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Original Paper

Damage mechanism analysis of polymer gel to petroleum reservoirs and development of new protective methods based on NMR technique

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A B S T R A C T

Polymer gels are widely used in water control and enhanced oil recovery in oil fields. However, the damage mechanism of polymer gels to layers with remaining oil and not requiring plugging and corresponding protective measures are unclear. In this paper, we investigated polymer gels' damage and protection performance through static gel-breaking experiments and dynamic plugging and oil recovery evaluations on rock cores. Moreover, nuclear magnetic resonance (NMR) technology was combined to analyze the damage performance of polymer gels on cores from the pore scale. In addition, a protective technique based on gel breakers for layers with remaining oil and not requiring plugging was proposed. Results showed that when polymer gels were injected into heterogeneous cores, they plugged high-permeability layers while also penetrating low-permeability layers. When the damage to the low-permeability layers was not alleviated, the conformance and oil displacement efficiency were significantly reduced. When the concentration of ammonium persulfate was 2%–5%, the gel-breaking time was shortest and the residue was very minimal. Therefore, ammonium persulfate could be used as a gel breaker and reservoir protective material. Furthermore, after injecting ammonium persulfate into heterogeneous reservoir cores, the gel damage on the face of low-permeability layers was relieved. Consequently, the improvement in sweep efficiency was achieved, showing the re-activation of the remaining oil in medium-low permeability layers. Therefore, the low-permeability layer protection process and core experiment study based on gel-breaking agents proposed in this study were suggested to provide a new technique for the field application of conformance modification agents, aiming to achieve higher recovery degrees.

1. Introduction

As the global economy continues to recover during the post-pandemic phase, the demand for fossil fuels is steadily increasing. Due to the need for water injection to ensure sufficient injection pressure for oil production in most oil fields, long-term water injection can lead to a very high water cut in the later stages of water flooding process (Bai et al., 2022; Zhu et al., 2017a). The global average water cut is 60%–70%, but the water cut of most mature oil fields has already exceeded 90%, which severely affects the efficient development of the oil field and brings about high water treatment costs and equipment corrosion issues (Pu et al., 2023; Zhu et al., 2017c, 2019). Therefore, new water control and oil recovery technologies for oil reservoirs have been receiving significant attention (Zhu et al., 2019).

Water control and oil recovery technologies for oil reservoirs usually consist of physical and chemical methods (Bai et al., 2015; Zhu, 2020). The physical method mainly relies on the installation of packers or downhole oil–water separators in the wellbore, but it requires high demands on the wellbore structure and detailed description of the reservoir (Liu et al., 2023; Song et al., 2022). The chemical method mainly involves injecting chemical systems (such as in situ cross-linked polymer gels, particles, foams, or inorganic gels) into the wellbore to plug high-permeability formations (Bai et al., 2007; Seright, 1995, 1997; Zhu et al., 2017a, 2021a, 2021b). Therefore, it can enable chase injection water to displace previously unswept highly oil-saturated zones, thereby achieving the purpose of conformance control and oil recovery improvement (Deng et al., 2022; Seright, 2006, 2009; Zhu et al., 2017b, 2019). Due to its low cost and relatively simple operation,

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chemical conformance control technology is the most widely used method.

In situ crosslinked polymer gels are mainly used in severely heterogeneous and high water-cut oil reservoirs due to their high gel strength and controllable gelation time (Sydansk, 1988). Typically, before gelation, the gelant (i.e., the polymer and cross-linker just mixed) is pumped into the formation, and after sufficient time for gelation, water is injected into the wellbore again (Liang et al., 1993; Sydansk and Southwell, 2000). Meanwhile, the previous water flow channels can be blocked, and the chase injection water flows towards the unswept oil layers (Elsharafi and Bai, 2015; Thomas et al., 2000; You et al., 2019; Zhu et al., 2021a). To verify it, many researchers have conducted experiments using parallel rock cores or sand-packed tubes and obtained certain results of fluid flow diversion (Li et al., 2022; Wang et al., 2023). Seright et al. (Seright, 1988, 1991; Seright and Brattekas, 2021) found through theoretical and experimental analysis that when gelant is injected into the parallel model, some gel will enter the matrix pores of the low-permeability layers and cause damage. When the parallel linear core model was adopted, an injectivity loss of 90% in the high-permeability layers and an injectivity loss of 47% in the low-permeability layers were observed. In addition, in the radial model, the gel causes greater damage to the low-permeability layers. A radial flow model with a permeability contrast of 2 was adopted, resulting in an injectivity loss of 90% in the high-permeability layers, and an increase in the injectivity loss to 87% in the low-permeability layers. Moreover, in recent years, Bai et al. (2023) studied the impact of gel on the formation matrix, and using a fractured core model, they found that gel under pressure differential would enter the rock matrix and cause damage to the matrix permeability. Wu et al. (2024) claimed that polymer gels can cause damage to the core matrix even after breakage. The damage mechanism of polymer gels to layers with remaining oil and not requiring plugging has been proposed multiple times by Seright (2009) and Bai et al. (2022). However, the corresponding protection methods for layers with remaining oil and not requiring plugging and their experimental results at the core scale still need further exploration. Specifically, there are few reports on gels' injection and migration mechanisms in heterogeneous matrix models. The gel-breaking system suitable for particulate gels, such as ammonium persulfate, was studied by Wang et al. (2019), but gel-breaking systems suitable for in situ crosslinked polymer gels have rarely been reported. Therefore, using advanced analysis techniques to study the injection, plugging, and damage mechanisms of gels in heterogeneous reservoir cores is of great significance for optimizing conformance control designs.

In this study, the injection, plugging, and matrix damage of in situ cross-linked polymer gel (using phenol-formaldehyde resin as a cross-linking agent) was evaluated in a three-layer heterogeneous model based on core nuclear magnetic resonance (NMR) T_2 spectrum analysis. The phenolic resin was adopted as a cross-linker. Then, the static gel-breaking performance of the in situ cross-linked polymer gel with a gel breaker (ammonium persulfate) was evaluated. Based on this, a protective method during gel treatment based on a gel-breaker for relieving damage to layers with remaining oil and not requiring plugging was proposed. Experimental validation was conducted using a three-layer heterogeneous model. Finally, the mechanism of the damage protection process was analyzed at the pore scale of the core using core NMR methods. The proposed method provided a new technological solution and theoretical basis for further improving the water flooding efficiency of high-water-cut mature reservoirs.

2. Experimental materials and methods

2.1. Experimental materials

Polyacrylamide (XP-5, molecular weight 12 million Da, 25% hydrolysis), phenolic resin crosslinker (FQ-1), coagulant (FX-1), formation water, and crude oil were provided by Xinjiang Oilfield. The cross-linking agent chromium has strong biotoxicity, which restricts its application in oilfields. Polyethyleneimine (PEI) is environmentally friendly, but it is expensive. Therefore, phenolic resin gel has been gradually and widely used in oilfields because of its excellent chemical stability and heat resistance, as well as the advantages of high gel strength and controllable gelation time. The salinity of the formation water was 25774.87 mg/L, and the viscosity of the crude oil was 3.96 mPa·s. Ammonium persulfate (AR, 99.5%) and heavy water (D_2O) were supplied by Shanghai Macklin Biochemical Technology Co., Ltd.

The three-layer heterogeneous sandstone cores were processed and manufactured by the laboratory, as shown in Fig. 1. From top to bottom, the three layers are the low-permeability layer, medium-permeability layer, and high-permeability layer, with thickness proportions of 1/3, 1/2, and 1/6, respectively, to simulate actual reservoir conditions. Table 1 provides the parameters of the experimental cores. The permeability of the core was measured by conducting permeability tests using the formula applied during the pressing of the sand samples and the sampling of the core; it was determined using air.

2.2. The preparation method of polymer gel systems

We slowly added 1.5 g of polymer particles into a beaker pre-filled with 500 mL formation water. Simultaneously, a magnetic stirrer was used to continuously stir the mixture at a speed of 800±20 rpm for 5 min during the addition process. After the polymer solid particles were fully dispersed in the solution, the stirring speed of the magnetic stirrer was reduced to 400±20 rpm and stirred for another 4 h. Upon completion of stirring, the resulting solution was sealed and aged at room temperature for 8 h to form a 0.3% polymer solution. The process was designed to allow polymer molecules to expand in aqueous solutions fully. Subsequently, under stirring with the magnetic stirrer, 0.2% phenol-formaldehyde resin cross-linking agent and 0.3% coagulant were sequentially added at a stirring speed of 400±20 rpm for 20 min to obtain the gelant solution.

2.3. The static gel-breaking evaluation experiment of gel-breaker on polymer gel systems

A certain mass of solid ammonium persulfate particles and then it was added to test tubes pre-filled with formation water. We prepared 2%–6% ammonium persulfate solutions and slowly added an equal volume of gelant to each test tube. The test tubes were left to stand in a constant temperature water bath at 73 °C. The remaining volume of the polymer gel during the static gel-breaking process was read every 30 min. The temperature of 73 °C was proposed based on the temperature of the SN unit in the oilfields of western China. Therefore, the static gel-breaking performance of the polymer gel system in the breaking liquid was analyzed based on the volume changes of gels.

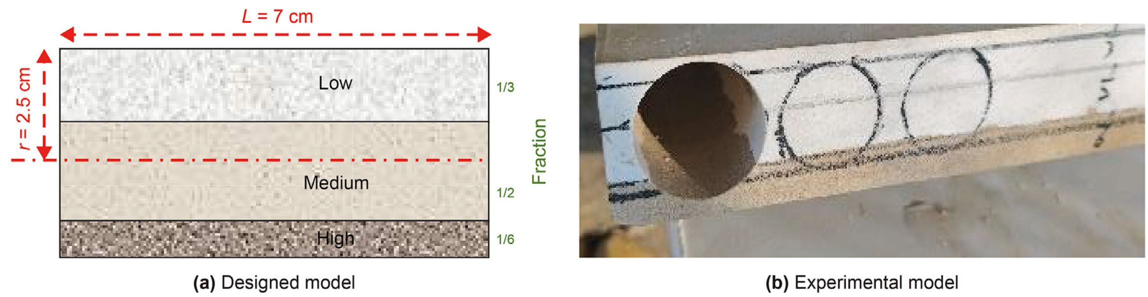


Fig. 1. Schematic diagram of heterogeneous sandstone core.

Table 1
Experimental core parameters.

No.	Length, cm	Diameter, cm	Porosity, %	Gas permeability of each layer, 10^{-3} μm^2	Experimental design
Core W1	7.08	2.524	0.2662	100/300/1500	Water-saturated (gel only)
Core W2	7.17	2.525	0.2660	100/300/1500	Water-saturated (gel-breaking)
Core O1	7.21	2.524	0.2433	100/300/1500	Oil-saturated (gel only)
Core O2	7.01	2.525	0.2431	100/300/1500	Oil-saturated (gel-breaking)

2.4. Experimental observations of core plugging and oil recovery performance

The plugging performance of polymer gel in heterogeneous cores before and after gelation was evaluated through core displacement experiments and NMR T_2 spectrum analysis. The experimental process is illustrated in Fig. 2. Three layers of heterogeneous artificial sandstone cores in Table 1 were selected for the study. The cores were first vacuumed and then saturated with water. The permeability was measured through water flooding. Heavy water (D_2O, without NMR signals) was injected, and the injection pressure difference ΔP_1 was measured. The T_2 spectrum analysis was used to analyze the bypassing along the high permeability layer during water flooding. Subsequently, a gelant prepared with heavy water (D_2O) was injected into the cores at a rate of 0.5 mL/min, and the experiment was conducted at 73 °C with T_2 analysis. After three days of gelation, the gel-breaking agent (i.e., ammonium persulfate) was applied for gel-breaking treatment. Meanwhile, another core was kept without gel-breaking as a control. Both were subjected to constant heating at 73 °C for one day under controlled conditions. Finally, secondary water flooding was performed, and the injection pressure differences ΔP_2 for the gel system before gel-breaking and ΔP_3 after gel-breaking were measured to calculate the plugging efficiencies D_1 and D_2 as follows,

$$D_1 = \frac{\Delta P_2 - \Delta P_1}{\Delta P_2} \times 100\% \tag{1}$$

$$D_2 = \frac{\Delta P_3 - \Delta P_1}{\Delta P_3} \times 100\% \tag{2}$$

where D_1 represents the plugging efficiency of the gel system in the rock core before gel-breaking; D_2 represents the plugging efficiency after gel-breaking; ΔP_1 denotes the injection pressure difference during the primary water flooding with heavy water; ΔP_2 represents the injection pressure difference of the gel system during the secondary water flooding without gel-breaking; and ΔP_3 represents the injection pressure difference of the gel system during the secondary water flooding after gel-breaking.

Through the oil displacement experiment and NMR T_2 spectrum analysis, the oil displacement effect of the polymer gel in the heterogeneous reservoir before and after gelation can be evaluated. Three-layer heterogeneous artificial sandstone cores in Table 1 were selected. Then, vacuum saturation and oil saturation were conducted to determine the permeability and total oil volume V. Heavy water was injected to determine the oil production V_1. The NMR T_2 spectrum was then used to analyze the oil distribution after

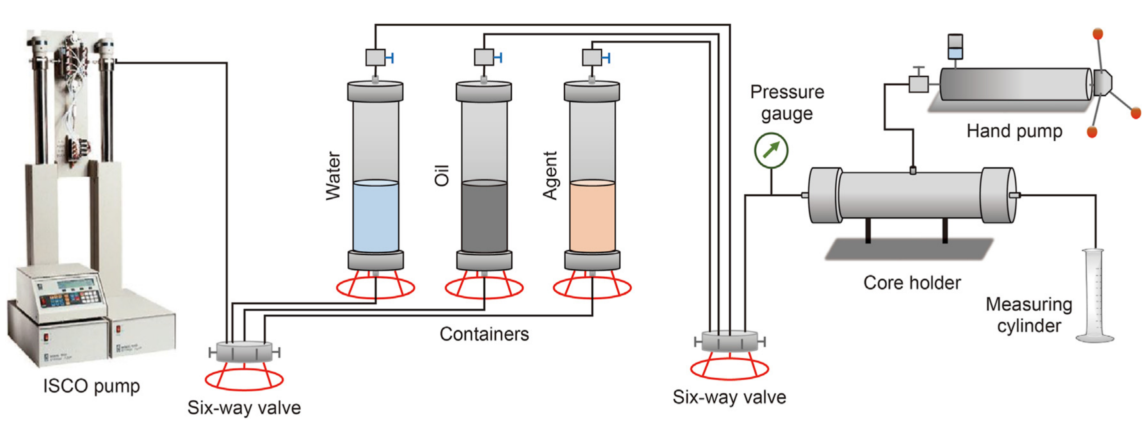


Fig. 2. Schematic of the experimental process for core plugging.

primary water flooding in each layer of the cores. Subsequently, a gelant prepared using heavy water was injected at a rate of 0.5 mL/min and an experimental temperature of 73 °C. The oil production V_2 was measured and analyzed using NMR T_2. After three days of gelation, a gel breaker (i.e., 2% ammonium persulfate) was used for gel-breaking, with one core also used as a control without gel-breaking treatment. Both were subjected to constant temperature heating at 73 °C for one day. Finally, secondary water flooding was conducted to measure the oil production V_3 of the non-gel-breaking gel system in the core and the oil production V_4 after gel-breaking. The recovery degrees E_1 and E_2 before and after gel-breaking as follow,

$$E_1 = \frac{V_1 + V_2 + V_3}{V} \times 100\% \tag{3}$$

$$E_2 = \frac{V_1 + V_2 + V_4}{V} \times 100\% \tag{4}$$

where E_1 represents the recovery degree of the gel system in the core without breakage; E_2 represents the recovery degree of the gel system in the core with breakage; V represents the total oil volume in the core; V_1 represents the oil production during the primary water flooding; V_2 represents the oil production during the gel injection; V_3 and V_4 represent the oil production of the secondary water flooding with and without breakage of the gel system in the core, separately.

2.5. Analysis of the microstructure of polymer gels before and after the gel-breaking

A scanning electron microscope (Quanta 200F FEI Company, Netherlands) was used to characterize the microstructural changes of polymer gels before and after gel-breaking. A small amount of polymer gel solution before and after gel-breaking was treated with liquid nitrogen, and placed under the scanning electron microscope for micro-imaging. During testing, the HV was 20 kV, the HFW was 149 μm, and the test atmosphere was vacuum with a temperature of 25 °C.

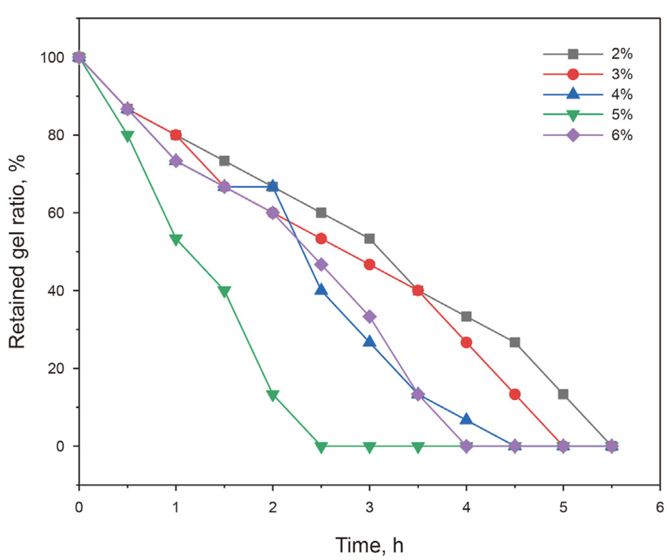


Fig. 3. Effect of ammonium persulfate concentration on the static gel-breaking performance for polymer gel systems.

3. Results and discussion

3.1. Static gel-breaking effect of gel-breakers on polymer gel systems

Before evaluating the dynamic breaking performance of the breaking agent in the porous medium, it is necessary to examine the influence of concentration on the gel-breaking performance of the polymer gel system in ammonium persulfate solution using the bottle test method. In this study, five different concentrations of ammonium persulfate solution were selected, ranging from 2% to 6%. The static breaking experiment method described in Section 2.3 was employed at an experimental temperature of 73 °C. The remaining volume of the cross-linked polymer gel being soaked was recorded every half hour, and the experimental results are shown in Fig. 3.

From Fig. 3, it can be seen that when the concentration of ammonium persulfate was 5%, with the increase of aging time, the retained volume of the polymer gel decreased rapidly, and finally completely broke at 2.5 h, showing a good gel-breaking effect. Other concentrations of ammonium persulfate also had good gel-breaking effects, but the time required to achieve a complete gel-breaking effect increased. With the increase in the concentration of ammonium persulfate, the gel-breaking speed showed a trend of first increasing and then decreasing, that is, there was a critical value for the concentration of the gel-breaking agent. Fig. 4 shows the final state photos of the polymer gel after 5 h of breaking in different concentrations of gel-breaking agents. Noticeably, when the concentration of ammonium persulfate was 5%, the residue content of the polymer gel was the lowest.

Therefore, when designing our experimental plan, if the requirement is for the shortest gel-breaking time, selecting an ammonium persulfate concentration of 5% will allow for complete gelation in a relatively short time. However, if gel-breaking time is not a consideration, it is preferable to use an ammonium persulfate concentration of 2%. By the way, this may lead to incomplete gel-breaking of small particles and potential clogging.

3.2. Damaging effect of polymer gel in heterogeneous reservoir cores

3.2.1. Evaluation of gel damage in water-saturated heterogeneous reservoir cores

We evaluated the damage effect of polymer gel by means of the core plugging experiment. The core was vacuumed and then saturated with water, and the permeability was determined by a water flooding test. It was followed by an injection of heavy water for NMR T_2 analysis. Then the gel injection experiment was conducted at 73 °C, with an injection of 1 PV polymer gelant at a rate of 0.5 mL/min. The injection and plugging performance of the

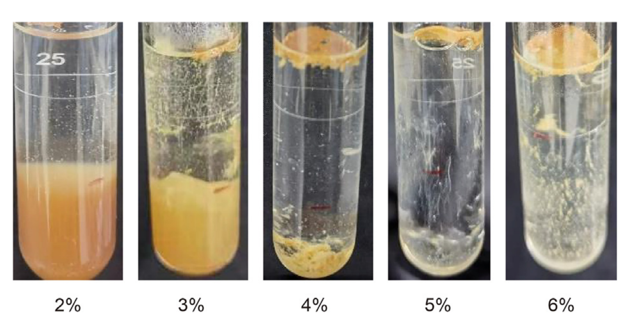


Fig. 4. Final gel-breaking status of polymer gels in different concentrations of gel breaker (5 h).

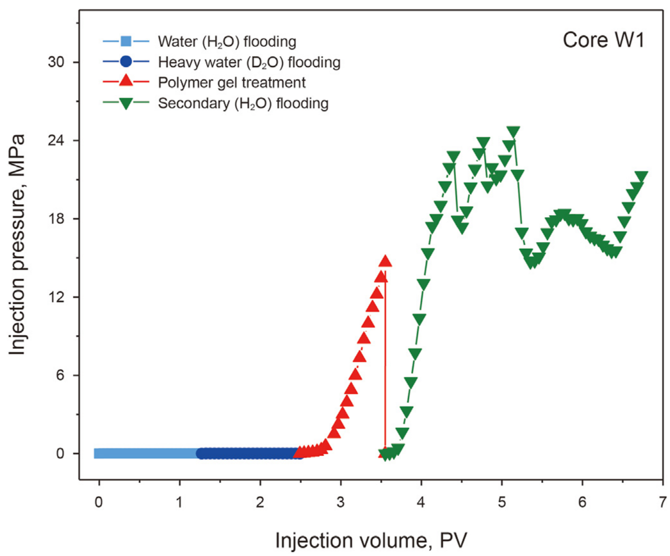


Fig. 5. Dynamic pressure of injection and plugging period of polymer gel in water-saturated heterogeneous rock cores.

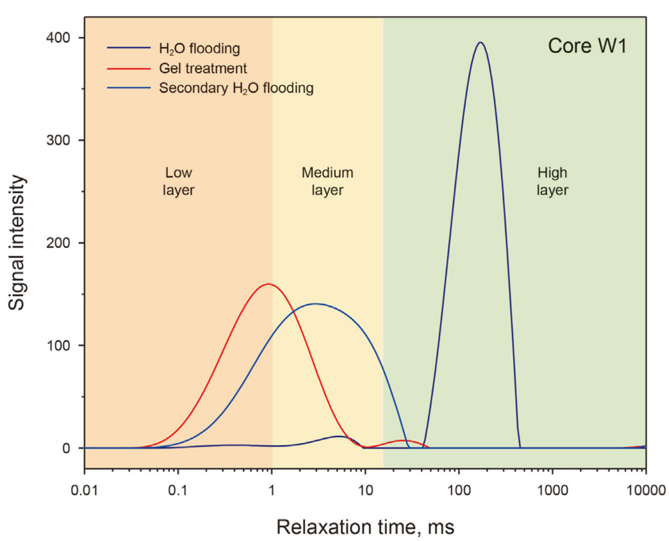


Fig. 6. Dynamic NMR T_2 curve of injection and plugging period of polymer gel in water-saturated heterogeneous rock cores.

polymer gel were analyzed by NMR T_2 signals. After three days of aging, a secondary water flooding was performed, and NMR T_2 spectrum analysis was also conducted. The injection pressure throughout the entire flooding experiment was recorded. The experimental results are shown in Figs. 5 and 6.

Fig. 5 showed that when injecting 1 PV polymer gel into heterogeneous sandstone cores saturated with water, the injection pressure sharply rose, reaching a maximum of 14.6 MPa during the gelant injection process and 21.3 MPa during secondary water flooding. It indicated that the polymer gel crosslinked and effectively plugged the core, as shown in Fig. 6. During the primary water flooding, the NMR T_2 signals were mainly distributed in the high-permeability layers. It was similar to the breakthrough characteristics of injecting water into high-permeability layers described in the literature (Song et al., 2024; Jia et al., 2024). After gel treatment, the NMR T_2 signals were moved toward the intermediate and low-permeability layers. Moreover, during the secondary water flooding, the NMR T_2 signals were changed to be in the medium-permeability layers. It indicated that during the primary water flooding, water entered the high-permeability layers where the polymer gelant mainly went, partially entering the medium and low-permeability layers. After the gel crosslinked, the secondary water flooding primarily targeted the medium-permeability layers. These results demonstrated that for geologic formations with significant heterogeneity, the polymer gel system effectively plugged rock pores. However, while entering the high-permeability layers, it also partially penetrated the medium and low-permeability layers, causing damage to layers with remaining oil and not requiring plugging and affecting conformance control performance.

3.2.2. *Evaluation of gel damage in oil-saturated heterogeneous reservoir cores*

To simulate the oil displacement effect of polymer gel systems under realistic heterogeneous reservoir conditions, we conducted oil displacement experiments to evaluate the damaging effects of the polymer gel system in oil-saturated cores. The sandstone cores were vacuumed and then saturated with water. After that, the cores were saturated with oil, and the oil distribution and saturation in each layer of the core were observed using NMR T_2. Subsequently, water flooding was performed, and the water channeling along the high-permeability layers and the changes in residual oil were analyzed using NMR T_2. Then, 1 PV of polymer gelant was injected into the cores at a rate of 0.5 mL/min, at a temperature of 73 °C. NMR T_2 analysis was used to observe the injection and plugging effects of the gel after gelation for 3 days. Simultaneously, the pressure at the inlet and the flow rate of both water and oil at the outlet were measured in real time. The experimental results are shown in Figs. 7 and 8.

Fig. 7 depicted that the injection pressure sharply rose when injecting 1 PV polymer gel into oil-saturated heterogeneous sandstone cores, with the highest injection pressure reaching 22.7 MPa during initial gelant injection and 9.1 MPa during secondary water flooding, separately. The polymer gel crosslinked within the cores and effectively plugged them. The oil recovery degree after the primary water flooding was 25.08% original oil in place (OOIP), which increased to 40.47% OOIP after the gel treatment, resulting in a 15.39% OOIP increase in recovery degree, indicating a certain oil recovery improvement effect. From Fig. 8, it can be seen that the

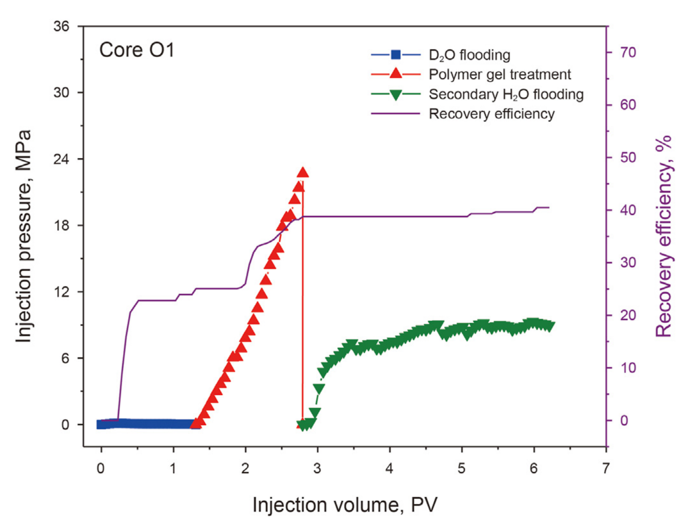


Fig. 7. Dynamic pressure of injection and plugging period of polymer gel in oil-saturated heterogeneous rock cores.

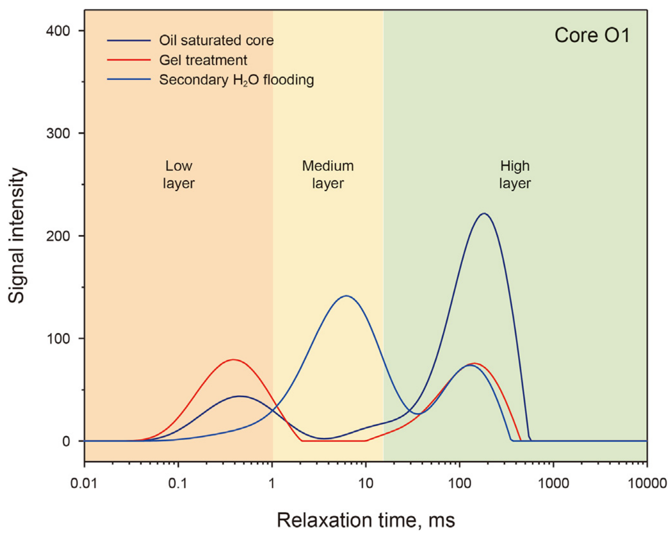


Fig. 8. Dynamic NMR T_2 of injection and plugging period of polymer gel in oil-saturated heterogeneous rock cores.

NMR T_2 signals were distributed in all layers after the gel treatment, indicating that the polymer gel entered not only the high-permeability layers but also the medium and low-permeability layers with remaining oil that did not require plugging. Therefore, it suggested that for oil-saturated cores, the polymer gel system has a certain damaging effect on the layers with remaining oil, leading to the limitation of oil recovery in the low-permeability layers and finally affecting the whole oil recovery degree.

3.3. *Protective method of polymer gel in heterogeneous reservoir cores*

As depicted in Section 3.2, during the injection of the polymer gel system into the heterogeneous rock core, the polymer gelant mainly entered the high-permeability layer but partially invaded the medium-to-low permeability layers, causing damage to the layers with remaining oil and not requiring plugging and affecting the plugging effect. Therefore, our study then established a protective method for mitigating the damaging effects of polymer gel in heterogeneous rock cores to reduce and prevent the damage caused to the layers with remaining oil and not requiring plugging. The schematic diagram of the damaging protection method of polymer gel in heterogeneous rock cores saturated with water is shown in Fig. 9. After aging for 3 days, the gel-injected heterogeneous sandstone core was taken out and inserted vertically downwards into a prepared solution of ammonium persulfate at a concentration of 2% for constant-temperature treatment for 1 day. By utilizing the damaging protection method of polymer gel in heterogeneous rock cores, the gel-saturated rock core was subjected to gel-breaking treatment, which could remove end-face contamination in the inlet of medium-to-low permeability layers, expand the treatment volume for subsequent water flooding, and finally improve oil recovery efficiency.

3.3.1. *Damage preventive method of polymer gel in water-saturated heterogeneous reservoir cores*

The evaluation of protective measures against the damage caused by polymer gel in water-saturated heterogeneous cores was conducted through core plugging experiments. This situation was to study the condition of oil reservoirs being completely water-flooded, as well as disregarding the impact when crude oil was present.

Initially, the cores were vacuumed and then saturated with water, and their permeability was measured by primary water flooding. Heavy water was then injected, and the displacement process along high-permeability layers was observed using T_2 relaxation time measurements. Subsequently, a 1 PV polymer gel system was injected into the cores at a rate of 0.5 mL/min, at an experimental temperature of 73 °C. The injection and plugging of the polymer gel were monitored using NMR T_2. After a 3-day aging period, gel-breaking treatment was conducted using a gel breaker

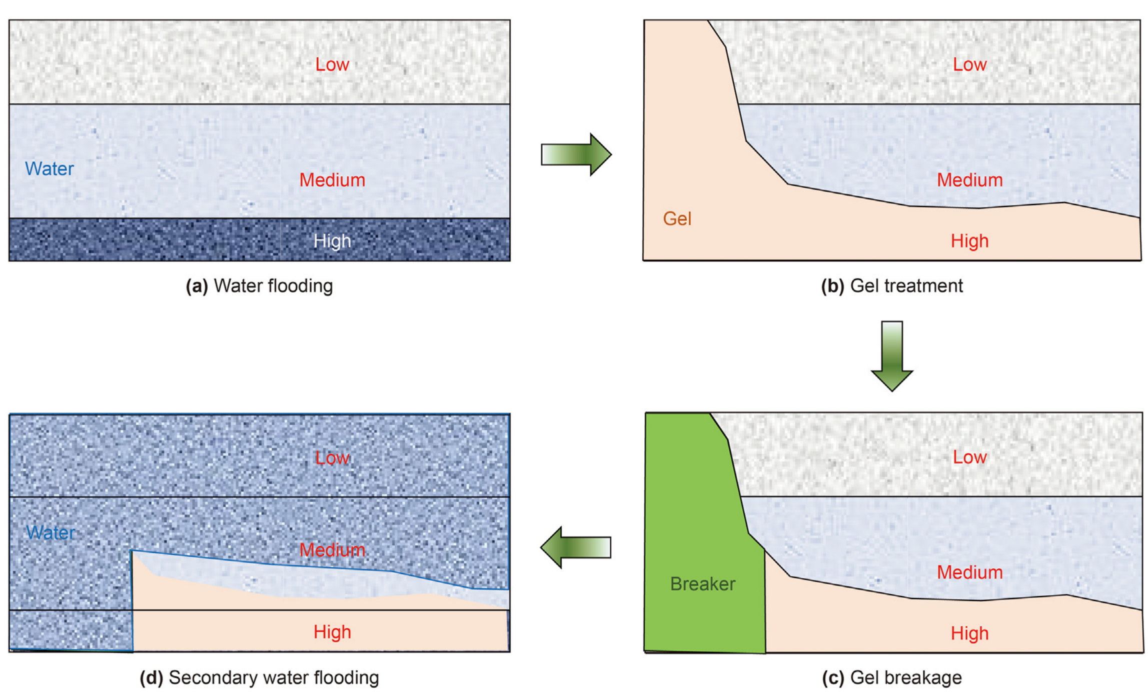


Fig. 9. Schematic diagram of the protective method against damage caused by polymer gel in saturated heterogeneous water-saturated rock cores.

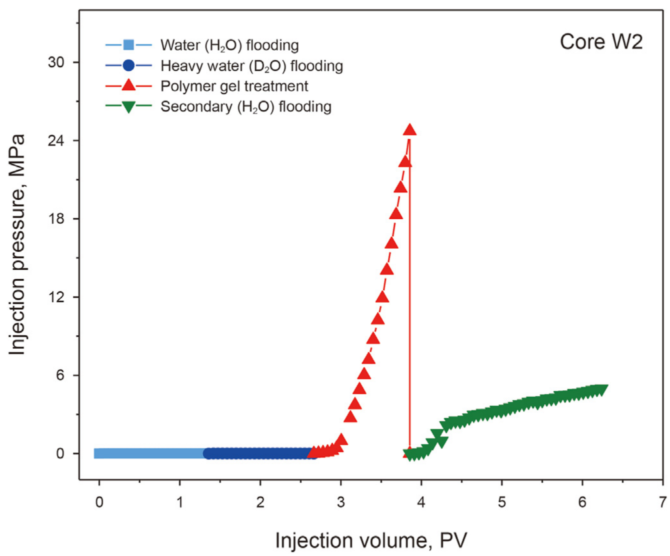


Fig. 10. Dynamic pressure of injection and plugging period of polymer gel in a heterogeneous water-saturated rock core when using the proposed protection method.

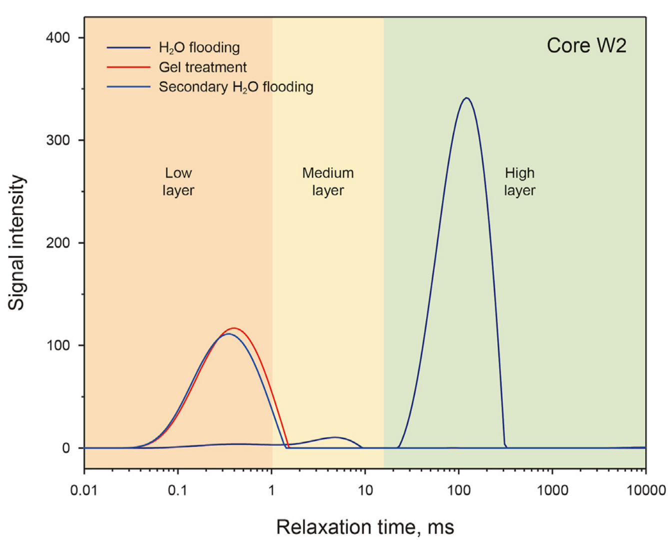


Fig. 11. Variation of T_2 dynamics for polymer gel injection and plugging in the heterogeneous water-saturated rock core when using the protection method.

(i.e., 2% ammonium persulfate), with a constant-temperature treatment duration of 1 day. Subsequently, secondary water flooding was carried out, followed by NMR T_2 analysis. The injection pressure throughout the entire experimental process was recorded, and the experimental results are shown in Figs. 10 and 11.

From Fig. 10, it can be observed that the injection pressure sharply increased when injecting a 1 PV polymer gelant into water-saturated heterogeneous cores, with the peak injection pressure reaching 24.72 MPa, while the highest injection pressure during secondary water flooding was 4.98 MPa. Fig. 11 illustrates that the NMR signals from primary water flooding were concentrated in the high-permeability layers, shifted to low-permeability layers after gel treatment, and concentrated again in the low-permeability layers during secondary water flooding. It indicates that water primarily entered the high-permeability layers. Therefore, the polymer gel mainly entered the high-permeability layers, and partially penetrated the medium and low-permeability layers. After gel treatment, the chase water predominantly entered the low-permeability layers. A comparative analysis between Figs. 6 and 11 revealed that after the gel-breaking treatment, the secondary water flooding shifted from entering the medium-permeability layers to the low-permeability layers. It shows that the implementation of this protective method against damage can alleviate the damage caused by polymer gel in the low-permeability layers (i.e., layers with remaining oil and not requiring plugging) and improve sweep efficiency.

3.3.2. Damage preventive methods for polymer gel in oil-saturated heterogeneous reservoir cores

The damaging effect of polymer gel systems in oil-saturated reservoirs was evaluated through oil displacement experiments. The rock core was vacuumed and then saturated with water, and its permeability was measured. Subsequently, the core was saturated with oil, and the oil saturation and distribution in each layer of the core after saturation were observed using NMR T_2 spectroscopy. Next, heavy water (without NMR signal) flooding was conducted to analyze the movement of water along the high-permeability layer during water flooding and changes in residual oil distributions. Furthermore, a 1 PV polymer gelant was injected at a rate of 0.5 mL/min and at a temperature of 73 °C, followed by NMR T_2 analysis. After aging for 3 days, gel-breaking treatment was performed using a gel breaker (i.e., 2% ammonium persulfate) at a constant temperature for 1 day, and secondary heavy water flooding was conducted to analyze the injection and plugging of the gel using NMR T_2. Simultaneously, the pressure at the inlet and the flow rate of both oil and water at the outlet were continuously monitored in real time. The experimental results are shown in Fig. 12 and Table 2.

Fig. 12 showed that the injection pressure sharply increased when injecting a 1 PV polymer gel into oil-saturated heterogeneous cores, with the peak injection pressure reaching 24.47 MPa. The highest injection pressure during secondary heavy water flooding was 1.58 MPa. The primary water flooding yielded a recovery degree of 23.45% OOIP, which increased to 42.20% OOIP after gel treatment. The recovery degree improved by 18.75% OOIP before and after plugging, indicating a good oil recovery improvement effect. A comparative analysis between Figs. 8 and 13 revealed that after employing the protective method against damage, there was a certain level of mobilization of residual oil in low-permeability layers. Compared to oil displacement experiments without the

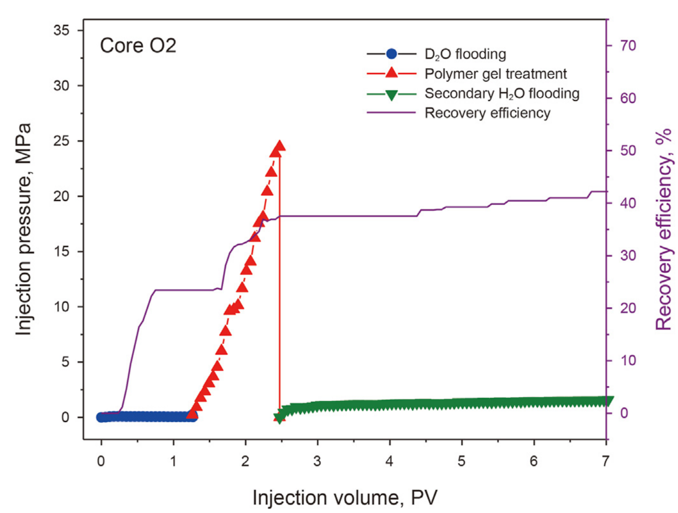


Fig. 12. Dynamic pressure of injection and plugging period of polymer gel in the heterogeneous oil-saturated rock core when using the protection method.

Table 2
Comparison of oil recovery before and after the protection process.

No.	Experimental design	Waterflood recovery, %	Recovery during and after plugging, %
Core O1	Injection of 1 PV of polymer gelant	25.08	40.47
Core O2	Injection of 1 PV of polymer gel followed by gel-breaking treatment	23.45	42.20

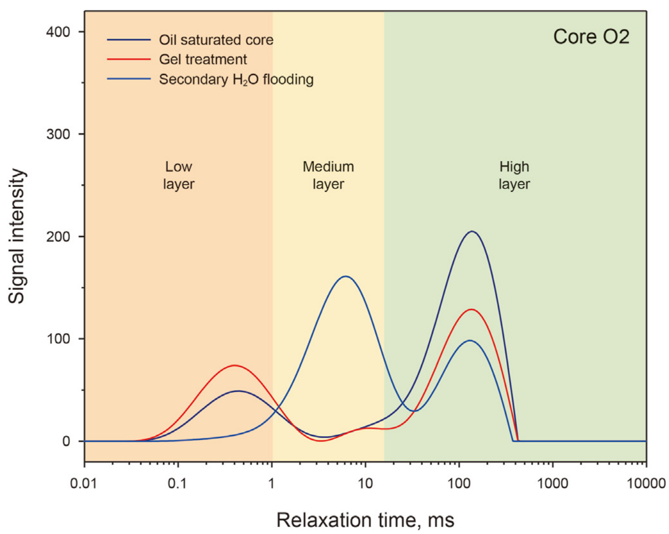


Fig. 13. Variation of T_2 dynamics for polymer gel injection and plugging in the heterogeneous oil-saturated rock core when using the protection method.

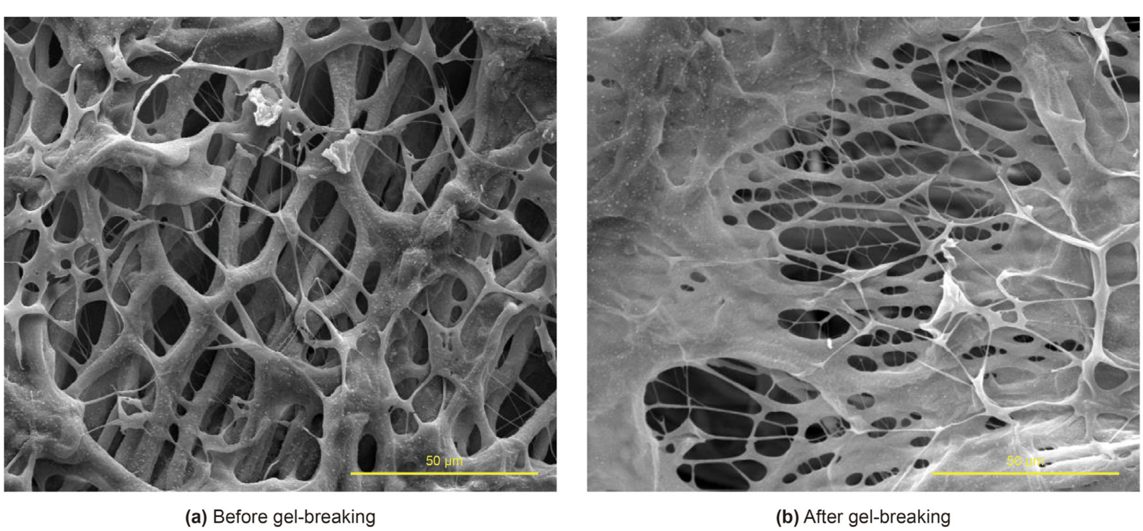
protective method, the oil recovery increased. It suggests that the protective method can reduce the damage of polymer gel to layers with remaining oil and not requiring plugging, expand the sweep efficiency of subsequent water flooding, and improve the oil recovery.

Generally, a higher injection pressure after gel plugging indicated a higher plugging efficiency and better conformance control effect. Contrasting Figs. 7 and 12, it was found that the final injection pressure in oil displacement experiments without the protective method was lower than with the protective method. However, the oil displacement experiments with the protective method showed a better incremental oil recovery effect, indicating that injection pressure alone should not be the sole criterion for evaluating conformance control effects and that factors such as injection conformance modifications should also be considered.

Using scanning electron microscopy imaging, the microstructure of the polymer gel was analyzed before and after gel-breaking. As shown in Fig. 14, under the action of ammonium persulfate, the stability of the polymer gel structure was disrupted, and the three-dimensional network structure fractured, almost forming two-dimensional linear molecules. This result was consistent with the conclusions published in the paper by Wang et al. (2019), indicating that the three-dimensional network structure of the polymer gel was severely damaged. Therefore, the water solubility of the polymer gel increased, showing significant degradation. By this, the reduction in the damaging effect of the polymer gel on layers with remaining oil and not requiring plugging expanded the volume affected by chase water flooding, validating the feasibility of the protective method against polymer gel damage to layers with remaining oil and not requiring plugging. The reservoir protection method proposed in this study was an effective solution to the problem of damage to low-permeability reservoirs during the re-injection process of polymer gels, as put forward by Seright (2009). It also served as a rock experiment validation of the reservoir protection method using breaker agents, which was proposed by Wang et al. (2019).

4. Conclusions

This study, employing nuclear magnetic resonance (NMR) technology, explored the impact of polymer gel in heterogeneous sandstone cores saturated with water and oil, respectively. A novel approach using a small slug of ammonium persulfate as a gel-breaking agent was developed to mitigate polymer gel damage and enhance oil recovery. The optimal concentration of the gel-breaking agent was determined at 2%–5%, which significantly reduced damage to layers with remaining oil and not requiring



(a) Before gel-breaking **(b)** After gel-breaking

Fig. 14. Scanning electron microscopy images of polymer gels before and after gel-breaking.

plugging and improved secondary water flooding effectiveness. The research revealed that polymer gel injection affected permeability variably across different layers, impacting overall conformance control efficiency. The introduction of protective methods successfully minimized this damage, enhanced the sweep efficiency, and mobilized residual oil in lower permeable layers, leading to an increase in oil recovery degree. The study highlighted the need for a comprehensive evaluation of conformance control effectiveness beyond just injection pressure, suggesting that factors such as injection conformances should also be considered. This research provides critical insights into optimizing polymer gel applications in heterogeneous reservoirs to maximize oil recovery while minimizing damage.

It is noteworthy that the low-permeability reservoir protection and sweep-volume-increment method based on gel-breaking agents proposed in this paper required the assurance that there were no large channels (e.g., fractures, etc.) in the formation. Otherwise, particulate-type plugging agents needed to be used for plugging, and new corresponding and environmentally friendly gel-breaking agents needed to be developed in future research.

CRediT authorship contribution statement

Dao-Yi Zhu: Writing – review & editing, Validation, Supervision. **Jiong Zhang:** Writing – original draft, Visualization, Validation, Methodology, Investigation. **Tao Zhang:** Validation, Investigation. **Ying-Qi Gao:** Visualization, Validation, Investigation. **Si Guo:** Visualization, Validation, Investigation. **Yong-Liang Yang:** Visualization, Validation, Investigation. **Jia-Mai Lu:** Visualization, Validation, Investigation.

Declaration of competing 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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