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Experimental study of reservoir damage of water-based fracturing fluids prepared by different polymers

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ABSTRACT

Fracturing operations can effectively improve the production of low-permeable reservoirs. The performance of fracturing fluids directly affects the fracturing efficiency and back flow capacity. As polymer-based fracturing fluids (such as guar gum (GG), polyacrylamide (HPAM), etc.) are high-viscosity fluids formed by viscosifiers and crosslinking agents, the degree of gel breakage after the fracturing operation directly influences the damage degree to the reservoir matrix and the mobility of oil and gas produced from the reservoir into the wellbore. This study compared the viscosity, molecular weight, and particle size of the fracturing fluid after gel breakage prepared by GG and HPAM as viscosifiers, as well as evaluate their damage to the core. Results show that the viscosities of the gel-breaking fluid increased with the concentration of the viscosifier for both the HPAM-based and GG-based fracturing fluids. For the breaking fluid with the same viscosity, the molecular weight in the HPAM-based gel-breaking fluid was much larger than that in the GG-based system. Moreover, for the gel-breaking fluid with the same viscosity, the molecular particle size of the residual polymers in the HPAM-based system was smaller than that in the GG-based system. The damage to the core with the permeability of $1 \times 10^{-3} \mu\text{m}^2$ caused by both the HPAM-based and GG-based gel-breaking fluids decreased with the increase in the solution viscosity. For the gel-breaking fluid systems with the same viscosity (i.e., 2–4 mPa s), the damage of HPAM-based fracturing fluid to low-permeability cores was greater than the GG-based fracturing fluid (45.6%–80.2%) since it had a smaller molecular particle size, ranging from 66.2% to 77.0%. This paper proposed that the damage caused by hydraulic fracturing in rock cores was related to the particle size of residual polymers in gel-breaking solution, rather than its molecular weight. It was helpful for screening and optimizing viscosifiers used in hydraulic fracturing process.

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1. Introduction

In recent years, as the difficulty of enhancing oil recovery in conventional mature reservoirs has increased year by year (Jia et al., 2023), the development of low-permeability reservoirs and unconventional reservoirs such as tight or shale reservoirs has gradually become a new driving force for worldwide oil and gas recovery (Kang et al., 2022). The efficient development of these unconventional oil

and gas resources directly affects global socioeconomic development (Zhao et al., 2023). However, the pore volumes in low-permeability and tight reservoirs are usually very small (Xie et al., 2022), making it challenging for oil and gas to flow through the formation pores to the wellbore (Zhou et al., 2022). Therefore, reservoir stimulation technology is currently an important method for increasing the stimulated reservoir volume (SRV) in these reservoirs (Huang et al., 2023; Li et al., 2022; Liu et al., 2022).

Among different reservoir stimulation processes, hydraulic fracturing technology has been widely utilized due to its advantages such as a very significant effect on enhancing the production of oil and gas wells (Jew et al., 2022), which makes it easier for

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construction and operation (Jiang et al., 2023). In addition, the hydraulic fracturing fluid is mainly composed of guar gum, cross-linkers (e.g., borax, organic chromium, etc.), and other additives (e.g., biocides, flow aids, etc.) (Davoodi et al., 2023), which form a highly viscous fluid before being injected into the formation (Sun et al., 2021). Through this, the proppant (e.g., ceramic beads or quartz sand) is carried into the fractures to support the fractures formed under high pressure (Zhang et al., 2022). It allows the oil and gas in the formation to flow into the wellbore more easily during the subsequent flowback stage thereby increasing oil and gas production (Xue et al., 2023). However, field pilot tests have shown that in the flowback process of guar gum fracturing fluid, the high-viscosity fluid forms a three-dimensional network structure gel (Patel et al., 2023). Even under the action of the gel breaker (Kubareva et al., 2022), it cannot be completely broken, resulting in a certain amount of fracturing fluid residue remaining on the fracture surface and even penetrating the reservoir matrix (Jing et al., 2021), thereby affecting the overall fracturing and oil and gas recovery efficiency.

As early as 1983, Volk et al. (1983) discovered the damage of fracturing fluid to the permeability of the reservoir matrix. In cores with permeabilities ranging from 0.6×10^{-6} to $115 \times 10^{-6} \mu\text{m}^2$, degraded hydroxypropyl guar gum (HPG) with a molecular weight lower than 10000 Da can still pass through the core. Moreover, the gel filter cake formed on the rock surface can cause certain damage to the core. Zhang et al. (2019) investigated the influence of HPG on the permeability of the core during drilling and fracturing processes using a core displacement device. The ultimate damage degree caused by the fracturing fluid was approximately 40%. They also analyzed the damage mechanism from a microscopic scale using nuclear magnetic resonance (NMR) technology. Asmorowati et al. (2022) studied the residue performance of guar gum-based fracturing fluid before and after gel breaking using a weighing method, and also analyzed the damage performance of the fracturing fluid based on oilfield fracturing operation data. Xiong et al. (2023) studied the impact of using polyacrylamide (HPAM) as a fracturing fluid on the core matrix. Cheng et al. (2022) evaluated the damage degree to the core caused by slickwater (i.e., HPAM) and guar gum-based (GG-based) fracturing fluids using CT technology, and also combined imaging techniques to analyze the related mechanisms. However, there are scarce literature reports on the damage degree to the core matrix after the gel breaking of fracturing fluid systems prepared with different types of viscosifiers, such as HPAM and GG. The research on this aspect is of great significance for further analyzing the damage mechanism of fracturing fluids, improving reservoir stimulation performance with fracturing fluids, and enhancing oil and gas recovery.

This study prepared gel-breaking fluids of two different viscosifiers: guar gum (GG) and polyacrylamide (HPAM). The influence of the type and concentration of the viscosifier on the solution viscosity after gel breakage was then investigated using a Brookfield viscometer. The effect of types and concentrations of different viscosifiers on the microscopic molecular particle size of the gel-breaking fluids was examined using gel chromatography and laser particle size analysis method, respectively. In addition, a core displacement experimental apparatus was employed to study the damage of the fracturing solution after gel-breaking prepared with different viscosifiers on core samples. Lastly, the mechanism of how different viscosifiers affect formation damage was compared. In this study, it was attempted to evaluate the irreversibly damaging effects of existing fracturing fluids on formations and further enrich the understanding of the interaction between the molecular structure of gel-breaking fluids and their damaging performance to formations, thereby facilitating the development of highly efficient recovery methods in low-permeability oil and gas reservoirs.

2. Experimental materials and methods

2.1. Experimental materials

Polyacrylamide SAV-82 (nonionic, HPAM, 8 million Da) was manufactured by France's SNF Company. Hydroxypropyl guar gum (HPG, 760,000 Da) was obtained from Guangrao Liuhe Chemical Co., Ltd. Ammonium persulfate (99%) and sodium borate (i.e., Borax Anhydrous, 99.5%) were sourced from the Sane Chemicals company. Flow-back additive (ZPJ-2) was provided by Xinjiang Oil Field. Cores with permeabilities around $1 \times 10^{-3} \mu\text{m}^2$ were manufactured by Beijing Yuanyang Huanyu Petroleum Technology Co., Ltd. The type of cores was sandstone, with the length of 7 cm and the porosity of about 16%.

2.2. Preparation of breaking solutions for fracturing fluids

First, different amounts of HPG were weighed and added to the guar gum-based (GG-based) fracturing fluid. Then, a certain amount of ammonium persulfate and sodium borate was weighed and added to the solution. The solution was stirred at a speed of 600 rpm/min for 10 min. Finally, a certain amount of flow-back additive was added, and the stirring continued for 10 min at room temperature. The formula for the gel-breaking solution of GG-based fracturing fluids is shown in Table 1. In addition, for the HPAM-based gel-breaking fluid, different amounts of SAV82 were added, also followed by the addition of fixed concentrations of ammonium persulfate and sodium borate. The solution was slowly stirred at a speed of 600 rpm/min. Finally, a certain amount of flow-back additive was added. The reaction continued for 10 min at room temperature. The formula for the gel-breaking solution of HPAM-based fracturing fluids is shown in Table 2.

2.3. Determination of the viscosity of the gel-breaking fluid

After the fracturing fluids were aged for 4 h, it was gel-broken and generated gel-breaking solutions. Then, the viscosity of the gel-breaking solutions prepared from different system formulations was measured using a Brookfield viscometer. The viscosity measurements were conducted at room temperature (25 °C) and performed using appropriate rotor types. The speed of the Brookfield viscometer was set to 6 r/min to simulate the flow rate in core samples caused by the fracturing fluid.

2.4. Determination of the molecular weight of residual polymers in the gel-breaking solution

The gel permeation chromatography (GPC) was used to test the molecular weight of residual polymers in the gel-breaking solutions. The MALLS laser wavelength was 632.8 nm, and the refractive index increment was 0.1460. Each sample was dissolved in the aqueous mobile phase (0.1 mol/L NaNO₃) separately to prepare a solution with a concentration of 5 mg/mL. After passing through a 0.22 μm microfiltration membrane, the sample was injected at a flow rate of 0.5 mL/min. The column temperature was set to 55 °C, and the injection volume was 100 μL . The gel permeation chromatography column used in this experiment was ULTRAHYDROGEL 8*106.

2.5. Determination of molecular particle size of residual polymers in the solution after gel-breaking of the fracturing fluid

A Mastersizer 3000 laser particle size analyzer was employed to determine the molecular particle size of residual polymers in the gel-breaking solution of the fracturing fluid. A solution with a

Table 1
Formulation of GG-based fracturing fluids.

No. of GG-based fracturing fluids	Composition, %			
	HPG	Ammonium persulfate	Sodium borate	Flowback additive
A1	0.90	0.005	0.2	0.3
A2	0.95	0.005	0.2	0.3
A3	0.96	0.005	0.2	0.3
A4	0.98	0.005	0.2	0.3
A5	1.00	0.005	0.2	0.3

Table 2
Formulation of HPAM-based fracturing fluids.

No. of HPAM-based fracturing fluids	Composition, %			
	SAV-82	Ammonium persulfate	Sodium borate	Flowback additive
B1	0.42	0.0025	0.05	0.15
B2	0.50	0.0025	0.05	0.15
B3	0.70	0.0025	0.05	0.15
B4	0.80	0.0025	0.10	0.15
B5	0.92	0.0020	0.12	0.15

concentration of 5 mg/mL was prepared, and 2 mL of the sample was placed in the sample tray. After dispersion using an ultrasonic instrument, it was placed in the optical measurement area at room temperature (25 °C). When the laser beam passed through the dispersed particle sample, the measurement of scattered light intensity was applied to complete the particle size measurement.

2.6. Displacement experiments on rock damage by gel-breaking solutions

A core displacement device was employed to measure the formation damage caused by the gel-breaking solution of different fracturing fluids on core samples, as shown in Fig. 1. The testing temperature was 25 °C, and the constant displacement speed was set at 0.5 mL/min. The permeability of the core sample was measured with water, and a constant pressure of 3.5 MPa was applied to simulate the real reservoir damage situation caused by the fracturing fluid. The core samples used in the experiment were artificial sandstone core samples. The permeability after the treatment of the gel-breaking solutions was measured at room temperature.

First, the permeability of the core sample was measured using

the core displacement device. The displacement fluid used was simulated formation water with a salinity of 28,870 mg/L. The displacement was performed at a constant rate of 0.5 mL/min. The confining pressure remained 3 MPa higher than the pressure at the inlet. The pressure changes and liquid flow rate at the outlet were recorded in real time to calculate the primary water permeability, K_1 . Subsequently, the gel-breaking solution was injected. The injection pressure was maintained at a constant of 3.5 MPa for half an hour, also with a confining pressure of 3 MPa higher than the injection section pressure. Finally, to simulate reservoir backflow, the core sample was taken out and the injection direction was reversed, making the inlet the outlet. The pressure changes and liquid flow rate were recorded again in real-time during the experiment to calculate the permeability after damage, K_2 . The equation for calculating the formation damage degree was

$$D = \frac{K_1 - K_2}{K_1} \times 100\%$$

(1)

where D represents the formation damage degree; K_1 is the primary water permeability of the core in $10^{-3} \mu\text{m}^2$; and K_2 is the water permeability of the core after damage, $10^{-3} \mu\text{m}^2$.

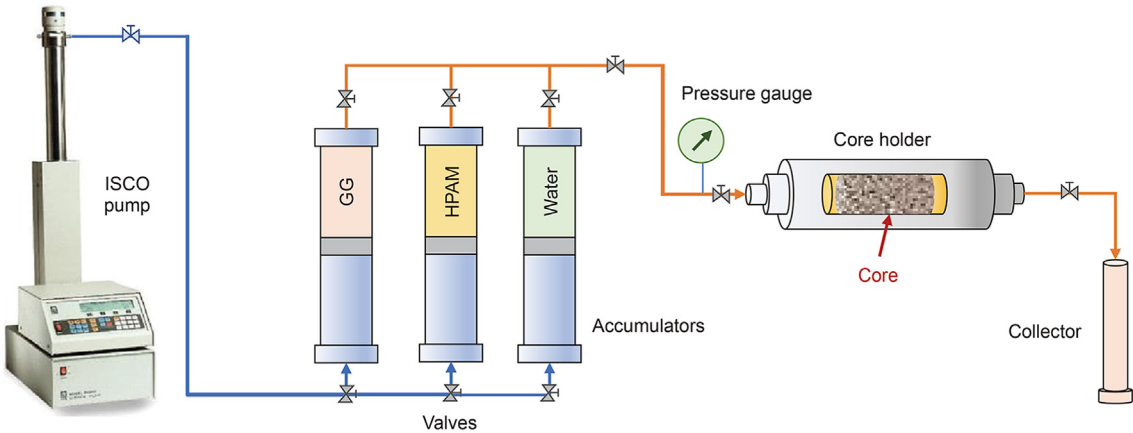


Fig. 1. Schematic diagram of the core displacement device.

3. Results and discussion

3.1. Comparison of viscosities of the gel-breaking solution prepared by different types of viscosifiers

The choice of viscosifier used in the formulation of fracturing fluid directly affects the viscosity of the gel-breaking solution. Typically, the increase in the viscosity of the gel-breaking solution for conventional fracturing fluids will increase their damage to the formation. However, the mechanism by which the type and concentration of viscosifiers affect the viscosity of the gel-breaking solutions is not yet clear. Therefore, the viscosities before and after gel-breaking for different formulations of GG-based and HPAM-based fracturing fluids were first measured using a Brookfield viscometer, respectively. The relationship between the concentration of the viscosifier and the viscosity of the fracturing fluid before and after gel breaking is shown in Fig. 2.

From Fig. 2, it can be observed that both GG-based and HPAM-based fracturing fluids exhibited a linear relationship between viscosity and the concentration of the viscosifier before breaking. Additionally, with the increase in the concentration of the viscosifier, the viscosity of the solution after gel-breaking also increased for both HPAM-based and GG-based fracturing fluids.

The concentration of GG increased from 0.9% to 1.0%, resulting in an increase in viscosity after gel-breaking from 1.8 to 9.8 mPa s. When the viscosity of the gel-breaking fluid was around 10 mPa s, the GG-based fracturing fluid required a viscosifier concentration of 1.0%, while the HPAM-based fracturing fluid required a concentration of 0.92%. In other words, under similar viscosities of the gel-breaking fluid, the GG-based gel-breaking fluid required a higher concentration of viscosifier compared to the HPAM-based gel-breaking fluid. Moreover, the curve showed a steeper increase. It was because the molecular weight of GG powder was smaller than that of the HPAM, resulting in fewer crosslinking sites per molecule. Therefore, a higher concentration of GG was required to achieve the same viscosity as the HPAM-based gel-breaking fluid. In addition, due to the very high molecular weight of polymer solutions, their solution viscosities were quite high. Therefore, they were prepared at a higher concentration, and the breaker had a lower concentration as well.

3.2. Comparison of molecular weights of residual polymers in gel-breaking solution for different types of fracturing fluids

The residual polymers in the gel-breaking solution still have a high molecular weight, which makes them difficult to degrade and prone to blockages. This characteristic may have a significant impact on the damage to the formation. Therefore, we tested the molecular weight of residual polymers in gel-breaking solution samples of two different types of fracturing fluids. The relationship between the molecular weight of residual polymers in the gel-breaking solutions with different viscosities is shown in Fig. 3.

It can be observed that when GG was used as the viscosifier, the residual molecular weight increased with the increase in the viscosity of the gel-breaking fluid. When the viscosity of the gel-breaking solution of the GG-based fracturing fluid increased from 2 to 10 mPa s, the residual molecular weight increased rapidly from 110,000 to 170,000 Da. It was because, with a constant amount of gel-breaking agent, higher viscosity of the gel-breaking fluid needed more viscosifier, resulting in less efficient breakage and thus larger residual molecular weight. It is worth noting that the molecular weight of the original GG powder was around 760,000 Da, while the residual molecular weight in the gel-breaking fluid was in the range of 110,000 to 170,000 Da, indicating that the gel-breaking agent caused the polymer chains of the original GG to break and form a smaller molecule.

When the viscosifier was HPAM, the residual molecular weight also increased with the increase in viscosity of the gel-breaking fluid. When the viscosity of the gel-breaking solution after the breakage of the HPAM-based fracturing fluid increased from 2 to 10 mPa s, the residual molecular weight rapidly increased from 230,000 to 460,000 Da. Moreover, the overall change in residual molecular weight in the solution of the HPAM-based gel-breaking fluid was greater than that in the GG-based gel-breaking solution. Additionally, at the same viscosity of the breaking fluid, the residual molecular weight in the HPAM-based gel-breaking solution was much higher than that in the GG-based solution. It was because the molecular weight of the HPAM powder itself was 8 million Da, which was much larger than the molecular weight of GG (760,000 Da). Therefore, after breaking, the residual molecular weight in the HPAM-based system was more significant.

Additionally, crosslinking agents are more likely to undergo intermolecular crosslinking in the HPAM system, rather than

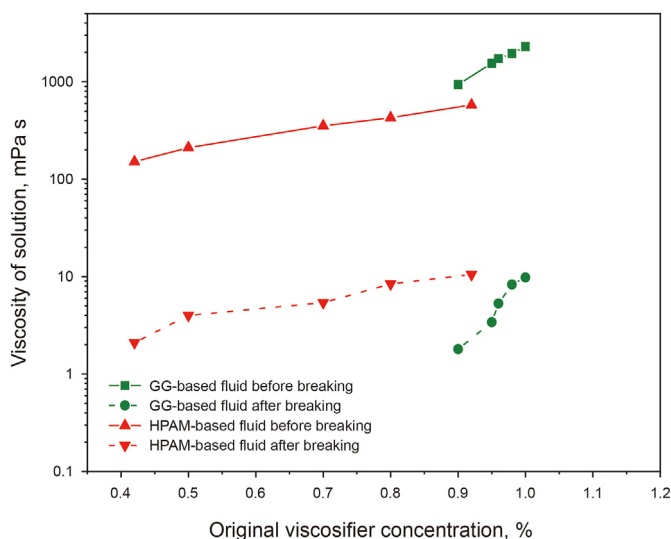


Fig. 2. The relationship between viscosity and concentration of viscosifiers before and after gel-breaking.

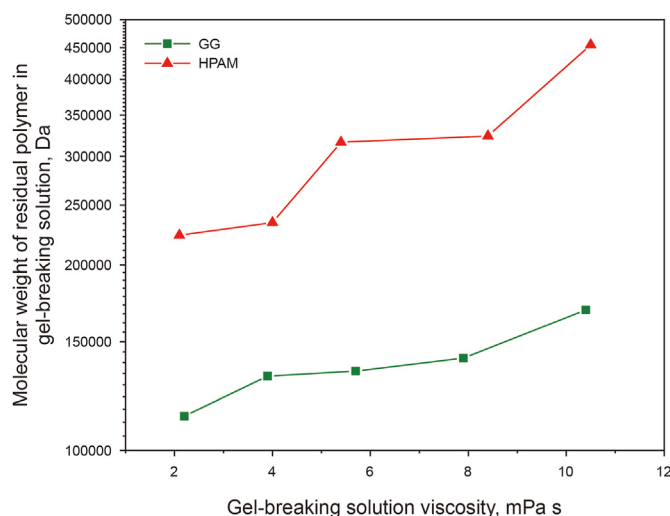


Fig. 3. Molecular weight of residual polymers in gel-breaking fluids with different viscosities.

intramolecular self-crosslinking reactions, leading to more retention of a high molecular weight in the HPAM solution even after breaking. Therefore, in Section 3.1, to obtain the same gel-breaking solution viscosity, the residual molecular weight of HPAM-based gel-breaking fluid was higher than that of GG-based. These conclusions help in the analysis of the damage mechanism of gel-breaking fluid in the core samples in Section 3.4.

3.3. Comparison of molecular particle sizes of residual polymers in gel-breaking solution for different types of fracturing fluids

Polymers, even under no external forces, can form stable and difficult-to-decompose molecular aggregates in aqueous solutions. The size of the molecular aggregates in the gel-breaking solution can also affect the damage degree of the formation matrix. For example, large-sized randomly distributed molecular aggregates can remain in the formation fractures, which can impact subsequent extraction activities. To further evaluate the influence of the molecular stereostructure of the gel-breaking solution prepared by different types of polymers on the damage to the core, the gel-breaking solution was prepared with a polymer concentration of 5 mg/mL. After ultrasonic dispersion, the experiment on measuring the particle size of molecular aggregates was conducted at room temperature (25 °C). The particle size of the GG-based and HPAM-based gel-breaking solutions of different viscosities is shown in Fig. 4.

When GG was used as the viscosifier, the residual molecular particle size increased with the increase in solution viscosity after the GG-based fracturing fluid was broken, exhibiting a predominantly linear relationship. When the viscosity of the gel-breaking solution increased from 2 to 10 mPa s, the molecular particle size of the residual polymer in the gel-breaking fluid gradually increased from 309 to 443 nm. It was because with a higher concentration of GG in the original fracturing fluid, and with a constant concentration of the gel-breaking agent, the degree of breaking became smaller, resulting in larger molecular particle sizes. In addition, with a constant amount of gel-breaking agent, the higher the viscosity of the gel-breaking fluid, the more GG needed to be added. It resulted in a smaller degree of gel-breaking and consequently larger molecular particle size of the residual polymer.

Moreover, when the viscosifier was HPAM, the molecular particle size of the residual polymers also increased with the increase

in viscosity of the HPAM-based gel-breaking solutions. When the viscosity of the HPAM-based gel-breaking fluid gradually increased from 4 to 10 mPa s, the molecular particle size of the residual polymers increased from 248 to 433 nm, showing a similar magnitude of increase compared to the GG-based system. However, when the solution viscosity after the breakage of the HPAM-based fracturing fluid increased from 2 to 4 mPa s, the molecular particle size of the residual polymers sharply increased from 82 nm to 248 nm, indicating rapid growth.

In addition, at the same viscosity of different types of gel-breaking fluids, the molecular particle size of the residual macromolecules in the HPAM-based system was smaller than that in the GG-based system. It was because, to achieve the same viscosity of the gel-breaking fluid, a significantly higher amount of GG was required compared to HPAM. Therefore, in comparison to the HPAM, the degree of breaking in the GG-based system was lower, resulting in larger molecular particle sizes of the residual polymers.

3.4. Rock damage caused by the solution after fracturing fluid breaking

3.4.1. Evaluation of the damaging effect of the GG-based fracturing fluid

To investigate the damage mechanism of the GG-based gel-breaking solution to porous media, a core displacement device was used to evaluate the damage of the GG-based gel-breaking solution to the core. During the experiment, a constant injection pressure of 3.5 MPa was maintained during injection, and the GG-based gel-breaking solution with different viscosities (i.e., 2, 4, 6, and 8 mPa s) was used for core displacement testing. The dynamic change of pressure during the displacement process is shown in Fig. 5. Then, the permeabilities of the core and the effluent volume before and after displacement are presented in Table 3.

From Fig. 5, it can be observed that when injecting the gel-breaking solution of the GG-based fracturing fluid with different viscosities (i.e., 2, 4, 6, and 8 mPa s) under constant pressure, the corresponding injection pressure differences were 3.5, 3.6, 3.7, and 3.8 MPa, respectively. It indicated that as the viscosity of the gel-breaking solution of the GG-based fracturing fluid gradually increased, the molecular particle size of the polymers also increased, thereby increasing the injection pressure differences. It was worth noting that during the constant pressure differential injection stage of the breakage fluid, the early inability to build up the pressure difference to 3.5 MPa, and even jumped in pressure (as shown in Fig. 5(a)), were caused by the delayed formation of the filter cake. Subsequently, as the filter cake formed, the pressure difference was able to maintain a level of around 3.5 MPa. However, during the secondary water flooding process, the corresponding injection pressure differences for the GG-based gel-breaking solution with viscosities of 2, 4, 6, and 8 mPa s were 5, 4, 2.4, and 2.1 MPa, respectively. It suggested that as the viscosity of the gel-breaking solution of the GG-based fracturing fluid increased, the corresponding injection pressure difference decreased during the secondary water flooding process.

From Tables 3 and it can be seen that as the viscosity of the gel-breaking solution of the GG-based fracturing fluid gradually increased (from 2 to 8 mPa s), the rock damage degree decreased gradually, from 80.2% to 45.6%. Additionally, the effluent volume during the constant pressure displacement stage also decreased gradually, from 3.20 to 1.15 mL. It was because, with the higher viscosity of the gel-breaking solution of the GG-based fracturing fluid, the molecular particle size of the polymers also increased (see Fig. 4), reducing the amount of liquid that can enter the core and thus decreasing the damage to the core.

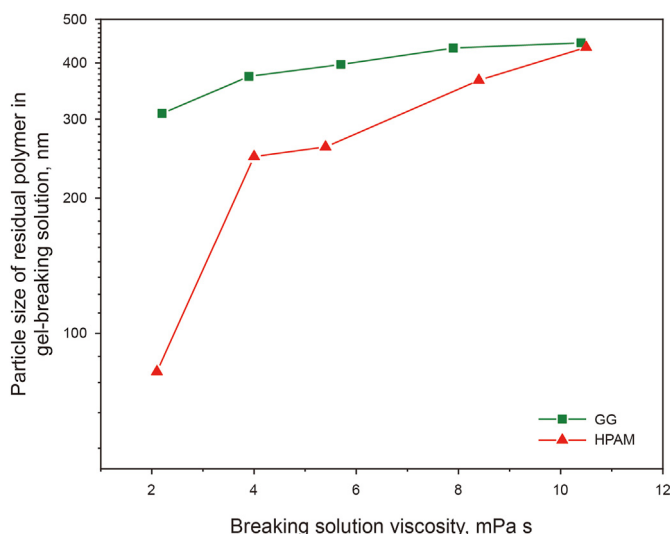


Fig. 4. Particle sizes of residual polymers in gel-breaking fluids of different viscosities.

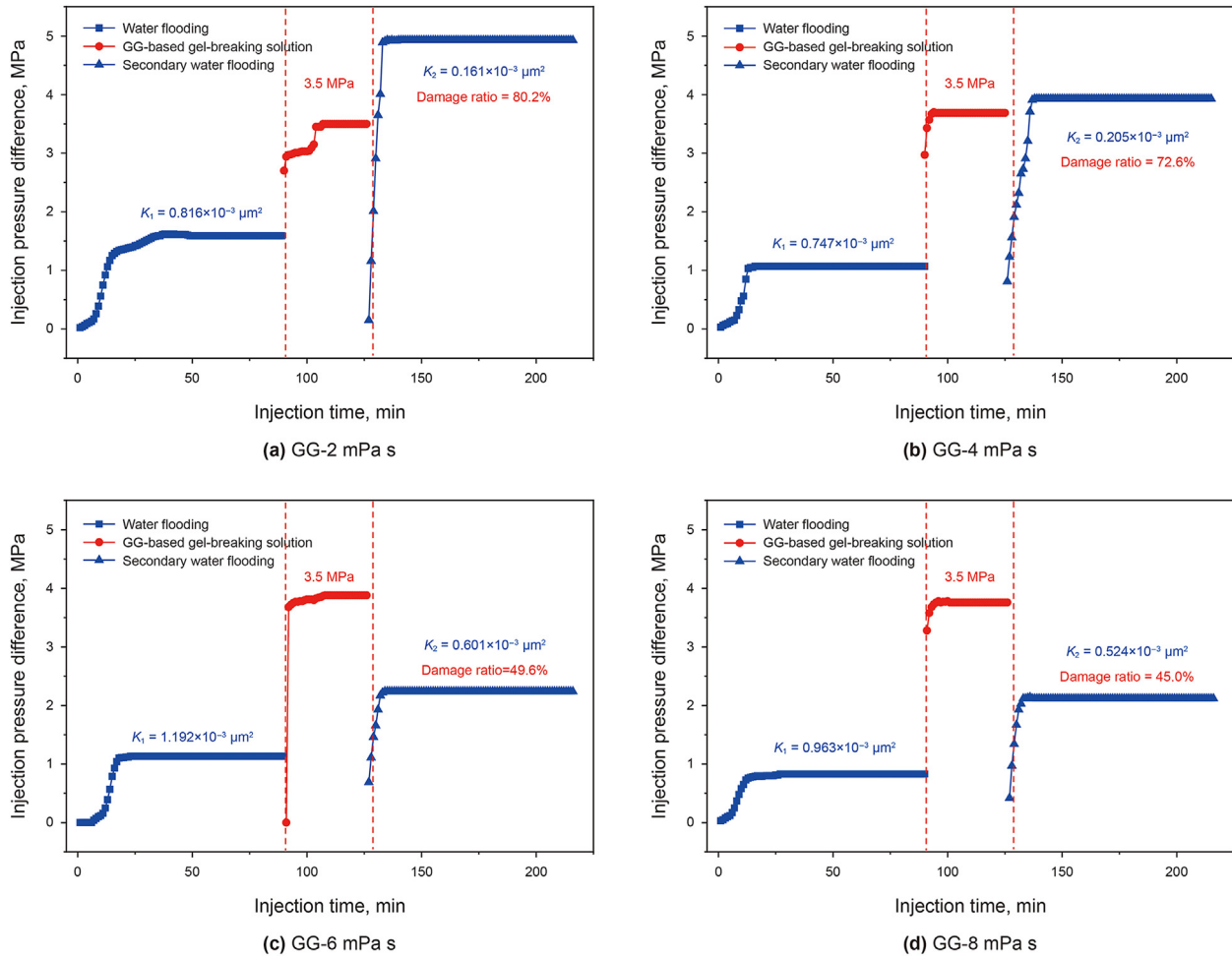


Fig. 5. Dynamic pressure curves during displacement for different viscosities of GG-based gel-breaking solutions.

Table 3

Core permeability before and after displacement for the GG-based gel-breaking system.

Test No.	Gel-breaking fluid and viscosity	Gas permeability, $10^{-3} \mu\text{m}^2$	Water permeability, $10^{-3} \mu\text{m}^2$	Effluent volume, mL	Permeability after damage, $10^{-3} \mu\text{m}^2$	Damage degree, %
1	GG-2 mPa s	1.77	0.816	3.20	0.161	80.2
2	GG-4 mPa s	1.75	0.747	2.80	0.205	72.6
3	GG-6 mPa s	1.73	1.192	1.45	0.601	49.6
4	GG-8 mPa s	1.78	0.963	1.15	0.524	45.6

3.4.2. Evaluation of the damaging effect of the HPAM-based fracturing fluid

Meanwhile, we also conducted core displacement testing using the HPAM-based gel-breaking solutions with different viscosities (i.e., 2, 4, 6, and 8 mPa s) to examine their damage to the core. The dynamic change curve of pressure during the displacement process is shown in Fig. 6. The permeabilities of the core and the effluent volume before and after displacement are then presented in Table 4.

From Fig. 6 and Tables 4 and it can be observed that as the viscosity of the HPAM-based gel-breaking solution gradually increased (from 2 to 8 mPa s), the rock damage degree decreased gradually, from 77.0% to 66.2%. Additionally, the effluent volume during the constant pressure displacement stage also decreased gradually, from 8.2 to 3.7 mL. It was because, with the higher viscosity of the HPAM-based gel-breaking solutions, the molecular

particle size of the polymers also increased (see Fig. 4), reducing the amount of liquid that can enter the core and thus decreasing the damage to the core.

The variations in the filtration volume and rock damage degree of the gel-breaking solution prepared with different viscosifiers are shown in Fig. 7. It can be observed that as the viscosity of the gel-breaking solution increased, both the GG-based and HPAM-based systems exhibited a gradual decrease in filtration volume under a constant injection pressure of 3.5 MPa. Furthermore, the lower amount of residual polymers entering the core after the breakage of the GG-based or HPAM-based fracturing fluid decreased the corresponding damage to the rock core.

Moreover, when the viscosity of the gel breaker solution was low (2–4 mPa s), the rock damage degree caused by the GG-based gel-breaking solution was 77.0%–73.2%, while the damage degree caused by the HPAM-based solution after the breakage was 80.2%–

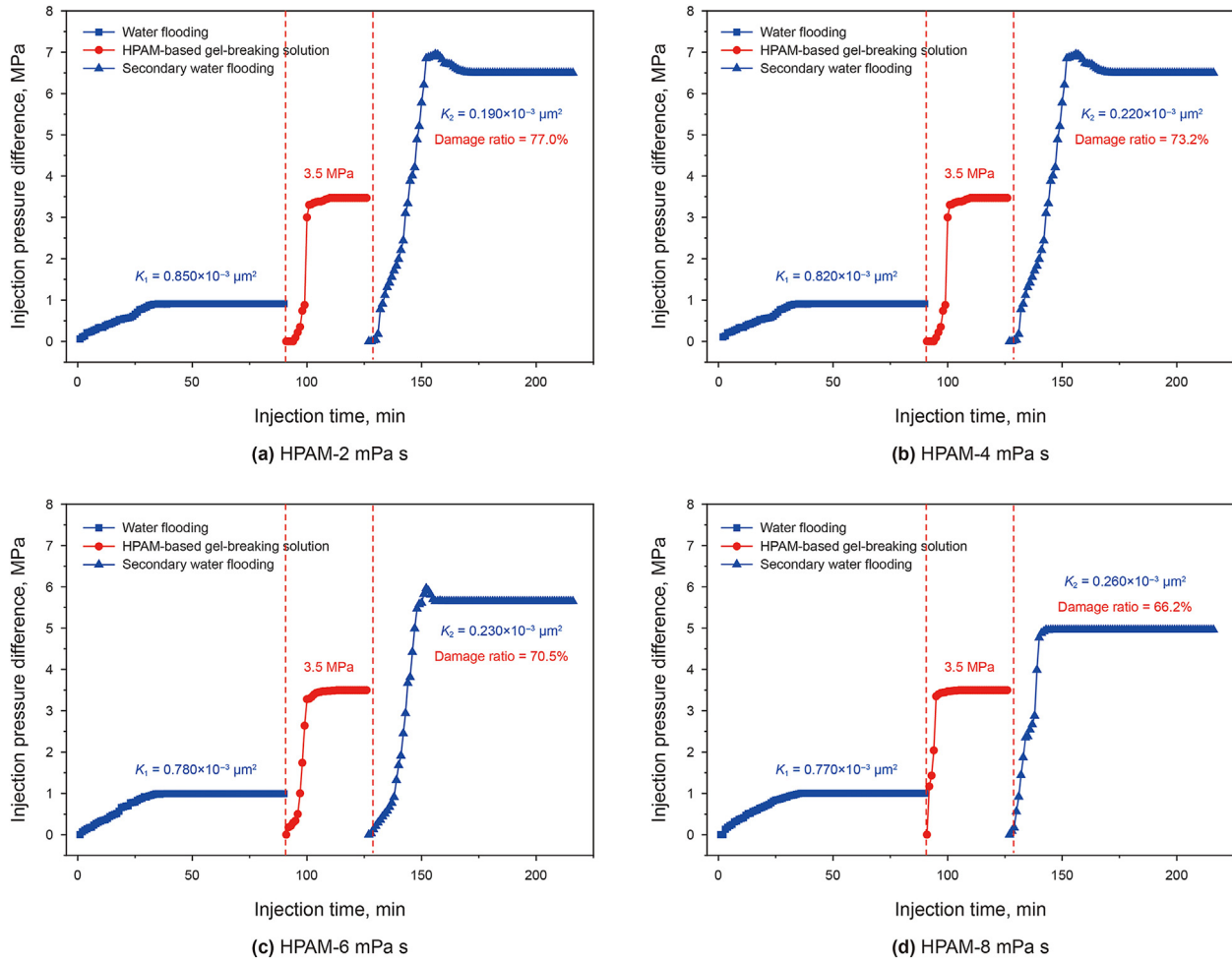


Fig. 6. Dynamic pressure curves during displacement for different viscosities of HPAM-based gel-breaking solutions.

Table 4

Core permeability before and after displacement for the HPAM-based gel-breaking system.

Test No.	Gel-breaking fluid and viscosity	Gas permeability, $10^{-3} \mu\text{m}^2$	Water permeability, $10^{-3} \mu\text{m}^2$	Effluent volume, mL	Permeability after damage, $10^{-3} \mu\text{m}^2$	Damage degree, %
5	HPAM-2 mPa s	1.77	0.850	8.2	0.190	77.0
6	HPAM-4 mPa s	1.77	0.820	6.8	0.220	73.2
7	HPAM-6 mPa s	1.73	0.780	5.5	0.230	70.5
8	HPAM-8 mPa s	1.78	0.770	3.7	0.260	66.2

72.6%. These two systems had similar levels of damage to low-permeability rock cores. However, under high viscosity conditions (i.e., greater than 4 mPa s), for gel-breaking solutions with the same viscosity (e.g., 8 mPa s), the rock damage degree caused by the GG-based gel-breaking solution was 45.6%, while the rock damage degree caused by HPAM-based gel-breaking was 66.2%. It was because the residual polymers of HPAM-based viscosifiers had smaller particle sizes compared to GG-type, as shown in Fig. 8. Under the constant pressure of 3.5 MPa, smaller particles entered the core more easily, leading to greater damage to the core and even the in-depth of the reservoir.

4. Conclusions

- (1) By formulating fracturing fluid systems with different concentrations of GG and HPAM, gel-breaking solutions with

different viscosities (i.e., 2, 4, 6, 8, and 10 mPa s) were obtained.

- (2) Due to the smaller molecular weight of GG compared to HPAM, a higher concentration was required to obtain the same viscosity for the gel-breaking solution. Additionally, after breakage, the viscosity of the GG-based gel-breaking fluid was lower than that of the HPAM-based gel-breaking fluid at the same dosage of polymers.
- (3) As the viscosity of the solution increased, the remaining molecular weight of the gel-breaking solution also increased. For the gel-breaking solution with the same viscosity, the residual molecular weight in the HPAM-based solution was higher than that of the GG-based solution.
- (4) As the viscosity of the gel-breaking solution made of GG or HPAM increased, the particle size of the residual polymers in the solution also increased. For the gel-breaking solution

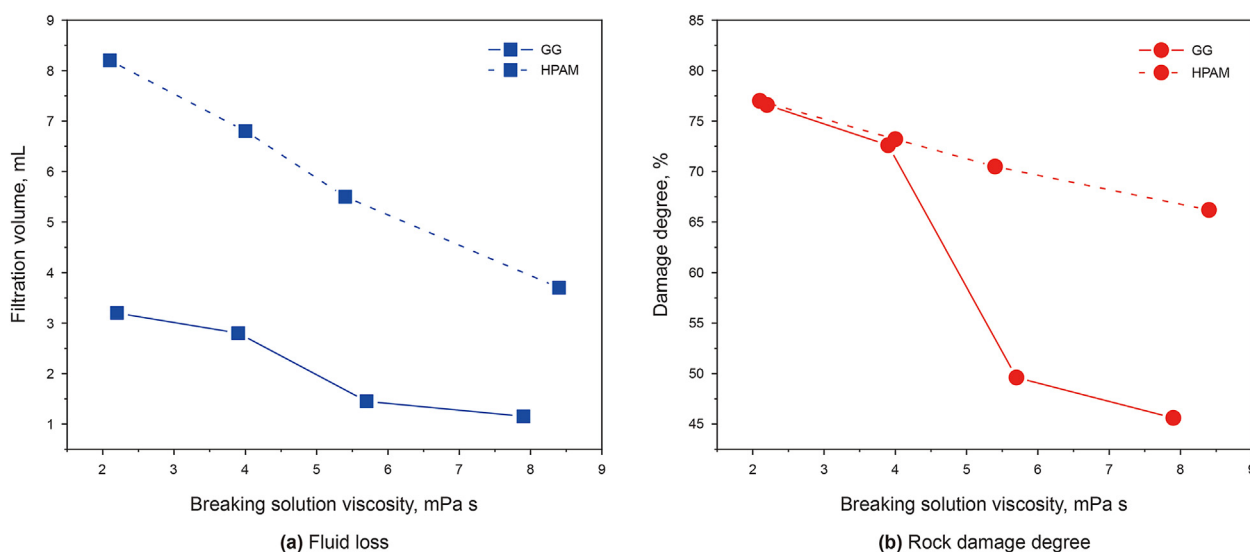


Fig. 7. Variations in fluid loss and rock damage degree of different gel-breaking solutions.

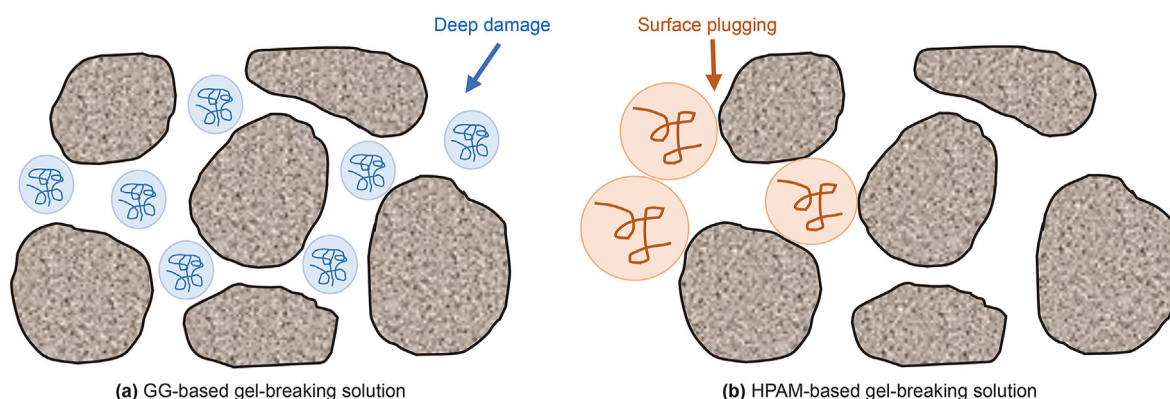


Fig. 8. Damage of different types of gel-breaking solutions to reservoir matrix after fracturing.

with the same viscosity, the residual polymer particle size of the HPAM-based was smaller than that of the GG-based.

- (5) For gel-breaking solution systems with the same viscosity, HPAM-based solution caused greater damage to low-permeability rock cores. It was because the residual polymers had smaller particle sizes, resulting in a higher quantity entering the rock core. However, when the viscosity of the gel-breaking solution was low (i.e., 2–4 mPa s), the damage caused by both GG and HPAM to low-permeability cores became similar.
- (6) The rock damage degree of the gel-breaking solutions was reduced with an increase in the viscosity of the gel-breaking solution made of GG or HPAM. In addition, The damage degree of the gel-breaking solution was mainly related to the particle size of the residual polymers instead of molecular weight, which was associated with the matching relationship between the residual polymers and the pore throats.

CRediT authorship contribution statement

Guo-Dong Wu: Writing – original draft, Investigation, Conceptualization. **Li-Kun Wang:** Writing – original draft, Investigation, Conceptualization. **Chun-Yan Zhao:** Investigation, Data

curation. **Ze-Jun Zhang:** Methodology, Investigation. **Jian-Yu Yin:** Investigation. **Maryamgul Anwaier:** Investigation. **Hong-Da Ren:** Investigation. **Dan Yang:** Investigation. **Shu-Li Yin:** Investigation. **Zhuo-Lin Cai:** Investigation. **Dao-Yi Zhu:** Writing – review & editing, Visualization, Methodology, Investigation, Conceptualization.

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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