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Research Article

Experimental Study on Chemical Recovery of Low-Permeability and Medium-Deep Heavy Oil Reservoir

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To improve the oil recovery of a block in the Wutonggou Formation of the Changji Oilfield, viscosity reducing and foaming agent was optimized to improve the development effect of the water flooding reservoir. The core flooding experiment and microscopic visual experiment were conducted to investigate the production characteristics and EOR mechanism of nitrogen foam flooding. The results show that the 0.5 wt% viscosity reducing and foaming agent DXY-03 was optimized. In the process of microscopic oil displacement by nitrogen foam, nitrogen foam continuously expands and spreads, improves oil displacement efficiency, and greatly improves oil recovery through emulsification and viscosity reduction, squeezing action, dragging action, and Jamin effect. The core flooding experiment shows that on the basis of the water flooding recovery rate of 20.3%, the nitrogen foam huff and puff is increased by 9.2%. The viscosity reducing and foaming agent flooding is increased by 7.8%, and the nitrogen foam flooding is increased by 12.9%. The main EOR mechanism of the viscosity reducing and foaming agent is that it can reduce the interfacial tension between oil and water and can promote heavy oil emulsification and dispersion, thereby forming an oil/water- (O/W-) type emulsion. The reduction in the viscosity of heavy oil makes crude oil easier to extract, realizing the synergistic viscosity reducing and efficiency enhancing effect of nitrogen and viscosity reducing and foaming agents. This study is helpful to provide reference for the development of low-permeability and high-viscosity medium-deep heavy oil reservoirs by chemical agents combined with cold production.

1. Introduction

The Wutonggou Formation of the Changji Oilfield belongs to a medium-porosity, low-permeability, lithologic-structural, and middle-deep heavy oil reservoir, which has an oil-bearing area of 18.96 km^2 and a geological reserve of 7018×10^4 t. The reservoir span is large, with a burial depth of 1317-1846 m, an effective thickness of 43.8-58 m, a porosity of 21.4%, and a permeability of 84.9 mD. The viscosity of crude oil at the formation temperature is 100.5-10027.0 mPa·s. At present, steam injection is the main recovery method for most heavy oil reservoirs and is suitable for more than 90% of heavy oil exploitation. However, low-permeability and medium-deep heavy oil reservoirs have the features of reservoir burial depths greater than 1500 m, reservoir permeabilities less than 200 mD, and high viscosities of crude oil. Conventional steam injection thermal recovery is characterized by a high steam injection pressure, low heat utilization rate, and large heat loss, resulting in a poor viscosity reduction effect and low productivity of a single well. In addition, after steam injection is adopted, most of the heavy oil blocks inevitably enter the high water cut stage, and the exploitation of the reservoir is extremely difficult. In conclusion, for the exploitation of low-permeability and medium-deep heavy oil reservoirs, the use of thermal recovery development is no longer applicable [1]. Microbial recovery technology [2, 3] and surface agent flooding technology [4, 5] should be considered.

In recent years, increasing attention has been given to EOR technology of heavy oil cold recovery [6–11]. Cold production can not only reduce the cost of exploitation but also abate the damage to the formation. The effect of water flooding in heavy oil reservoirs is generally poor [12–14]. At the early stage of exploitation, when the formation is in the stage of a low water cut, an oil/water- (O/W-) type emulsion is formed, and the result of water flooding is obvious. However, with the continuous improvement of the water cut, when the formation is in the phase of medium to high water cut, it is easy to form a channel for water, and the production performance of water flooding gradually worsens. Foam is formed by mixing nitrogen with viscosity reducing and foaming agents, which can be used as a profile control agent to displace most of the residual oil in the formation, mainly blind terminal and film residual oil in porous media after water flooding [15–17]. The mechanisms of EOR of the nitrogen foam flooding system include profile control, emulsification and viscosity reduction, and foam plugging water without plugging oil. When foam is injected into heterogeneous reservoirs, the oil displacement efficiency is improved by relying on the profile control and water shutoff effect of the foam, and the remaining oil in the small pores after water flooding can be displaced. For reservoirs with preferential flow channels in water flooding, the effect of nitrogen foam flooding is more obvious. The interfacial tension between oil and water can be greatly diminished, heavy oil can be promoted to emulsify and disperse, an O/W-type emulsion is conveniently formed, and oil droplets can be carried forward at the same time by viscosity reducing and foaming agents. When the foam encounters oil droplets, the flow resistance is reduced, the foam disappears when it meets oil, and the foam does not disappear when it encounters water to achieve the development effect of water plugging without oil plugging [18–21].

Nitrogen foam flooding is a technology that can effectively EOR by reducing the water-oil mobility ratio of heavy oil reservoirs and improving the viscous fingering of water flooding, and the nitrogen foam flooding has the two unique advantages of profile control and oil displacement. The development efficiency of heavy oil reservoirs and improving economic benefits has a guiding significance [22–28]. The application of nitrogen foam flooding techniques to unconventional reservoirs has recently been investigated by many researchers. Raza [29] conducted an experiment on the factors affecting foam generation, diffusion, quality, and properties in porous media and found that the quality of foam was dependent mainly on the type of foaming agent, the concentration of foaming agent solution, the size of differential pressure, and the composition and saturation of fluid. Foam tests, which were up to four years in three test areas of the North Sea Oilfield, were carried out by the United Kingdom and Norway, and the extent of surfactant adsorption and the oil resistance of the foam had a greater impact on the successful treatment of the foam [30]. Simjoo et al. [31] used the computed tomography (CT) scanning technique to study the regulation of the rheological properties of nitrogen foam when it was percolated in porous media. Zhang and Zhao [32] selected a gas-liquid volume ratio of 1 : 1 through an indoor simulation test and optimized the foam injection location and well pattern distribution in practical applications. In May 2013, a nitrogen foam flooding field test was carried out in well Group Xiao 22-12-13, and a good effect of precipitation stimulation was achieved. To address the problems of low EOR caused by insufficient formation energy and high water cut of oil wells in the middle and late stages of the Tahe Oilfield, Fan et al. [33] conducted a comparative evaluation test of nitrogen flooding and nitrogen foam flooding for EOR in the laboratory. Directed at the features of low-permeability reservoirs with poor injection capacity and unsuitable for polymer injection and other high-viscosity fluids, Xiao et al. [34] carried out indoor experiments on water flooding, nitrogen foam flooding, and nitrogen foam flooding after water flooding to explore the oil flooding efficiency and its influencing factors.

Therefore, this paper took a low-permeability and medium-deep heavy oil reservoir in a block of the Wutong Formation in the Changji Oilfield as the research object. To improve the problems of low recovery efficiency in high water cut and high-viscosity areas, the viscosity reducing and foaming agent system with a better oil flooding efficiency was obtained through screening on the basis of existing exploitation technology. A viscosity reducing and foaming agent system suitable for the growth of this low-permeability and medium-deep heavy oil reservoir was preferably selected. At the same time, the microscopic distribution features of fluid and the mechanism of the nitrogen foam flooding in the stimulation process were discovered by microscopic visual experiments and the core flooding experiment to discuss the production characteristics and flooding efficiency of each core flooding experiment stage. Then, the results provide some technical support for viscosity reduction recovery of this kind of heavy oil reservoir.

2. Experiments

2.1. Experimental Materials and Apparatus. The low-permeability cores applied in the experiment were supplied by the Changji Oilfield, with a length of 8 cm and a diameter of 2.5 cm. The crude oil employed in the experiment was acquired from a heavy oil reservoir in this block of the Changji Oilfield. The crude oil degassed and dehydrated was used, and the viscosity of crude oil was 3856 mPa·s at 50°C. The viscosity-temperature curve and the content of four components of the experimental oil are shown in Figure 1. The water used in the experiment was the formation water of the Changji Oilfield. Its salinity is 7500 mg/L, pH value is 8, and the formation water type belongs to $NaHCO_3$ type. The chemical reagent has four kinds of viscosity reducing and foaming agents (Shandong Ruiheng Xingyu Petroleum Technology Development Ltd., Shandong, China). DXY-03 is an anionic surfactant that is composed mainly of alpha-olefin sulfonate. Alcohol ether sodium sulfate was the main constituent of the negative nonionic surfactant DXY-02. HY-2N is a negative nonionic surfactant composed mainly of alcohol ether carboxylate. The essential component anionic surfactant CH-03 was alkyl sulfonate. Gas (nitrogen with a purity of 99.9 wt%) was supplied by Tianyuan Industry Ltd. (Qingdao, China).

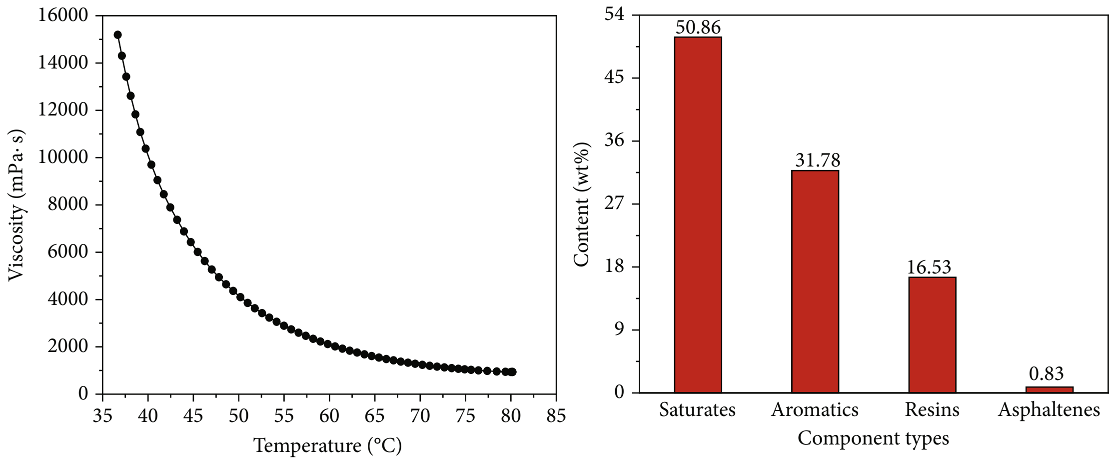


Figure 1: Viscosity-temperature curve and the content of four components of crude oil.

The experimental apparatus included mainly a rotary rheometer (Anton Paar, MCR302), interface rheometer (Tracker, Teclis), core gripper (Jiangsu Haian Petroleum Science and Technology Instrument Co., Ltd., size $\phi 25 \times 25 - 150$ mm, pressure range 0-32 MPa), plunger pump (Model 100DX, Teledyne Co., Ltd., USA, flow accuracy $\pm 0.25\ \mu$L$\cdot$min^{-1}, pressure accuracy $\pm 0.5\%$), pressure sensor (Senex, Jiangsu Haian Petroleum Science and Technology Instrument Co., Ltd., temperature accuracy of ± 0.1°C, pressure accuracy of 0.5 kPa), micrometer tube (minimum readable volume 0.002 mL), and microscopic flow model (Jiangsu Haian Petroleum Science and Technology Instrument Co., Ltd., dimensions of 40×40 mm and pore-throat diameter 30-70 μm).

2.2. Performance Evaluation of the Viscosity Reducing and Foaming Agent. Because the components of heavy oil are very complex and different, viscosity reducing and foaming agents have a certain selectivity for the heavy oil, and it is necessary to evaluate the performance of the agent for the reservoir. The indoor performance evaluation of the viscosity reducing and foaming agent included mainly foaming ability, viscosity reduction rate, and surface tension.

2.2.1. Method for Determination of Foam Capacity. The experimental procedures for evaluating the foaming ability of viscosity reducing and foaming agent were as follows.

(1) Preparation of viscosity reducing and foaming agent solution: formation water (100 mL) was used to prepare 0.1, 0.3, 0.5, and 0.7 wt% viscosity reducing and foaming agent solutions according to the mass concentration, and the solutions were stirred evenly to dissolve fully

(2) Stirred the sparkling: then, 100 mL of viscosity reducing and foaming agent solutions was poured into the measuring cup of the high-speed mixer and stirred for three minutes at 8000 r$\cdot$min^{-1}

(3) Foaming volume test: the foam formed in the measuring cup of the high-speed mixer was immediately poured into the 500 mL measuring cylinder, the foaming volume was recorded, and the timing was started

(4) Half-life of the foam test: the change in the volume of liquid precipitated from the bottom of the graduated cylinder was observed, and the timing was stopped when the volume of precipitated liquid reached 50 mL. This time was the half-life of the foam, expressed as $t_{1/2}$

(5) The experimental data are noted in the table. The experimental steps (2)-(4) were repeated, and four different kinds of viscosity reducing and foaming agents were evaluated. The results of four groups of evaluation experiments were recorded and compared, and the foaming ability and stability of different viscosity reducing and foaming agents were analyzed. Finally, the best concentration of viscosity reducing and foaming agent was selected

2.2.2. Method for Determination of Viscosity Reduction. First, a certain amount of degassed and dehydrated heavy oil samples was placed in a 250 mL measuring cylinder, and then, viscosity reducing and foaming agent solutions of different concentrations were added according to the oil-water ratio of 7 : 3. After they were placed in a constant temperature water bath at 60°C for ten minutes, the oil and water mixtures were stirred at a consistent speed until emulsification was uniform. At 60°C, the viscosity μ_1 of the emulsion was quickly measured with a rotary rheometer and was compared with the viscosity μ_0 of the original heavy oil sample at the same temperature. The experiment was repeated three times to obtain the average value. Finally, the viscosity reduction rate η of the viscosity reducing and foaming agent on the heavy oil was determined according to the following equation:

$$\eta = \frac{\mu_0 - \mu_1}{\mu_0} \times 100\%, \tag{1}$$

where η is the viscosity reduction rate, μ_0 is the original viscosity of heavy oil (mPa·s), and μ_1 is the viscosity value of crude oil after adding the viscosity reducing and foaming agent solution (mPa·s).

2.2.3. Method for Determination of Surface Tension Capacity. To reduce the error produced in the experiment, the equipment was thoroughly cleaned with ethanol before starting the experiment. Then, 40 mL of viscosity reducing and foaming agent solutions was poured into the quartz sample cell, the U-shaped needle was plunged into the solution, and a bubble was inflated slowly. The charged-coupled device (CCD) camera was adjusted to obtain clear and stable bubble pictures on the computer. The gas-liquid interfacial tension was tested and recorded by the computer. The experiment was stopped after recording for ten minutes. Finally, the viscosity reducing and foaming agent species were changed, and the experiment was repeated. The surface tension was measured by the pendant drop method and was calculated by the Laplace equation:

$$\frac{1}{x}\frac{d}{\mathrm{dx}}(x \cdot \sin\theta) = \frac{2}{b} - \mathrm{cz}, \tag{2}$$

where θ is the included angle between the tangent line of the cross point (x, z) on the droplet contour and the x axis, b is the radius of curvature of the droplet contour, and c is the capillary constant.

2.3. Microscopic Visualization Experiment of the Oil Displacement Mechanism. The flow chart of the microscopic visualization experiment device is shown in Figure 2. The microscopic flow experiment procedure of viscosity reducing and foaming agent solution is as follows:

(1) The microscopic glass etching model was cleaned with petroleum ether, ethanol, and distilled water successively, and the microscopic glass etching model was placed in an oven at 80°C to dry. The experimental equipment was connected according to the experimental procedure. After the model was installed, formation water was injected into the microscopic glass etching model at a speed of 0.01 mL·min^{-1} to achieve water saturation

(2) Heavy oil was saturated into the microscopic glass etching model after the process of water saturation

(3) The microscopic glass etching model of fully saturated heavy oil was aged under constant temperature for one day. Then, formation water was injected into the microscopic glass etching model at a speed of 0.01 mL·min^{-1} to water-flood the heavy oil. During water flooding, the displacement process in the microscopic glass etching model was recorded by video, and the remaining oil distribution process and the existing form of residual oil were recorded by photos. In addition, to enhance the visual effect of the experiment, 0.1 wt% eosin stain was used to dye the water red

(4) A mass concentration of 0.5 wt% viscosity reducing and foaming agent solution was injected into the model at a rate of 0.01 mL·min^{-1} after water flooding. The phenomena of the experimental process were observed

(5) Dynamic images of the displacement process were taken and analyzed

(6) To analyze the stability of foam and emulsion during foam flooding, ImageJ was used to process the images after nitrogen foam flooding at different times, and the particle size of bubbles and oil droplets after foam flooding at different times were quantitatively analyzed

2.4. Nitrogen Foam Flooding Experiment. A natural core from a block of the Wutonggou Formation in the Changji Oilfield was used in this experiment. The cores used in this experiment were properly treated before the one-dimensional core flooding experiment began. First, the cut and oil-washed cores were dried in an oven at 105°C for four hours, and then, their quality was measured.

Then, the core was placed in a vessel for 12 hours and saturated with formation water. The core weight was measured after adding the formation water, and the porosity was determined. The absolute permeability of the 100% aqueous phase of the core was measured after formation water flooding. Degassed and dehydrated crude oil, formation water, 0.5 wt% DXY-03 viscosity reducing and foaming agent solution, and nitrogen were sequentially filled into the middle vessel. The core was loaded into a core holder in a constant temperature oven, which was set at 60°C, and a rate of 0.01 mL·min^{-1} was used for oil flooding. After the core was filled with oil, oil saturation was computed. The saturated core was placed in a 60°C constant temperature oven for 12 hours. As a consequence, the natural core was selected in this experiment, in which the water permeability is seven mD, porosity is 18%, and initial oil saturation is 79%. For the short core experiment, there are some differences between the actual measured cumulative oil and water production and the real situation because there are dead volumes in pipelines and joints connected to the experimental device [35, 36], which cannot be ignored. Therefore, for the accuracy of the experimental results, the influence of dead volume should be considered in data processing. To improve the gauge correctness, a standard stainless pipeline with an inner diameter of 0.5 mm was used for the oil production pipeline at the outlet of the experiment, and the dead volume of the experiment was 0.3 cm^3. In addition, a micrometer tube (minimum readable volume 0.002 mL) was used at the outlet to pick up the produced fluid because little oil was produced in the experiment.

The core flooding experiment was divided into four stages:

(1) Water flooding: formation water was injected at 0.5 mL·min^{-1} until the water cut of the produced fluid reached 98%. After stopping the water flooding

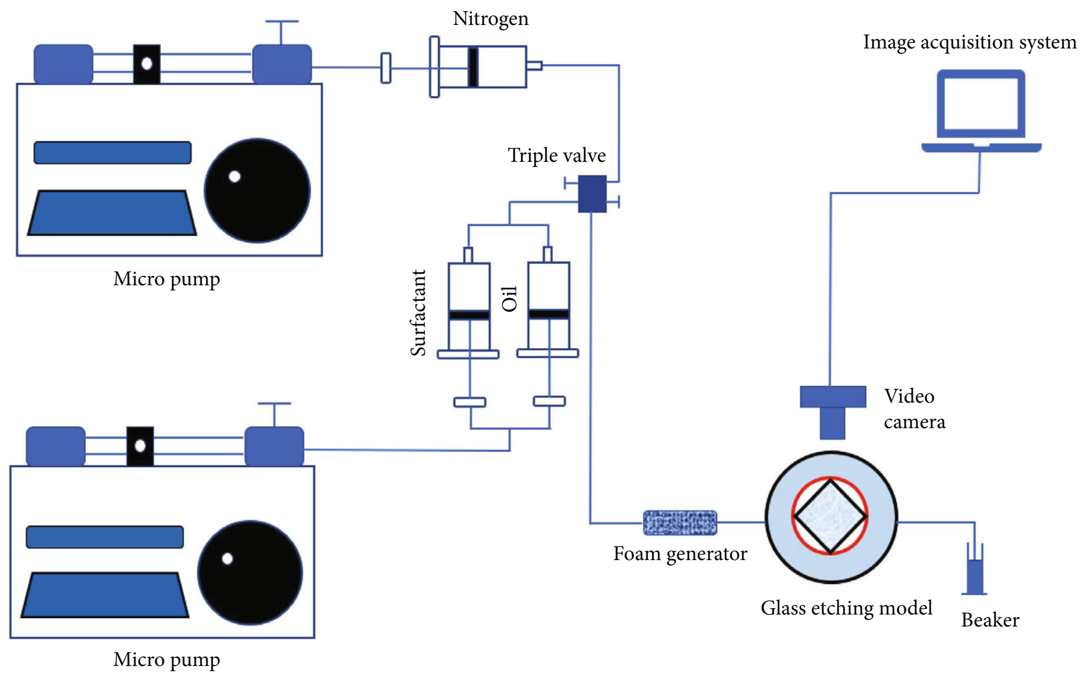


FIGURE 2: Flow chart of the microscopic visualization experiment device.

experiment, the pressure difference, produced water, and produced oil volume at different moments were recorded in the water flooding process, and the water flooding oil displacement efficiency was calculated

(2) Nitrogen foam huff and puff: after water flooding, nitrogen foam huff and puff was carried out, and nitrogen was injected into the core holder until the pressure reached 14 MPa. From the injection end, 0.1 pore volume (PV) viscosity reducing and foaming agent solution was injected at a constant speed of 0.25 mL·min^{-1}, and gas injection was stopped when 0.1 PV nitrogen was injected at a constant rate of 0.5 mL·min^{-1}. The vessel of the production end was opened, and a certain amount of viscosity reducing and foaming agent solution and nitrogen was injected continuously into the core holder. The production end and injection end were closed, and the well was soaked for seven hours. After soaking, the valve of the injection end was opened so that crude oil and nitrogen were recovered. The experiment was stopped after production, the current cycle of the huff and puff experiment was stopped, and the cumulative crude oil output at different times was recorded. The experiment was finished after repeated huff and puff for two rounds, and the oil displacement efficiency in the huff and puff stage was determined

(3) Viscosity reducing and foaming agent flooding: when the nitrogen foam huff and puff cycle was completed, viscosity reducing and foaming agent solution was injected into the core at a speed of 0.5 mL·min^{-1}. The viscosity reducing and foaming agent flooding was stopped until the water cut of the produced fluid reached 98%, and the pressure difference, produced water, and produced oil volume at different times were noted

(4) Nitrogen foam flooding: viscosity reducing and foaming agent flooding was finished, and the viscosity reducing and foaming agent solution and nitrogen were continuously injected alternately. The gas-liquid ratio was 1 : 1, the concentration of viscosity reducing and foaming agent solution was 0.5 wt%, and the experiment was stopped after the injection of 1 PV. The changes in the pressure difference, produced water, and produced oil volume during the whole flooding process were noted. The ability of nitrogen foam flooding to improve recovery was discussed, and the oil displacement efficiency of nitrogen foam flooding was determined. The experimental device was kept at a constant temperature of 60°C during the experiment, and an experimental schematic diagram of the one-dimensional core flooding experiment is displayed in Figure 3

3. Results and Discussion

3.1. Foaming Properties of Different Types of Viscosity Reducing and Foaming Agents. According to the features of heavy oil in the target block, four kinds of agents with viscosity reducing and foaming agent were chosen, and the foaming performance of different types of viscosity reducing and foaming agents was evaluated under the same environmental conditions. The foaming volume and half-life of the viscosity reducing and foaming agents are presented in Figure 4. Foaming volume refers to the total volume of foam

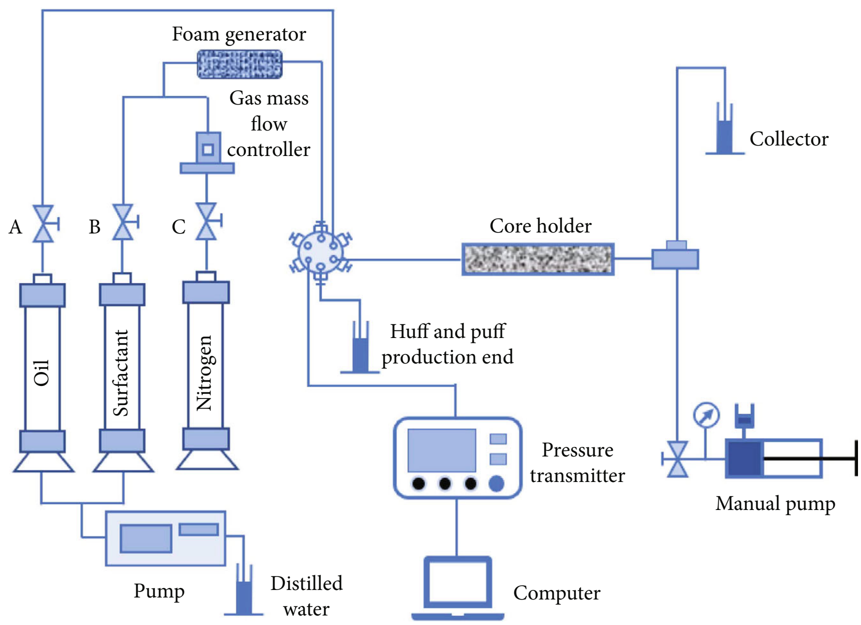


FIGURE 3: Schematic diagram of the one-dimensional flooding experimental device.

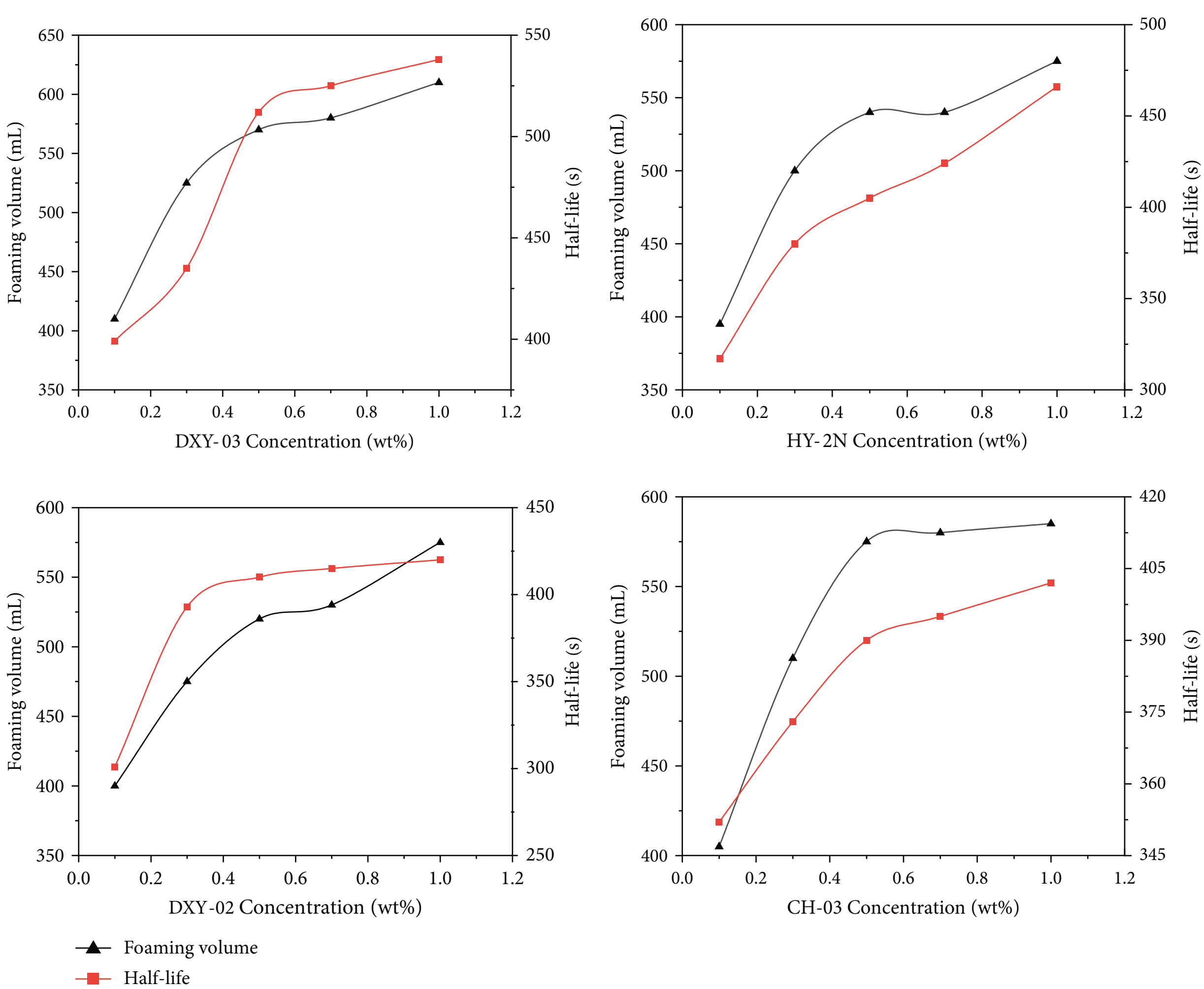


FIGURE 4: Foaming volume and half-life curves of four viscosity reducing and foaming agents.

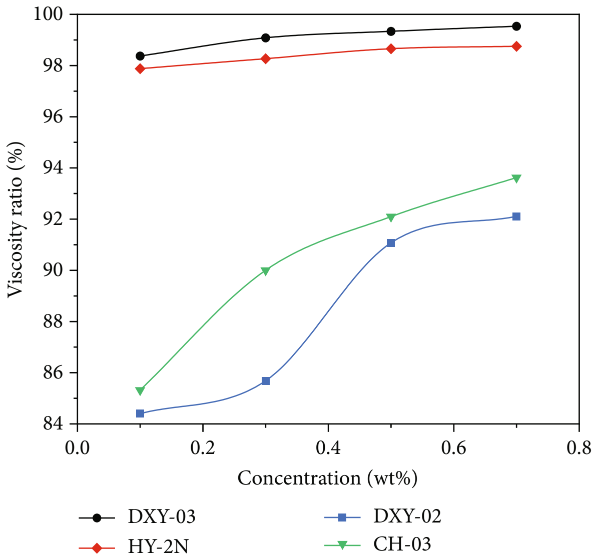


Figure 5: Viscosity reduction curves of four viscosity reducing and foaming agents.

that can be formed after viscosity reducing and foaming agent is fully stirred at a uniform speed under specific conditions, which is used mainly to evaluate the ability of viscosity reducing and foaming agent. The initial concentration of four viscosity reducing and foaming agents was 0.1 wt%. With the increase in the concentration of the viscosity reducing and foaming agent solutions, the foaming volume keeps increasing, and the foaming volume of viscosity reducing and foaming agents is all more than 400 mL. DXY-03 has the best foaming ability. When the concentration is higher, the foaming volume even exceeds 600 mL. CH-03 is the second best, and the maximum foaming volume is more than 580 mL when the concentration reaches 0.5 wt%. HY-2N and DXY-02 have average foaming capacity, and the maximum foaming volume is 575 mL. Based on the above, the foaming volumes of four viscosity reducing and foaming agents are large, and the growth rate of the foaming volume tends to increase slowly when the viscosity reducing and foaming agent solution concentration is 0.5 wt% [37].

The half-life refers to the time required to separate 50 mL of liquid from the foam produced by stirring the viscosity reducing foam agent under certain conditions, which is an important parameter of the initial stability of the reactive foam system. In general, the higher the viscosity reducing and foaming agent concentration are, the higher the volume of the foam, and the longer the half-life of the foam. In the results of Figure 4, the change in viscosity reducing and foaming agent concentration has a relatively significant impact on the half-life of DXY-03. When the concentration is more than 0.5 wt%, the half-life of DXY-03 is higher, and the highest half-life is approximately 9 minutes. The half-lives of HY-2N and DXY-02 increased with increasing solution concentration, reaching approximately 7 minutes when the concentration was 0.7 wt%. CH-03 is the worst, with almost no change in half-life as the solution concentration increases, remaining at approximately 6 minutes. Considering the foaming volume and half-life of different viscosity reducing and foaming agents, DXY-03 can form a relatively firm foam system under certain formation conditions.

3.2. Emulsification and Viscosity Reduction Effect of Different Types of Viscosity Reducing and Foaming Agents. Viscosity reduction and viscosity reduction concentration are important arguments to evaluate whether a viscosity reducing and foaming agent is suitable. Viscosity reduction is the basic parameter to judge whether a certain viscosity reduction agent is qualified, and the important parameter to evaluate whether it meets the economic cost performance is the consistency of the viscosity reducer. The viscosity reduction of heavy oil with diverse types and concentrations of viscosity reducing and foaming agent is revealed in Figure 5.

Based on the experimental results, the crude oil was emulsified to form stable O/W emulsions after a certain total viscosity reducing and foaming agent solution was injected into the crude oil. With the increment of viscosity reducing and foaming agent concentration, the viscosity of O/W emulsions presents a substantial decrease. The concentration of viscosity reducing and foaming agent has a great influence on the viscosity of the crude oil. When 0.5 wt% DXY-03 solution was mixed, the viscosity of the O/W emulsion was reduced from 3856 mPa·s to 25.7 mPa·s, and the viscosity reduction rate was 99.33%. When 0.5 wt% HY-2N solution was added, the viscosity of the O/W emulsion decreased from 3856 mPa·s to 27.2 mPa·s, and the rate of viscosity reduction was 98.65%. The results suggest that both DXY-03 and HY-2N have satisfactory viscosity reduction effects on crude oil, and the viscosity reduction rates are above 98%. However, the viscosity reduction rates of DXY-02 and CH-03 are relatively low.

3.3. Surface Tension of Different Types of Viscosity Reducing and Foaming Agents. Figure 6 is the relationship curve of surface tension and time of four kinds of viscosity reducing and foaming agents. As exhibited in Figure 6, when different types and concentrations of 0.5 wt% viscosity reducing and foaming agent solutions were mixed with formation water, the surface tension decreased continuously. As time goes on, the surface tension basically remains constant. With the passage of time, the surface tension of the DXY-03 solution can quickly decrease, and the surface tension reaches a minimum value of 24.25 mN/m at 600 seconds. In accordance with Gibbs' principle, the system always tends to be in a state of relatively low surface energy. Low surface tension can reduce the energy of the foam system, which is more conducive to the relative stability of the foam generated within the system. As a result, the experimental results show that the foam system of DXY-03 is relatively stable compared with the foam system of the other three viscosity reducing and foaming agents.

3.4. Microscopic Displacement. According to the experimental evaluation of foaming volume, half-life, viscosity reduction rate, and surface tension of four kinds of viscosity reducing and foaming agents in Section 2.2, the results show that the best viscosity reducing and foaming agent is 0.5 wt% DXY-03. Therefore, 0.5 wt% DXY-03 solution was used as

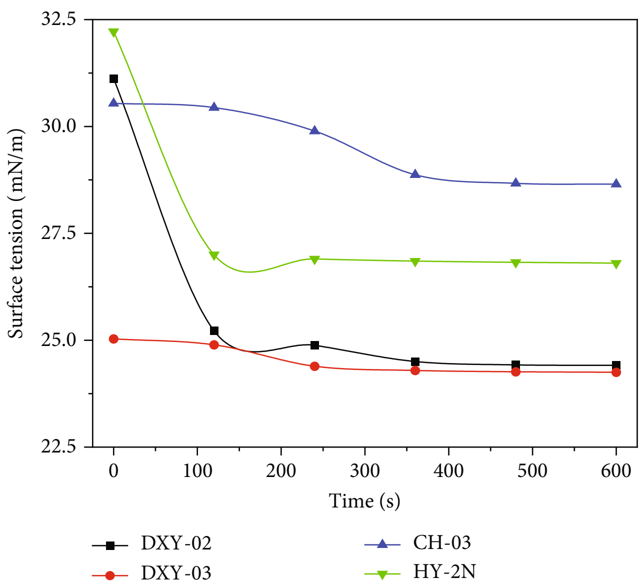


Figure 6: Relationship between surface tension and time.

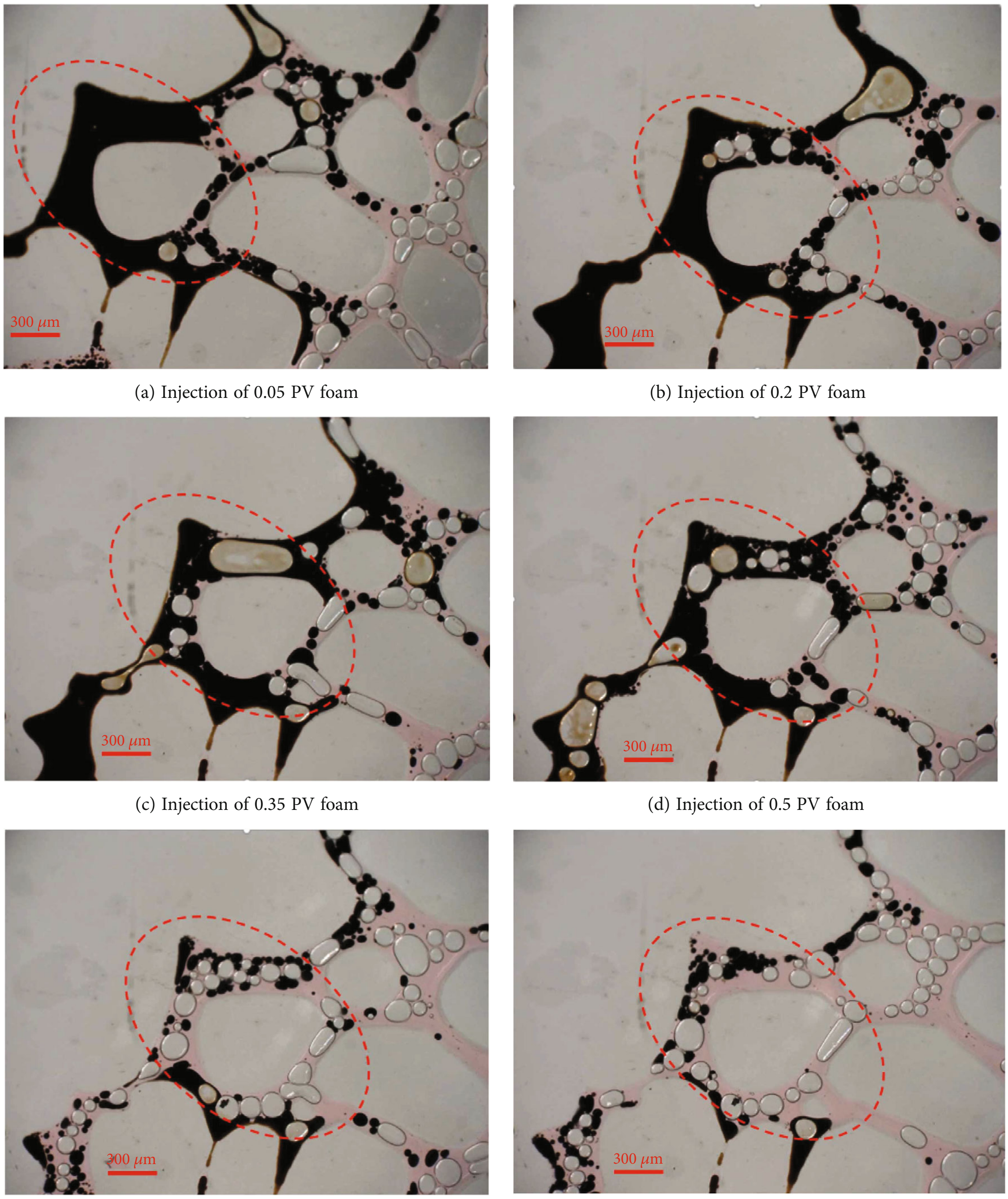
the viscosity reducing and foaming agent in the microscopic visualization experiment. Figure 7 presents the microscopic flow photos of foam flooding. We can conclude that after water flooding, a large amount of the remaining oil remains in the model. Foam is injected into the model to improve crude oil recovery. As displayed in Figures 7(a)–7(f), after foam flooding, the residual oil after water flooding is mostly displaced, and the oil displacement efficiency is evident. Figures 7(b) and 7(c) exhibit the results of injecting foam 0.02 PV and 0.5 PV. These results indicate that when the foam flows into the pore with more residual oil, the remaining oil in the pore can be displaced by the squeezing and carrying effect between the injected bubbles, and then, the dispersed residual oil in small pores and pore throats is also greatly reduced. Figure 7(c) exhibits that after the foam enters the pore, most of the remaining oil is displaced by the dragging action of the foam. The residual oil is significantly reduced compared with water flooding. It can be found in Figure 7(e) that when the bubble system enters the pore throat structure, single or multiple bubbles exhibit a stacked deformation pressure difference to form the Jamin effect or superposition of the Jamin effect to block the dominant flow channels. The flow resistance of foam can effectively be improved in the high-permeability channel, and the subsequent fluid can be forced to divert to the unaffected area to achieve the effect of plugging and expanding the affected area [38, 39]. The whole process of nitrogen foam flooding is shown in Figure 7. The heavy oil can be emulsified into flowing oil droplets by viscosity reducing and foaming agent, and many O/W emulsions are distributed within the porous medium. On the one hand, these dispersed oil droplets have plugging in the formation. On the other hand, the force effect can be produced by emulsion oil droplets and foam so that crude oil can be effectively released, and the oil displacement efficiency can be improved.

Figures 8 and 9 show the particle size distribution of the emulsified bubbles and oil droplets at different injection times. The particle size of the bubbles and oil droplet emulsification at different times basically present a normal distribution. At the initial stage of injection, the proportion of small particle sizes of bubbles is large. With increasing injection time, an increasing number of foams are filled in the injection model. At the later stage of injection, the proportion of bubble particle sizes changes, the bubble particle size increases, and the large particle size bubbles account for the majority, indicating that the stability of the injected foam is good. With the increase in the amount of foam injected, the number of oil droplets emulsified from crude oil increases, and the particle size of the oil droplets gradually decreases. The initial particle size is concentrated mainly in the 50-90 μm range. After nitrogen foam flooding, the particle size of oil droplets tends to be stable, and the particle size is mainly 20-50 μm. The residual oil after water flooding can be emulsified into oil droplets with smaller particle sizes by nitrogen foam flooding, making it easier for crude oil to be displaced out in porous media, and increasing the oil displacement efficiency.

3.5. Experimental Evaluation of the Oil Displacement Effect

3.5.1. Water Flooding Stage. Figure 10(a) is the curve of pressure difference change during water flooding. The water flooding process of the heavy oil reservoir includes three main stages [40]. The first stage is to start the pressure breakthrough phase. In this stage, as the viscosity of heavy oil is higher than the viscosity of water, it is difficult for crude oil to flow in porous media, and the heavy oil has a start-up pressure gradient [41], which leads to the injection pressure gradually increasing at first, and the crude oil in the core is displaced with continuous injection of injected water. The second stage is the rapid pressure to decline phase. In this stage, when the injection pressure reaches the breakthrough pressure, water begins to be produced, and the injection pressure decreases rapidly, mainly because the oil-to-water viscosity ratio is very large and the water flow resistance is very small. Hence, the injection water flows along the high-permeability channel, forming the dominant channel of water flow, which causes the rapid reduction of the injection pressure. The third stage is the sustained low-pressure phase. The injection pressure decreases slowly, and the injected water gradually reaches a stable flow stage. Due to the high viscosity and poor fluidity of heavy oil, the low injection pressure is at a low level. The heavy oil actually cannot flow in the core; only water flows in the core, and there is no longer crude oil output at the extraction end. Thus, the sweep efficiency of water flooding is low. From the analysis of the water flooding results, when 4 PV formation water is injected, the water cut of the produced liquid attains 98%, and the oil recovery in the water flooding stage is 20.3%. A flow channel was formed by injected water after the injection pressure broke through the startup pressure gradient, resulting in a substantial increase in the water cut and a low recovery of water flooding.

3.5.2. Nitrogen Foam Huff and Puff Stage. At the beginning of the nitrogen foam huff and puff experiment, the water



(a) Injection of 0.05 PV foam

(b) Injection of 0.2 PV foam

(c) Injection of 0.35 PV foam

(d) Injection of 0.5 PV foam

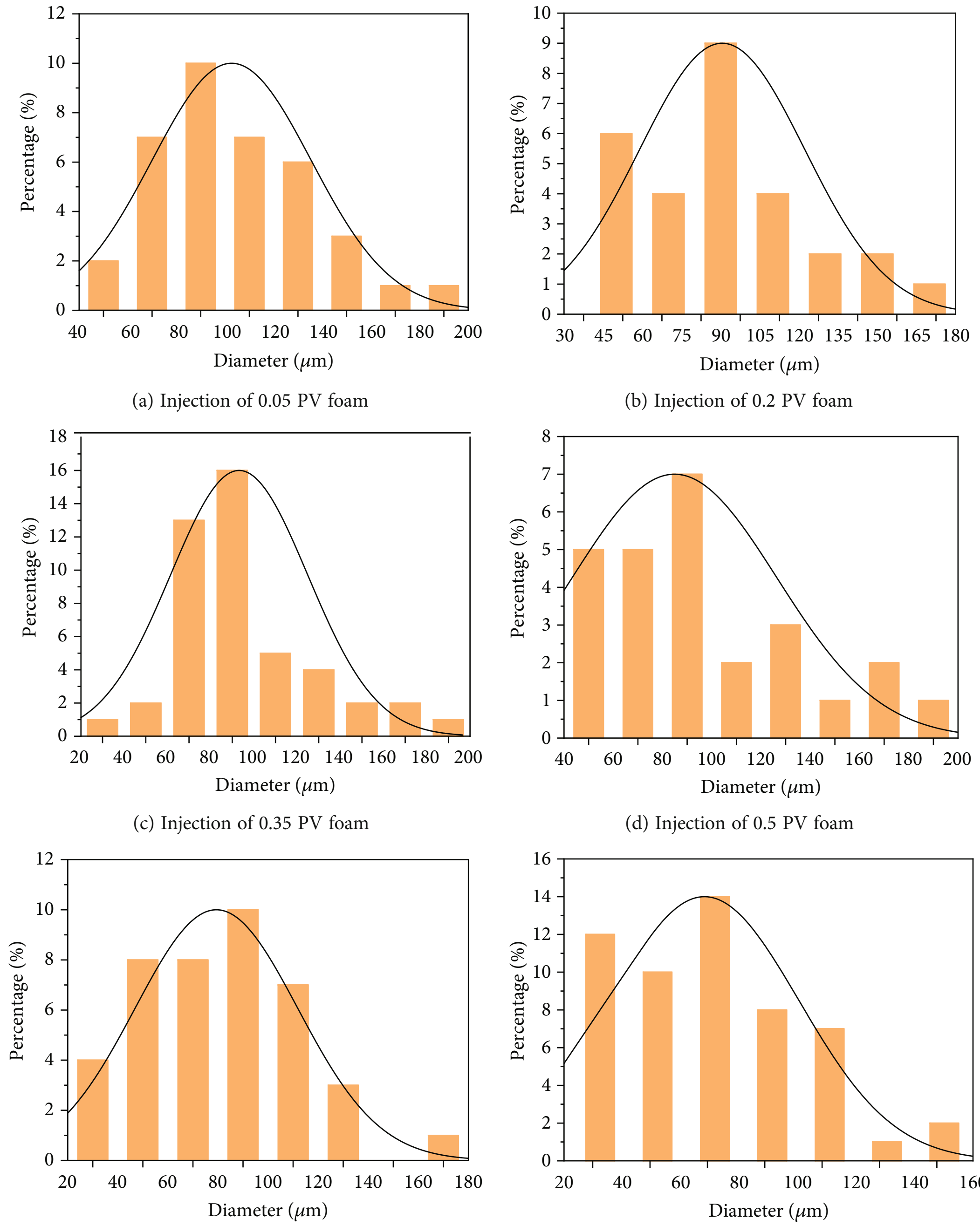
(e) Injection of 0.8 PV foam

(f) Injection of 1.0 PV foam

Figure 7: Microscopic flow characteristics of foam flooding oil displacement.

cut of the produced liquid reached 98%. After 0.1 PV nitrogen and 0.1 PV viscosity reducing and foaming solution agent was injected into the well, and the well was soaked for seven hours. After two rounds of huff and puff, the final water cut of the produced liquid is reduced to 93%, with a decrease of 5.2%. In the nitrogen foam huff and puff stage, the recovery is improved by 9.2%. The injection pressure in the rock core is increased, and the interfacial tension between oil and water is reduced after nitrogen foam is injected. At the same time, the viscosity of crude oil is reduced by the emulsification reaction between nitrogen foam and crude oil, and the fluidity of crude oil is improved [42]. Therefore, a part of the heavy oil in the core can be carried out by the higher injection pressure, and the heavy oil recovery is improved to a certain extent.

3.5.3. Viscosity Reducing and Foaming Agent Solution Flooding Stage. The viscosity reducing and foaming agent flooding process can also be divided into three stages, which is similar to the heavy oil water flooding process. From the



(a) Injection of 0.05 PV foam

(b) Injection of 0.2 PV foam

(c) Injection of 0.35 PV foam

(d) Injection of 0.5 PV foam

(e) Injection of 0.8 PV foam

(f) Injection of 1.0 PV foam

Figure 8: Bubble particle size distribution at different injection times.

change in the pressure difference between water flooding and viscosity reducing and foaming agent solution flooding, when the reservoir is in the high water cut stage at the late stage of extraction, it is difficult for water flooding to continue to enhance the recovery of crude oil. The viscosity of heavy oil is reduced greatly, the oil-water mobility changes well, and the transport of crude oil can be promoted by the viscosity reducing and foaming agent, which has a strong emulsification ability. After water flooding, the viscosity reducing and foaming agent reacted with heavy oil in the core. An O/W emulsion with low viscosity was formed, and the friction between the oil film became a water film between the friction so that the flow friction resistance was reduced. The ability of heavy oil flow is improved, the flow resistance of the porous medium is reduced, and the core flooding pressure is reduced. At the early stage of viscosity reducing and foaming agent solution flooding, the injection pressure is lower than the injection pressure of water flooding, and the start pressure breakthrough time is earlier than the start pressure breakthrough time of water flooding. Because the viscosity of the O/W emulsion is very low, the O/W emulsion flows mainly along the high-permeability

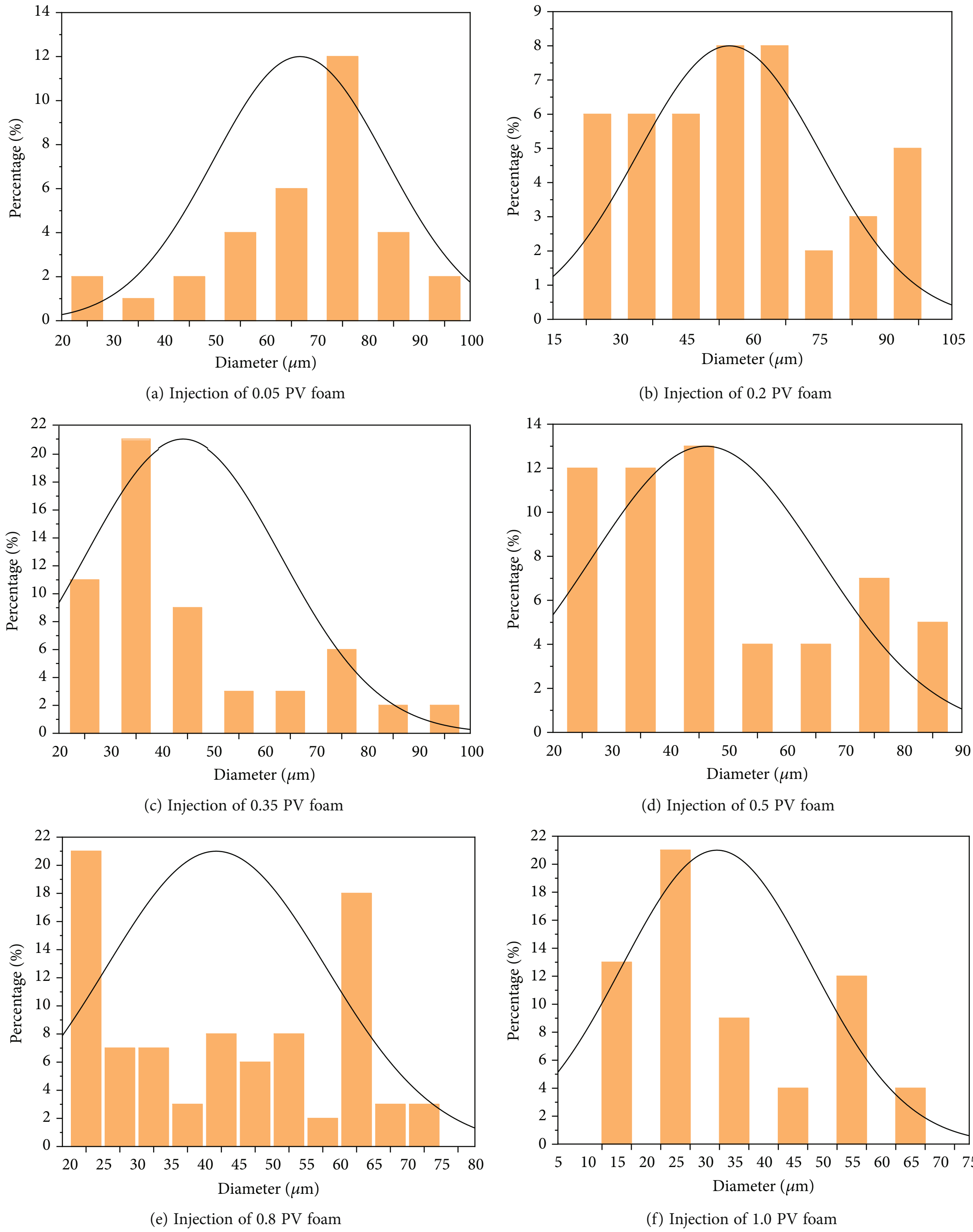
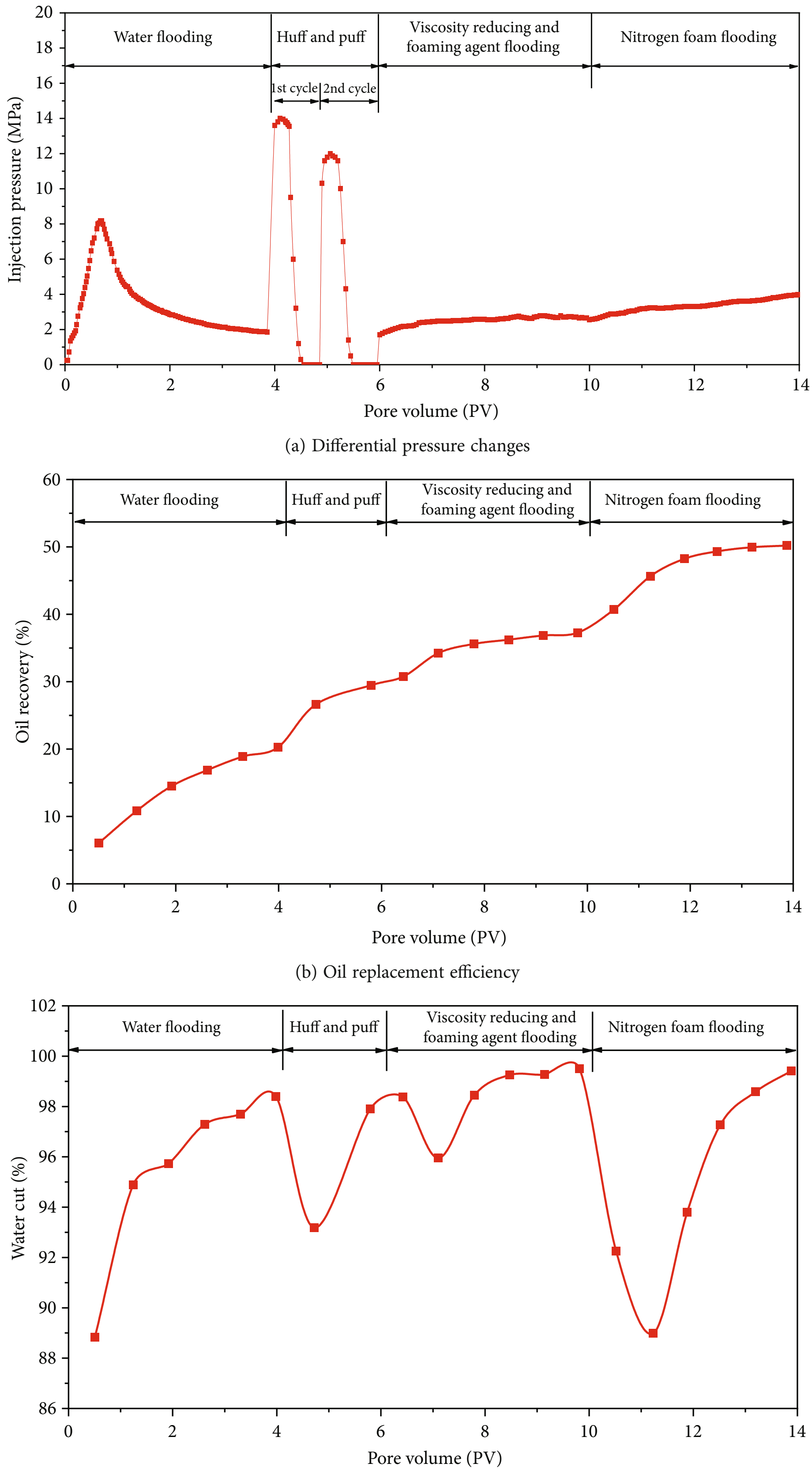


Figure 9: Emulsified particle size distribution of oil droplets at different injection times.

channel. Compared with crude oil, the availability of heavy oil in the affected area is improved by the O/W emulsion, which more easily flows in the core. After viscosity reducing and foaming agent solution flooding, the recovery increased by 7.8% [43].

3.5.4. Nitrogen Foam Flooding Stage. Nitrogen foam flooding is an oil flooding method that combines the common advantages of nitrogen and foam. In the water flooding stage, the displacement pressure difference is low, and the degree of impact of injected water on crude oil in porous media is very



(a) Differential pressure changes

(b) Oil replacement efficiency

(c) Water cut

Figure 10: Results curve of core flooding experiment.

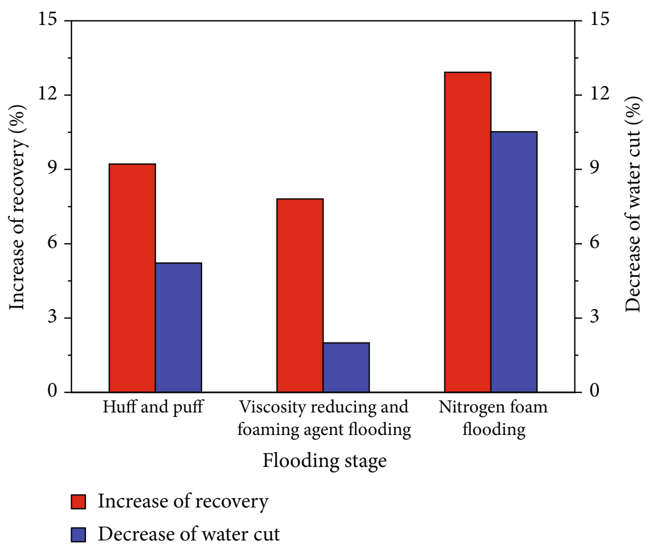


Figure 11: Increase in oil recovery and decrease in water cut at different core flooding stages.

limited. Compared with water, foam has high viscosity and relatively large flow resistance, which can effectively increase the flow resistance in the core. When nitrogen foam was injected, the displacement pressure difference increased gradually during the experiment. The results show that effective blocking in the large pores of the core is gradually formed by foam, which is beneficial for the foam to enter the small and medium pores so that the residual oil in the core is driven out by the subsequent fluid flowing into the core, the sweep volume is expanded, and the recovery efficiency of oil is improved. Moreover, the O/W emulsion can easily be formed by the nitrogen together with water and oil that was injected into the core, the viscosity of crude oil is reduced, the oil-to-water flow ratio is improved, and the oil efficiency is increased [44]. The produced liquid of nitrogen foam flooding flows out from the production end in an emulsified state, and the color of the produced emulsion is dark brown compared with the viscosity reducing and foaming agent solution flooding stage, indicating that the emulsification phenomenon is more obvious, the emulsification degree is higher, the oil content of produced liquid is higher, and the oil efficiency is continuously improved at this stage because nitrogen and viscosity reducing and foaming agent solution are injected at the same moment, and the two are fully mixed to form denser foam, which plays a better plugging role. However, most of the emulsions produced at this stage have oil-water stratification after a period of static sedimentation. With the increase in the comprehensive water cut of the produced liquid, free water appeared gradually in the produced liquid, the output of the emulsion decreased, and the color slowly became lighter. The oil washing ability and emulsifying ability of nitrogen and viscosity reducing and foaming agent for cores gradually shortened, but the O/W emulsion still existed in the produced fluid.

Figures 10(b) and 10(c) and 11 demonstrate that the recovery of crude oil is 50.2% after nitrogen foam flooding; that is, nitrogen foam flooding can improve the recovery by 12.9% and reduce the water cut of the produced liquid by 10.5% on the basis of water flooding, nitrogen foam huff and puff, and viscosity reducing and foaming solution flooding [45]. Consequently, nitrogen foam flooding is appropriate for low-permeability and medium-deep heavy oil reservoir development to improve recovery efficiency.

4. Conclusions

(1) According to the experimental evaluation of foaming volume, half-life, viscosity reduction rate, and surface tension of four kinds of viscosity reducing and foaming agents, the results show that the best viscosity reducing and foaming agent is 0.5 wt% DXY-03

(2) The results of core flooding experiments show that the recovery of water flooding is only 20.3%. The recovery in the nitrogen huff and puff stage is 9.2% higher than that in the water flooding stage, and the water cut of the produced liquid decreases by 5.2%. The recovery of viscosity reducing and foaming agent solution flooding increased by 7.8%, and the water cut of the produced liquid decreased by 2%. The recovery of nitrogen foam flooding is upgraded by 12.9%, and the water cut of the produced liquid declines by 10.5%. Therefore, nitrogen foam flooding is more beneficial for improving the efficiency of crude oil flooding

(3) The microscopic visual experiments discover that in the process of microscopic oil displacement by nitrogen foam, nitrogen foam continuously expands and spreads, improves oil displacement efficiency, and greatly improves oil recovery through emulsification and viscosity reduction, squeezing action, dragging action, and Jamin effect

(4) Nitrogen foam flooding can effectively improve the serious water channel phenomenon, high water cut, and poor development effect in the middle and late stages of heavy oil reservoir development, effectively control water cut, achieve balanced production, and improve oil recovery

Data Availability

The underlying data that support the results of this study are reported in the figures.

Conflicts of Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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