Research Article

Development Performance and Pressure Field Evolution of ASP Flooding

Junjian Li , Hao Wang , Jinchuan Hu, Hanqiao Jiang, Rongda Zhang, and Lihui Tang

State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing 102249, China

Correspondence should be addressed to Junjian Li; junjian@cup.edu.cn

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ASP (alkali-surfactant-polymer) is acknowledged as an effective technology to improve the oil recovery. The microscopic displacement efficiency and macroscopic sweep efficiency have been discussed in detail for the past few years. However, development performance, especially pressure characteristics, needs to be further studied. This paper aims to explore the pressure evolution performance during ASP flooding, of which the results will shed light on development characteristics of ASP flooding. The study on ASP flooding pressure field development is conducted by laboratory and numerical methodology. A large sandpack laboratory model with vertical heterogeneous layers is used to monitor pressure performance during the ASP flooding. With the help of interpolation methods, a precise and intuitive pressure field is obtained based on pressure data acquired by limited measurement points. Results show that the average formation pressure and its location are changing all the time in the whole process. In addition, the influence of heterogeneity and viscosity on recovery and pressure is also probed in this paper. We built a numerical simulation model to match the experiment data considering the physical and chemical alternation in ASP flooding. Also, response surface methodology (RSM) is adopted to obtain the formula between pressure functions and influencing factors.

1. Introduction

After a long period of natural depletion and waterflooding, there are still considerable proportions of crude oil that are untapped in the reservoir, especially for heterogeneous reservoirs, leaving about 50%~67% original oil in place [1]. Therefore, how to enhance oil recovery (EOR) is the key to develop the remaining oil left in the reservoir and increase oil production rate. Chemical flooding technology has the potential to play an important role in unlocking the hydrocarbon resources left behind after natural depletion and waterflooding stages in mature reservoirs [2–4]. Now that quantities of physical and chemical reactions between fluid and rocks exist in the reservoir [3, 5–8], there are still many problems in the process of chemical flooding. Many researchers have studied the effects of salinity [9], dehydration [10], shear stress [11], etc. on production and developed many new chemical agents. Zhao et al. [9] developed a new antisalt polymer that was prepared by produced water and was successfully applied in low-permeability reservoirs. They

found that this new polymer outperformed HPAM in terms of viscosity, stability, resistant factor, and core displacement experiment. Zhao et al. [10] also studied the effect of composition and brine concentration on gel compression-induced dehydration. The results showed that damage occurred inside the gel after compression due to some microscopic fractures.

Alkali-surfactant-polymer (ASP) flooding, as a promising chemical EOR technology, has greatly attracted attention in recent years [12–14]. For example, the ASP flooding test conducted in Daqing Oilfield confirmed that about 20% additional OOIP was recovered [15]. The ASP flooding mechanism includes the individual mechanism of each of its components and their synergism. Polymer is responsible for improving mobility ratio and increasing the sweep efficiency, while diminishing viscous fingering issues and creating a smooth flood front in the reservoir [16]. Another mechanism of the polymer is that there is a large normal stress exerted on the residual oil droplets and oil films due to its high viscosity. Thus, the residual oil

saturation will decrease; in other words, the microscopic displacement efficiency will increase [17]. In addition, as for heterogeneous reservoirs, polymer plays an important role in profile control and increases the vertical sweep efficiency. The mechanism of surfactant is low interfacial tension (IFT) effect. Waterflooding becomes ineffective as the oil is trapped in the small pore by capillary forces; therefore, the residual oil appears. And the indicator that characterizes whether the residual oil can flow is defined as capillary number (Nc). The larger the capillary number, the more easily the residual oil flows. After the waterflooding stage, the capillary number is estimated to be about 10^{-7} [18]. An increase in the capillary number to around 10^{-5} is required to produce additional oil after waterflooding [19, 20]. And the surfactant in ASP can practically increase the capillary number by about 1000 times through its low IFT effect, thus unlocking the residual oil. Besides, the emulsification of the surfactant can hamper the breakthrough along the main streamline and increase sweep efficiency [21]. And for oil-wet reservoirs, the surfactant can alter the wettability of the rock surface to water-wet, which is beneficial to microscopic displacement efficiency. Alkali reacts with the natural organic acids (naphthenic acid group) present in the crude oil, forming an in situ surfactant (different from the injected surfactant) at the oil-water interface which reduces the interfacial tension (IFT) [22]. And alkali also possesses the emulsification and wettability alternation effect.

The synergies of ASP may be summarized as follows: (1) there is a competition of adsorption between the polymer and the surfactant; thus, the addition of polymer can reduce the adsorption of surfactant on rock surfaces [23]. (2) Alkali also reduces the surfactant adsorption, which makes the surfactant work more efficiently and reduces costs. (3) Polymer helps to stabilize emulsions due to the emulsification of surfactant and alkali, which contributes to improving the sweep efficiency. (4) There are synergies between soap (generated from the reaction between alkali and organic acid) and injected surfactant. And the mixed system possesses stronger IFT reduction and emulsification effects. (5) Polymer can react with Ca^{2+} and Mg^{2+} to prevent the surfactant from becoming calcium and magnesium salt of low activity. (6) It was reported that the decrease of water production was not only related to the increase of the viscosity of displacing fluid but also related to emulsification and scaling after injection of ASP slug [24]. (7) Molecular chain of polymer combines with the nonpolar part of the surfactant to form association under the salt condition. Besides, the interaction between the surfactant and the polymer changes the configuration of polymer aggregation and stretches molecular chain, thereby increasing the viscosity of displacing fluid [21].

Although ASP flooding has been proven to be an effective method for enhancing oil recovery and has been fruitful in actual oil fields [25–27], due to the late birth of this technique, its enhanced recovery mechanism and characteristics, especially the evolution of pressure field, remain to be explored. Physical experiments [27–29] and numerical simulation [30–34] about ASP have been conducted in recent years. Li et al. [35] studied performance of ASP systems

and effects of the individual component. Wang et al. [36] established the loss law of ASP systems, and they also found that formation damage is available in the ASP flooding EOR. Delshad et al. [31] developed a simplified ASP numerical model considering a large number of reactions, and several ASP pilots were successfully modelled. However, as an important indicator of the effectiveness of ASP flooding, pressure gained little attention in the past. So, how does pressure evolve at various stages of ASP flooding? What is the difference between the pressure in the near-well zone and that in the deep reservoir? How to guide the injection process of ASP flooding in actual oil fields according to the evolution characteristics of pressure field? These questions will become the research content of this paper.

In this study, a large sandpack heterogeneous model is used to study development performance and pressure characteristics of different ASP flooding stages. Recovery and pressure are recorded dynamically. Average pressure front, the distance between the inlet and the average pressure front, and area ratio are proposed to characterize the pressure evolution process. In addition, different experimental conditions (different viscosities and heterogeneities) are provided to discuss adaptability of heterogeneous reservoirs to ASP flooding. Lastly, evolution characteristics of the pressure field are obtained by experimental and numerical methods to gain response expression between pressure and injection parameters, which helps engineers design better project plans to extract the residual oil in an oriented way.

2. Material and Method

The physical simulation about ASP flooding pressure field development is conducted in this section. A large three-layer heterogeneous laboratory model was employed to monitor the pressure field of different stages in ASP flooding. It could provide reference and fundamental for numerical simulation.

2.1. Laboratory Model. The laboratory model used in this experiment was a 60 cm × 60 cm × 4.5 cm sandpack model with high/middle/low-permeability layers from top to bottom in order to represent heterogeneous formation. It was equipped with limited measurement points to obtain pressure data that reflect actual pressure field through the interpolation method.

Restricted to the size of the laboratory model, the amount of measurement points was limited and excessive measurement points also brought complex to the data acquisition procedure. So, how to achieve the most precise reduction by means of those measurement points and simultaneously simplify the experiment procedure as much as possible were our primary task. There were numerous measurement point configurations, such as Full-Matrix, Semimatrix, Side Bidirectional Axis, and Full + One-way Axis, which are shown in Figure 1.

To optimize the pressure monitor system, reduction rate and saturation rate were defined. The reduction rate is defined as

FIGURE 1: Available measurement point configurations. (a) Full-Matrix. (b) Semimatrix. (c) Side Bidirectional Axis. (d) Full + One-way Axis.

$$P = \frac{n}{N}, \quad (1)$$

where n is the number of valid measurement points (mistake is less than 5%) and N is the total number of measurement points. A waterflooding pressure field was available by interpolating pressure data of measurement points. By comparing the interpolation results and numerical simulation results, the reduction rate could be calculated naturally.

The effect of oil saturation process was the key basis for the success of the experiment. Based on numerical simulation, the optimal saturation mode (injection order and relationship between injection and production) and corresponding saturation rate under different pressure measurement point arrangement modes were obtained, which guided saturation process in the experiment.

The saturation rate is defined as

$$\eta = \frac{1 - \overline{S}_w}{1 - S_{wc}}, \quad (2)$$

where $\overline{S}_w$ is the average water saturation and S_{wc} is the residual water saturation.

The optimization of saturation process is shown in Figure 2. Different saturation orders were designed to calculate saturation rate through numerical simulation.

The optimization process of measurement point detection (including number, configuration, and saturation process) is shown in Figure 3. Thus, the Side Bidirectional Axis pattern achieved the largest reduction rate and would act as the candidate for pressure measurement configuration of our laboratory model, which is depicted in Figure 1(d).

The interpolation method was crucial for reduction results of the pressure field. Quantities of interpolation methods were available (e.g., "Inverse Distance to a Power," "Kriging," and "Minimum Curvature") to accomplish our goal, whereas there was slight distinction between them for our measurement point configuration. Figure 4 shows the optimization process of the interpolation method. We can see that the kriging method possessed the highest precision, which would be adopted for future study.

In conclusion, the final laboratory model is depicted in Figure 5.

In order to explore the influence of heterogeneity on pressure field improvement, models of 3 kinds of

FIGURE 2: Optimization of saturation process.

FIGURE 3: Optimization of (a) measurement points and (b) saturation points.

FIGURE 4: Optimization of the interpolation method.

FIGURE 5: Layout of measurement points in the laboratory model. (a) Schematic diagram of the laboratory model. (b) Photo of the laboratory model.

TABLE 1: Experimental conditions.

Number	Variable	
	Heterogeneity (mD)	Injection viscosity (cp)
1	200 : 600 : 1000	30
2	200 : 600 : 1000	40
3	300 : 600 : 900	30
4	300 : 600 : 900	40
5	400 : 600 : 800	30
6	400 : 600 : 800	40

heterogeneity and 2 kinds of mobility were designed. Table 1 lists permeability and injection viscosity of each model.

2.2. Experiment Material

2.2.1. ASP

(1) *Alkali*. To lower the caustic consumption of NaOH/Na₂SiO₃, sodium carbonate (Na₂CO₃) was selected instead as the alkali agent in the flooding [5, 6]. The active alkali content is 99.5%.

(2) *Surfactant*. Because of relatively low adsorption on sandstone, XPS anionic petroleum sulfonate was employed as the surfactant in the chemical preparation. The active surfactant content is 38.8%.

(3) *Polymer*. The typical synthetic polymer we used was partially hydrolysed polyacrylamide (HPAM) (Daqing Refining & Chemical Company, China), which is a water-soluble polyelectrolyte with negative charges. The solid

TABLE 2: Formula of simulated formation water.

Component	Concentration (g/L)
NaCl	2.294
KCl	0.013
CaCl ₂	0.042
MgCl ₂ · 6H ₂ O	0.172
Na ₂ SO ₄	0.075
NaHCO ₃	1.86

content is over 90%, hydrolysis degree is less than 6%, and the molecular weight ranges from 6 million to 10 million.

2.2.2. *Oil*. The oil sample we used in the experiment was the mixture of kerosene and crude oil. The viscosity was 10 MPa·s at 45°C (Table 2).

2.2.3. *Formation Water*. The salinity of the formation water sample was 4456 mg/L, and the formula is shown in Table 1.

2.3. *Experiment Equipment*. The whole displacement device included data acquisition system, constant flux pump, vacuum system, incubator, physical model, oil/water metering system, and backpressure system (Figure 6). The temperature of the experiment was 45°C.

2.4. *Experiment Procedures*. The whole experiment was divided into five steps: sealing inspection; water saturation; oil saturation; waterflooding; and ASP flooding (Figure 7).

FIGURE 6: Experiment equipment.

(a)

(b)

(c)

FIGURE 7: Experiment procedures. (a) Leak detection. (b) Water saturation. (c) Oil saturation.

Due to numerous measurement points, sealing of the laboratory model was a key factor to the success of the experiment. As is shown in Figure 7(a), we used foam to detect the leaky valves and repaired them with glue.

Particularly, during ASP flooding stages, the slug solution in each stage is shown in Table 3. After each slug solution was made, added it to the intermediate container and connected to the pipeline. The injection rate was 1 mL/min, took samples every 30 min to measure the oil production, water cut, and water phase viscosity.

3. Results and Discussion

3.1. Development Performance. Development performance is shown in Figure 8 (take model 1 as an example). In the primary waterflooding stages, oil cut was 100%, and oil recovery was increasing rapidly. At about 0.25 d of waterflooding, water front reached the outlet of the model and water cut rose sharply. And the recovery climbed steadily to 39.5% until waterflooding ended. Then, ASP flooding that contained preflush, main, auxiliary, and postprotection stages began. The minimum water cut (67.1%) occurred at the end of main slug stages. Since the end of main slug stages,

the synergistic effect of the ASP had decreased, and the water cut had gradually increased due to the retention of a large amount of the chemical agent in the pores (especially near the inlet). The pressure near the outlet maintained a high level. Finally, the subsequent waterflooding supplemented the slug displacement energy. The viscosity of the production fluid began to decrease significantly and returned to the initial level. All pressures also began to decrease, and when the water cut rose steadily to 98%, the entire development ended.

Viscosity of the produced fluid is shown in Figure 9. In the waterflooding and early stage of the main slug process, viscosity of the produced fluid remained constant about 2.5 MPa·s, which indicated that there was only water flowing out of the model. At the end of the main slug stage, the ASP system reached the outlet of the model, and viscosity of effluent increased to over 10 MPa·s. And when the subsequent waterflooding came, viscosity returned to the initial level. Meanwhile, the shear thinning phenomenon of the produced fluid was observed.

3.2. Water Cut. The water cut curve is shown in Figure 10. We can draw the conclusion that minimum water cut was smaller and its appearance time was later under the

TABLE 3: Formula of each slug in ASP flooding.

Stage	Injection volume	Polymer	Mass fraction (%)	
			Surfactant	Alkaline
Preflush slug	0.08 PV	100	0	0
ASP main slug	0.3 PV	98.5	0.3	1.2
ASP auxiliary slug	0.2 PV	98.9	0.1	1
Postprotection slug	0.2 PV	100	0	0

FIGURE 8: Development performance of No. 1 experiment.

FIGURE 9: Viscosity change of produced liquid.

condition with higher injection viscosity. Water cut began to decrease earlier but to a small extent as to the model with strong heterogeneity. It was worth noting that, at the same viscosity, the water cut curve fluctuation of the 200 : 600 : 1000 model was more severe than the other two models, demonstrating that the model of strong heterogeneity was unstable and it was prone to occur local breakthrough phenomenon.

3.3. Oil Recovery. Under the same conditions, the stronger the heterogeneity, the greater the contradiction between layers due to permeability difference and the lower the oil recovery in the waterflooding stage (Figure 11). In the ASP

flooding stage, the model with weak heterogeneity can better recover oil in the middle and low-permeability layers. For models with the same heterogeneity, a greater enhanced recovery corresponded to a higher viscosity of the injected fluid. Due to the higher viscosity/concentration, injected fluid could reduce the mobility ratio and improve the profile (especially the high and the middle permeability layer) more effectively. And this phenomenon was more remarkable in the model with strong heterogeneity.

3.4. Liquid Production Index per Meter. Liquid production index was an indicator of the production ability of oil wells.

FIGURE 10: Water cut curve comparison. (a) Water cut with viscosity of 40 MPa·s. (b) Water cut with viscosity of 30 MPa·s.

FIGURE 11: Oil recovery comparison. (a) Oil recovery with viscosity of 40 MPa·s. (b) Oil recovery with viscosity of 30 MPa·s.

Prediction of the liquid production index under different water cut conditions was a main basis for the production evaluation. In the ASP flooding stages, liquid production index per meter showed a falling tendency (Figure 12), which was ascribed to high viscosity of the ASP system. Due to the increase of macroscopic sweep efficiency and microscopic displacement efficiency, liquid production index restored to a certain degree in the main slug stages.

At the same viscosity, the liquid production index per meter was at a lower level with stronger heterogeneity, which was obvious in the preflush stage. Meanwhile, liquid production increase during the main slug stage was not obvious. After the auxiliary slug stage, viscosity and heterogeneity had little effect on the liquid production index.

3.5. Pressure Field Development

3.5.1. One-Dimensional Reduction. As is shown in Figure 13, the lower left corner was the inlet, the upper right corner was

the outlet, and the diagonal line constituted the main streamline. In the one-dimensional pressure field development reduction, we selected the main streamline as our research objective.

The pressure difference along the main streamline was divided into four parts (Figure 14). In the waterflooding stages, all 4 pressure differences were small and tended to be stable at the end. Then pressure near the inlet increased sharply as the preflush polymer was injected into the model. The pressure wave gradually spread forward along the main streamline, and pressure in the middle also began to climb. It was observed that the middle part pressure soared, indicating the previous polymer solution migrated ahead. During the late stage of the main slug, the injected polymer travelled to the vicinity of the outlet, causing the last two pressure differences (ΔP_3 and ΔP_4) rose in turn but the amplitude was weakened. When injecting postprotection slug, the value of 4 pressure differences reversed.

FIGURE 12: Liquid production index per meter (a) with viscosity of 40 MPa-s and (b) with viscosity of 30 MPa-s.

FIGURE 13: Schematic diagram of pressure differences along the main streamline.

FIGURE 14: Sectional pressure differences.

FIGURE 15: Two-dimensional pressure field of (a) different heterogeneities and (b) different viscosities.

FIGURE 16: Average pressure curve comparison of different heterogeneities and viscosities.

FIGURE 17: Production dynamics and pressure field.

3.5.2. Two-Dimensional Reduction. The interpolation method was used to process the data collected at the measuring point for the purpose of restoring the two-dimensional pressure field. Figure 15(a) shows the two-dimensional pressure field of different heterogeneities. From the preflush to the auxiliary slug stage, pressure of model ② was lower than model ① but maintained a higher level in the late period (the postprotection and the subsequent waterflooding stage). There was an obvious breakthrough along the main streamline in model ②. The pressure tendency of model ① was to rise primarily and then dropped, while the pressure of model ② fluctuated in the late stage.

Figure 15(b) is the two-dimensional pressure field of different viscosities. The pressure increased to a larger extent and the pressure gradient was more obvious of highly viscous system. For model ②, because of the low displacement

intensity, the difference between three layers was relatively small, and the moving rate was similar. Model ① has a better recovery in high and middle permeability layers (mainly the middle permeability layer), and model ② has better recovery in middle and low-permeability layers (mainly the lower permeability layer).

The average formation pressure was a significant indicator for reservoir energy, and it could be acquired via interpolated data of two-dimensional reduction. It was a steeply rising-falling-rising in fluctuation-falling process in our experiment (Figure 16). The preflush slug pressure rose greatly but contributed little to the average formation pressure. The average pressure of the model with weak heterogeneity was lower, but its pressure increasing scale in the ASP flooding stage was much larger than that of other models. And the pressure and pressure increasing scale were at a higher level under the higher viscosity condition.

FIGURE 18: Average pressure difference curve. (a) Average pressure difference between the middle and the high permeability layer. (b) Average pressure difference between the low and the high permeability layer.

FIGURE 19: Average pressure front of (a) different heterogeneities and (b) different viscosities.

Through the above calculation and analysis, the corresponding relationship between production dynamics and the pressure field is depicted in Figure 17.

In order to compare pressure of each layer under different heterogeneous conditions, we made the subtraction between pressure of the middle or low-permeability layer and that of the high permeability layer (Figure 18). Due to the resistance, the average formation pressure of the middle and low-permeability layers was greater than that of the high permeability layer. In the waterflooding stage, the model of strong heterogeneity had a great pressure difference between the middle and low-permeability layer, whereas in the ASP flooding stage, the middle and low-permeability layer possessed a great pressure difference in the homogeneous model. The model of weaker heterogeneity represented a

more frequent fluctuation of pressure difference, indicating that the flow steering between layers was more sensitive and frequent.

Based on the two-dimensional pressure field above, we could find out the average pressure front characteristics (Figure 19(a)). The average pressure front figure reflected the overall pressure level of different layers. We could see that the pressure front became smooth in the late period of ASP flooding, showing that the flow profile was improved. Model ② (weak heterogeneity) performed better in the subsequent waterflooding according to its smoother pressure front. In particular, as for the low-permeability layer, profile amelioration of model ② performed better than that of model ①.

Figure 19(b) is the average pressure front of different viscosities. Ascribed to low viscosity, there was an apparent

FIGURE 20: Schematic diagram of distance between the average pressure front and the inlet.

FIGURE 21: L of (a) high permeability layer, (b) middle permeability layer, and (c) low-permeability layer with different viscosities.

front breakthrough phenomenon in model ① in the preflush and subsequent waterflooding stage. The injection profile modification on the high permeability layer of model ① was effective which was ascribed to stabilization effect on pressure front of the high-viscosity injected agent. And the low-viscosity agent was prone to enter the low-permeability layer and improved its development effect.

Here, we define L was the distance between the inlet and the average pressure front in the main streamline and d was the distance between the inlet and the model centre point (Figure 20). In this experiment, $d = 39.6$ cm.

And L versus injection volume (PV) curve of different viscosities is shown in Figure 21. The figure shows that, at different viscosity conditions, L declined initially and rose later. L was close to d and demonstrated a more stable pressure front. And the most stable pressure front occurred in the main slug stage. At low viscosity, the movement amplitude of the pressure front was reduced, and declining time was delayed. It was also concluded that the low-viscosity agent had little influence on the middle permeability

layer but had a great influence on the high and low-permeability layer.

In order to make a deep sight in the pressure front advancement, we defined the area ratio of the average pressure front as

$$S = \frac{S_1}{S_2}, \quad (3)$$

where S_1 is the area enveloped by the pressure front and S_2 is the area of the rest part of the pressure field, which is illustrated in Figure 22. The pressure field would be more uniform if S is closer to 1, and in this case, the development performance was better.

Under different heterogeneity conditions, S initially declined and rose later (Figure 23). In the preflush stage, pressure near the inlet increased sharply, resulting in the retreat of pressure front, so the value of S began to fall. And the pressure field was likely to be more uniform during the main and auxiliary stages for $S < 1 \pm 0.5$. At the subsequent waterflooding stage, S returned to a relatively high level.

FIGURE 22: Schematic diagram of the area ratio.

FIGURE 23: S of (a) high permeability layer, (b) middle permeability layer, and (c) low-permeability layer with different heterogeneities.

Compared with the other layers, the area ratio of the middle permeability layer decreased more obviously, revealing the best profile control. The area ratio of the relatively homogeneous model was less than that of other models, indicating that advancement of the pressure front preferred to be more stable, which ensured a better development performance.

In summary, with regard to the strong homogeneous formation, the water cut curve performed a wide, shallow, and more fluctuant funnel, which had poor production ability. In addition, waterflooding and ASP flooding recovery were much lower. On the contrary, for the weak homogeneous formation, the inlet pressure and average pressure increasing scale of the ASP stage skyrocketed to a larger extent, and in this case, achieving a good development effect of the low/middle permeability and less contradiction between different permeability layers. Viscosity of the injected agent also made a difference to the ASP flooding effect. When a high-viscosity agent was injected into the

reservoir, water cut would drop later and drastically, and the ASP flooding would be more efficacious. Low-permeability layer was attractive to the low-viscosity agent; thus, its development status was ensured to be enhanced naturally. And the high-viscosity agent was beneficial to profile control, which unlocked the untouched reserve.

3.6. Numerical Simulation Methodology. Given the production data and chemical properties from laboratory test, the numerical model was established all based on the data acquired from the physical model. After history match, the numerical simulation model was used to further study the development process of the ASP flooding.

3.6.1. Numerical Simulation Model of ASP Flooding. At present, most mechanisms could be characterized by the commercial reservoir simulators, but there were still some parts that cannot be described reasonably. In this section,

FIGURE 24: Relative permeability curves used in the simulator.

FIGURE 25: The numerical simulation model.

FIGURE 26: History matching result of water cut.

FIGURE 27: History matching result of recovery.

the low adsorption so that the ASP agent would work further.

The adsorption was characterized by inputting a series of isothermal adsorption curves, which were expressed as Langmuir equation:

$$Ad = \frac{A \times c_i}{(1 + B \times c_i)} \quad (4)$$

where c_i is the component of fluid and A and B is the constant related to temperature. It is noted that the maximum adsorption is A/B .

considering the physical and chemical process during the ASP flooding, we established the numerical simulation model on the basis of the CMG reservoir simulator. The factors that were considered in the model contain as follows:

(1) *Adsorption*. Due to the higher surface to volume ratio of the rock, adsorption phenomenon would happen during the ASP flooding. The adsorption caused the retardation of surfactant transport [37]. And the adsorption was higher in the low-permeability rock as it had smaller grain sizes, and thus, it had a larger specific surface [38]. We preferred

(2) *Porosity and Permeability Reduction*. When the polymer passes through the porous medium, the adsorption due to chemical or mechanical retention would reduce the pore volume, thereby reducing the permeability of the formation. It could be characterized by the following formula:

$$\overline{K} = \frac{k}{R_k}, \quad (5)$$

where k is the initial permeability of the formation; R_k is the function of the adsorption and the residual resistance factor, which is defined by

FIGURE 28: Pressure field of the numerical simulation model.

TABLE 4: Values of influence factors in RSM.

Variables	Value 1	Value 2	Value 3
Permeability (md) (k_r)	300	600	900
Variation coefficient (V_k)	0.27	0.41	0.54
Viscosity (cp) (μ)	30	40	50
Injection rate/(PV/a) (ν)	0.2	0.25	0.3

$$R_k = 1 + (\text{RRF} - 1) \times \frac{\text{AD}}{\text{ADMAXT}}, \quad (6)$$

where AD is the cumulative adsorption of the polymer per unit volume rock, ADMAXT is the maximum of AD, and RRF is the residual resistance factor, which can be determined through experiments.

(3) *Viscosity*. In CMG STARS, we used the nonlinear mixture method to calculate the liquid mixed viscosity:

$$\ln(\mu_\alpha) = \sum_{i=1}^{n_{\text{CES}}} f(f_{\alpha_i}) \times \ln(\mu_{\alpha_i}) + N \times \sum_{i=1}^{n_{\text{CES}}} f_{\alpha_i} \times \ln(\mu_{\alpha_i}), \quad (7)$$

where μ_α is the mixed viscosity, μ_{α_i} is the viscosity of component i , f_{α_i} is the weight of i th noncritical component in the water or oil phase, and $f(f_{\alpha_i})$ is the weight of i th critical component in the water or oil phase.

Besides, since the ASP system is a kind of non-Newtonian fluid, its rheology inevitably has an impact on its viscosity. The relationship between the shear velocity and Darcy velocity was described as [7]

$$\dot{\gamma} = \frac{\gamma_{\text{fac}} \times |u_l|}{\sqrt{k_{\text{abs}} \times k_{rl} \times \phi \times S_l}}, \quad (8)$$

where k_{abs} and Φ are the absolute permeability and porosity, u_l , k_{rl} , and S_l are the Darcy velocity, relative permeability, and saturation of some phase, respectively.

In addition, the salinity of formation water, emulsification, and degradation were also considered in the numerical model. Polymer, such as HPAM, is very sensitive to the salinity of formation water. Due to the presence of emulsification, emulsion that has higher apparent viscosity will form in the formation, thereby increasing the viscosity of the ASP agent. The degradation of the polymer contributes to a lower viscosity of the ASP agent. All of the above factors were integrated into the nonlinear mixture method.

(4) *Inaccessible Pore Volume*. As the macromolecular polymer flows through the porous medium, it may be confined to the tiny throat. And those pores that are not in contact with the flowing macromolecular polymer are called inaccessible pore volumes (IPV) [8]. It is also verified by the experiment [25]. So, the effective porosity of the ASP agent was defined as

$$\phi_p = (1 - \text{IPV}) \times \phi, \quad (9)$$

where ϕ is the initial porosity.

(5) *IFT*. Owing to the addition of surfactant and alkali, the interfacial tension is significantly reduced, resulting in an increase in the capillary number (Nc) and a decrease in residual oil saturation (S_{or}). The synergistic effect of the

TABLE 5: Final schemes used in RSM.

Schemes	Permeability (mD)	Variation coefficient	Viscosity (MPa·s)	Injection rate (PV/a)
1	600	0.408	30	0.2
2	600	0.408	50	0.3
3	600	0.272	50	0.25
4	600	0.408	40	0.25
5	300	0.544	40	0.25
6	900	0.272	40	0.25
7	300	0.408	40	0.2
8	900	0.408	30	0.25
9	300	0.272	40	0.25
10	600	0.408	40	0.25
11	900	0.408	50	0.25
12	300	0.408	30	0.25
13	600	0.408	40	0.25
14	600	0.408	40	0.25
15	600	0.408	40	0.25
16	600	0.408	50	0.2
17	600	0.272	30	0.25
18	600	0.544	50	0.25
19	300	0.408	50	0.25
20	900	0.408	40	0.3
21	600	0.272	40	0.2
22	600	0.544	30	0.25
23	900	0.408	40	0.2
24	900	0.544	40	0.25
25	600	0.544	40	0.3
26	600	0.408	30	0.3
27	600	0.544	40	0.2
28	600	0.272	40	0.3
29	300	0.408	40	0.3

FIGURE 29: Objective pressure employed in RSM.

(a)
FIGURE 30: Continued.

FIGURE 30: The response surface results.

surfactant and alkali was characterized by inputting the interfacial tension at different concentrations.

(6) *Relative Permeability Curve*. The relative permeability curve would alter during the ASP flooding. CMG STARS can solve this problem through interpolation methods (Figure 24).

A laboratory-scale $60\text{ cm} \times 60\text{ cm} \times 4.5\text{ cm}$ model was established (Figure 25). All the parameters were identical to the experiment above.

The history match result is shown in Figures 26 and 27. The fitting degree of water cut was 92% and that of oil recovery was 90%.

Figure 28 shows the oil saturation calculated by numerical simulation. In the waterflooding stage, there was obvious water advancing along the mainstream line. The development effect increased with the increase of permeability, and the difference between layers was notable. In the ASP flooding, displacement effect on both sides of the mainstream line was significantly improved. The sweeping and displacement efficiency were also continuously improved, and the difference between layers was weakened.

3.7. Evolution Characteristics of Pressure Field of ASP Flooding. The evolution characteristics of pressure field of ASP flooding were going to be studied through response

surface methodology (RSM), including the heterogeneity, mobility ratio, injection rate, and formation permeability. And the values of these influence factors are listed in Table 4.

A total of 29 experimental groups were finally generated according to the RSM design requirements (Table 5). Substitute these data into the numerical simulation model, and we can obtain the development performance and data for future use.

We selected the following points, which are illustrated in Figure 29, as our objective functions in RSM:

- (1) P_1 : the pressure when the preflush slug stage ended
- (2) $P_{\max}$: the maximum pressure of the main slug stage
- (3) P_2 : the pressure when the main slug ended
- (4) P_3 : the pressure when the auxiliary slug ended
- (5) P_4 : the pressure when the postprotection slug stage ended
- (6) $(P_{\max} - P_{\text{wf}})/(P_0 - P_{\text{wf}})$: the increase magnitude of pressure,
where P_{wf} is the well bottom pressure and P_0 is the pressure when the waterflooding ended.
- (7) $PV_{\max}$: The injection volume when $P_{\max}$ occurred

Then, RSM was carried out to explore the quantitative relationship between influence factors and our objective

functions. The response surface results are shown in Figure 30 (Take $(P_{\max} - P_{\text{wf}})/(P_0 - P_{\text{wf}})$ as an example). Analysing the response surfaces, we could obtain the conclusion that a larger increase magnitude of pressure was corresponding to a larger average permeability, a faster injection rate, and a higher viscosity. With the increase of variation coefficient, the increase magnitude of pressure declined primarily, which was followed by a rise. And the influence levels were sorted as injection rate > average permeability > viscosity > variation coefficient.

Hence, the response expression of the increase magnitude of pressure was acquired:

$$\begin{aligned} \frac{(P_{\max} - P_{\text{wf}})}{(P_0 - P_{\text{wf}})} = & 2.65 - 1.1 \times 10^{-3} k_r - 6.92 V_k - 7.67 \\ & \times 10^{-3} \mu - 6\nu - 1.1 \times 10^{-4} k_r V_k + 2.7 \\ & \times 10^{-5} k_r \mu + 7 \times 10^{-3} k_r \nu + 0.02 V_k \mu \\ & + 3.37 V_k \nu + 0.036 \mu \nu - 8.1 \times 10^{-7} k_r^2 \\ & + 6.35 V_k^2 - 1.1 \times 10^{-4} \mu^2 + 22 \nu^2 \end{aligned} \quad (10)$$

and that of other objective functions emerged in the same way.

4. Conclusions

The following conclusions can be drawn from both experimental and numerical results:

- (1) Pressure field proved to be an effective indicator for the development performance in the ASP flooding. Pressure in the main slug stage increased dramatically and began to decline in the auxiliary slug stage. The preflush slug stage contributed little to the average formation pressure.
- (2) The low-permeability layer was favourable for the entry of low-viscosity injection fluid, thereby improving its development effect. The high-viscosity fluid preferred to improve the flow profile.
- (3) The stronger heterogeneity resulted in the more prominent contradiction between the low-permeability recovery and profile improvement. Single-viscosity slug was difficult to meet this contradiction.
- (4) The response surface methodology was used to determine the relationship between pressure field and development parameters.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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