Research Article

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A new method for plugging the dominant seepage channel after polymer flooding and its mechanism: Fracturing–seepage–plugging

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Abstract: After polymer flooding, a low-resistant dominant seepage channel forms at the bottom of the high-permeability reservoir, which is extremely disadvantageous for further enhanced oil recovery. In this study, we proposed a new method to plug the dominant seepage channel after polymer flooding, through fracturing–seepage–plugging using a solid-free plugging agent, which can achieve deeper and further regional plugging. This method involved dissolving the crosslinking agent and stabilizer in the water-based fracturing fluid (hereinafter referred to as the fracturing plugging agent) and transporting it to the target reservoir through hydraulic fractures. The fracturing plugging agent percolated into the deep part of the reservoir under the action of fracture closure pressure and gelled with the residual polymer in the formation to achieve deep regional plugging of the advantageous channel. To study the percolation law of fracturing plugging agent in the dominant channel, high-pressure displacement experiments were conducted using natural cores under different permeability and concentration conditions of the fracturing plugging agent. The results showed that the percolation rate of the fracturing plugging agent was almost linearly related to reservoir

permeability. Due to the formation of micro-fractures and crosslinking reactions, the percolation rate first increased and then decreased to a stable state. After a certain period, the pores were blocked, resulting in a sharp decrease in the percolation rate and then decayed. In addition, the higher the concentration of fracturing plugging agent, the better the core plugging performance. Moreover, when the concentration of fracturing plugging agent injected into the core exceeded 3,000 mg/L, the core permeability increased, and the breakthrough pressure evidently increased three to four times. On the basis of this, rheometer tests, scanning electron microscopy (SEM) observations, and mercury intrusion tests were performed to evaluate gelation performance, shear effect, and pore retention morphology of the crosslinking system made by mixing the injected plugging agent and residual polymer in the reservoir. The results showed that the shear action could reduce the gelling property, and the concentration of fracturing plugging agent should be >3,000 mg/L to meet the requirements of gelling. Furthermore, the viscosity of the crosslinking system reached the peak value at approximately 72 h, forming a network space structure of layered superposition, thereby increasing viscosity by 40–50 times. Finally, SEM images revealed that after the fracture plugging agent was injected into the core, the micelles were mostly concentrated in the front and middle sections. The average pore radius of the core decreased by 8.620 μm , and the average porosity decreased by 54.85%.

Keywords: fracturing and plugging, percolation mechanism, dominant seepage channel, polymer flooding, regional block

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1 Introduction

With the continental sandstone oilfields entering the stage of high water cut in China, the inefficient circulation of injected fluid becomes increasingly serious (1–3). Polymer flooding has always been an outstanding method for enhanced oil recovery (EOR) in the tertiary oil recovery of sandstone reservoirs since the 1990s (4,5). However,

numerous dynamic monitoring data show that a low-resistant dominant seepage channel easily forms at the bottom of the reservoir after long-term polymer flooding, and the injected fluid easily flows along it (6–8), rendering it difficult for the external injection flooding system to effectively displace the remaining oil in low-permeability reservoirs. Therefore, the high-permeability reservoir is severely flooded, while the low-permeability target layer cannot be effectively swept. The injected fluid thus undergoes inefficient circulation (9,10), which is evidently disadvantageous to EOR. These have become the major problem of water-driving development in ultra-high water cut stage (11) and affect the economics of oilfield development. Therefore, effective plugging of the dominant seepage channel is necessary.

Most of the traditional plugging technologies primarily involve injecting the polymer gel system near the water injection well to plug the dominant channel and ensure the injected fluid enters the low-permeability reservoir. However, long-term field experiments revealed that during water injection after plugging, the injected fluid would immediately bypass the front plugging area, entering the high-permeability area again, resulting in plugging failure (12). This is primarily due to two reasons. First, it is extremely difficult for the high-viscosity polymer gel system to migrate into deeper parts of the reservoir (13). Second, for the dominant seepage channel, provided that there is an unblocked area, deeper and further fluid channeling still exists. Therefore, achieving deeper and further regional plugging in high-permeability reservoir and controlling the plugging area have become the key considerations of EOR after polymer flooding.

Recently, researchers have been increasingly studying deep profile control. Previously, Murata *et al.* (14) proposed deep profile control to improve sweep efficiency (SEI) by simulating 32 heterogeneous reservoir models. He also evaluated the adaptability of thermal active polymer, precast particle gel, Ollie Dahl disperse gel, and other profile control systems to the reservoir and the effect of depth profile on SEI. Through dehydration experiments, Hamouda and Amiri (15) analyzed the factors affecting the gelation of sodium silicate and evaluated the application of sodium silicate in reservoir depth profile control. Under the condition of high-temperature and high-salinity reservoir, Li *et al.* (16) studied the contradiction between the injection of a plugging agent and deep plugging ability and developed DCA (DVB co AM) microsphere, flexible microsphere, and cationic microsphere plugging agents. In addition, they emphasized that deep huff and puff water plugging composite technology is the method for EOR in horizontal well and water controlling in a high-temperature and high-salinity reservoir and revealed the relationship

between EOR and polymer microsphere migration distance. Dai *et al.* (17) studied the relationship between the size of dispersed particle gel (DPG) and the pore throat geometry of the reservoir and its distribution in the porous media and the migration to depths via displacing experiments and scanning electron microscopy (SEM). She proposed the mechanism of DPG EOR under different correlating factors (the ratio of the average size of DPG particles to the average size of pore throat). Huo *et al.* (18) analyzed the expansibility and plugging efficiency of nano polymethyl methacrylate and determined its applicability in deep profile controlling of reservoir and its corresponding reservoir size. In addition to experimental research, Daqing Oilfield in China has rich field knowledge in deep profile controlling. Daqing Oilfield was discovered in 1959 and developed in 1960. It is the largest oilfield in China and one of the few large continental sandstone oilfields worldwide. With the Daqing Oilfield entering the late stage of high water cut, low efficiency and inefficient circulation have become major constraints of water drive development. There are presently 36 blocks in Daqing Oilfield, including 3,106 production wells and 2,706 injection wells, which have entered the stage of water flooding development following polymer flooding (19). The Daqing Oilfield has mature construction technology, which can achieve an injection of 20–150 m³/day. The Daqing Oilfield has been dedicated to the research and development of deep profile control and plugging technology (20) and has made extensive attempts in several aspects, including the selection of wells and layers (21), development of alkali-resistant polymer microsphere profile control system and alkali-resistant resin gel profile control system (22), optimization of the slug design of profile control and injection mode of profile control agent (23–25). All these provide rich and valuable information for the development of this technology.

The fracturing–seepage–plugging technology described herein is an innovative combination of hydraulic fracturing and plugging profile control by combining the reservoir characteristics after polymer flooding in Daqing Oilfield and the information regarding hydraulic fracturing for several years. As shown in Figure 1, fracturing plugging technology uses plugging agent as fracturing fluid and transports it to the target formation via hydraulic fracturing. Under the effect of fracture closure pressure, the plugging agent percolates the reservoir and crosslinks with the residual polymer of the reservoir after polymer flooding, thereby achieving regional plugging in the deep dominant channel. In this study, we first conducted high-pressure displacement experiments using natural cores under different permeability and concentrations of the fracturing plugging agent. Based on this, we analyzed the percolation law of plugging agent

Figure 1: Schematic of fracturing plugging technology.

in the dominant channel and the plugging effect of its different concentrations. Furthermore, rheometer tests, SEM observations, and mercury intrusion tests were performed to evaluate the gelling performance, shear effect, colloid retention in pores, and plugging effect. The present results can provide reference basis for EOR after polymer flooding in oilfield.

2 Materials and methods

2.1 Experimental materials

Core samples were obtained from the high-permeability reservoirs after polymer flooding, which were provided by the core reference repository of the Exploration and Development Research Institute of Daqing Oilfield Company in China. The total salinity of the clean water used during the development of the reservoir sampled by the core was approximately 750 mg/L, which had little effect on polymer viscosity. Moreover, only this experiment explained the percolation law and plugging effect of the fracturing plugging agent. Therefore, the influence of the formation water salinity was not considered, and thus, distilled water was used for the experiment. The experimental water was distilled at the Laboratory of Northeast Petroleum University. The polymer used in the experiment was polyacrylamide (relative molecular weight was 1.9×10^6), and the effective solid content was 90%. The crosslinking agent used in the experiment was chromium acetate ($C_6H_9CrO_6$), and the effective solid content was 90%. The stabilizer used in the experiment was a composite system dominated by thiourea (CH_4N_2S). All the above-mentioned chemicals were produced by the Daqing Refining and Chemical Company and provided by the Daqing Oilfield Oil Production Engineering Research Institute.

2.2 Preparation for experiment

The peak viscosity of the polymer solution at the concentration of 1,500 mg/L was selected based on the peak viscosity of the polymer solution used in the laboratory. Multiple parts of polymer mother liquor were prepared with a concentration of 1,500 mg/L with distilled water as standby. In addition, we prepared multiple parts of fracturing plugging agent containing chromium acetate crosslinking agent with concentrations of 1,500, 3,000, and 4,500 mg/L and added 0.03 mg/L of stabilizer as standby.

The permeability of the cores adopted were 996×10^{-3} , $2,003 \times 10^{-3}$, $2,991 \times 10^{-3}$, $2,997 \times 10^{-3}$, $3,015 \times 10^{-3}$, and $3,022 \times 10^{-3} \mu m^2$. The core samples used in the experiment were vacuumized for 5 h and then saturated with water. Subsequently, it was placed in an incubator with 45°C for more than 24 h as standby.

2.3 Testing and characterization of parameters

The permeability and porosity of the core samples were tested by the YC-4 overburden porosity and permeability instrument of the Nantong Yichuang Experimental Instrument Co., Ltd. The viscoelasticity of the crosslinked polymer system was tested by HAAKE's Rs 6000 rheometer (Berlin Huck, Germany). When the water temperature was constant at 45°C, the crosslinking system was placed in the conical plate system, and the viscosity data were controlled by computer (the system can obtain the viscosity value at a certain shear rate). The spatial structure of polymer crosslinking system was observed by Quanta FEG 450 environmental SEM (FEI, USA). The polymer crosslinking system was frozen in liquid nitrogen,

Figure 2: HBYQ-2 core flow test device.

and then the temperature was rapidly increased to obtain the dry observation sample. A layer of conductive metal film was sprayed on the sample surface to observe its micro spatial structure.

The pore size distribution of the sample was measured via mercury injection experiment. Mercury was injected into the core sample until the pressure was stable, and the injection volume and pressure value were recorded. The injection pressure was then increased. Subsequently, the above steps were repeated to obtain the capillary pressure curve, and the interval distribution of different pore radius was calculated in combination with the volume of mercury.

2.4 Apparatus

The core displacement test adopts the high-temperature and high-pressure resistant core flow test device HBYQ-2 and double cylinder constant speed and constant pressure

Figure 3: HBS300/50 double cylinder constant speed and constant pressure pump.

pump HBS300/50 produced by Yangzhou Huabao Petroleum Instrument Co., Ltd.

Figures 2–4 show the major experimental equipment and experimental process. In the experiment, the fracturing plugging agent in the intermediate container was injected into the rock core through the constant speed and constant pressure pump. The pressure change at the injection end was then monitored.

2.5 Methods

2.5.1 Experiment of fracturing plugging agent seepage law

This experiment explored the percolation law of sand-free fracturing plugging agent into the reservoir under fracture closure pressure after fracturing. In the experiment, using

Figure 4: Connection diagram of displacement experiment equipment.

core displacement equipment, a certain concentration of fracturing plugging agent was injected into the rock cores with different permeabilities at a certain injection pressure to simulate its percolation in the reservoir under fracture closure pressure.

- (1) Core samples with different permeabilities (996×10^{-3} , $2,003 \times 10^{-3}$, and $2,991 \times 10^{-3} \mu\text{m}^2$) were selected.
- (2) The displacement pressure was set at 1 MPa.
- (3) Under constant pressure, 3,000 mg/L fracturing plugging agent was injected into the selected core.
- (4) The changes in injection velocity were recorded until the injection velocity was decayed to 0.

2.5.2 Gelatinization evaluation experiment

This experiment involved three parts. First, different concentrations of fracturing plugging agents were added to the polymer mother liquid to test its efficiency in increasing viscosity and analyze the effect of shear on the viscosity of the crosslinking system by stirring. Afterward, the spatial structure of different systems was observed via SEM to assess the gelling performance of fracturing plugging agent with residual polymer after injection into the formation. Second, fracturing plugging agent was injected into the rock core following water flooding. After the completion of crosslinking reaction, follow-up water flooding was conducted until the pressure was stable. The changes in pore throat scale before and after core plugging were tested via mercury injection experiment. Finally, the retention of polymer gel at different parts of the core was observed through SEM.

- (1) Briefly, fracturing plugging agent at concentrations of 1,500, 3,000, and 4,500 mg/L was added to 1,500 mg/L polyacrylamide solution to form a crosslinking system. A part of the system was naturally gelled, and the change in viscosity was tested using rheometer. The other part of the system was sheared in a stirrer to test the change in viscosity using rheometer. Afterward, the spatial structure of different systems was observed via SEM.
- (2) A core ($3,022 \times 10^{-3} \mu\text{m}^2$) was selected for water drive, and fracturing plugging agent (3,000 mg/L) was injected. This core was divided into three equal parts and sampled on the front of these parts. After freezing, drying, and spraying gold, the structure of the crosslinked system in the pores was observed via SEM.
- (3) Another core ($3,015 \times 10^{-3} \mu\text{m}^2$) was selected, and water was injected into it until the pressure was stable. The core was cut into two parts, one of them

was not blocked to conduct the mercury injection test. Briefly, 0.3 PV (injectable pore volume) fracturing plugging agent (3,000 mg/L) was injected into another part. After completion of the crosslinking reaction, water was continuously injected until the pressure was stable and pore size distribution of the core was tested via the mercury injection test.

2.5.3 Core plugging experiment

Following the evaluation test, the experiment explored the plugging of cores containing residual polymers by injecting fracturing plugging agents with different concentrations. In the experiment, different concentrations of fracturing plugging agents were injected into the rock core using the displacement device at a pressure of 1 MPa to block. Afterward, the plugging of cores containing residual polymers at different concentrations of fracturing plugging agents was explored by detecting the pressure changes during water flooding.

- (1) A core sample ($2,997 \times 10^{-3} \mu\text{m}^2$) was divided into three equal parts.
- (2) Water was injected into the three parts of the core until the pressure was stable.
- (3) The displacement pressure was set to 1 MPa. Under constant pressure, different concentrations (1,500, 3,000, 4,500 mg/L) of fracturing plugging agents were injected into the three parts of the core.
- (4) After the completion of the reaction, water flooding was conducted on the plugged core, and the change in core breakthrough pressure was recorded.

3 Results and discussion

3.1 Seepage law of fracturing plugging agent

Figure 5 shows the monitoring results of instantaneous flow of different fracturing plugging agents during injection. The experimental results of fracturing plugging agent seepage law indicate that the percolation rate of fracturing plugging agent increased with the increase of permeability during fracturing. During high-pressure injection, micro-fractures were produced in the core and percolation rate was accelerated. With the continuous injection of the fracturing plugging agent, the residual

Figure 5: Instantaneous flow rate during injection of fracturing plugging agent with different concentrations.

Figure 6: Viscosity change in crosslinking system with different concentrations without shear.

polymer in the core reacted with the fracturing plugging agent, resulting in decrease of permeability and decrease of percolation velocity to a stable value. After a period of time, the core was sealed by polymer gelling, resulting in a steep decrease in the percolation rate followed by decay.

3.2 Evaluation of gel properties

Based on the results of the gelatinization evaluation experiment and a comparison of the crosslinking strength of different concentrations of the fracturing plugging agent, all three samples could be gelled without shear. Additionally, the gelation effect improved with a higher concentration of fracturing plugging agent. The viscosity of the system increases rapidly in the initial stage (Figure 6), which was due to the hydrolysis of carboxylic groups on the branched chain of the polymer and the crosslinking reaction with Cr^{3+} in the plugging agent. After approximately 72 h, the viscosity value peaked and stabilized; this phenomenon was due to the dynamic equilibrium of crosslinking reaction in the system. In addition, due to the high concentration (4,500 mg/L) fracturing plugging agent has more Cr^{3+} , the time required for the equilibrium state of crosslinking reaction was less than 72 h.

In actual production, there were various shear effects on the viscosity of the system, such as filter, perforation, and porous media shear. Therefore, it was necessary to simulate the shear action on the experimental samples and the change of viscosity is shown in Figure 7.

Comparing Figures 6 and 7, the viscosity of the crosslinking system decreased substantially after shear action. The polymer solution with 1,500 mg/L of fracturing plugging agent can effectively gel without shear and achieve reliable strength, but cannot effectively gel under the influence of shear. In contrast, the polymer solution with 3,000 mg/L of fracturing plugging agent can effectively gel under the influence of shear, but exhibited a highest viscosity of only 1,832 mPa.s. This was because the molecular chain and space structure of the low concentration system were destroyed due to the shear, which affected its gelling properties. The molecular chain of the system with high Cr^{3+} concentration, such as the polymer

Figure 7: Viscosity change in crosslinking system with different concentrations under shear.

Figure 8: Spatial structure of the polymer mother liquor before crosslinking reaction.

solution with 4,500 mg/L of fracturing plugging agent, was not damaged to a great extent; the molecular chain was not completely broken and gradually repaired, allowing it to gel effectively, but with reduced gel strength.

After the crosslinking reaction, the space structure of the different crosslinking systems was observed via SEM. Figure 8 shows the spatial morphology of the polymer mother liquor before the crosslinking reaction. There were many cavities in the polymer space structure, and most of the fine branches did not form a dense space structure. Figure 9 shows the spatial structure of the system after crosslinking reaction without shear action.

It was observed that after the crosslinking reaction, the network structure of the system appeared layer by layer, with clearly visible layers. The fine branches were complexed with each other to form a space network structure. Based on Figures 8 and 9, for a higher fracturing plugging agent concentration, the spatial network structure was more complex and gelatinization was more improved. Figure 10 shows that in the presence of shear, the backbone of the system structure broke and the spatial structure was destroyed after crosslinking reaction. Macroscopically, the viscosity of the system decreased, but the spatial structure of samples with high fracturing plugging agent concentrations continued to exist.

The pore morphology of the core and the retention of crosslinking system in pores were observed through SEM. Figure 11 shows the pore structure before fracturing and plugging. Notably, the pore type is primarily intergranular, and there is almost no clastic material. This was due to the long-term water injection washing away the clasts in the rock and forming high-permeability pores. Figure 12 shows the pore conditions after the injection of the fracturing plugging agent with full crosslinking reaction. A large number of micelles are concentrated in the front and middle sections of the core, while only a small number of micelles exist at the back, which corresponded to the migration from the front and middle sections by subsequent water flooding. Notably, micelles are retained in the front and middle sections, blocking the pores and effectively plugging the core.

In addition to the change of pore morphology observed by SEM, the capillary pressure curve obtained from the mercury injection experiment reflects the change of pore throat distribution frequency. Figure 13 shows that prior

Figure 9: Spatial structure of crosslinked system with different concentrations of fracturing plugging agent without shear. (a) 1,500 mg/L, (b) 3,000 mg/L, (c) 4,500 mg/L.

Figure 10: Spatial structure of crosslinked system with different concentrations of fracturing plugging agent with shear. (a) 1,500 mg/L, (b) 3,000 mg/L, (c) 4,500 mg/L.

to plugging, the pore radius of the core is in the range of 40 μm and the average pore radius is 19.094 μm . Figure 14 shows the capillary pressure curve and pore throat distribution frequency of mercury injection test after plugging. The main pore radius of the core is distributed in the range of 25 μm and the average pore radius is 8.620 μm . According to the analysis of mercury injection data, the large pores were blocked by the crosslinking system, the size of the pore decreased, and the overall average porosity of the core decreased by 54.85%.

3.3 Effect of plugging

The results of the plugging core experiment showed that the pressure change of the core injected with 1,500 mg/L

fracturing plugging agent in the follow-up water drive process was not distinct compared with that of the initial water flooding, and the breakthrough pressure was only 0.145 MPa. Macroscopically, it cannot plug the core effectively. The pressure changes in the cores injected with 3,000 and 4,500 mg/L fracturing plugging agent in the follow-up water drive process were distinct compared with those of the initial water flooding. The breakthrough pressure increased significantly, and the resistance coefficient increased. The higher the injection concentration was, the faster was the rate of increase of pressure. Macroscopically, the permeability decreased, and the core pores were effectively plugged; additionally, the higher the injection concentration was, the better was the plugging effect. Figure 15 shows the change of water drive pressure with injection volume after plugging with different concentrations of plugging agent.

Figure 11: Pore morphology before core fracturing and plugging. (a) Front section, (b) middle section, (c) posterior section.

Figure 12: Pore structure after core fracturing and plugging. (a) Front section, (b) middle section, (c) posterior section.

Figure 13: Capillary pressure curve and pore size distribution before plugging.

Figure 14: Capillary pressure curve and pore size distribution after plugging.

Figure 15: Water drive pressure curve after plugging.

4 Conclusion

- (1) In fracturing–seepage–plugging technology, the percolation rate of the fracturing plugging agent was nearly linear to the reservoir permeability. Due to the generation of micro-fractures and the crosslinking reaction, the percolation rate first increased and then decreased before stabilizing. After a certain period, the pores were blocked, resulting in a steep decrease in the percolation rate and then decayed.
- (2) In the gel test, the gel system reached the peak value of viscosity at approximately 72 h (the gel time of polymer solution added fracturing plugging agent of 4,500 mg/L was less than 72 h because of excessive concentration of Cr^{3+}), forming a stacked network structure, and the viscosity increased by 40–50 times. The polymer solution with fracturing plugging agent of 1,500 mg/L could effectively gel, while under the influence of shear; fracturing plugging agents with concentrations higher than 3,000 mg/L can meet the demands of production. SEM analysis revealed that the gelled micelles were concentrated in the front and the middle of the core. The average pore radius of the core measured by mercury injection experiment decreased by 8.620 μm , and the average porosity decreased by 54.85%.
- (3) The higher the concentration of fracturing plugging agent was, the better was the core plugging performance. After the injection of fracturing plugging agent, of concentration more than 3,000 mg/L, into the core, the permeability of the core declined, and the breakthrough pressure increased by 3–4 times.

The resistance coefficient increased and the core pores are effectively plugged.

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