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Research Article

Laboratory Study on Core Fracturing Simulations for Wellbore Strengthening

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The lost circulation in a formation is one of the most complicated problems that have existed in drilling engineering for a long time. The key to solving the loss of drilling fluid circulation is to improve the pressure-bearing capacity of the formation. The tendency is to improve the formation pressure-bearing capacity with drilling fluid technology for strengthening the wellbore, either to the low fracture pressure of the formation or to that of the naturally fractured formation. Therefore, a laboratory study focused on core fracturing simulations for the strengthening of wellbores was conducted with self-developed fracture experiment equipment. Experiments were performed to determine the effect of the gradation of plugging materials, kinds of plugging materials, and drilling fluid systems. The results showed that fracture pressure in the presence of drilling fluid was significantly higher than that in the presence of water. The kinds and gradation of drilling fluids had obvious effects on the core fracturing process. In addition, different drilling fluid systems had different effects on the core fracture process. In the same case, the core fracture pressure in the presence of oil-based drilling fluid was less than that in the presence of water-based drilling fluid.

1. Introduction

Fractured lost circulation is one of the types of drilling fluid-related lost circulation in drilling engineering. It is a technological problem that always complicates drilling engineering. Usually, it is very difficult to eliminate fractured lost circulation. It is also easy to induce a series of safety problems that cause collapse, blowouts, and disastrous accidents, leading to heavy losses of lives and property. Fractured lost circulation is also a choke point in the development of high-efficiency drilling technology. It is an urgent problem that must be solved quickly [1–4].

As research on lost circulation has progressed, the solutions have gradually developed from simple plugging to a combination of plugging and prevention. Prevention has been accepted widely, and a series of prevention technologies such as improving the narrow window of safe mud density in drilling fluid technology, borehole strengthening technology, and wellbore strengthening technology have been developed. All these technologies are designed to improve the integrity of the wellbore and improve the formation fracture pressure in order to stop and prevent lost circulation [5].

Strengthening the wellbore essentially improves the fracture pressure of the formation in the wellbore. The method for strengthening the wellbore includes adding materials that can repair and protect the wellbore against drilling fluid. The wellbore fluid pressure is balanced by plugging and supporting the formation fracture, which is known as actively taking measures to cope with the formation's lost circulation problem. Strengthening the wellbore includes considering the drilling fluid and the different kinds of materials that are added to drilling fluid, and the object of interest is the formation, namely, the wellbore. This is mainly intended to improve the performance of the drilling fluid to form a high-quality mud cake, which can strengthen the wellbore.

Abundant research and applications for improving the wellbore drilling fluid technology to improve formation pressure-bearing capacity have been performed domestically and abroad. Nayberg classified plugging materials into three groups according to their morphologies: fibres, flakes, and granules. Moreover, the experimental results showed that the granular material can withstand higher pressure after plugging the fractures, and the pressure-bearing effect was better than that of the fibrous material and flaked material [6]. Alsaba and Nygaard discussed the most recent developments in lost circulation materials (LCM) such as plugging assurance technology and nanotechnology and also presented a comprehensive summary of currently available lost circulation materials. In addition, they reclassified lost circulation materials into seven categories based on their appearance and application: granular, flaky, fibrous, LCM mixture, acid/water-soluble, high fluid loss squeeze, swellable/hydratable combinations, and nanoparticles. The authors proposed that due to different understandings of the mechanism of wellbore strengthening, it was difficult to develop a unified standard for testing methods [7]. Experiments with slotted disks that simulated fractures have been performed, wherein the amount of fluid loss and sealing pressure was used as evaluation criteria. Jeennakorn et al. investigated LCM behaviour with different slot designs and fluid flow patterns for water-based and oil-based drilling fluids. They improved the experiment by adding a bladder-type accumulator to the system to provide instantaneous flow conditions. The results of the experimental setup showed that the set of experiments can change the result. As such, caution should be taken when quantitatively comparing LCM tests based on slot disks to different experimental setups [8]. Alsaba et al. believed there were shortcomings in the laboratory experimental setups that utilized slotted disks. A fluid loss apparatus was developed to mimic wellbore circulation to study the effect of annular fluid flow on building an LCM bridge at the fracture aperture [9]. Tehrani et al. found that strengthening the wellbore was achieved by plugging and propping fractures. The effect of strengthening the wellbore is closely related to the kind of materials used for plugging, the gradation and the filter loss of drilling fluid. It was found that graphitic materials may be more effective in propping fractures open, whereas carbonates and cellulosic materials can improve the effect of plugging [10]. Wang et al. studied the effect of plugging materials on plugging and supporting fractures using the boundary element method. The relationships between fracture pressure, wellbore pressure, wellbore radius, fracture length, and other parameters under the action of plugging and supporting of materials were analysed [11, 12]. Friedheim et al. developed a high-fluid-loss and high-strength (HFHS) plugging material. The HFHS was designed to be applicable over a wide range of losses, miscible with aqueous and nonaqueous fluid, pumpable through measurement while drilling (MWD) tools and bottomhole assembly (BHA), and resistant to high shear stress, even after being weighted with barite. The material is mainly composed of cellulosic fibres and particles. The strength of mud cakes formed after filtration is very high. In addition, the material has been applied well in wells along the north slope of Alaska, the Grimes of Texas, and offshore Indonesia [13]. Contreras and Nwaoji introduced a method for strengthening the wellbore by adding a mixture of nanomaterials and graphite to the oil-based drilling fluid, which showed good results with respect to wellbore strengthening and improved formation pressure-bearing capacity. The pressure test was carried out in a 9/16″ wellbore. Two kinds of drilling fluid systems are prepared using calcium-based nanoparticles and iron-based nanoparticles, respectively. The fracture pressure was increased by 65% when calcium-based nanoparticles were used, whereas fracture pressure increased by 39% in the presence of iron-based nanoparticles. The optimum nanoparticle concentrations were established after a comprehensive experimental screening. A strong relationship between wellbore strengthening and mud filtration at high pressure and high temperature, using a filter press on ceramic discs, was determined [14, 15]. Whitfill et al. evaluated resilient graphitic carbon using experiments and pointed out that resilient graphitic carbon has many special properties that can be applied to the operation of plugging. The addition of resilient graphitic carbon can improve the resilience of the plugging materials [16–18]. Savari et al. suggested that the resilient materials played an important role in wellbore strengthening and validated the characteristics of resilient graphitic carbon related to resiliency, lubricity, resistance to attrition, and compatibility with downhole tools. It had a good effect in wellbore strengthening applications. Whether in sandstone or carbonate formations, with water-based drilling fluid or oil-based drilling fluid, resilient materials have shown obvious strengthening effects on wellbores [19]. Mansour et al. introduced a new class of "smart lost circulation materials" to effectively seal fractures. The smart LCMs were made out of thermoset shape memory polymers that were activated upon exposure to the formation's in situ temperature, which caused expansion and acted as an effective seal for the fractures. The physical properties of the smart lost circulation materials could prevent damage to production zones and tool plugging [20]. Collins et al. noted the problem associated with the amount of plugging materials when the drilling fluid was mixed and pointed out that it is necessary to consider the density of the plugging materials and that the amount of plugging materials should be calculated according to the volume, rather than the weight. When adding materials according to the weight percentage, under the condition that the weights are equal, the volume of materials with lower density is larger. When it is added, the plugging results will be affected [21]. Pu Xiaolin studied the drilling fluid technology associated with improving the formation pressure-bearing capacity with the theory of temporary shielded plugging. The formula system was developed by adjusting the gradation of calcium carbonate materials in the drilling fluid and using inert water loss material as filling materials and has had achieved remarkable effects in the lost-circulation zone of the Luohe Formation in the Changqing Oilfield, effectively improving formation pressure-bearing capacity and ensuring a smooth drilling process and wellbore quality [22].

Wellbore-strengthening drilling fluid technology has been used widely both domestically and abroad. Respective preventative and plugging drilling fluid systems have achieved perfect results [23–37], which is very important to studies dedicated to improving formation pressure-bearing capacity. Many field experiments have also confirmed that a reasonable material ratio and drilling fluid system can improve the formation pressure-bearing capacity. For a brittle formation with low pressure-bearing capacity, when the drilling fluid column pressure is more than the formation fracture pressure, the formation will be fractured, and then lost circulation will occur. The low pressure-bearing capacity of a brittle formation is a significant cause of drilling fluid lost circulation. As such, it is important to improve the fracture pressure of brittle formation.

The existence of a mud cake can affect the formation fracturing process. In addition, the different mud cake performances have different effects on the formation fracturing process. The yield strength, thickness, and permeability of the mud cake can affect formation fracture pressure. The performance of the mud cake depends on the composition of the drilling fluid. To increase the formation pressure-bearing capacity, different kinds of plugging materials are usually added to the drilling fluid. How the addition of these materials affects the drilling fluid-related strengthening of the wellbore must be to explored and verified in practice. Therefore, many experiments focused on core fracturing simulations for strengthening the wellbore must be carried out to study the effect of drilling fluids and different kinds of plugging materials on strengthening the wellbore.

2. Materials and Methods

2.1. Setup. The self-developed equipment for the fracturing experiment consisted of three parts: (1) fluid intrusion system, (2) core holding system, and (3) pressure control and measurement system.

The fluid intrusion system consists of an outer sleeve pedestal (11), an outer sleeve (12), a piston (13), an outer sleeve head cover (14), an outer sleeve bottom cover (15), and a pressure sensor (16). The outer sleeve bottom cover is fixed on the outer sleeve pedestal. The lower end of the outer sleeve is fixed inside the outer sleeve bottom cover. The outer sleeve head cover is arranged on the top of the outer sleeve, and the piston is fitted inside the outer sleeve. The pressure sensor is set up at the top of the outer sleeve head cover.

The core holding system consists of a base support (21), a bracket (22), an autoclave (23), a rubber sleeve (24), an inlet line (25), a plug (26), an inlet plunger (27), an outlet plunger (28), an inlet hole (29), and a silicon seal (210). The autoclave is a hollow cylindrical structure. The inlet plunger is fixed at the top of the autoclave, and the outlet plunger is fixed at the bottom of the autoclave. The rubber sleeve is installed inside the autoclave. An airtight cavity is formed between the inner wall of the autoclave and the outer wall of the rubber sleeve to exert confining pressure on the core. The cavity that is formed by the inner wall of the rubber sleeve, the inlet plunger, and the outlet plunger is internally fixed with the core. The two sections of the central circular hole of the core are inserted with the inlet line and the plug, respectively, and a closed space is formed. The inlet line passes through the inlet plunger, and the plug passes through the outlet plunger. The core is fixed in the autoclave. The inlet line and the plug are also tightly fixed in the core. The other end of the inlet line is connected to the outlet of the outer barrel cover. The outer wall of the autoclave also has an inlet hole. The bracket is vertically fixed on the base support and is connected to the autoclave. The silicon seals are, respectively, fixed between the inlet line and the inner hole of the core and between the plug and the inner hole of the core. Figure 1 is a schematic diagram of the fracturing experiment equipment.

The pressure control and measurement system consists of a confining pressure pump (31), a displacement pump (32), a confining pressure sensor (33), a displacement pressure sensor (34), a core pressure sensor (35), and a computer (36). The confining pressure sensor is installed on the confining pressure pump. The confining pressure pump is connected with the inlet hole. The displacement pressure sensor is installed on the displacement pressure pump. The displacement pump is internally connected with the outer sleeve bottom cover. The computer is connected to the pressure sensors.

The theory behind the fracturing experiment equipment is that pressure offered by the pumps goes through the fluid intrusion system and drives drilling fluid into the core's inner hole in the core holding system, which can fracture the core. Therefore, the effect of improving formation pressure-bearing capacity, or wellbore strengthening facilitated by drilling fluid, will be evaluated.

In the test, first, the prepared drilling fluid is poured into the sleeve in the fluid intrusion system. The outer sleeve head cover is tightened. The pressure sensors are connected to the computer, and the outer sleeve bottom cover is connected to the pressure control and measurement systems. The intact core is taken, and the inlet pipe and plug are inserted into the central circular hole of the core. The core is then placed in the autoclave of the core holding system and is positioned in the middle of the rubber sleeve. The inlet plunger and outlet plunger are tightened to fix the core. The inlet pipe is connected to the outlet at the upper end of the outer sleeve head cover, and the inlet hole is connected with the pressure control and measurement systems. The pressure control and metering systems are initiated, and the required confining pressure is set by the computer. The confining pressure pump is initiated, and hydraulic oil is injected into the space between the autoclave and the rubber sleeve to apply the confining pressure on the core. After the confining pressure reaches the required value, the displacement pressure is set and the displacement pump is initiated. The hydraulic oil pushes the piston upward to drive the drilling fluid into the central circular hole of the core. With the increase in pressure, the core is finally fractured. During this period, the confining pressure sensor, displacement pressure sensor, and core pressure sensor, respectively, record the confining pressure, displacement pressure, and pressure change of the inner hole of the core, and the recorded values are used for

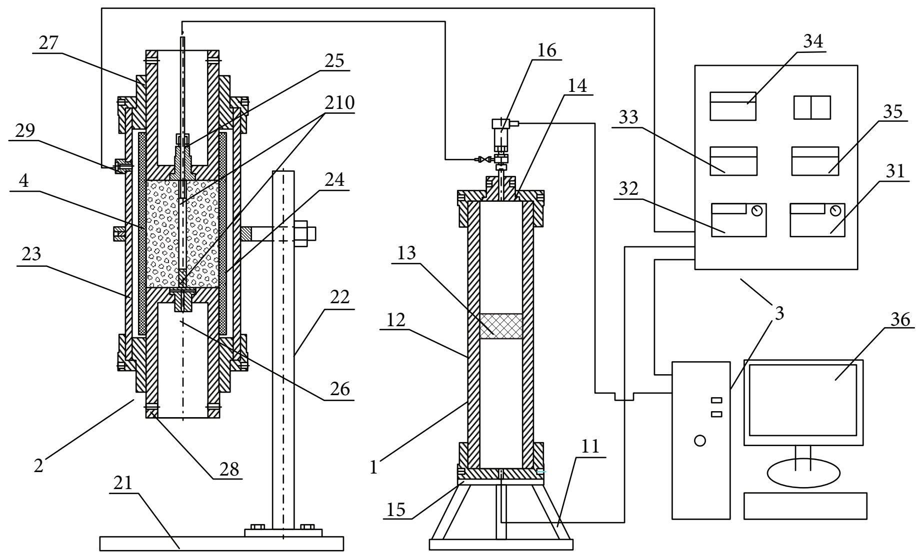


Figure 1: Schematic diagram of the fracturing experiment equipment.

subsequent tests. After the core is fractured, the drilling fluid or filtrate flows out through the guide groove on the end-face of the outlet plunger and the plug.

2.2. Materials

2.2.1. Core. The core used in the experiment was cylindrical, and its length was 140-150 mm with a diameter of 100 mm. There was a circular hole with a diameter of 10 mm in the centre of the core. Figure 2 shows a schematic diagram and photograph of the core. The core was made of cement mortar. The cement was ordinary 425 Portland cement. The sand was composed of quartz. The particle size range of the sand was 0.2-2 mm.

The physical properties and mechanical properties of the core are shown in Tables 1 and 2.

2.2.2. Plugging Materials

(1) Particulate Materials. The selected particulate materials included nanomaterials, calcium carbonate particles, quartz particles, graphite particles, and new, self-developed, high-strength polyester particles. Figure 3 shows several kinds of particulate materials used in the experiments.

Because different kinds of particles would be needed in the experiment, for the sake of completeness, all of the particles were numbered and their characteristics are shown in Table 3.

(2) Fibrous Material. The fibrous material selected for the experiment was paper fibre. The paper fibre was dark grey, light-weight, and less than 3 mm in diameter. Its physical and chemical properties were stable. The paper fibre is shown in Figure 4. Paper fibre was helpful in reuniting particulate materials, filling particulate materials in micropores, and improving the integrity and compactness of plugged zone.

(3) Flaky Material. The flaky material selected for the experiment was a new kind of high-friction material with high strength, uneven surfaces, and fibrous edges. The flaky material had a package effect on particulate materials. At the same time, the frictional resistance between the plugging layer and the fracture wall was enhanced, which was beneficial to the formation and stabilization of the plugging layer. Figure 5 shows the selected flaky material.

(4) Other Materials. Emulsified asphalt was used in the experiment. The asphalt materials are deformable, and they will deform to fill various pores and fractures under the influence of temperature and pressure, which can improve the plugging performance of drilling fluid and can form more compact mud cakes.

2.2.3. Base Fluid. Water-based and oil-based drilling fluids were used in the experiment. The formulas and properties of the drilling fluids are shown in Table 4.

The water-based drilling fluid was an ordinary dispersion system. The oil-based base drilling fluid was an oil-water emulsion drilling fluid system, and the oil-water ratio was 8 : 2.

The flow curves for the water- and oil-based drilling fluids are shown in Figure 6.

2.3. Method. The experiment for the core fracturing simulation for strengthening the wellbore was conducted under a confining pressure of 2 MPa. The core was used as the simulated formation. The drilling fluid for fracturing the core was injected into the inner hole in the core at a speed of 2 mL/min.

3. Results and Discussion

3.1. The Difference between Water and Bentonite Mud in Core Fracturing. There are many existing studies on hydraulic fracturing. In addition to hydraulic fracturing in oil and gas field simulations, there has been more attention paid to water conservancy, mines, and other fields. Hydraulic fracturing is

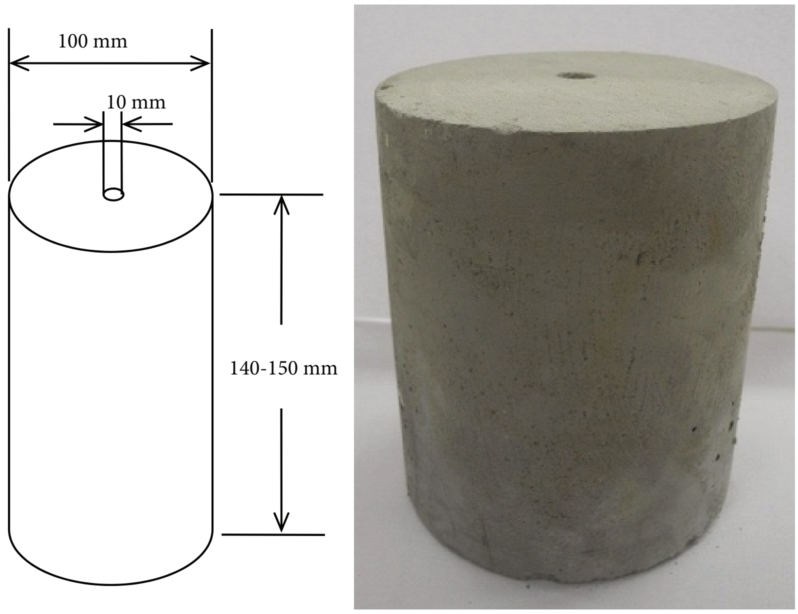


Figure 2: Schematic diagram and photograph of the core.

Table 1: Porosity and permeability of the core.

Core	Cement : sand : water = 1 : 3 : 0.9		Cement : sand : water = 1 : 2 : 0.67	
	21.77		21.52	
Porosity (%)	23.61	Average: 22.58	18.76	Average: 20.19
	22.35		20.29	
	2.541		0.124	
Permeability (mD)	2.227	Average: 2.48	0.146	Average: 0.128
	2.673		0.115	

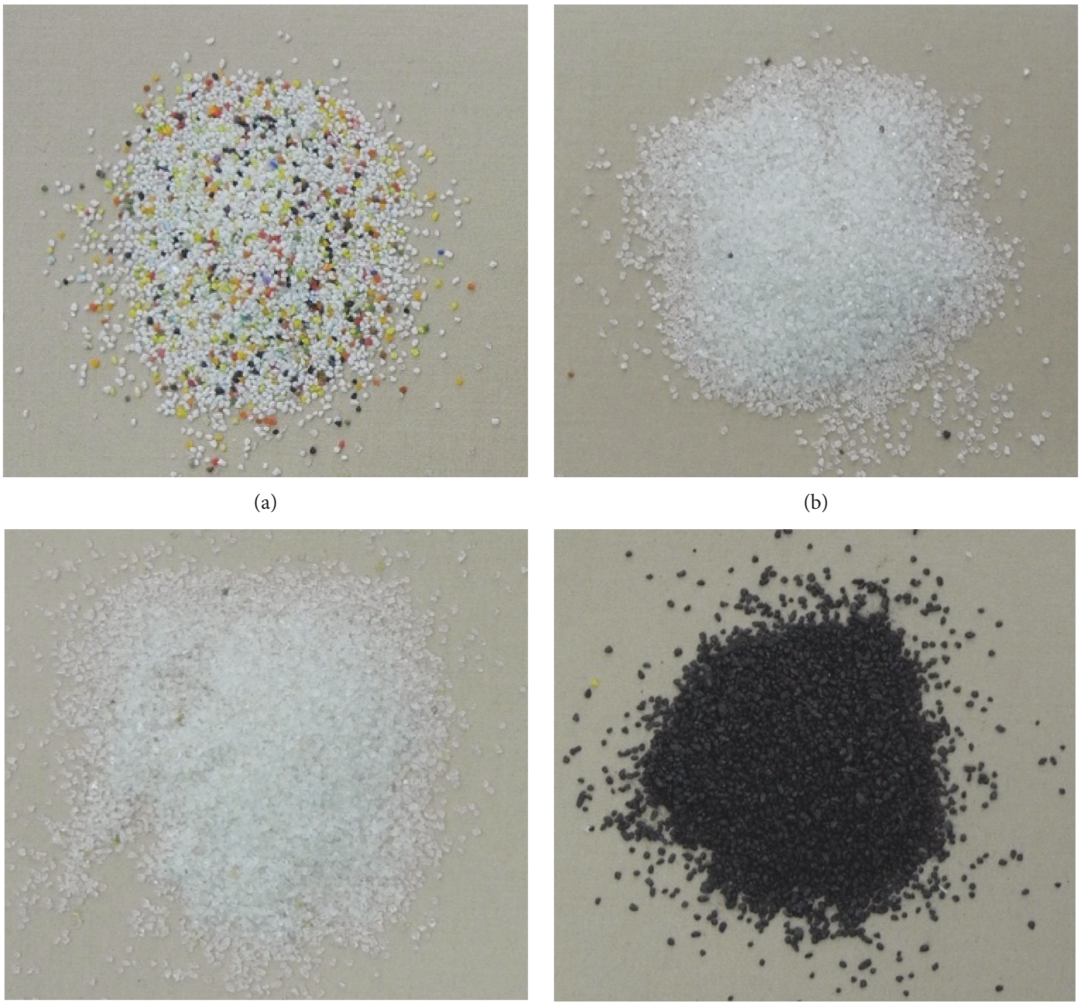
Table 2: Mechanical parameters of the core.

Core	Cement : sand : water = 1 : 3 : 0.9	Cement : sand : water = 1 : 2 : 0.67
Young's modulus (GPa)	6.99	23.87
Poisson's ratio	0.2	0.23
Compressive strength	35	49
Tensile strength	5.42	9.34

different from drilling fluid fracturing. Therefore, a bentonite slurry and water were used in the experiment. The fracturing results are compared in Table 5. It is apparent that under the same experimental conditions, the fracture pressure of the core under water pressure was much lower than under the action of the bentonite slurry.

Figure 7 shows curves of the change in pressure over time in the inner hole during the core fracturing process for water and the bentonite slurry. When the water was injected into the core with small displacement, water permeated through the core and it was difficult for pressure to accumulate inside the core. Therefore, it was necessary to inject water with large displacement into the core. Under the influence of large displacement, the pressure inside the core increased rapidly and then fractured the core. When the bentonite slurry was injected into the core with small displacement, because of the characteristics of the drilling fluid and because the mud cake formed in the walls of the pores in core, it was easy to accumulate pressure inside the core and fracture the core. Figure 8 shows the fractured core. There is no obvious change in the surface of core before and after fracturing. There are no fracture traces or visible fractures on the core surface. However, there are visible fractures on the surface of core that was fractured by the bentonite slurry. Essentially symmetric fractures appear on the fractured core. Visible fractures can be observed on the sides and ends of the core.

There is a difference in the forms of fractures produced by water and the bentonite slurry. When the water was used for fracturing the core, the pore pressure near the walls of pores increases rapidly and reaches the water pressure in the inner hole of the core. Because the displacement flow is beyond the absorption capacity of the core and the pressure in the inner hole of the core is also increasing, under the joint influence of pore pressure and inner hole pressure, the core is fractured. The pore pressure contributes greatly to the fracturing of the core. When the bentonite slurry was used for fracturing the core, bentonite was deposited on the wall of the inner hole to form mud cakes. Due to the low permeability of the mud cakes, there was very little liquid phase in the core, which did not cause a rapid increase in pore pressure within the core. In addition, the mud cakes had an effect of protecting the wellbore, buffering the pressure. When water was used for fracturing the core, the permeation of water had great influence. The fracturing of the core was essentially permeability damage. However, under the influence of the drilling fluid, the permeation of filtrate had relatively little effect on the fracturing of the core. The fracture mechanisms of the core under the action of water and drilling fluid are different, which also provides evidence that drilling fluid can increase the fracture pressure in the core.



(a) (b) (c) (d)

Figure 3: (a) Polyester particles. (b) Calcium carbonate particles. (c) Quartz sand. (d) Graphite particles.

Table 3: The size distribution of particles used in the experiment.

Gradation	XA	A_0	A	A_1	A_2	B
Mesh number	30-40	40-60	60-120	60-80	80-120	>120
Diameter (mm)	0.6-0.425	0.425-0.25	0.25-0.125	0.25-0.18	0.18-0.125	0.125<
Gradation	B_1	B_2	B_3	B_4	C	D
Mesh number	120-150	150-180	120-180	180-325	>325	1000
Diameter (mm)	0.125-0.106	0.106-0.083	0.125-0.083	0.083-0.047	0.047<	0.013

3.2. The Effects of the Gradation and Concentration of Plugging Materials on Core Fracturing. Particulate plugging materials have been used widely in drilling fluid. Adding plugging materials has the function of protecting and repairing the wellbore and formation, which can improve formation pressure-bearing capacity. However, the amount and proportion of plugging material will affect the performance of the drilling fluid. Therefore, it is necessary to study the effect of particulate materials that are added to drilling fluid for strengthening the wellbore in detail. It is apparent from fracturing the core using water and bentonite that the existence of a solid phase in the drilling fluid has great influence on the fracture pressure of the core. A change in the solid phase and content thereof in the drilling fluid will inevitably affect the fracture pressure of the core. Therefore, an experiment of fracturing the core after adding plugging material to the drilling fluid was performed to study the effect of the size and concentration of plugging material on core fracture pressure. Table 6 shows the results of the core fracturing experiment with different drilling fluid formulas.

Figure 4: Paper fibre.

Figure 5: High-friction flaky material.

3.2.1. Gradation

(1) The Influence of Material Gradation on Fracture Pressure. Particulate materials of different sizes that are added to the drilling fluid would affect the performance of the drilling fluid and, thus, the core fracturing process. An experiment of core fracturing was performed using drilling fluid with different sizes of calcium carbonate particles. Figure 9 shows the pressure curves derived from the experiment. Curve #1 is the curve for fracturing based on the use of water-based drilling fluid, used here as a comparison curve.

As shown in the figure, different sizes of particles have different effects on the fracturing process. In experiment #2, the material size was larger and the results were almost identical to those of the base drilling fluid, indicating that the particle size had less influence on the performance of the drilling fluid. The fracture pressures of the core in experiments #3 and #4 were significantly improved compared to that of the base drilling fluid. Moreover, after the core was fractured in experiment #3, the pressure remained at a higher value, which was different from the results of other experiments. In addition, in the other experiments, the fracture pressure of the core was not significantly improved compared to that under the action of the base drilling fluid and rather decreased somewhat. In experiments #5, #6, and #7, the particulate materials greatly increased the water loss of the drilling fluid, and the material affected the performance of the mud cakes. It is also apparent that the slopes of the pressure curves of these three experiments are significantly smaller than those of the other experiments.

Figure 10 shows the cores fractured in several experiments, in which longitudinal fractures formed after the fractures on the sides of the cores.

According to the experimental results, particle size has a great influence on the core fracturing process. It is difficult to increase the fracture pressure of the core under the action of the particles with a size greater than 50 mm and a relatively single size (such as in experiments #2, #5, #6, and #7). Moreover, the smaller the particle size of a single size particle, this size range is not conducive to increasing the fracture pressure of the core. For example, experiment #7 was repeated many times and yielded consistent results, and the fracture pressure of the core was significantly lower than that of the base drilling fluid. When the particle size is less than 50 mm, the performance of the drilling fluid improves, and the fracture pressure of the core improves greatly. In addition, the particle size distribution range is wide; that is, the particles of various sizes occur, which can significantly increase the fracture pressure of the core due to the interactions between particles.

(2) The Effect of the Gradation of Plugging Materials on the Core Fracturing Process. The gradation of particles represents the proportion of particles with different sizes. By optimizing the gradation of particulate materials, the density of plugging can be improved. However, for the experiment of fracturing intact core, the gradation of particles can affect the ability of the drilling fluid and can protect the core. Therefore, the influence of particle gradation on the core fracturing process was investigated.

Figure 11 shows the pressure curves in the core fracturing process for three particle gradations. Based on the pressure curves, the gradation of the materials also has a great influence on the core fracturing process. The size of the particles in experiment #2 is large and the size distribution is relatively narrow. The influence on the mud cake is very small, and the fracture pressure of the core is low. The particle gradation in experiment #8 is relatively good, and the fracture pressure of the core is 26.16 MPa. The water loss of drilling fluid is small, and the filter cake is relatively dense. As shown by the figure, the drilling fluid was continuously pumped into the core after the core was fractured. Under this action, the core fracture pressure can be reconstructed, and the pressure of the core rupture was more than 20 MPa. The overall particle size in experiment #9 is less than that in experiment #8, and its effect is also slightly worse than in experiment #8. However, the size of particles in formula #9 is relatively small and the size distribution is relatively wide. Formula #9 has a great influence on the mud cake and the walls of pores in the core. The core fracture pressure under its action is higher than in experiment #2. In conclusion, in order to increase the fracture pressure of the formation, the selection of particle size gradation should consider the following: particle size cannot be too unitary, and the size distribution should be wide. Coarse particles, fine particles, and microfine particles have different functions, and the effect of their combination will be better.

Table 4: Formulas and properties of drilling fluids.

Number	Formula	ρ(g/cm^3)
1	Water-based drilling fluid: 4% bentonite slurry + 2% SMP-2 + 0.3% CMC-HV	1.04
2	Oil-based drilling fluid: white oil + water (25% of oil weight) + 2% primary emulsifier MOEMUL+ 2% coemulsifier MOCOAT + 2% CaO + 1% filtrate reducer JFL-1 + $CaCl_2$ (25% of water weight) + 0.5% shear-strength improving agent TQ-1	0.902

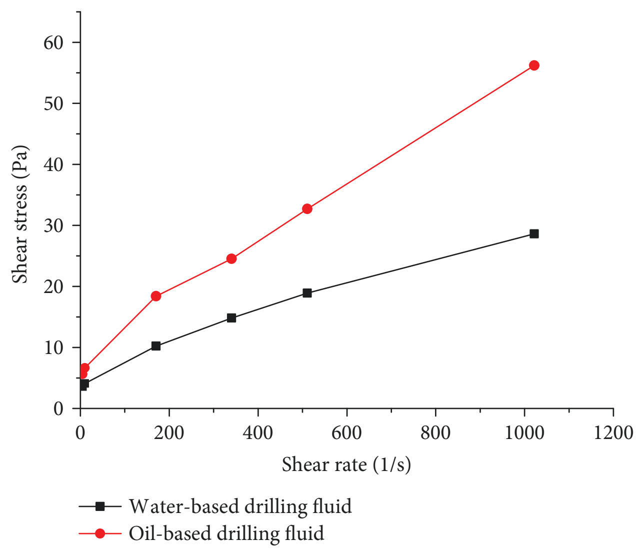


Figure 6: The flow curves for the drilling fluids.

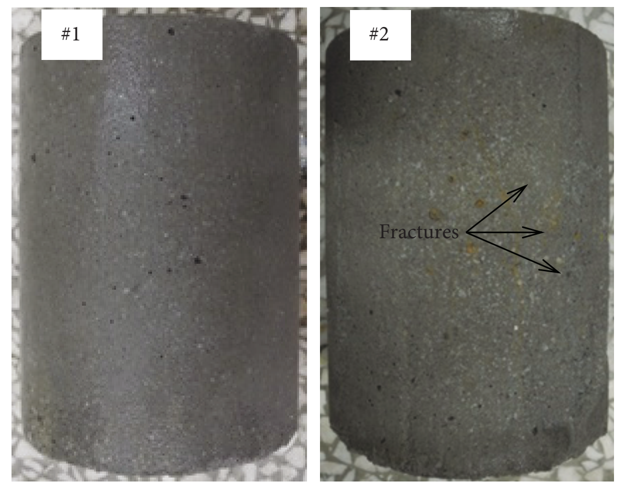


Figure 8: The cores fractured by water (#1) and a bentonite slurry (#2).

Table 5: The results of water and bentonite slurry fracturing experiments.

Number	Formula	Fracture pressure (MPa)	FL_{API} (mL)
1	Water	5.73	— —
2	4% bentonite slurry	21.97	28.4

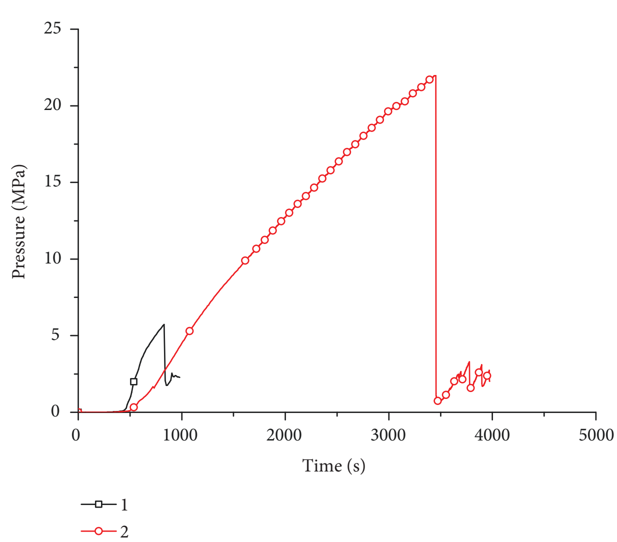


Figure 7: Pressure curves of fracturing core by water and a bentonite slurry.

3.2.2. Concentration. It was found in experiment #3 that the fracture pressure of the core was higher, and the fractured core can withstand higher pressure without immediate damage, which was a good effect of protecting the walls of the pores and strengthening the wellbore. Therefore, based on the formula of experiment #3, the concentration of particulate material was changed to observe the influence of particle concentration on the core fracturing process. Figure 12 shows pressure curves of the core fracturing process under the action of drilling fluid with different concentrations of particulate materials. For consistency, the pressure curves of experiment #3 are those of the experiments described above.

With an increase in calcium carbonate concentration, the filtration loss of drilling fluid is not significant, which has little effect on the density of the mud cake that is formed by the drilling fluid. The figure shows that under different particle concentration conditions, the fracture pressures of the core are slightly different, indicating that after the size distribution of the material is determined, the change in concentration has relatively little effect on the fracture pressure of the core. However, a change in the concentration of particulate material has different effects on the performance of core fracturing. When the concentration of added calcium carbonate reached and exceeded 8.5% after the core was fractured, the pressure of the inner hole in the core could be maintained at a higher value for a period of time, which extended the time of the core from fracture to total destruction. This phenomenon is very beneficial for improving formation pressure-bearing capacity.

Table 6: Results of the core fracturing experiment with different drilling fluid formulas.

Number	Formula	Fracture pressure (MPa)	FL_{API} (mL)
1	Water-based base drilling fluid	18.99	5.8
2	Water-based base drilling fluid + 10% A	18.66	5.4
3	Water-based base drilling fluid + 10% B	23.56	4
4	Water-based base drilling fluid + 10% C	24.04	4.4
5	Water-based base drilling fluid + 10% B_1	19.93	6.2
6	Water-based base drilling fluid + 10% B_2	18.81	6
7	Water-based base drilling fluid + 10% B4	15.43	6.4
8	Water-based base drilling fluid + 5.12% A + 3.9% B + 0.98% C	26.16	4
9	Water-based base drilling fluid + 7.98% B + 2.02% C	22.26	3.6
10	Water-based base drilling fluid + 3% B	20.91	6.4
11	Water-based base drilling fluid + 6.5% B	23.25	5.8
12	Water-based base drilling fluid + 8.5% B	22.96	5.8
13	Water-based base drilling fluid + 15% B	22.24	5.8

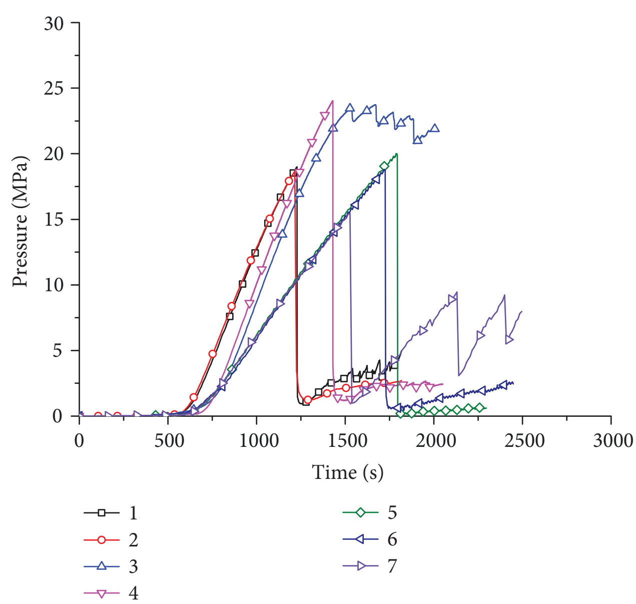


Figure 9: Pressure curves in the core fracturing process.

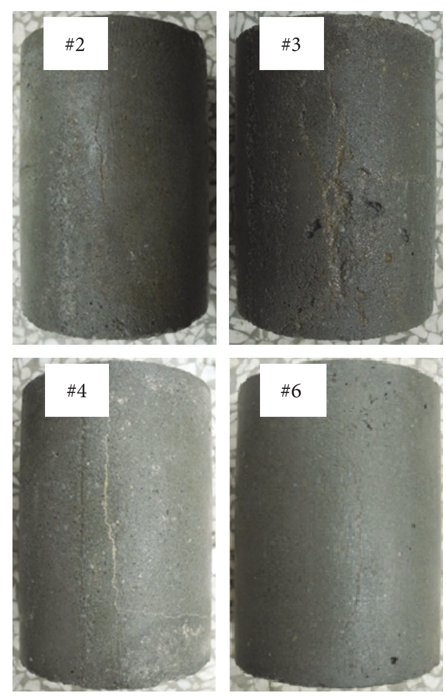


Figure 10: Fractured cores.

When the added concentration of calcium carbonate reached a certain value, the pressure of the inner hole in the core was maintained at a higher value for a period of time until the core was completely fractured. To determine when the core fractured, a drilling fluid with a calcium carbonate concentration of 10% was used for repeated experiments. The experiment was stopped immediately after the first small fluctuation of pressure. Then, after the device was unloaded, the core was removed and observed for the appearance of fractures. Figure 13 shows the pressure curve and displacement flow curve of the core fracturing process, and the fracture pressure of the core is 22.37 MPa. This also supports the repeatability of the experiment.

Figure 14 shows the removed core. The position indicated by the arrow in the figure shows microfractures that appeared on the surface of the end of the core. The macroscopic end of the microfracture is approximately 1 cm away from the ektexine of the core, and there are no microfractures on the side of the core. This phenomenon indicates that when the pressure curve experienced a small decrease, the core had already produced microfractures. According to the experimental results, the microfractures that appeared in the core were quickly filled with mud cakes and solid phase materials from the drilling fluid, which prevented the fracture from spreading rapidly and made the core withstand higher pressure for a period of time. However, this phenomenon occurs only when the material is properly graded and is at a certain concentration.

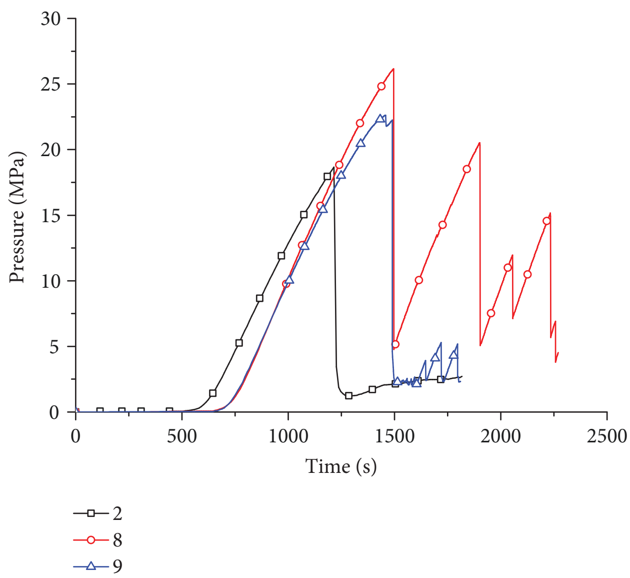


FIGURE 11: Pressure curves in the core fracturing process.

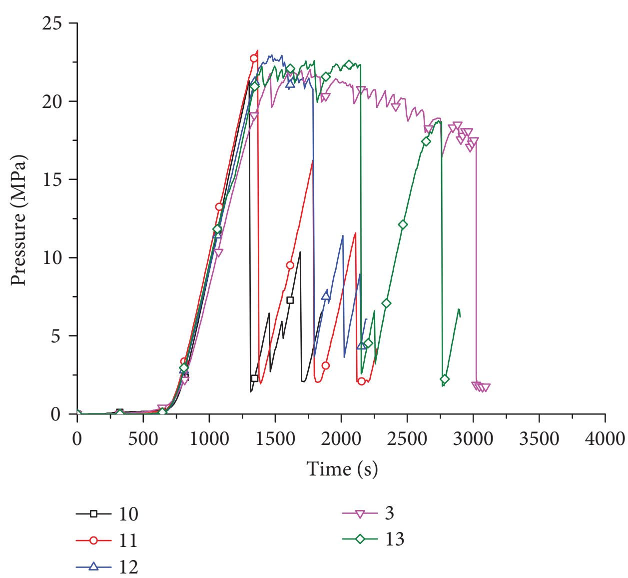


FIGURE 12: Pressure curves in the core fracturing process.

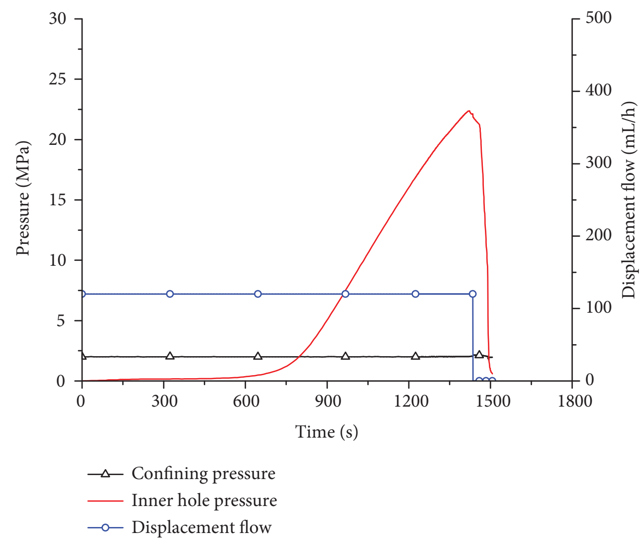


FIGURE 13: Pressure curves and displacement flow curve of the core fracturing process.

3.3. The Effect of the Kind of Plugging Materials on the Fracture Pressure of the Core. In addition to calcium carbonate, there are many other kinds of plugging materials. Different materials have unique characteristics and functions. Quartz sand, graphite, and high-strength polyester particulate materials were used in the experiment, which were compared to calcium carbonate particles to investigate the effects of different kinds of particulate materials on the core fracturing process. There are also deformable materials, nanomaterials, etc., which can plug even smaller pores and repair tiny defects in rocks to improve the density of the mud cake. These can affect the core fracturing process. In addition to increasing the density of drilling fluid, and as an important solid part of drilling fluid, barite provides solid particles that can plug and repair the formation of drilling fluid, having great influence on the filter cake that forms from the drilling fluid. Therefore, various materials were added to the drilling fluid and another core fracturing experiment was performed. Table 7 shows the results of the core fracturing experiment after the addition of different materials to drilling fluid.

3.3.1. Particulate Materials. Different kinds of particulate materials have different hardnesses and strengths, which may also affect the core fracturing process. Figure 15 shows the pressure curves of fracturing a core with calcium carbonate, quartz sand, graphite, and high-strength polyester, which were added to the drilling fluid.

As shown in Figure 15, after adding different particulate materials to the drilling fluid, the forms of pressure curves in the core fracturing process are different. The fracture pressure of the core under the action of drilling fluid with added polyester particles is the highest. After the core was fractured, the drilling fluids with added polyester, quartz sand, and calcium carbonate could withstand high pressure rather than incur immediate damage. Compared to other drilling fluids, the plugging time of drilling fluid with added graphite material is relatively short. In the previous material strength tests, the fracture rate of graphite materials under pressure was very low because of its flexibility. However, its strength and hardness are lower, which may be the reason why the plugging effect of graphite on microfractures is less than that of other materials. Among these materials, polyester materials have the highest hardness and strength. Under pressure, the particles rarely fracture. Therefore, under the same conditions, polyester materials have the best effect on strengthening the wellbore.

3.3.2. Nanomaterials. The addition of nanomaterials can increase the distribution of solids in the drilling fluid system, can form nanolevel plugging, and can further improve the

Figure 14: The removed core with microfractures on its surface.

Table 7: The results of the core fracturing experiment under the action of different materials.

Number	Formula	Fracture pressure (MPa)	FL_{API} (mL)
1	Water-based base drilling fluid + 10% B (calcium carbonate)	23.56	4
2	Water-based base drilling fluid + 10% B (quartz sand)	22.96	4.4
3	Water-based base drilling fluid + 10% B (graphite)	21.48	4.4
4	Water-based base drilling fluid + 10% B (polyester)	25.66	5
5	Water-based base drilling fluid	18.99	5.8
6	Water-based base drilling fluid + 3% emulsified asphalt	18.5	5.2
7	Water-based base drilling fluid + 10% B (calcium carbonate) + 3% emulsified asphalt	27.92	3.2
8	Water-based base drilling fluid + 10% B calcium carbonate + 3% nano calcium carbonate	24.56	3.6
9	Water-based base drilling fluid + barite	26.55	4.8

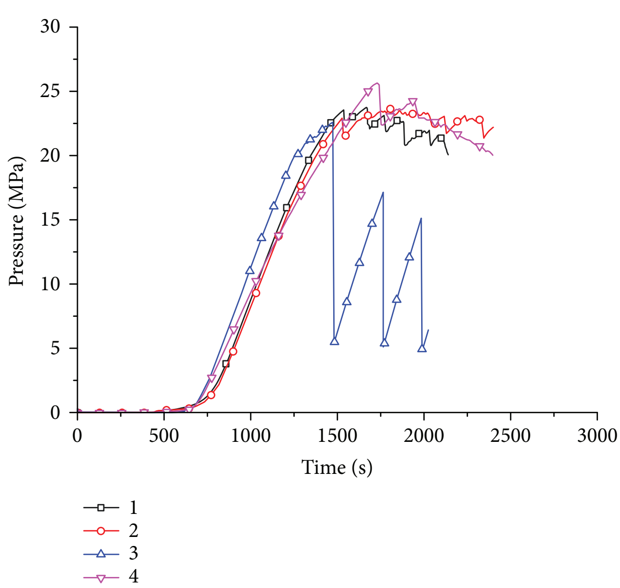


Figure 15: Pressure curves in the core fracturing process.

compactness of mud cakes and the compactness of the plugging layer. Figure 16 shows the pressure curves of drilling fluid in the core fracturing process before and after adding nanomaterials.

As shown in Figure 16, the addition of nanomaterials has little effect on the fracture pressure of the core. After adding nanomaterials, the fracture pressure of the core increased slightly, and the beginning time of the increasing stage of the pressure curves is earlier than that without nanomaterials. In addition, in experiment #8 with adding nanomaterials after the core was fractured, the pressure curve inside the core decreased rapidly, which shows that when the fractures appeared inside the core, the core was quickly destroyed. In contrast to experiment #1, the core can withstand certain pressure under the action of particulate materials after fractures appeared. This phenomenon reflects the obvious influence of nanomaterials on the plastic flow deformation of mud cakes. After the fractures appeared, the deformation ability of mud cakes to carry the particles decreased, after which they cannot plug and repair the fractures very well. This then led to the rapid development of fractures, which made the core fracture completely.

3.3.3. Deformable Materials. The plugging materials used for drilling fluid include some deformable materials such as asphalt. The deformable materials can fill the pores between particles to make the plugging layer or mud cakes denser. Emulsified asphalt was used as a deformable material in the experiment. The influence of the deformation materials and the combination of deformation materials and the particulate materials on the core fracturing process was studied in the experiment. Figure 17 shows the pressure curves for the core fracturing process.

As shown in Figure 17, the water-based drilling fluid with emulsified asphalt has little effect on the core fracturing process. The core fracture pressure is slightly less than that of the

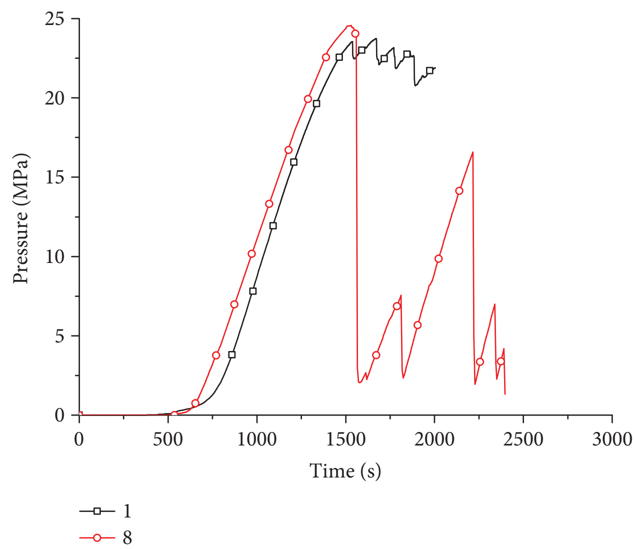


FIGURE 16: Pressure curves in the core fracturing process.

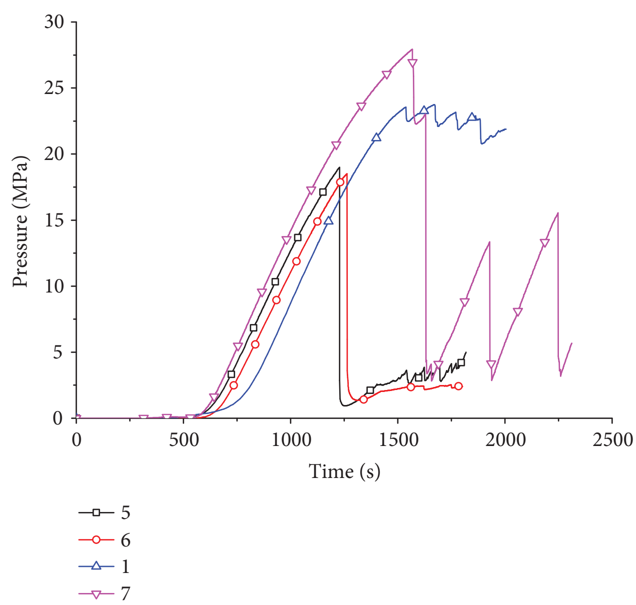


FIGURE 17: Pressure curves in the core fracturing process.

water-based drilling fluid. However, after adding emulsified asphalt to the water-based drilling fluid with calcium carbonate, the fracture pressure of the core obviously improved. The fracture pressure value increased by 4.36 MPa, which shows that the combination of deformable materials and particulate materials can improve the effect of strengthening the wellbore, and the pressure of the core can be improved.

3.3.4. Barite Materials. To balance the formation pressure, it is usually necessary to add weighted materials to the drilling fluid to increase its density drilling fluid. As an inert, rigid, particulate material, barite can affect the solid phase distribution in drilling fluid and the performance of the mud cakes. Figure 18 shows the pressure curves of water-based base

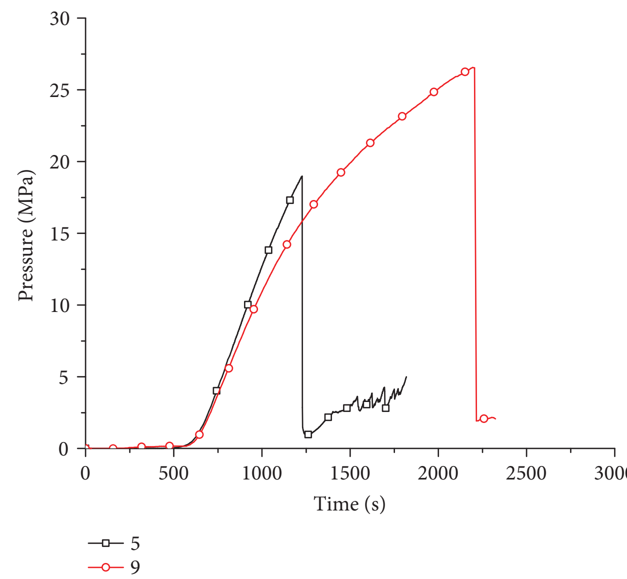


FIGURE 18: Pressure curves in the core fracturing process.

drilling fluid and water-based base drilling fluid weighted to the density of 1.6 g/cm^3 in the core fracturing process.

As shown in Figure 18, the fracture pressure of the core under the action of drilling fluid is significantly improved after weighting. The core fracturing process also changes correspondingly. The pressure curve after the aggravation shows an obvious bending phenomenon. The bending time is significantly earlier than before, which indicates that the beginning of the curve does not necessarily mean that fractures appeared in the core; it may have been caused by the change in the mud cakes under the action of the pressure. The solid phase content in the weighted system is higher, and the barite particles are a kind of rigid particle of uniform size. As such, the deformation and sliding between barite particles and bentonite particles under pressure were more obvious than those of single bentonite particles.

Figure 19 shows the mud cakes that formed on the wall of the inner hole in the core under two conditions. It is apparent that the thickness of the mud cakes that formed in the inner hole is greater than before the drilling fluid was weighted. The solid phase content of the mud cakes is also much higher than before the drilling fluid was weighted. Moreover, the mud cakes are pressed tightly and compactly, which partly confirms the mechanism for the apparent bending of the pressure curve.

3.4. Difference between the Effects of Water-Based Drilling Fluid and Oil-Based Drilling Fluid on Core Fracturing. In recent years, the application of oil-based drilling fluid in China has increased, and there are some essential differences between oil-based drilling fluid and water-based drilling fluid. There are also some differences between the changes in hydrophilic formation rocks that are caused by water-based drilling fluid and oil-based drilling fluid. The differences between the composition of oil base drilling fluid and the composition of water-based drilling fluid lead to very different natures of resulting mud cakes. All of these aspects

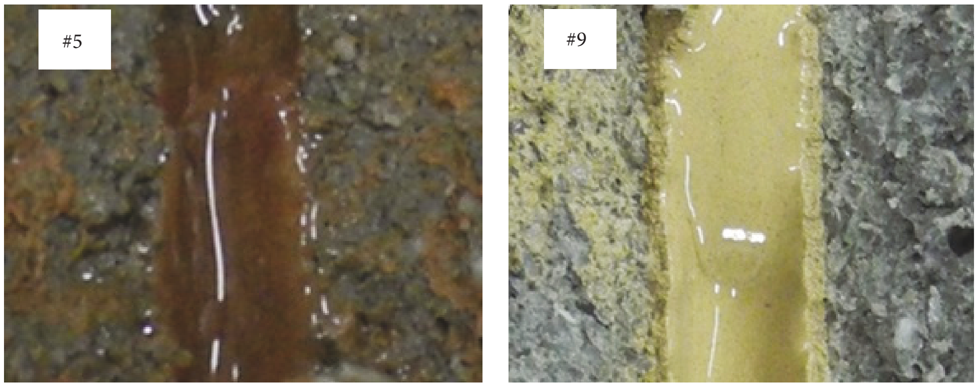


Figure 19: Mud cakes formed on the wall of the inner hole in the core.

Table 8: Results of the core fracturing experiment for several different conditions of oil-based drilling fluid and water-based drilling fluid.

Number	Formula	Fracture pressure (MPa)	FL_{API} (mL)
1	Water-based base drilling fluid	18.99	5.8
2	Oil-based base drilling fluid	12.32	4.4
3	Water-based base drilling fluid + 10% B (calcium carbonate)	23.56	4
4	Oil-based base drilling fluid + 10% B (calcium carbonate)	12.54	4
5	Water-based base drilling fluid + 10% B (polyester)	25.66	5
6	Oil-based base drilling fluid + 10% B (polyester)	17.5	3.8
7	Water-based base drilling fluid + barite	26.55	4.8
8	Oil-based base drilling fluid + barite	22.45	3.4

will affect the strengthening effect of drilling fluid on the wellbore. Therefore, an experiment of fracturing core by oil-based drilling fluid was performed to observe the core fracturing process under the influence of two kinds of drilling fluids, compared to the influence of water-based base drilling fluid. Table 8 shows the results of the core fracturing experiment for several different conditions of oil-based drilling fluid and water-based drilling fluid.

3.4.1. Water-Based Base Fluid and Oil-Based Base Fluid. There is a great difference in composition between the oil-based drilling fluid and water-based drilling fluid, which leads to very different natures of mud cakes that form on the wall of the wellbore, which then affect the core fracturing process. Figure 20 shows the pressure curves in the core fracturing process of oil-based drilling fluid and water-based drilling fluid.

According to the pressure curve of the core fracturing process that is shown in Figure 20, the fracture pressure of the core under the action of oil-based drilling fluid is much lower than that of water-based drilling fluid. The reasons for such obvious differences are related to the composition of drilling fluid. There is a large content of clay solids in the water-based drilling fluid, which can form good mud cakes on the wall of the inner hole. The oil-based base drilling fluid is a water-in-oil emulsification, and a large number of them are emulsion droplets. The droplets are very low in strength. Under the action of pressure, although the oil-based base

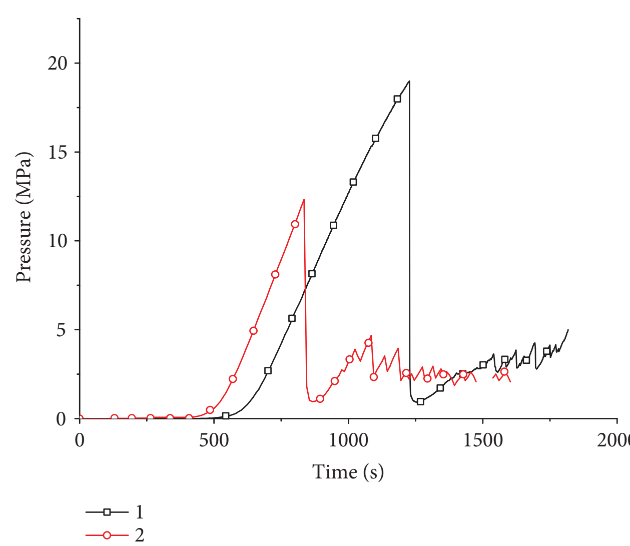


Figure 20: Pressure curves in the core fracturing process.

drilling fluid formed mud cakes on the walls of the pores, the filtration loss of oil-based drilling fluid is also very low, but the mechanical properties of the oil-based base drilling fluid are difficult to compare to the mud cakes formed from the water-based drilling fluid. Moreover, there is no solid phase material to repair and perfect the wall of the inner hole in the core in the oil-based drilling fluid, and the differences in the mud cakes ultimately result in a large difference in the core fracture pressure of the two drilling fluid systems.

3.4.2. After the Addition of Particulate Materials. The fracture pressure of core under the action of oil-based drilling fluid is low. Plugging materials were added to the oil-based base drilling fluid to improve the composition of the oil-based drilling fluid, to increase the solid phase content in the mud cakes, and to improve the performance of the mud cakes. This was done to investigate whether the fracture pressure of the core can be improved by adding plugging materials and to compare to the results of water-based drilling fluid. Figure 21 shows the pressure curves of several drilling fluids with different plugging materials in the core fracturing process. It is apparent from the pressure curves that the fracture pressure of the core in the water-based drilling fluid is still significantly higher than that of the core in the oil-based drilling fluid after plugging material was added. The fracture pressure of the core under the action of the oil-based drilling fluid with calcium carbonate is 12.54 MPa, but the fracture pressure of the core under the action of the oil-based base drilling fluid is 12.32 MPa, which shows that the addition of calcium carbonate did not improve the effect of the oil-based drilling fluid on strengthening the wellbore. In addition, the fracture pressure of the core under the action of the oil-based drilling fluid with polyester is greatly improved. Although the fracture pressure value is not as high as that of the water-based drilling fluid, the effect is very similar to that of the water-based drilling fluid, which can withstand higher pressure without immediate damage after the core is fractured. Calcium carbonate and polyester materials are very different when added to the oil-based drilling fluid. The effect of polyester materials is better than that of calcium carbonate, which may be related to the compatibility of polyester materials and oil-based drilling fluid and the high strength of polyester materials.

3.4.3. After Aggravation of the Drilling Fluid. To increase the density of the drilling fluid to meet the requirements of different formations, it is necessary to add weighted materials to the drilling fluid. Especially for oil-based drilling fluid, barite has a great influence. The water-based drilling fluid and oil-based drilling fluid were each weighted to 1.6 g/cm^3, and the core fracturing experiment was performed to investigate the influence of weighted drilling fluid on the core fracturing process. Figure 22 shows the resulting pressure curves.

From the experimental results, it is apparent that whether water-based drilling fluid or oil-based drilling fluid is used, compared to the base drilling fluid, when barite is added, it obviously improves the fracture pressure of the core. At the same time, the fracture pressure of the core in the presence of water-based drilling fluid is still greater than that of oil-based drilling fluid. It was found that there is a significant difference between the slopes of the pressure curves in the core under the action of both kinds of drilling fluid. In the presence of oil-based drilling fluid, the slope of the curve is stable. However, in the presence of water-based drilling fluid,

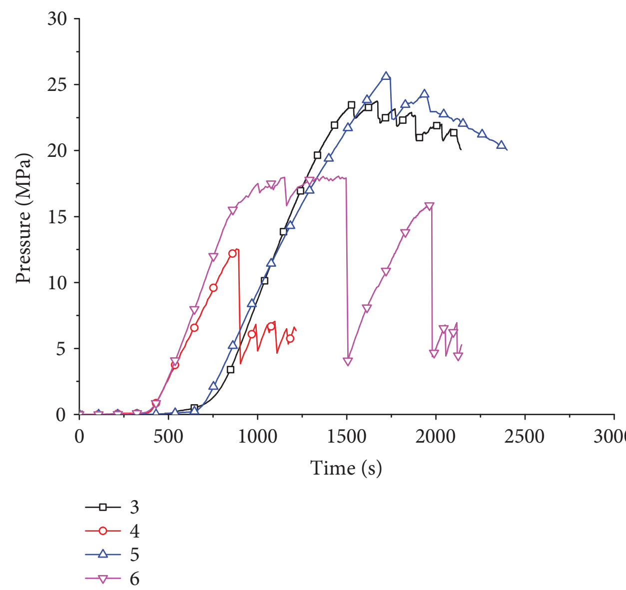


Figure 21: Pressure curves in the core fracturing process.

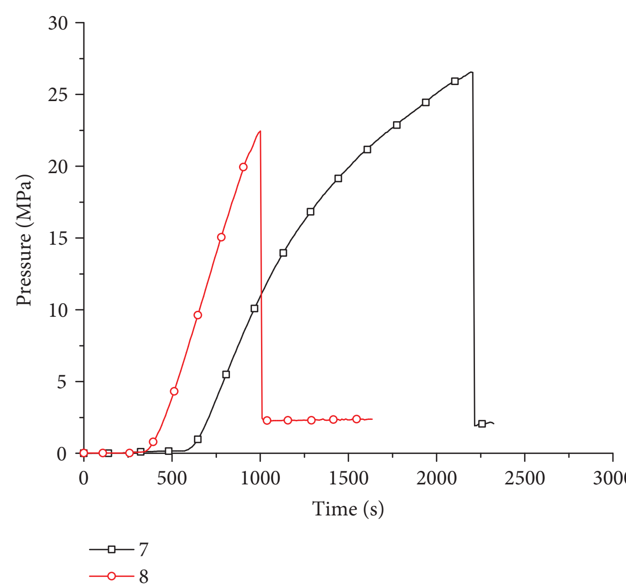


Figure 22: Pressure curves in the core fracturing process.

the curve is obviously bent, and the slope of the pressure curve is gradually reduced. The change in the curve reflects the influence of drilling fluid on the core fracturing process. The deformation ability of mud cakes formed by the water-based drilling fluid is better than that of mud cakes formed by the oil-based drilling fluid under the action of pressure. The change in mud cakes also slowed the core fracturing process. Therefore, improving the mechanical properties of mud cakes formed by the oil-based drilling fluid can improve the effect of oil-based drilling fluid on strengthening the wellbore.

3.5. Analysis of Core Fracturing Curve Characteristics. Through a large number of intact core fracturing experiments, it is found that the composition of drilling fluid, the particle size distribution of the plugging materials, the performance of the materials, and other parameters have great influence on the core fracturing process. Because drilling fluid is a very complex decentralized system, the core fracturing process is extremely complicated under the action of drilling fluid. A large number of core fracturing experiments have also confirmed that a change in composition of drilling fluid can have a significant impact on the core fracturing process. The core fracturing process differs in the presence of different drilling fluids, and the associated pressure curves have unique characteristics. However, there are some common characteristics. Based on the analysis and summary of all characteristics of the pressure curves, some commonalities and characteristics of the core fracturing process are described. The understanding of the details of core fracturing is strengthened, and characteristics associated with different situations are different, which provides reference for selecting plugging materials.

3.5.1. Analysis of Integral Fracturing Curves. In the experiments, pressure change curves from the inner hole of the core were obtained. The pressure curves for different drilling fluids and different plugging materials also differ. The fracture curve of one experiment is selected, and some common characteristics of the whole core fracturing process are analysed, as shown in Figure 22. According to the curve analysis in Figure 23, the entire core fracturing process can be divided into five stages.

(1) Initial formation stage of the mud cakes: at this stage, with the drilling fluid continuously pumped into the core, the drilling fluid gradually forms mud cakes on the wall of the inner hole of the core under the action of pressure. The mud cakes then reach stability. At this stage, the pressure changes with time, and the pressure value in the core exceeds the confining pressure.

(2) Resilient-plastic deformation stage of the core and mud cakes: with the stability of the mud cakes, the mud cakes have a certain thickness and permeability. Pressure builds up rapidly in the core, and the pressure curve is basically a straight line until a point when the curve begins to bend, which indicates that fractures begin to appear in the core. Then, the fractures gradually expand as the pressure continues to increase.

(3) Stable development stage of the fractures: after the fractures appear in the core, the core does not fracture completely. The fractures propagate stably under pressure, which is a controllable stage. At this stage, the pressure in the core continues to increase under the action of the mud cakes.

(4) Unstable development stage of the fractures: with the propagation of the fractures, the plugging materials had difficulty plugging the fractures stably. The pressure inside the core fluctuated greatly, and the propagation of fractures gradually developed to an uncontrollable stage, and the core eventually fractured.

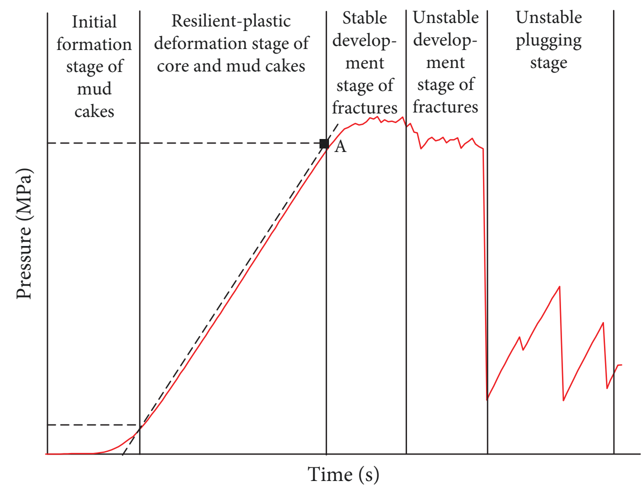


Figure 23: Changes in the core fracturing process.

(5) Unstable plugging stage: the core was completely fractured, and fractures with a certain width were formed. The solid phase in the drilling fluid still had a certain ability to plug fractures. Only the gradation, concentration, and properties of the materials were different, and therefore, their ability to plug fractures was different.

To strengthen the wellbore, it is necessary to improve the maximum of the second stage, to prolong the stable time of the third stage, and to control the unstable development of the fourth stage by adjusting the drilling fluid and adding plugging materials. After fracturing of the core, the core can still have formation pressure-bearing capacity under the action of plugging materials.

3.5.2. Some Kinds of Fracturing Curves. In the core fracturing experiment, based on the statistics of pressure curves, not all of the curves included all of the processes mentioned above. Some experiments may lack a stage, showing characteristics that can be roughly classified into four types of pressure curves, as shown in Figure 24.

The curves shown in Figure 24 reflect the moment of core fracturing and the interactions between the drilling fluid and the core after the core fractured. In the first type of curve, with fracture of the core, the pressure of the inner hole in the core rapidly decreases to the confining pressure value. It is maintained near the confining pressure value, and the pressure curve is smooth. The second and third types of curves are the same as the first type. The difference is the pressure response in the core after the core is fractured. The pressure in the core will continue to increase under the action of drilling fluid. Then, it decreases to a certain value and shows a zig-zag pattern. The difference between the two is the magnitude of the zig-zag. The size of the zig-zag reflects the ability of the drilling fluid to plug the fractures that formed on the

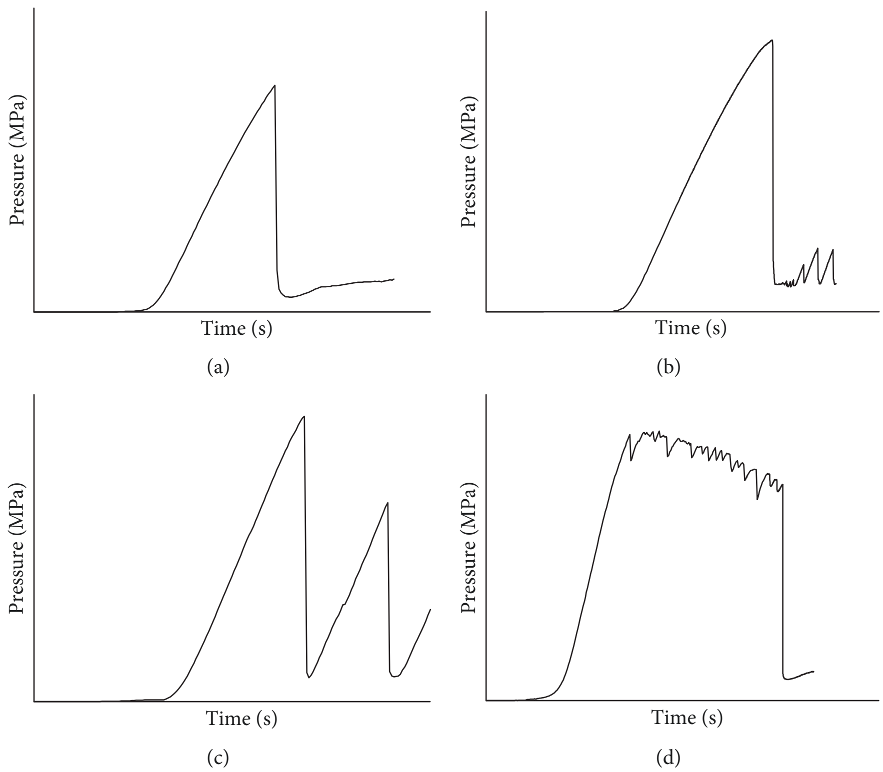


Figure 24: Some kinds of pressure curves.

wall in the core. The peak of the zig-zag is an extreme value of the plugging, and the low point of the peak indicates that the plugging is invalid. There are no stable development or unstable development stages of fractures in the first three types of curves. After the pressure of the inner hole in the core reaches a certain value, it is completely fractured. The fourth type of curve shows the entire core fracturing process. At the moment when the core is fractured, the pressure of the inner hole in the core did not decrease rapidly, which shows that the solid particles in the drilling fluid can quickly plug the microfractures on the wall of the pore without causing the fractures to fracture completely. The drilling fluid corresponding to the fourth type of the curve not only improves the core fracture pressure but also effectively prevents the propagation of fractures.

4. Conclusions

The fracture pressure of cores by water is much less than the fracture pressure of cores by drilling fluid, which indicates that drilling fluid can significantly increase the core fracture pressure. The fracturing mechanism of water is different than that of drilling fluid. The permeation of water had a substantial influence on the fracturing of the core. The fracturing of the core was essentially permeability damage. Under the protection of mud cakes that formed from the drilling fluid, the permeation of filtrate had relatively little effect on the fracturing of the core.

Different materials and their proportions will affect the core fracturing process and change the fracture pressure of the core. This conclusion is mainly reflected by the following aspects. To increase the fracture pressure of core, the size distribution of the particle material should be extensive. The combination of coarse, fine, and microfine particles produces a better effect. Under the same size distribution of material, the concentration has relatively little effect on the fracture pressure of the core. Compared to other particle materials, polyester materials have the best effect on wellbore strengthening. The combination of deformable materials and particulate materials can increase the fracture pressure of the core. Nanomaterials have little effect on the fracture pressure of the core. In contrast, the fracture pressure of the core under the action of drilling fluid is significantly improved after it is weighted by barite material.

Under the same conditions of the kind, content, gradation, and concentration of particulate materials, the core fracture pressure of oil-based drilling fluid is lower than that of water-based drilling fluid.

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Acknowledgments

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