

Feasibility Study on Chemical Flooding in Super High Porosity and Permeability Heavy Oil Reservoir

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Abstract

In this paper, the feasibility study of chemical flooding is carried out for ultra-high porosity and high permeability heavy oil field with permeability higher than $10 \mu\text{m}^2$ and porosity greater than 35%. The viscosity-concentration relationship of four kinds of oil flooding systems such as hydrolyzed polyacrylamide, structural polymer A, structural polymer B and gel was studied. The results showed that the viscosity of ordinary polymer and structural polymer B was lower compared with other two types of oil displacement agents, and the viscosity of structural polymer A was higher. The higher the concentration, the higher the viscosity retention rate. The gel system has the highest viscosity and best anti-shear ability. The resistance coefficient and residual resistance coefficient of structural polymer A and gel system were further studied. The results show that permeability, velocity and polymer concentration all affect the resistance coefficient and residual resistance coefficient. From the point of view of resistance establishment ability, it is considered that structural polymer A is not suitable for permeability formation above $10 \mu\text{m}^2$. Gel system has stronger ability to establish resistance coefficient than structural polymer A flooding system, and it is more feasible for formation system with permeability above $10 \mu\text{m}^2$.

Keywords

Super High Porosity and High Permeability, Chemical Flooding, Viscosity-Concentration Relationship, Resistance Coefficient, Coefficient of Residual Resistance

1. Introduction

According to different permeabilities, reservoirs [1] [2] [3] can be divided into

five types: super high permeability reservoir: air permeability of reservoir rock $> 2000 \times 10^{-3} \mu\text{m}^2$; high permeability reservoir: $500 \times 10^{-3} \mu\text{m}^2 \leq$ air permeability of reservoir rock $\leq 2000 \times 10^{-3} \mu\text{m}^2$; medium permeability reservoir: $50 \times 10^{-3} \mu\text{m}^2$ air permeability of reservoir rock $< 500 \times 10^{-3} \mu\text{m}^2$; low permeability reservoir: air permeability of reservoir rock $< 50 \times 10^{-3} \mu\text{m}^2$. According to porosity, it is generally divided into ultra-high porosity reservoir (porosity $> 30\%$), high porosity reservoir (porosity $25\% - 30\%$), medium porosity reservoir (porosity $15\% - 25\%$), low porosity (porosity $10\% - 15\%$) and ultra-low porosity (porosity $< 10\%$). Different types of reservoirs have different development methods [4] [5], for reservoirs with high permeability and serious heterogeneity, chemical flooding is often used. In low permeability reservoirs, fracturing measures can be adopted, and then water injection and gas injection can be used to supplement formation energy. Chemical flooding [6] [7] [8] technology has become an important means to greatly enhance oil recovery in medium and high permeability oilfields. Chemical flooding technology plays an important role in increasing production and stabilizing production in both onshore and offshore oilfields. The mechanism of polymer flooding [2] [3] [4] [5] is to improve the oil-water mobility ratio, effectively improve the sweep efficiency of displacement phase, reduce oil saturation, and achieve the improvement of oil recovery. Bohai oilfield belongs to offshore oilfield. Chemical flooding technology of high porosity and high permeability reservoir started in 2003. After more than ten years of development, it has formed a large scale and achieved good economic benefits. The research on adaptability of chemical flooding for ultra-high porosity and high permeability heavy oil fields with average permeability greater than $10 \mu\text{m}^2$ can provide technical countermeasures for efficient development of such reservoirs; on the other hand, it is of great significance to expand the scope of chemical flooding in offshore oilfield and improve chemical flooding technology. In this paper, the viscosity, resistance coefficient and residual resistance coefficient of partially hydrolyzed polyacrylamide, structural polymer A [9], structural polymer B [10] and gel were studied, and the best system was selected out of four.

2. Experimental Conditions and Methods

2.1. Experimental Conditions

Experimental temperature: 50°C .

Experimental water: the simulated water is prepared according to the ion composition of the mixed water in the oilfield at the present stage. The mineralization degree is $13,930 \text{ mg/L}$. the ion composition is shown in **Table 1**.

Experimental drug:

Table 1. Ion composition of simulated water in oil field.

Na^+ (mg/L)	Cl^- (mg/L)	SO_4^{2-} (mg/L)	HCO_3^- (mg/L)	Na^+ (mg/L)	Ca^{2+} (mg/L)	Mg^{2+} (mg/L)	K^+ (mg/L)	Sr^{2-} (mg/L)	TDS (mg/L)
1934	5887	229	1609	4826.7	143	98	4023	4.7	13,930

Partially hydrolyzed polyacrylamide (HPAM, industrial product, molecular weight of 1200×10^4 g/mol, hydrolysis degree 21.2%), structural polymer A (solid content 91.22%, molecular weight 1200×10^4 g/mol, hydrolysis 21.65%), structural polymer B (molecular weight 600×10^4 g/mol), gel (partially hydrolyzed polyacrylamide and phenolic resin crosslinking agent and auxiliaries) Gel system).

2.2. Experimental Methods

1) Viscosity concentration relationship before and after shearing

The simulated formation water was used to prepare different polymer mother liquor (5000 mg/L) and diluted to different polymer concentrations. The polymer was sheared with a warming agitator at a shear rate of 3000 r/min and a shearing time of 20 s. The viscosity and viscosity retention rate of polymer solution before and after shear were measured, and the viscosity concentration relationship and viscosity retention curve before and after shear were drawn. The viscosity and concentration of all kinds of polymers and gels before and after shearing were determined.

The apparent viscosity retention was calculated according to the formula

$$R_v = \frac{\eta_t}{\eta_0} \times 100\%$$

where,

R_v —apparent viscosity retention rate, expressed as a percentage;

η_0, η_t —apparent viscosity of polymer solution before and after stirring, unit: mPa·s.

2) Resistance coefficient and residual resistance coefficient

The resistance coefficient and the residual resistance coefficient are the technical indicators of the ability of the PPG system to improve mobility ratio and reduce reservoir permeability. The experimental device is shown in **Figure 1**, and the flow rate was 1 mL/min. Experimental steps are as follows:

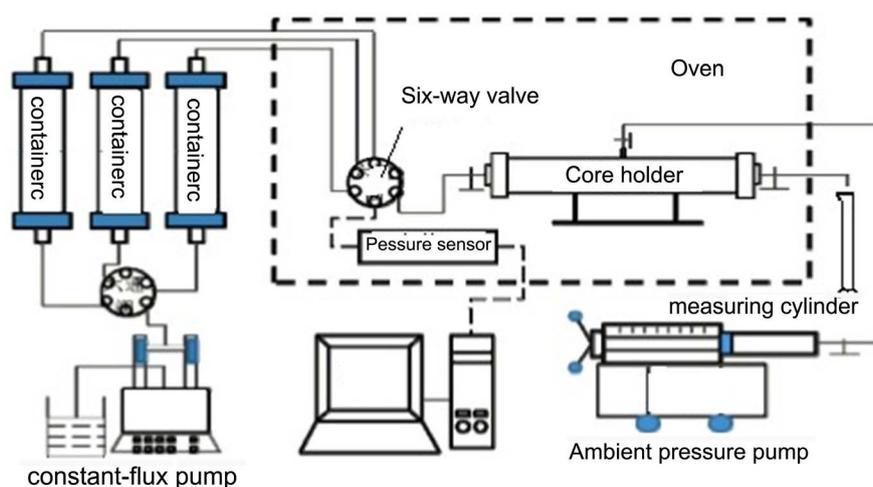


Figure 1. Schematic diagram of injection experimental device of profile control agent.

- a) All devices were connected according to **Figure 1**;
- b) The simulated water and PPG solution was put into the middle containers respectively;
- c) The incubator was preheat to the experimental temperature of 65°C;
- d) Water was injected into the sand pack at a constant flow rate until the pressure is stable, at which the pressure difference is ΔP_{wb} ;
- e) PPG solution was injected with the same flow rate as the water injection until the pressure is stable, at which the pressure difference is ΔP_{wb} ;
- f) The simulated water was injected with the same flow rate as the water injection until the pressure is stable, at which the pressure difference is ΔP_{wa} .

The resistance coefficient is shown in formula (1) and the residual resistance coefficient is shown in formula (2):

$$F_R = \frac{\Delta P_{wh}}{\Delta P_{wi}} \quad (1)$$

$$F_{RR} = \frac{\Delta P_{wa}}{\Delta P_{wi}} \quad (2)$$

where,

F_R —the resistance coefficient;

F_{RR} —the residual resistance coefficient;

ΔP_{wh} —Pressure difference when the pressure of PPG solution is stable, MPa;

ΔP_{wi} —Pressure difference when the pressure of initial waterflooding is stable, MPa;

ΔP_{wa} —The pressure difference when the PPG solution is injected and the pressure of subsequent waterflooding is stable, MPa.

3) Oil displacement experiment with parallel sand pack

The parallel sand pack experiment reflects the heterogeneity of the formation and the profile adjustment of the system. The experimental process is as follows:

- a) Connect all devices according to **Figure 2**;
- b) Put the simulated water, simulated oil and chemical solution into the container in the middle respectively;
- c) Preheat the incubator to the experimental temperature of 65°C;

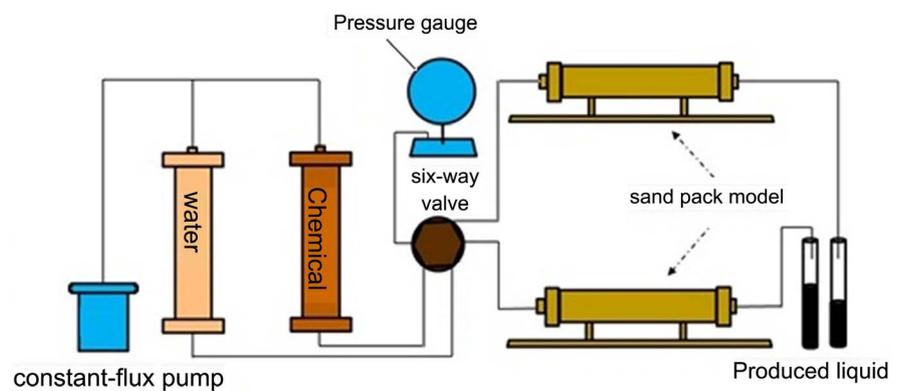


Figure 2. Schematic diagram of parallel sand-filling tube oil displacement device.

d) The permeability of water phase in sand pack is calculated when the pressure is stable after injecting water in a constant flow rate;

e) Saturate the simulated oil at high temperature to prevent core damage or sand migration caused by too high viscosity of the simulated oil. The saturation temperature should be 10°C higher than the experimental temperature. Record the volume of displaced water, and that value is the saturated oil volume. (recording must be finished at experimental temperature, and the device must be sealed well to prevent loss caused by volatilization);

f) Aging sand pack: close the inlet and outlet and age for 72 hours at the experimental temperature;

g) Set water cut for water flooding;

h) Inject the chemical solution at same flow rate as water injection until the pressure is stable;

i) Inject the simulated water at same flow rate as water injection to the target water cut.

3. Experimental Results

3.1. Viscosity Concentration Relation

1) Partially hydrolyzed polyacrylamide

Dilute the mother liquor of partially hydrolyzed polyacrylamide to 1000 mg/L, 2000 mg/L, 3000 mg/L and 4000 mg/L, and shear with Wuyin stirrer. Determine the viscosity after shearing, viscosity concentration relationship and viscosity retention rate are shown in **Figure 3**.

2) structural polymer A

The mother liquor of structural polymer A was diluted to 1000 mg/L, 2000 mg/L, 3000 mg/L and 4000 mg/L. the shear viscosity was determined by Wu Yin agitator. The viscosity concentration relationship and viscosity retention rate were shown in **Figure 4**.

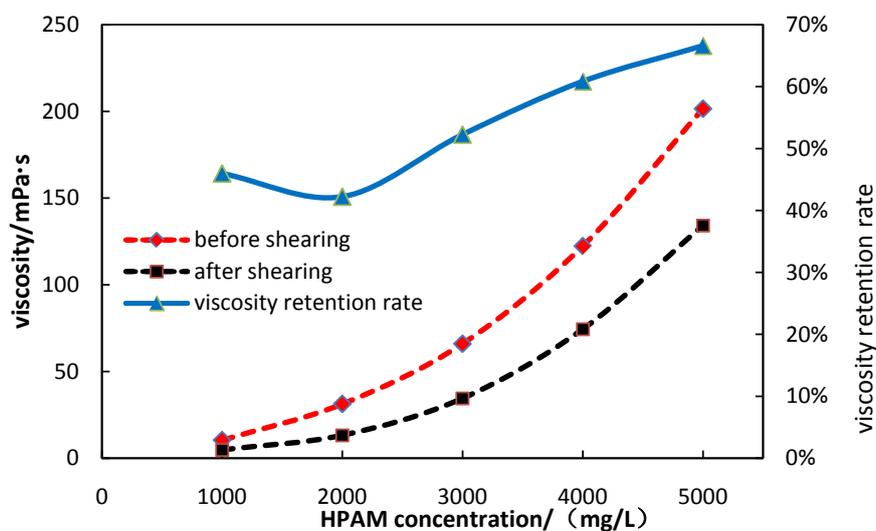


Figure 3. Viscosity concentration curve of HPAM before and after shearing.

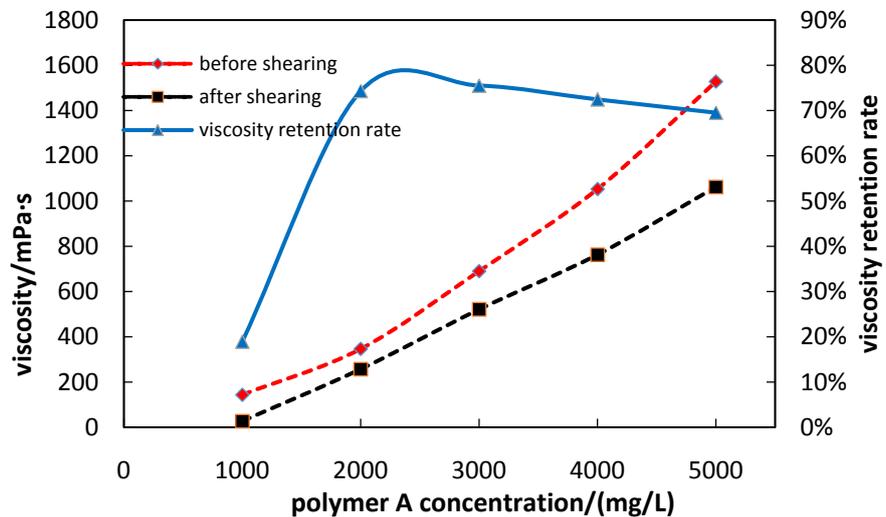


Figure 4. Viscosity concentration curve of polymer A before and after shearing.

3) structural polymer B

Dilute the mother liquor of structural polymer B to 1000 mg/L, 2000 mg/L, 3000 mg/L, 4000 mg/L, and shear with Wuyin agitator. Determine the viscosity after shearing. See **Figure 5** for viscosity concentration relationship and viscosity retention rate.

4) gel

Gel composition: 1000 mg/L - 3000 mg/L structural polymer A +0.15% main crosslinking agent +0.15 cross linking agent, main crosslinking agent and auxiliary crosslinking agent concentration unchanged, changing polymer viscosity. Crosslinking time: 30 h, crosslinking temperature: 50°C. As the concentration of the main crosslinking agent and the crosslinking agent is unchanged, the consistency of the gel before and after shearing is shown in **Figure 6** with the polymer concentration as the abscissa.

Gel stability is an important property that restricts its application. Static gel aging for 15 days at different concentrations of 50°C is shown in **Table 2**. From **Table 2**, it is known that gel 2000 mg/L has higher viscosity and higher shear retention rate after gelation. When polymer concentration is 3000 mg/L, long time static will lead to gel dehydration, so the polymer concentration in gel formula is 2000 - 2500 mg/L, and the performance is better.

The data in **Figures 2-5** are summarized to get **Table 3**. **Table 3** shows that the viscosity of ordinary polymer and structural polymer B is lower before and after shearing. The viscosity of structural polymer A is higher before and after shearing. The higher the concentration, the higher the viscosity retention rate, the highest viscosity of the gel system, and the best shear resistance. and gel were used to carry out the experiment of drag coefficient and residual resistance coefficient.

3.2. Resistance Coefficient and Residual Resistance Coefficient

The porosity of sand filling pipe with permeability of 10 μm^2 and 20 μm^2 is

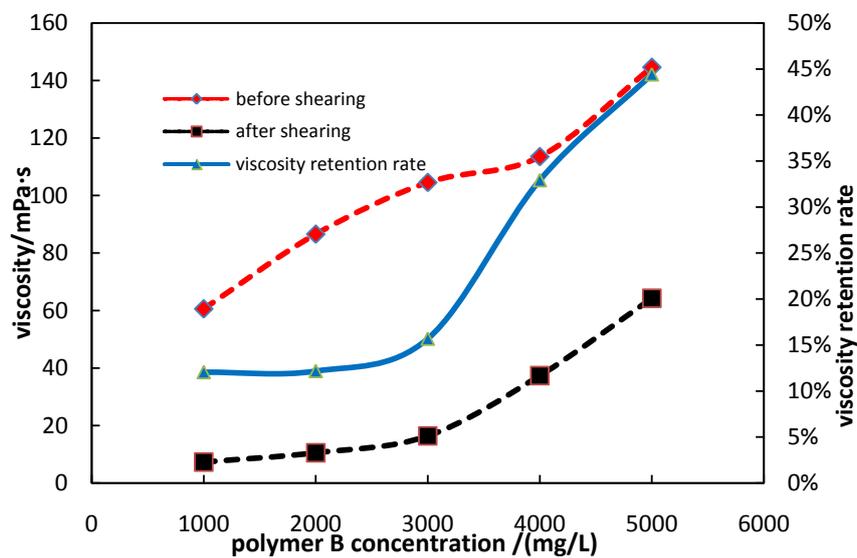


Figure 5. Viscosity concentration curve of structural polymer B before and after shearing.

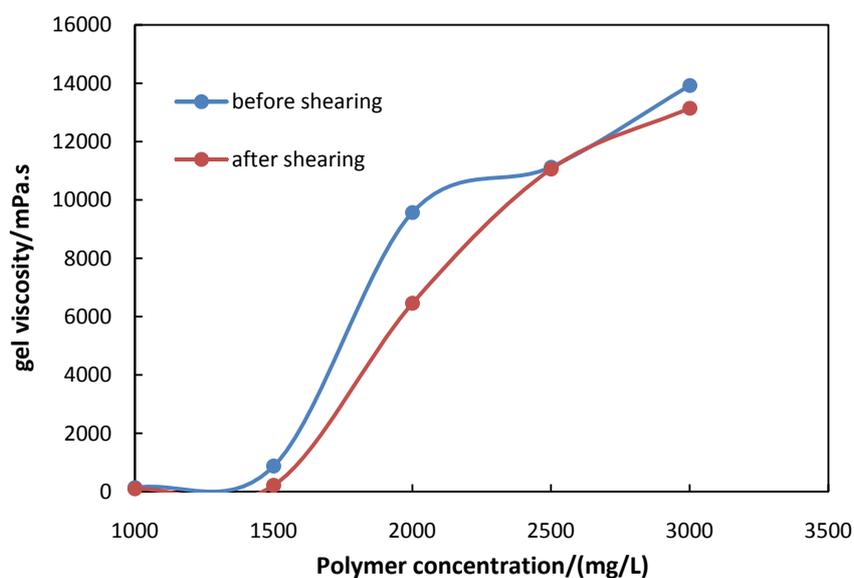


Figure 6. Viscosity curve of gel before and after shearing.

Table 2. Gel aging results.

polymer concentration (mg/L)	gel aging results
1000	No dehydration
1500	No dehydration
2000	No dehydration
2500	No dehydration
3000	Dehydration after 15 days

higher than 35%. The drag coefficient and residual resistance coefficient were determined by injecting structural polymer A or gels respectively. The structural

Table 3. Summary of viscosity concentration relationship of system.

system	viscosity before shearing/mPa·s	viscosity after shearing/mPa·s	viscosity retention rate/%
HPAM	10 - 201	4.8 - 134.2	45 - 66
structural polymer A	143 - 1528	27 - 1062	19 - 70
structural polymer B	60 - 144	7 - 64	12 - 44
gel	135 - 13,924	97 - 13,145	72 - 99

polymer A concentration is 1250 mg/L - 3000 mg/L, the results are shown in **Table 4**, **Table 5**; gel formula is 1500 mg/L polymer +1500 mg/L phenolic resin cross-linking agent +1500 mg/L assistant, and the results are shown in **Table 6**.

It can be seen from **Table 4** to **Table 5** that the resistance coefficient building ability of structural polymer A varies greatly among different flow rates under the permeability model of 10 μm^2 . High flow rate of 1.5 ml/min at low concentration has strong resistance building ability, and low flow rate of 0.5 ml/min at high concentration has the maximum resistance building ability. When the permeability is greater than 10 μm^2 , the influence of each flow rate on resistance coefficient establishment ability is small, from the point of view of resistance building ability, it is considered that polymer is not suitable for formations with permeability above 10 μm^2 . From **Table 6**, it is known that when the permeability of the gel system is 10 μm^2 the resistance coefficient of 0.5 mL/min is minimum. When the permeability is greater than 10 μm^2 , the smaller the flow rate, the greater the drag coefficient and the residual resistance coefficient. The gel system has stronger ability to establish resistance coefficient and residual resistance than structural polymer A flooding system.

3.3. Gel Flooding System to Improve Recovery Test

Use the parallel sand filling pipe model to study on gel enhanced oil recovery capability.

Formula: 2500 mg/L polymer + 0.15% cocrosslinking agent + 0.15% cocrosslinking agent.

Injection volume: 0.3 times of total pore volume.

The permeability and porosity of high-low permeability model and the change of diversion efficiency and recovery degree in each stage of displacement experiment were recorded in the process of displacement (**Table 7**).

With the injection pore volume multiplier as the abscissa, the pressure recovery and moisture content were used as the ordinate to draw the parallel recovery factor and water cut curve of weak gel system see in **Figure 7**.

Taking the multiple of injected pore volume as the abscissa and the diversion rate as the ordinate, the variation trend chart of diversion rate with the change of injection stage in high and low permeability formation is drawn as shown in **Figure 8**.

The results were as follows

Table 4. Resistance coefficient and residual resistance coefficient of at $10 \mu\text{m}^2$.

		flow rate mL/min		
concentration (mg/L)		0.5	1.0	1.5
resistance coefficient	1250	50.5	78	89.21
	2250	85	74	92
	3000	110	70	100
residual resistance coefficient	1250	2.72	5.77	4.89
	2250	7	6	4.5
	3000	10.56	8.81	4.48

Table 5. Resistance coefficient and residual resistance coefficient of at $20 \mu\text{m}^2$.

		flow rate mL/min		
concentration (mg/L)		0.5	1.0	1.5
resistance coefficient	1250	1.72	2.2	2.7
	2250	8.2	5.54	7.02
	3000	13.2	13.5	14.1
residual resistance coefficient	1250	1.25	1.25	1.3
	2250	1.25	1.3	1.35
	3000	1.2	1.3	1.41

Table 6. Gel resistance coefficient and residual resistance coefficient.

		flow rate mL/min		
concentration (mg/L)		0.5	1.0	1.5
$10 \mu\text{m}^2$	resistance coefficient	202	231	245
	residual resistance coefficient	263	276	285
$20 \mu\text{m}^2$	resistance coefficient	187	174	161
	residual resistance coefficient	214	198	183

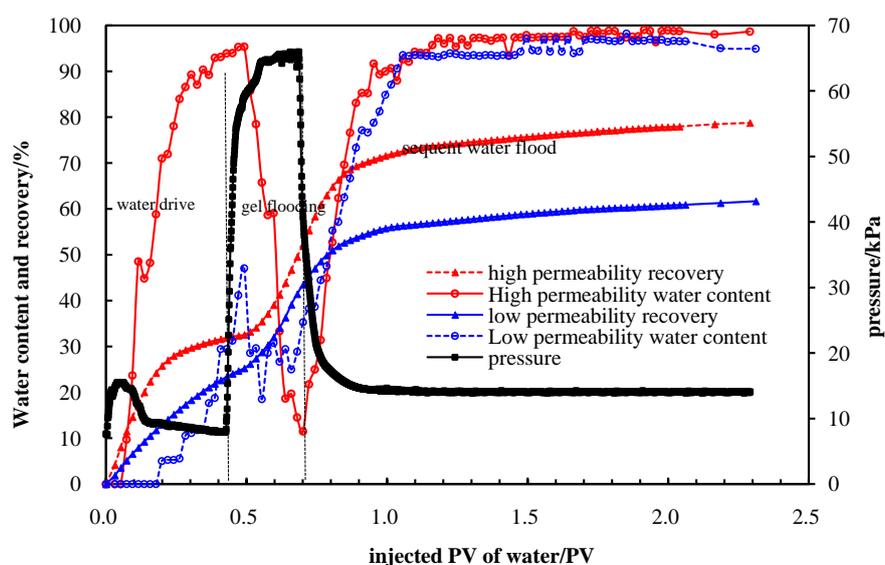
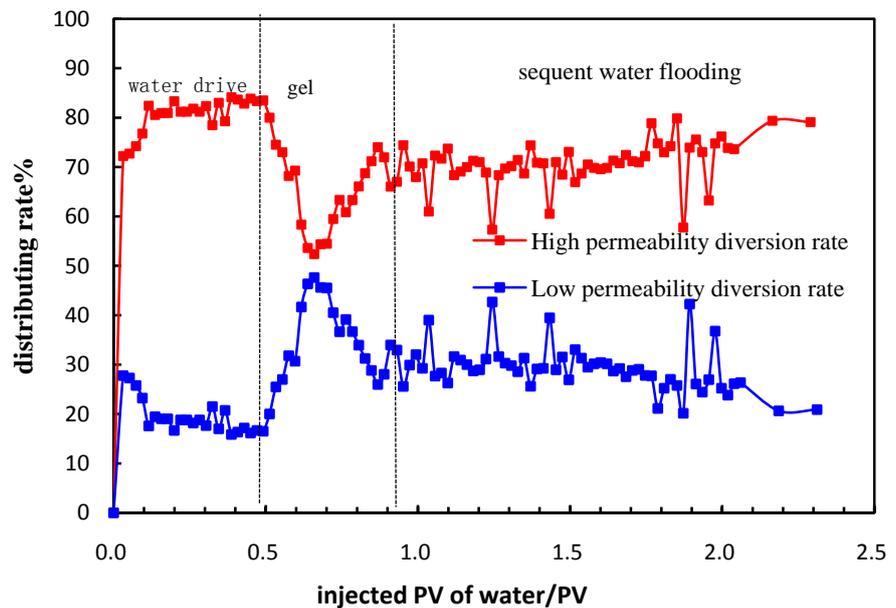
**Figure 7.** Curve of parallel recovery and water cut.

Table 7. Improve recovery test.

sand pack	Permeability/ μm^2	porosity/%	total pore volume/mL	diversion rate in water drive stage/%	diversion rate in gel flooding stage/%	diversion rate in post waterflooding stage/%	recovery ratio/%
low permeability	10.23	37.25	472	16.35	36.67	20.88	61.66
high permeability	19.85	39.34		83.65	60.87	79.12	78.77

**Figure 8.** Shunt rate curve.

- 1) Under the condition of stage difference 2, the recovery rate of low permeability water drive is 22.63%, and that of high permeability water drive is 31.6%.
- 2) The recovery of low permeability polymer flooding is 24.37%, and that of high permeability polymer flooding is 29.31%.
- 3) Under the condition of stage difference 2, the recovery rate of water flooding after low permeability is 14.66%, and that of water flooding after high permeability is 17.86%.
- 4) Analysis of the diversion rate curve shows that in the water drive stage, the low permeability basically does not enter the liquid, the diversion rate is low, polymer flooding effectively improves the diversion rate, and finally in the later water drive stage, the diversion rate is effectively improved.

4. Conclusions

- 1) The viscosity of ordinary polymer and structural polymer B is lower before and after shearing. The viscosity of structural polymer A is higher before and after shearing. The higher the concentration, the higher the viscosity retention rate, the highest viscosity of the gel system, and the best shear resistance.
- 2) Permeability, velocity and polymer concentration all affect the drag coefficient and residual resistance coefficient. From the point of view of resistance establishment ability, it is considered that structural polymer A is not suitable for

permeability formation above $10 \mu\text{m}^2$. Gel system has stronger ability to establish drag coefficient than structural polymer A flooding system, and gel system is more suitable for formations with permeability above $10 \mu\text{m}^2$. It is feasible.

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Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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