Study on the Effect of Fracturing Fluid on the Structure and Mechanical Properties of Igneous Rock

Kun Zhang, Yuxuan Liu,* Lianqi Sheng, Bojun Li, Tianxiang Chen, Xiongfei Liu, and Erdong Yao*

ABSTRACT: Igneous rock oil and gas reservoirs have great development potential. Hydraulic fracturing is an important means for the development of these reservoirs. In the process of fracturing and increasing production, fracturing fluid is prone to a hydration reaction with clay minerals in igneous rock, and then, the structure and mechanical properties of the igneous rock are changed, affecting increased production. Therefore, it is necessary to establish a systematic water–rock reaction experiment method to understand the influence of fracturing fluid on the structure and mechanical properties of igneous rocks and to optimize the fracturing fluid system of igneous rock reservoirs. In this experiment, four solutions were used: slickwater, guar fracturing fluid, 2% KCl aqueous solution, and 4% KCl aqueous solution. Acoustic testing, porosity and permeability testing, XRD analysis, micro-CT scanning, and displacement experiments were performed. The influence of different fracturing fluids on the structure and mechanical properties of igneous rocks was studied. Igneous rock samples with a permeability of 0.05–0.1 mD and average porosity of 7–14% were used. The results show that all four liquid systems will reduce the permeability, Young’s modulus, and brittleness index and increase the porosity and Poisson’s ratio of the rock after fracturing. Among them, the permeability damage rate is as high as 37.37%, which may be related to the plugging of pores with solid residues in the gel breaking liquid; CT results show that there are microcracks in the rock, which increase over time, up to 13.54%. The brittleness index decreases. Among the fluids, the influence of slickwater on the rock brittleness index is the smallest, no more than 5%. Guar gum had the greatest effect on the Gel breaking liquid, up to 58%. One of the reasons for the increase in porosity is that adding a clay stabilizer composed of inorganic salts and organic cationic polymers to the slickwater fracturing fluid can effectively reduce the damage caused by the fracturing fluid to the rock during the fracturing process and can reduce the maximum by 50%. This paper can clarify the damage law of fracturing fluid systems to igneous rock reservoirs and provide the theoretical basis for the hydraulic fracturing of igneous rock reservoirs.

1. INTRODUCTION

With the advancement of petroleum exploration technology and the continuous discovery of igneous rock oil and gas reservoirs, igneous rock oil and gas reservoirs have attracted the attention of scholars as a new field of oil and gas exploration and development. Like sedimentary rock oil and gas reservoirs, igneous rock oil and gas reservoirs are widely distributed in more than 300 basins or blocks in more than 20 countries on 5 continents. They have been found in many countries including Russia, China, the United States, and Japan. However, igneous rock reservoirs have complex reservoir conditions, strong heterogeneity, and low-permeability reservoirs, and their natural productivity is not high. Therefore, hydraulic fracturing has become a necessary means to fully develop igneous rock reservoirs.

The area of volcanic rocks in the Sichuan Basin is about 2 × 10^4 km^2, which is mainly developed in a large area in Western Sichuan/Southern Sichuan. Among them, the volcanic rocks of effusive facies in the Mianyang Santai area are widely distributed, which is a favorable area for volcanic exploration, with an area of 6000 km^2. The Yongtan-1 well deployed by PetroChina Southwest Oil and Gas Field company in 2018 is a key risk exploration well for Permian volcanic rocks, with a depth of 5700 m. There were four occurrences of gas invasion during drilling, and the oil and gas display was good. Yongtan-1 shows good reservoir physical properties through core physical property analysis. The well eventually yielded a highly productive industrial gas flow of 22.5 × 10^4 m^3/day, further...
Fracturing fluid is prone to hydration reaction with clay minerals in igneous rock which then changes the structure and mechanical properties of igneous rock. For example, the reservoir rock contains clay minerals and carbonate minerals, and there are varying degrees of water sensitivity, alkali sensitivity, and velocity sensitivity damage in the later development process. The following situations may arise: (1) The radius of the pore throat of the reservoir space is small. The fracturing fluid enters the micropores, which can easily block the pore throat and cause the permeability of the reservoir to decrease. (2) The incompatibility between fracturing fluid and the reservoir will cause water sensitivity and acid sensitivity to decrease the permeability of the fracture. An improper selection of proppants can also easily cause the fracture conductivity to decrease, which will affect the overall postcompression production. The oil and gas production of reservoirs using hydraulic fracturing is greatly affected by the brittleness of the reservoir. Brittleness has a positive effect on hydraulic fracturing. Larger reservoir brittleness is conducive to achieving higher production. However, igneous rock reservoirs are relatively brittle, and multiple fractures are prone to fracture and extension during hydraulic fracturing. However, the understanding of the initiation and extension laws is not clear, and it is impossible to optimize the fracturing construction plan for its complex characteristics. Although the above occurs in all aspects of reservoir damage, it is essentially caused by the water–rock reaction between the rock and the fracturing fluid. The water–rock reaction interacts with oil and gas reservoirs in many ways, and there are few studies on the water–rock reaction of igneous rocks. In contrast, many people have studied the rock reaction of sandstone, and tested the water damage caused by sandstone, mudstone, and shale under hydration. For example, sandstone is physically damaged by water due to the migration and diffusion of cement and clastics between particles of sensitive minerals. After the rock is immersed for 1 month, the secondary porosity can reach 40–80% of the total secondary porosity. This is the main reason for the physical and chemical effects of water on the mechanical properties of sandstone. Ion composition and pH values have a greater impact on the mechanical properties of red sandstone. The peak strength, residual strength, and elastic modulus of the rock after corrosion by various chemical solutions all decrease by varying degrees. Among them, the axial peak stress decreased by 58.13%, and the elastic modulus decreased by 79.11%. The width of cracks on the surface of silty mudstone increases rapidly with the increase of immersion time. The expansion of silicate clay minerals in water is caused by the internal damage of the silty mudstone. The fracture mechanics of natural mudstone is significantly affected by the water–rock reaction. As the immersion time increases, its peak load continues to decrease, with a maximum decrease of 67.6%. Although there have been certain results in the water–rock reaction of sandstone, mudstone, carbonate rock, etc., they hardly involve hydraulic fracturing of igneous rock reservoirs. The latter is a dual medium with strong brittleness, low ductility, and a large number of natural fractures. The mechanical properties of pores and molten pores are very different from those of other oil and gas reservoirs. At present, there is little research on igneous rock water damage. The understanding of the influence of fluids, especially fracturing fluids, on the structure and mechanical properties of igneous rocks is insufficient. This makes it difficult to select fracturing fluid systems in the development of igneous rock reservoirs.

The presence of clay minerals in rocks can alter the rock’s mechanical properties when interacting with fresh water. In the oil field industry, potassium chloride (KCl) is the most commonly used clay stabilizer to prevent wellbore instability caused by swelling in sandstone upon its hydration. The current use of clay stabilizers includes surfactants like quaternary ammonium-based dicationic surfactants and polyoxyethylene quaternary ammonium surfactants; plant extracts like okra mucous extracted from okra plants; polymers; and nanoparticles.

In this experiment, two fracturing fluids used in the field, slickwater and guar fracturing fluid, were selected, and two KCl aqueous solutions of different concentrations were used for comparison. The porosity and permeability test, sonic wave test, XRD analysis, and core micro-CT scan were used for comparison. Porosity, permeability, and CT scans were performed to characterize changes in the core structure; Young’s modulus, Poisson’s ratio, and the brittleness index were used to characterize changes in core mechanical properties. The degree of damage to the core by different fracturing fluid systems was evaluated. Based on an understanding of the mechanism of fracturing fluid and igneous rock hydration, the damage law of the fracturing fluid system regarding igneous rock reservoirs is clarified, which provides the theoretical basis for hydraulic fracturing of igneous rock reservoirs.

2. EXPERIMENTAL SECTION

2.1. Rock Sample Preparation. Due to the limited number of downhole cores, outcrop samples from the Sichuan Basin and surrounding areas were used. To ensure a more representative sample, the Permian igneous stratigraphy of the Sichuan Basin was used as a reference. The outcrops in and around the Sichuan Basin were systematically analyzed, and the outcrop samples from the Yanjin area were finally selected, as shown in Figure 1a.

Figure 1. Reservoir rock samples: (a) igneous rock outcrop and (b) igneous cores.

According to the sonic wave, porosity, and permeability data tested before the experiment, rock samples with similar mechanical properties were selected for the experiment. A total of 20 cores were prepared and combined. Sixteen pieces were selected for experimentation to ensure that the similarity between all samples was maximized. The sample numbers are BC-2, BC-3, BC-4, BC-5, AS-1, AS-2, AS-3, AS-4, AC-2, AC-3, AC-4, AS-5, BS-1, BS-3, BS-4, and BS-5. The sample is a cylinder with a diameter of 25 mm and a length of 50 mm (Figure 1b).

The core is ground into powder for XRD analysis. As shown in Figure 2, the reservoir rock consists of 4 components: 35.6% clay, 1.71% quartz, 17.6% potash feldspar, and 45.1% plagioclase.
In clay, chlorite and kaolin are the main components. They account for more than 90% of the total amount of clay in the rock, and the clay also contains a small amount of illite and mixed layers of limonite. Particle transport of kaolinite will result in a significant reduction in reservoir permeability. F$^{3+}$ in chlorite will precipitate with acid and thus block the pore space. The fracturing fluid system selected for this experiment is alkaline, mainly for the damage caused by the water–rock reaction on clay swelling and particle transport; chlorite is not sensitive to the alkaline conditions and cannot cause damage.

2.2. Liquid Preparation. The fluids used in this experiment are slickwater fracturing fluid, guar fracturing fluid, 2% KCl solution, and 4% KCl solution. Among them, slickwater and guar fracturing fluid are fracturing fluids used on-site, and two different concentrations of KCl aqueous solutions with excellent antiscratching properties are used as controls.

The slickwater used in this experiment is 100 000 ppm high salt tolerance, low adsorption slickwater fracturing fluid. It contains salt-resistant friction reducers, NaCl, and drainage aids. Because of the high clay content in the rock, inorganic salts 0.5% KCl and organic cationic polymers 0.5% TDC-15 were added, and the fracturing fluid pH was 7.2. The compound clay stabilizer can reduce clay hydration swelling and particle dispersion and migration. The guar fracturing fluid used in the experiment is a non-antiscratching liquid. The required reagents are HPG, sodium carbonate, organoboron, and sodium persulfate. The specific process is to add HPG and anhydrous Na$_2$CO$_3$ to the water and adjust the pH of the solution to 9–11. Then, organoboron was added as a cross-linker and ammonium persulfate as a glue breaker according to the volume concentration. The solution is poured into a beaker and stirred. The solution to be configured is put into a constant temperature water bath and heated at a constant temperature of 80 °C for 2 h to break the gel. The gel breaking liquid is obtained as a solution filled with suspended colloids, which is filtered through a laboratory filter to finally obtain the gel breaking liquid.

2.3. Water Damage Test Procedure. The experiment was carried out at room temperature, using a displacement device with a confining pressure of 5 MPa and a displacement pressure of 3 MPa (Figure 3). A total of 16 cores were used. All cores were saturated with deionized water for 24 h before the displacement experiment. Among them, cores BC-2, BC-3, BC-4, and BC-5 were subjected to slickwater displacement experiments with displacement times of 3, 6, 9, and 12 h, respectively; cores AC-2, AC-3, AC-4, and AS-5 with 4% KCl solution for 3, 6, 9, and 12 h, respectively; and cores BS-1, BS-3, BS-4, and BS-5 with gel breaking liquid for 3, 6, 9, and 12 h, respectively. A total of 2000 mL of each of the four fracturing fluids was used in the displacement experiment. After the displacement experiment, we conducted several tests using cores. Specifically, the cores of BC-2, BC-3, BC-4, and BC-5 were used for XRD analysis; BC-2, BC-3, BC-4, BC-5, AC-2, AC-3, AC-4, AS-5, BS-1, BS-3, BS-4, and BS-5 were used for micro-CT scanning. All samples were subjected to sonic wave, porosity, and permeability tests before and after the experiment.

2.4. Structural and Mechanical Properties Test Analysis. Both porosity and permeability are tested by the differential pressure method. The porosity adopts Boyle’s law, and the porosity is calculated using the pressure difference between the front and back. The permeability of the rock is calculated according to the Darcy formula. By calculating the porosity change rate and the permeability damage rate, the damage degree of different fracturing fluids on the rock can be quantitatively described.

The three-dimensional image of the internal structure of the core is obtained by CT scanning, and the device is shown in Figure 4.

The acoustic wave test uses the SCMS-E high-temperature and high-pressure core multiparameter instrument with P-wave and S-wave test functions to conduct experimental research on core samples. The dynamic mechanical properties of the core, such as Young’s modulus $E_d$ (eq 1) and Poisson’s ratio $\nu_d$ (eq 2), can be calculated using the relationship between the P wave and S wave velocity.
The brittleness index calculation based on rock mechanical parameters determines Young’s modulus and Poisson’s ratio in the rock mechanical parameters by taking 50% of the weights, respectively. Among them, Poisson’s ratio (\( \nu \)) reflects the rock’s fracture ability under external force, and Young’s modulus (\( E \)) reflects the rock’s supportability after rupture. The theory of rock brittleness is a comprehensive manifestation of Poisson’s ratio and Young’s modulus. Poisson’s ratio and Young’s modulus can be used to calculate the brittleness index of the rock according to eqs 3 and 4, and the brittleness index based on rock mechanics characteristics (eq 5) can be obtained by calculating the average value of the two. Different combinations of Young’s modulus and Poisson’s ratio indicate that the rock has different brittleness values. Generally, a higher Young’s modulus and a lower Poisson’s ratio indicate the stronger brittleness of the rock, and it is easier to form complex fractures during fracturing. The brittleness is calculated from Poisson’s ratio and Young’s modulus using the following equations:

\[
E_d = \frac{\rho V_p^2 (3V_p^2 - 4V_s^2)}{V_p^2 - V_s^2} \tag{1}
\]

\[
\nu_d = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)} \tag{2}
\]

where \( V_p \) is the P-wave velocity, \( V_s \) is the S-wave velocity, and \( \rho \) is the density of the sample.

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\[
\text{Bl}_E = \frac{E - E_{\text{min}}}{E_{\text{max}} - E_{\text{min}}} \tag{3}
\]

\[
\text{Bl}_V = \frac{\nu - \nu_{\text{min}}}{\nu_{\text{max}} - \nu_{\text{min}}} \tag{4}
\]

**Figure 4.** Photograph of the MicroCT instrument.

**Figure 5.** Core porosity changes after flooding with different solutions: (a) slickwater fracturing fluid, (b) 2% KCl solution, (c) 4% KCl solution, and (d) guar gum breaking fracturing fluid.
fracturing fluids. The results show that the porosity of the cores has increased to different degrees, indicating that different solutions have different effects on the porosity of igneous rocks. 2% KCl solution and 4% KCl solution have the greatest impact on porosity. For example, the 4% KCl solution can increase the porosity of the original core by 46.46%. Gel breaking liquid and slickwater have little effect on porosity, only about 10%. Changes in the porosity of igneous rocks may be caused by the following reasons: (1) After the water-based fracturing fluid enters the reservoir, the soluble salt minerals in the dissolved rock make the porosity increase.\(^{41}\) (2) Microcracks are generated during the displacement process, which increases the porosity of the core.\(^{42}\) (3) Porosity is reduced by blocking the pores by polymer or guar residue.\(^{43,44}\)

3.2. Permeability damage law. Figures 7 and 8 show the core permeability changes before and after displacement. The results show that the permeability of the igneous rock decreases by different degrees after the four liquids are displaced. However, different solutions have different effects on the permeability of the igneous rock. The gel breaking liquid causes the most damage to permeability; the highest can reach 37.75%. Slickwater shows the least damage to permeability, which is only about 15%. The drop in permeability may be caused by the following two reasons: (1) The core contains a small amount of illite and mixed layers of illite. This leads to hydration and swelling, reducing permeability. (2) Particles migrate in the core, and smaller particles will cause greater stratum damage and greatly reduce the permeability of the core.\(^{45}\) (3) Guar fracturing fluid residue plugs pores.\(^{44}\)

3.3. Macro- and Microdamage Observation. Figure 9 shows the surface observation of the core before and after the experiment. The results show that microfractures were produced on the surface of the igneous rocks after the liquid displacement experiment. Figure 10 shows the rock sample after the liquid damage observed by the CT scan section. The internal fine fractures of the rock and the trend of increasing fractures with time can be observed. The internal fractures of the rock sample underwent the phenomenon of intersection, communicating other fracture networks, making the fracture volume increase significantly up to 13.54%. The software calculation shows that the number of cracks per unit area gradually increases, reaching 9 at 12 h, with a 40% increase in width. Figure 11 shows the core pore images extracted from the MicroCT scan of the core and the lesser pore space. Figures 12–14 show the images of the core pores extracted after MicroCT scanning of the core, and the results show the following:

1. The pores inside the core increase significantly with the increase of the displacement time. The main reason for the increase in porosity is fracture generation by fracturing. We believe that if there are no microfractures, the porosity should decrease slightly because the fluid causes a small amount of clay swelling, particle transport, and clogging by residues in the fracturing fluid.
2. The pore space increases mostly at the pressurized end face in the core replacement experiment, consistent with kaolinite particle transport properties.
3. The pore distribution of 4% KCl solution after repelling by three solutions is significantly larger than that of broken glue solution and slickwater fracturing solution, which is consistent with the increase of porosity mentioned above.

3.4. Law of Mechanical Damage. The softening of the reservoir rock caused by the water—rock reaction will lead to the embedment of proppants and the closure of hydraulic fractures. This cannot be observed through the surface. Therefore, sonic wave tests are performed to calculate Young’s modulus, Poisson’s ratio, and the brittleness index to quantify the changes in mechanical properties after the water—rock reaction. Table 1 lists the changes in Young’s modulus and Poisson’s ratio of the core before and after the experiment. The results show that Young’s modulus decreased and Poisson’s ratio increased after the experiment. Figures 15 and 16 show the changes in the core brittleness index before and after displacement. The results show that the brittleness index decreases by varying degrees after the experiment. The brittleness index remained unchanged before and after the slickwater fracturing fluid displacement, and the decrease was within 5%; the brittleness index of KCl solution decreased by about 30%, and the guar gum fracturing fluid caused the most serious damage, above 50%.

4. DISCUSSION

4.1. Reasons for the Increase in Porosity. Different liquids cause different amounts of damage to permeability, which may be due to the following three reasons: (1) Hydraulic fracturing produces microfractures. The CT scan slices of the core after liquid damage can confirm this. It is positively correlated with the water—rock reaction time. Regardless of the liquid type, it is the leading factor in the increase in porosity. There are fine cracks in the rock, and the cracks tend to increase

\[ BI = \frac{B_{E} + B_{I}}{2} \times 100\% \]  

where BI is the brittleness index, %; E is Young’s modulus of the rock, GPa; I is Poisson’s ratio of the rock, dimensionless; and the subscripts min and max represent the minimum and maximum values, respectively. B_E and B_I are the brittleness index calculated by Young’s modulus and Poisson’s ratio, respectively.

3. RESULTS

3.1. Porosity Damage Law. Figures 5 and 6 show the porosity changes of the cores after being flooded by the four different solutions. The results show that the porosity of the cores has increased to different degrees, indicating that different solutions have different effects on the porosity of igneous rocks. 2% KCl solution and 4% KCl solution have the greatest impact on porosity. For example, the 4% KCl solution can increase the porosity of the original core by 46.46%. Gel breaking liquid and slickwater have little effect on porosity, only about 10%. Changes in the porosity of igneous rocks may be caused by the following reasons: (1) After the water-based fracturing fluid enters the reservoir, the soluble salt minerals in the dissolved rock make the porosity increase.\(^{41}\) (2) Microcracks are generated during the displacement process, which increases the porosity of the core.\(^{42}\) (3) Porosity is reduced by blocking the pores by polymer or guar residue.\(^{43,44}\)

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with time. The permeability measured in this experiment is absolute porosity, and the increase of cracks leads to an increase in overall rock porosity. (2) Clay minerals in igneous rock cores produce particle migration. Due to pressure, migrating particles accumulate in the pore throat and produce compaction, resulting in excess pore space and increased porosity. Figures 12 and 13 show the core CT scan data obtained from 3, 6, 9, and 12 h of core displacement with 4% KCl solution and gel breaking liquid. The results show that as the experiment time increases, the internal pores of the igneous rocks gradually increase. Since the migration of particles mostly occurs on the upper-pressure surface, the increase in porosity is mainly concentrated in the upper part. In addition, the pores of the 4% KCl solution in the figure are more than those in the gel breaking liquid, which is consistent with Figure 6. (3) The clogging of polymers and residues is an important reason for the reduction of porosity. Among the four fluids, the increase in porosity of slickwater and guar fracturing fluid is inferior to that of the KCl system because
the polymer adsorption in slickwater and the blockage of guar residues cause damage to the low-porosity and low-permeability reservoirs and reduce the porosity. Therefore, as time increases, the core porosity increases after the action of the four fluids. The increase of the two fracturing fluid systems is lower than that of the KCl solution system.

4.2. Reasons for Reduced Permeability. After the experiment, the rock permeability decreased to varying degrees. There are three reasons for this: (1) There is hydration and expansion of clay minerals in the core. The XRD analysis shows that the content of clay minerals in the igneous rock used in the experiment is more than 35%. This is one of the main components of igneous rock. Through the analysis of clay minerals of igneous rocks, it can be known that the core used in this experiment contains mixed layered limonite and illite. The main component of the fracturing fluid system is water, and clay minerals that are not compatible with the fracturing fluid appear very easily. The phenomenon of hydration and expansion causes the permeability of the rock to decrease. Therefore, slickwater contains a clay stabilizer composed of inorganic salts and organic cationic polymers, which is the best antiswelling system with the lowest permeability damage. Guar gum fracturing fluid does not contain antiswelling agents, and the penetration rate is the most harmful. (2) There is the migration of clay mineral particles. When the displacement experiment started, due to the pressure displacement, the particle migration of clay minerals (such as kaolinite) in the core caused the clogging of the channels between the pores, which lowered the permeability. However, since the cationic polymer in slickwater can effectively inhibit the migration of particles, it can reduce the decrease in permeability. Therefore, the core permeability decreases the least after the slickwater reaction. (3) Lastly, there is residue damage. Guar fracturing fluid contains certain residues that will block the pores and greatly reduce the permeability. It is the most harmful to permeability. The insolubility in water blocks the effective pores of the supporting fractures, thereby reducing the conductivity of the fractures, causing damage to the formation, and affecting the fracturing effect.

4.3. Changes in Rock Mechanical Properties. After the experiment, the overall strength of the core decreased. Among them, the core brittleness index did not decrease significantly after the slickwater reaction, and the core brittleness index decreased the most after the guar fracturing fluid was displaced, reaching more than 50%. (1) The content of clay minerals in the core is relatively high. The swelling of clay and the migration of

![Figure 10. Internal changes of the core at different times: (a) 3 h; (b) 6 h; (c) 9 h; and (d) 12 h.](image)

![Figure 11. Pre-experimental core: (a) top view and (b) front view.](image)

![Figure 12. Porosity distribution of 4% KCl solution at different displacement times: (a) 3 h; (b) 6 h; (c) 9 h; and (d) 12 h.](image)
particles in the clay will reduce the overall strength of the rock. The slickwater contains clay stabilizers that prevent swelling and inhibit the migration of particles, and the breaker is not stabilized by clay. Therefore, the reduction of slickwater brittleness index is the smallest, and the reduction of gel breaking liquid is the largest. (2) The breaker liquid is alkaline as a whole and will react with minerals such as potassium feldspar and quartz in the rock, which will reduce the overall strength.

5. CONCLUSIONS

In this paper, four fluids including slickwater, 2% KCl solution, 4% KCl solution, and gel breaking liquid are used to study the fracturing fluid and igneous rock using sonic wave, porosity and permeability test, mineral analysis, micro-CT scan, and displacement experiments. The influence law and the reason for changes in the rock structure and mechanical properties such as porosity, elastic modulus, and Poisson’s ratio of the core before and after the water–rock reaction were determined. This study draws the following conclusions:

(1) After the liquid damages the rock sample, the porosity continues to rise. CT results show that microcracks are generated in the rock, and they increase over time, up to 13.54%.

(2) The four liquid systems will all decrease the permeability of the rock. Among them, the gel breaking liquid causes the greatest damage to the permeability, which can reach 37.37%.

Table 1. Information of Core Samples in Brazilian Splitting Tests

| Fracturing Fluid Type | Processing Time (h) | Young’s Modulus (GPa) | Poisson’s Ratio | Young’s Modulus (GPa) | Poisson’s Ratio |
|-----------------------|---------------------|-----------------------|----------------|-----------------------|----------------|
| Slickwater fracturing fluid | 3 | 42.4 | 0.19 | 33.30 | 0.28 |
|                        | 6 | 36.4 | 0.12 | 31.40 | 0.24 |
|                        | 9 | 39.5 | 0.16 | 33.70 | 0.28 |
|                        | 12 | 38.6 | 0.14 | 34.20 | 0.28 |
| 2% KCl aqueous solution | 3 | 38.8 | 0.1 | 35.90 | 0.28 |
|                        | 6 | 38.5 | 0.1 | 36.30 | 0.32 |
|                        | 9 | 37.7 | 0.11 | 34.10 | 0.28 |
|                        | 12 | 39.4 | 0.1 | 37.10 | 0.33 |
| 4% KCl aqueous solution | 3 | 39.6 | 0.13 | 36.18 | 0.29 |
|                        | 6 | 35.6 | 0.09 | 32.71 | 0.27 |
|                        | 9 | 38.96 | 0.14 | 35.32 | 0.31 |
|                        | 12 | 38.37 | 0.10 | 34.41 | 0.29 |
| Guar fracturing fluid | 3 | 44.02 | 0.18 | 33.60 | 0.315 |
|                        | 6 | 43.69 | 0.16 | 33.95 | 0.305 |
|                        | 9 | 39.88 | 0.14 | 33.65 | 0.31 |
|                        | 12 | 46.27 | 0.18 | 34.60 | 0.32 |

Figure 13. Porosity distribution of slickwater at different displacement times: (a) 3 h; (b) 6 h; (c) 9 h; and (d) 12 h.

Figure 14. Porosity distribution of breaker fluid at different displacement times: (a) 3 h; (b) 6 h; (c) 9 h; and (d) 12 h.
The slickwater has a higher viscosity than the other three fracturing fluids, but the overall impact on the rock is smaller.

Adding a clay stabilizer composed of inorganic salts and organic cationic polymers to the slickwater fracturing fluid can effectively reduce the damage to rock brittleness by a maximum of 50%.

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