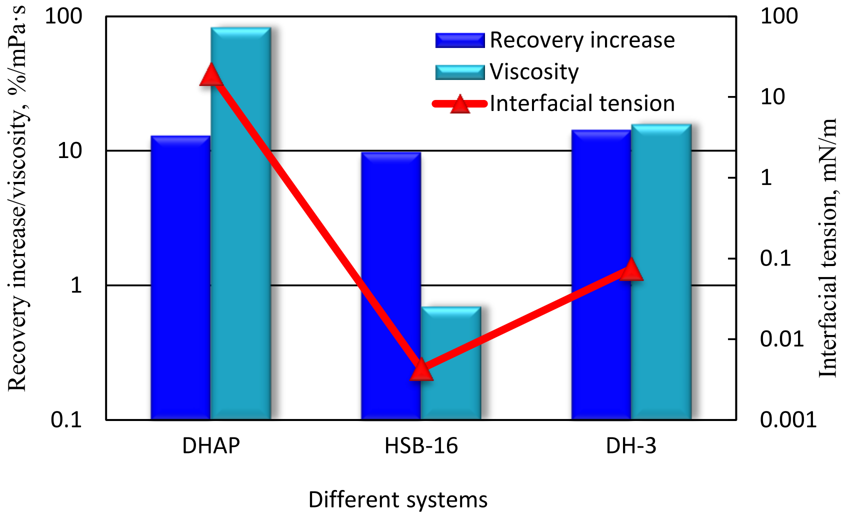


Figure 3. Effect analysis of polymer flooding in different systems.

Figure 3 illustrates that all three systems can achieve significant increases in recovery rates even under high water content conditions. The primary function of the DHAP polymer is mobility control, which establishes flow resistance, enhances the sweep efficiency in low-permeability zones, and contributes to a 12.89% increase in the recovery rate. The HSB-16 surfactant reduces the interfacial tension between water and oil, thereby expanding the unaffected area in medium permeability, which leads to a 9.7% increase in crude oil recovery rate. 14.28%. Comparative analysis indicates that the synergistic effect of the two systems contributes more significantly to the oil displacement efficacy than either system alone.

3.2.2. Effects of Different Properties of Binary Composite Systems on Oil Displacement

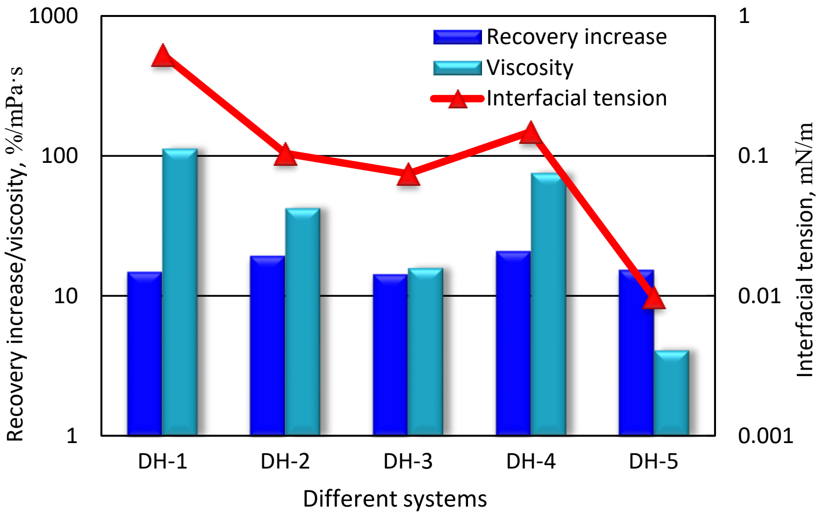


Figure 4. Displacement effect of different two element composite system.

To further elucidate the contributions of binary composite systems, an analysis of the oil displacement results pertaining to various system properties was conducted, as depicted in **Figure 4**. Significant differences exist in the oil displacement effects among various performance oil displacement systems, with the overall recovery rate increasing by over 14%. A comparative analysis of five displacement systems reveals that the two systems exhibiting superior oil displacement performance, DH-2 and DH-4, have an interfacial tension of 0.1 mN/m and an apparent viscosity of approximately 100 mPa·s. Both of these systems primarily rely on apparent viscosity (mobility control), supplemented by interfacial tension, for effective oil displacement.

3.2.3. Contribution of system performance to oil displacement effectiveness

The apparent viscosity and interfacial tension of the system exert distinct effects on oil displacement. The contributions of solution apparent viscosity and interfacial tension to oil displacement were investigated using the grey correlation method [21] implemented on the MATLAB platform, as presented in **Figure 5** and **Table 4**.

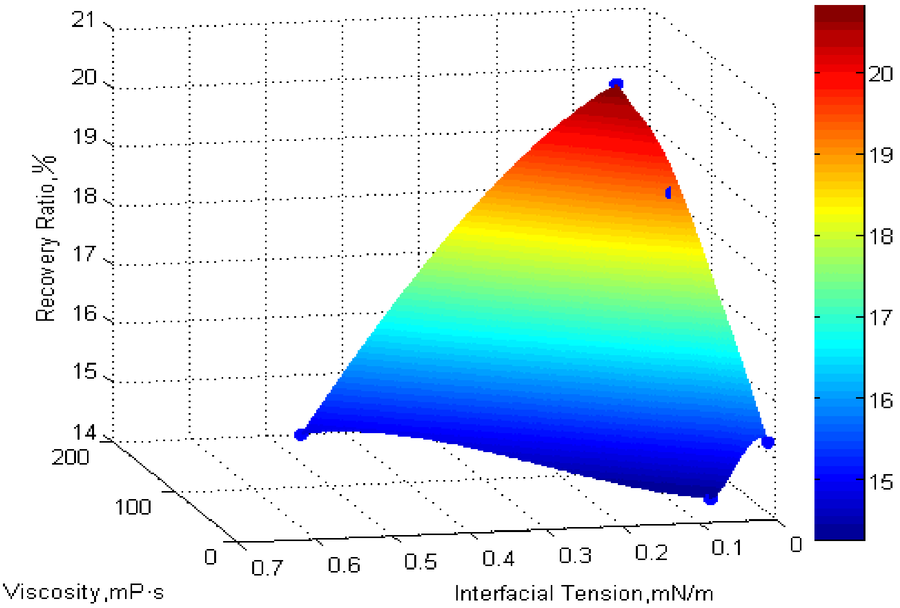


Figure 5. Contribution of viscosity and interfacial tension to oil displacement efficiency.

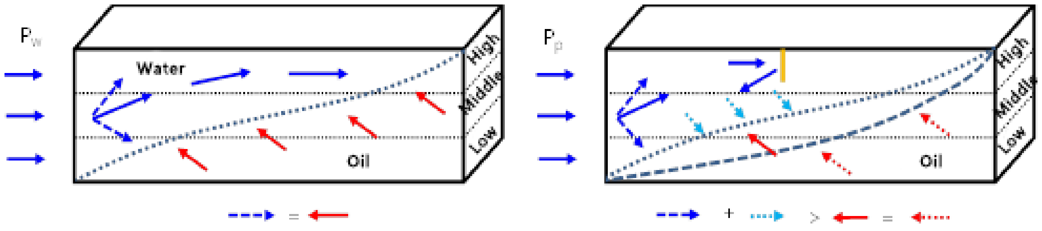
Table 4. Contribution analysis table.

	Viscosity, mPa·s	interfacial tension, mN/m
correlation coefficient	0.113	0.0929
Contribution	54.88%	45.12%

According to the analysis presented in **Table 4.** Contribution analysis table. and **Figure 5**, the correlation coefficient between viscosity and recovery rate in the binary composite system is 0.113, whereas the correlation coefficient for interfacial tension is 0.0929. This indicates that each 1 mPa·s increase in solution viscosity or each 1 mN/m decrease in interfacial tension results in an increase in recovery rate contributions of 0.113 and 0.0929, respectively, which account for 54.88% and 45.12% of the total contribution. Thus, both increasing solution viscosity and decreasing interfacial tension enhance oil recovery efficiency; however, viscosity contributes approximately 9% more to oil recovery than interfacial tension. In terms of overall contribution, viscosity plays a relatively dominant role, suggesting that in binary composite systems, the primary focus should be on controlling flowability, with interfacial tension reduction as a secondary consideration.

3.2.4. The impact of system synergy on oil displacement efficiency

Using the indoor three-layer heterogeneous core as an example, the new dynamic equilibrium characteristics of displacement in the core following high water content are illustrated in **Figure 6**.



(A) (B)

Figure 6. Schematic diagram of stress analysis before and after polymer injection. (**A**) is before injection, (**B**) is after injection).

Long-term water injection development creates preferential pathways in high-permeability zones, making it challenging for subsequent water flooding to impact the low and medium permeability areas of the reservoir. Analysis of the core displacement diagram in Figure 6 indicates that if effective flow resistance cannot be established in the high-permeability region, it becomes difficult to disrupt the dynamic equilibrium of the crude oil displacement process and facilitate the subsequent fluid's influence on the medium and low-permeability layers. Solely relying on the reduction of interfacial tension between oil and water can only marginally enhance the sweep efficiency under the primary flow channel of the displacement fluid. Establishing sufficient flow resistance (which is influenced by injectability) in the high-permeability layer is crucial for redirecting the fluid toward the medium and low-permeability zones; however, this cannot be achieved merely by increasing flow resistance [30]. The synergistic effect of binary composite systems not only reduces the injection pressure of the system [31] but also enhances the dynamic balance of displacement under specific flow resistance conditions. Therefore, for heavy oil reservoirs with high water cut, the binary composite system should primarily focus on mobility control, while also appropriately reducing interfacial tension.

4. Conclusion

(1) The oil displacement efficacy of the binary composite system surpasses that of a single system, and the synergistic effect of the composite system is advantageous for extracting residual oil in low-permeability layers.

(2) The contribution of mobility control within the composite system (54.88%) is greater than that of low interfacial tension (45.12%). In the absence of polymer mobility control, the effectiveness of surfactants is significantly limited.

(3) Variations in the solution properties of composite systems can influence the oil displacement effectiveness. The binary composite system, which primarily employs mobility control and appropriately reduces interfacial tension, is more effective for enhancing the recovery rate of water-flooded high-permeability heavy oil reservoirs in the later stages.

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