

Article

Optimization of Flushing Fluid Plugging Theory Based on Plugging Experiments and Simulations

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Abstract

During sand cleanout operations in shale oil horizontal wells, severe wellbore leakage occurs due to incompatibility between plugging particles and the formation, resulting in a failure to establish circulation. This study determined the optimal plugging theory for the target formation characteristics through laboratory leakage sealing tests and numerical simulations such as fluid–discrete element coupling (CFD–DEM). The results show the following: Plugging experiments indicated that the Vickers criterion achieved the best performance, with an invasion depth of 9 mm, followed by the Ideal Packing Theory, at 12 mm, while the D90 rule performed the worst, with an invasion depth of 13 mm. The simulations results from the CFD–DEM coupling model demonstrated that the Vickers criterion achieves the most effective plugging performance, followed by the Ideal Packing Theory, with the D90 rule exhibiting the least effectiveness. This indirectly validates the rationality and effectiveness of the Vickers criterion in configuring particle sizes for plugging materials. Finally, sand-packed-tube displacement experiments demonstrate that the Vickers criterion yields the lowest permeability and optimal plugging performance, further validating its rationality and effectiveness in configuring particle sizes for plugging materials. This research provides crucial technical support for the safe and efficient development of shale oil horizontal wells, effectively reduces operational costs, and holds significant importance for advancing technological progress in shale oil extraction.



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Keywords: Vickers criterion; ideal packing theory; D90 rule; plugging theory optimization; numerical simulation

1. Introduction

During the development of shale oil horizontal wells, as the production cycle progresses, formation energy continuously depletes and reservoir pressure gradually declines. During the development of shale oil horizontal wells, continuous production progression leads to persistent depletion of formation energy and a gradual decline in reservoir pressure. During subsequent sand cleanout operations, wellbore leakage becomes increasingly severe, and in critical situations may even prevent the establishment of a stable circulation system, significantly compromising both operational efficiency and safety [1–5]. Wellbore leakage refers to a complex phenomenon where working fluids (such as drilling fluid, workover fluid, etc.) infiltrate into the formation under differential pressure during operations like drilling or workovers [6]. Based on the type of leakage channels, wellbore leakage can be categorized into porous leakage, fractured leakage, and vuggy leakage [7].

The fluid loss encountered during well cleaning operations is predominantly characterized by porous leakage. The application of inert particles for temporary plugging of loss zones represents one technical approach to restoring normal wellbore circulation and ensuring safe, efficient sand cleanout operations. The key to achieving the desired plugging effect lies in the rational design of particle size distribution for temporary plugging agents [8–11].

Lost-circulation control in horizontal wells faces challenges including complex and difficult-to-identify leakage channels, low migration and retention efficiency of lost-circulation materials due to weakened gravitational effects, uneven stress distribution in horizontal sections that easily leads to poor stability, and insufficient pressure-bearing capacity of the plugging layer [12]. Meanwhile, existing materials also suffer from inadequate adaptability, failing to balance the plugging strength for dynamic leakage channels in horizontal sections and long-term stability under formation stress, which tends to result in plugging failure [13].

Due to the extensibility and complexity of horizontal wellbore trajectories, as well as the development of micro–nano-scale pores and fractures in reservoirs such as shale, lost-circulation materials must not only possess superior adhesion, deformability, and temperature–pressure resistance to effectively seal lost zones, but also fully consider reservoir protection to avoid irreversible damage caused by lost-circulation control operations. Meanwhile, the heterogeneous flow characteristics of fluids in complex fracture networks in horizontal wells further increase the difficulty of lost-circulation control, requiring plugging strategies to accurately adapt to the geometric morphology and pressure distribution of different leakage channels. Consequently, the technical complexity and implementation difficulty of lost-circulation control in complex fracture networks in horizontal wells are significantly higher than those of lost-circulation control operations in other types of wells [14,15].

In recent years, significant progress has been made in related technologies. Novel lost-circulation materials have continuously emerged, with remarkably improved sealing performance and adaptability to better cope with complex geological conditions. Lei Yao et al. developed a new gel-based lost-circulation control system with acrylic resin particles as the core, which exhibits excellent thermal stability and adaptability, effectively solving the technical challenge of lost circulation in complex fractured formations [16]. Peng Xu et al. synthesized a high-temperature-resistant gel lost-circulation material via aqueous solution polymerization using acrylamide, N-vinylpyrrolidone, sodium p-styrenesulfonate, and polyvinyl alcohol as monomers. The study found that this material displayed favorable thermal stability, water absorption and swelling properties, and plugging performance at 140 °C [17].

The commonly used plugging theories include the Vickers criterion, the Ideal Packing Theory, and the D90 rule. The advantage of the Vickers criterion lies in its precise matching of particle size distribution with pore throat dimensions, enabling efficient plugging of narrowly distributed pores. It is particularly suitable for homogeneous or low-permeability formations and can significantly reduce filtrate invasion [18]. The Ideal Packing Theory optimizes particle gradation through the $d^1/2$ proportion, enabling coverage of a wider range of pore sizes. It demonstrates enhanced adaptability in heterogeneous formations while allowing flexible balancing of plugging strength and permeability recovery rate through adjustment of gradation parameters [19]. The D90 rule requires the D90 value on the cumulative particle size distribution curve of temporary plugging agents to correspond to the maximum pore diameter or fracture width of the reservoir. Its advantage lies in ensuring that most particles can effectively plug the main pores, forming a stable sealing layer. However, when dealing with complex and heterogeneous formations, relying solely on the D90 value may fail to comprehensively consider particle interactions and

the plugging effectiveness in secondary pores, potentially leading to uneven sealing and compromised overall plugging performance [20,21].

Currently, the evaluation of plugging effectiveness primarily relies on plugging experiments. Mei Wenrong et al. adopted the plugging depth to evaluate the effectiveness of temporary plugging agents, and this method has been widely adopted [22]. Feng Wenqiang et al. developed bridging particle optimization software based on the Ideal Packing Theory. Through dynamic damage experiments and core displacement tests, they investigated the improvement effects of ideal packing technology in drilling fluids on filtration control and reservoir damage mitigation in heterogeneous sandstone reservoirs [23]. Overall, the current evaluation of plugging effectiveness primarily relies on experimental methods, resulting in an overly singular approach to assessment.

To address the wellbore leakage issues during sand cleanout operations in shale oil horizontal wells, this project employs a combined approach of laboratory experiments and numerical simulations to evaluate and optimize the compatibility of the Vickers criterion, Ideal Packing Theory, and D90 rule with formation characteristics. CT scanning technology is employed to reconstruct realistic pore geometry, thereby obtaining parameters such as porosity and pore size distribution in the target area. Based on these data, the particle size distribution of plugging agents is designed according to three different plugging theories. Plugging experiments, fluid–discrete element coupling (CFD-DEM) simulations, and sand-packed-tube permeability tests are utilized to select the optimal plugging theory for the target formation.

2. Research Procedure

This study focuses on a formation with a depth of 3560 m in the Ordos Basin. In the target formation, after completing a propping operation implemented with quartz sand with a particle size range of 20–40 mesh, well washing fluid was used for plugging the operation area, and an optimal analysis of the plugging theory was carried out based on the plugging effect. To determine the plugging theory best suited to the target formation characteristics, the pore structure of the proppant-packed zone was first quantitatively characterized. Subsequently, simulated cores were used to conduct optimization experiments for different plugging theories. The selected plugging theories were then further simulated and optimized through numerical modeling. Finally, sand-packed-tube experiments were employed to quantitatively select the plugging theory most compatible with the target formation. The specific approach is as follows:

- (1) Prepare a standard steel core with a 5 mm fracture width and 17 mm fracture length, filled with 20–40-mesh quartz sand. Conduct optimization experiments using different plugging theories and compare the plugging effectiveness of the three theories through invasion depth testing.
- (2) A standard-sized core is prepared by fixing 20–40-mesh quartz sand with a thermoplastic tube, followed by CT scanning to obtain its pore size distribution characteristics and porosity, providing fundamental parameters for model establishment. Based on the parameters acquired from CT scanning, a foundational numerical simulation model is constructed to simulate the plugging processes of different plugging theories, thereby optimizing and selecting the most effective plugging theory.
- (3) The simulation results are validated and analyzed through sand-packed-tube displacement experiments. Permeability tests for the three plugging theories are conducted using sand-packed tubes to quantitatively characterize their plugging effectiveness. This enables the selection of the optimal plugging theory and verification of the simulation results.

2.1. Sample Data

(1) Plugging Experiment Samples

The plugging experiments utilized a standard-sized steel core ($d \times L = 2.5 \text{ cm} \times 5.0 \text{ cm}$) (Figure 1), featuring a central fracture measuring 17 mm in length $\times$ 5 mm in width $\times$ 50 mm in height, for proppant placement. The fracture was packed with 20–40-mesh quartz sand, and the end faces were secured using mesh/rubber sleeves.

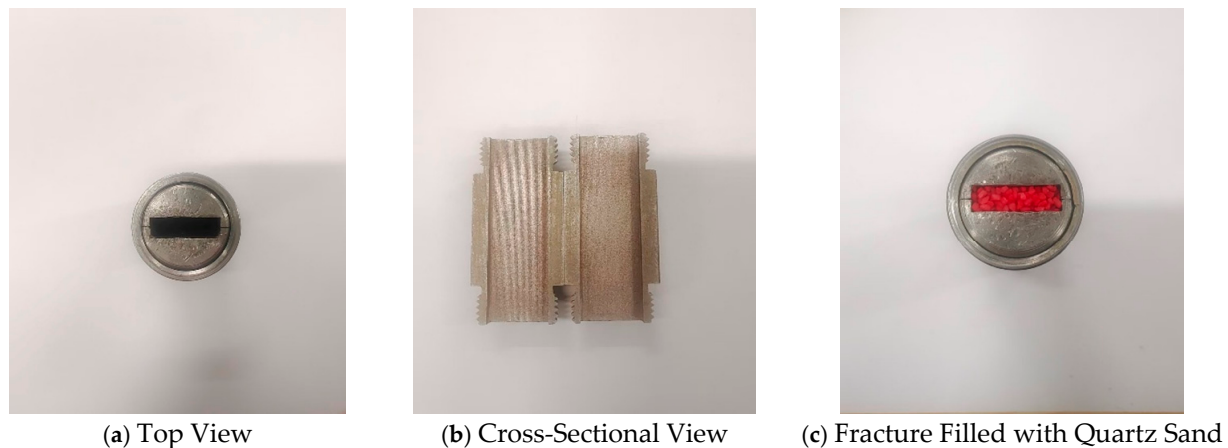


Figure 1. Standard-sized steel core.

For the plugging experiments, a steel core simulating a standard core ($d \times L = 2.5 \text{ cm} \times 5.0 \text{ cm}$) (Figure 1) was used, with a fracture of length 17 mm $\times$ width 5 mm $\times$ height 50 mm cut, to pack the proppant. Next, 20–40-mesh quartz sand was packed into the fracture, and the end faces were secured using mesh/rubber sleeves, etc.

(2) Basic Data for Simulation Samples

According to actual field conditions, this experiment primarily used 20–40-mesh quartz sand as the experimental proppant, with quartz sand of other mesh sizes serving as plugging materials for the plugging study. First, 20–40-mesh quartz sand was packed into a thermoplastic tube to simulate the proppant-packed zone, serving as a standard core for analyzing its structural characteristics, as shown in Figure 2a.

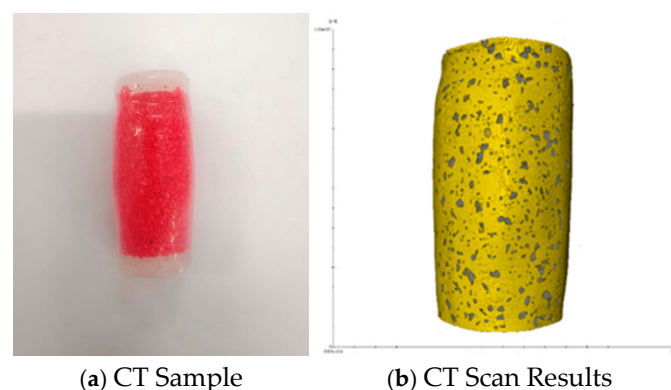


Figure 2. CT experimental samples.

A 3D visualization of the CT scan is shown in Figure 2b. The porosity of the packed region was determined to be 34.5%, providing fundamental parameters for model construction. The pore size distribution characteristics were also obtained, as shown in Figure 3, revealing a maximum pore diameter of 1691.7 μm and an average pore diameter of 1013.47 μm .

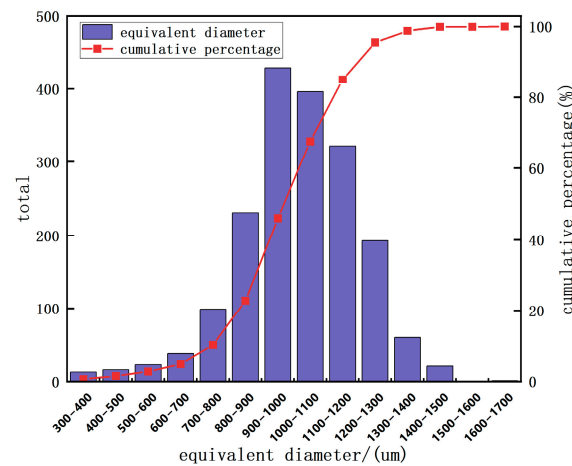


Figure 3. Core pore size distribution.

2.2. Plugging Experiment

The plugging experiments were primarily conducted using a high-temperature high-pressure dynamic fluid loss apparatus (Figure 4), with standard steel cores as experimental samples. The design parameters for the three plugging theories (Vickers criterion, Ideal Packing Theory, and D90 rule) are presented in Table 1.



Figure 4. High-temperature high-pressure dynamic fluid loss apparatus.

Table 1. Particle size distribution for plugging theories.

Plugging Theories	Particle Size (Mesh)	Percentage (%)
Vickers Criterion	8–26	25
	26–45	25
	45–100	25
	100–200	25
Ideal Packing Theory	8–10	10
	10–16	40
	16–200	50
D90 Rule	8–10	10
	10–200	90

2.3. Plugging Simulation

To further evaluate the applicability of the Vickers criterion, Ideal Packing Theory, and D90 rule in the target formation, a coupled CFD-DEM numerical model was constructed. This model analyzed the particle migration, bridging, and accumulation plugging processes of the three plugging theories, and we conducted a comparative analysis of their plugging effectiveness.

This study adopts a numerical method coupling Computational Fluid Dynamics and the Discrete Element Method (CFD-DEM). The fluid phase is determined by solving the locally averaged Navier–Stokes equations, while the discrete phase is tracked by solving Newton’s second law for each particle. Two-way coupling between the two phases is achieved through the interaction forces between particles and fluid. Among these forces, the drag force is the most critical, and is determined by the relative velocity between fluid and particles and serves as the main source of momentum exchange. The pressure gradient force drives particles to migrate from high-pressure zones to low-pressure zones in the fluid pressure field. By solving these forces in real time, the model can accurately capture the momentum exchange between the two particle–fluid phases, thereby effectively simulating micro-dynamic processes such as particle migration and clogging in porous media [24].

In the fluid, which is regarded as free-flowing and solved by the Navier–Stokes (N–S) equations, the continuity and momentum conservation equations are presented as follows [25,26]:

$$\frac{\partial}{\partial t}(\varepsilon_f \rho_f) + \nabla \cdot (\varepsilon_f \rho_f u_f) = 0$$

$$\frac{\partial}{\partial t}(\varepsilon_f \rho_f) + \nabla \cdot (\varepsilon_f \rho_f u_f) = -\varepsilon_f \nabla p + \nabla \cdot (\varepsilon_f \tau) + \varepsilon_f \rho_f g + f_f^p$$

ε_f denotes the fluid volume fraction;

ρ_f represents the density in kg/m³;

u_f stands for the velocity in m/s;

p indicates the fluid pressure in Pa;

f_f^p is the momentum source term, i.e., the force exerted by particles on the fluid within each fluid cell in N/m³;

τ denotes the fluid stress tensor;

g represents the gravitational acceleration in m/s².

In the DEM module, for calculating particle migration, the governing equations are as follows:

$$m_i \frac{du_i^p}{dt} = \sum_{j=1}^{n_i^c} F_{ij}^{p,p} + F_i^{f,p} + F_i^g$$

$$I_i \frac{dw_i}{dt} = \sum_{j=1}^{n_i^c} M_{ij}$$

u_i and w_i denote the velocity and angular velocity of particle, with units of m/s and rad/s, respectively;

$F_{ij}^{p,p}$, $F_i^{f,p}$ and F_i^g represent the particle–particle interaction force, fluid–particle interaction force, and gravity, respectively, in N;

I_i indicates particle inertia momentum in kg·(m/s);

M_{ij} denotes the torque acting on particle i in N·m.

The fluid–particle interaction forces consist of drag force, lift force, pressure gradient force, viscous force, etc. In general, except for drag force, pressure gradient force, and viscous force, all of the forces have little influence on the particle flow behavior.

The fluid drag force equation is expressed as follows:

$$F_D = C_{D0} \frac{\pi d_p^2}{8} \rho_f |u_f - v_p| (u_f - v_p) \varepsilon_f^{(2-\beta)}$$

For spherical particles, the resistance coefficient correlation is expressed as

$$C_{D0} = \left(0.63 + \frac{4.8}{\sqrt{Re}} \right)^2$$

Finally, it is corrected by the empirical formula of coefficient β :

$$\beta = 3.7 - 0.65e^{\left[-\frac{(1.5 - \log(Re))^2}{2}\right]}$$

The Reynolds number is

$$Re = \frac{\rho_f d_p |u_f - v_p|}{\mu}$$

v_p is the particle velocity in m/s;

C_{D0} is the drag coefficient;

β is the correction coefficient;

ε_f is the fluid volume fraction;

$|u_f - v_p|$ is the absolute velocity of the fluid relative to the particles in m/s.

The CFD-DEM coupling relationship is shown in Figure 5.

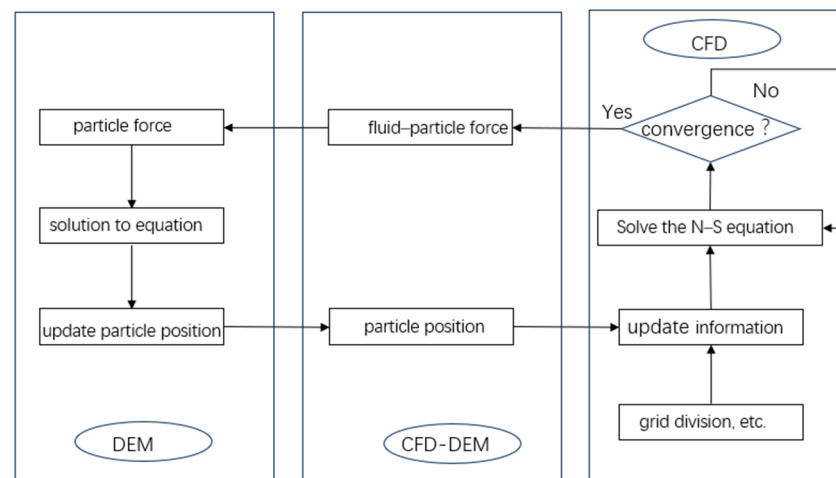


Figure 5. CFD-DEM coupling flow chart.

Based on CT scan data, the porosity after packing with 20–40-mesh quartz sand was determined to be 34.5%. The artificial fracture dimensions used in the simulation were length $\times$ width $\times$ height = 17 mm $\times$ 5 mm $\times$ 50 mm, consistent with the prepared sample. The particle size distributions of the plugging materials designed according to the three theories (Vickers criterion, Ideal Packing Theory, and D90 rule) are presented in Table 2, Table 3, and Table 4, respectively.

Table 2. Parameters for temporary plugging particles based on Vickers criterion.

Particle Size Range (mm)	0.075–0.15	0.15–0.56	0.56–0.7	0.7–2.36
Average Particle Size (mm)	0.05625	0.1775	0.315	0.765

Table 3. Parameters for temporary plugging particles based on Ideal Packing Theory.

Particle Size Range (mm)	0.075–1.01347	1.01347–1.6917	1.6917–2.36
Average Particle Size (mm)	0.2721175	0.6762925	1.012925

Table 4. Parameters for temporary plugging particles based on D90 rule.

Particle Size Range (mm)	0.075–1.6917	1.6917–2.36
Average Particle Size (mm)	0.441675	1.012925

First, professional software was used to construct the fracture geometry module and complete the refined meshing. Subsequently, the processed mesh model was imported into the simulation system to establish a particle generation factory. Finally, the dynamic simulation of the fluid–particle system was realized through a multi-physics field coupling algorithm. The model structure dimensions were set to 17 mm (length) $\times$ 5 mm (width) $\times$ 50 mm (height). The base layer of filler material inside the fracture consisted of anisotropically packed particles of different sizes, compacted at a velocity of 1 m/s to achieve a porosity of approximately 34.5% within the packed volume (i.e., compressed to a height of 30.535 mm). The pore particles were bonded to form the solid portion of the filler material. Subsequently, based on different plugging theories, particles of varying sizes were generated to conduct the plugging simulation.

2.4. Permeability Optimization Experiment

To quantitatively evaluate the plugging effectiveness of the Vickers criterion, Ideal Packing Theory, and D90 rule, this study employed sand-packed-tube displacement experiments to conduct permeability tests on three different plugging particle combinations. The experiments continued to use 20–40-mesh quartz sand to simulate natural fractures. By comparing the rate of permeability change before and after plugging under different theoretical frameworks, the plugging effectiveness (i.e., plugging efficiency) of the three theories on the target formation was evaluated, thereby identifying the optimal plugging theory compatible with the formation characteristics.

3. Results and Discussion

3.1. Plugging Experiment Results

Invasion depth serves as one of the key indicators for evaluating the performance of plugging materials. Typically, a smaller invasion depth indicates stronger plugging capability of the material against pores or fractures, more effectively preventing fluid invasion, thereby enhancing wellbore stability and drilling fluid performance [27–29]. The intrusion depths of the Vickers criterion, Ideal Packing Theory, and D90 rule are 0.9 cm, 1.2 cm, and 1.3 cm, respectively. The plugging effects under the three plugging theories are illustrated in Figure 6.

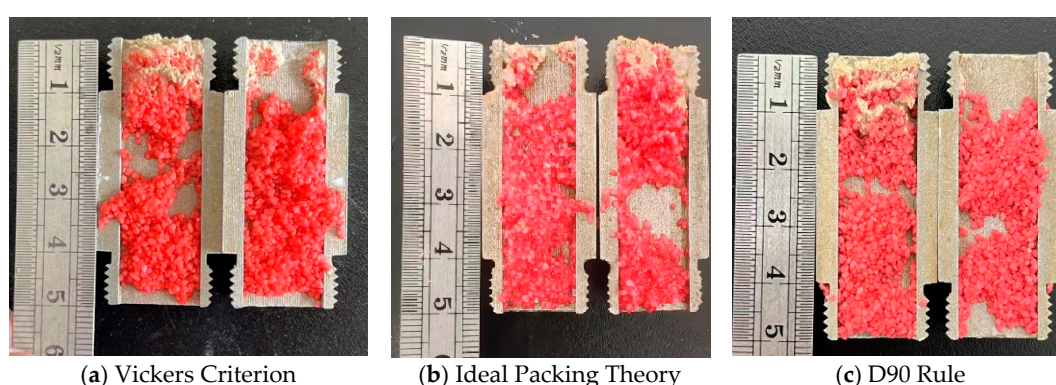


Figure 6. Comparison of plugging effects under different plugging theories.

The Vickers criterion achieves a relatively uniform particle size distribution of plugging particles ranging from 8 to 200 mesh. This design of a relatively uniform particle size distribution contributes to better fracture plugging. Smaller particles can fill the gaps between larger particles, forming a more compact sealing layer that effectively prevents fluid invasion and reduces the invasion depth. The Ideal Packing Theory sets different proportions according to different particle size ranges, for example, 50% for 16–200 mesh,

40% for 10–16 mesh, and 10% for 8–10 mesh. It aims to achieve optimal filling of formation pores through the rational combination of different particle sizes. However, in practical applications, factors such as the complexity of formation pore structures and uneven distribution of plugging materials within fractures may create certain leakage pathways in the plugging layer, allowing fluids to penetrate to some depth. The D90 rule mainly focuses on the particle size range accounting for 90% of the particle size distribution, among which 10% is 8–10 mesh and 90% is 10–200 mesh. This formulation may overly emphasize particles within a specific size range, resulting in an unreasonable particle size distribution of the plugging material. Larger particles may fail to effectively fill small pores, while smaller particles might form unstable accumulations in larger pores, leading to a less compact plugging layer that is more susceptible to fluid invasion.

The invasion depths observed with different plugging theories reflect their respective plugging effectiveness. These experimental results demonstrate that the Vickers plugging theory shows better compatibility with the target formation.

3.2. Simulation Results

Based on the CFD-DEM model established in Section 2.3, plugging simulations were conducted for the particle size distributions of different plugging theories, dynamically demonstrating the plugging paths of various particles. Through the simulation of the plugging process, an intuitive assessment of the plugging effectiveness of the three theories was achieved. The numerical simulation results are shown in Figures 7–9.

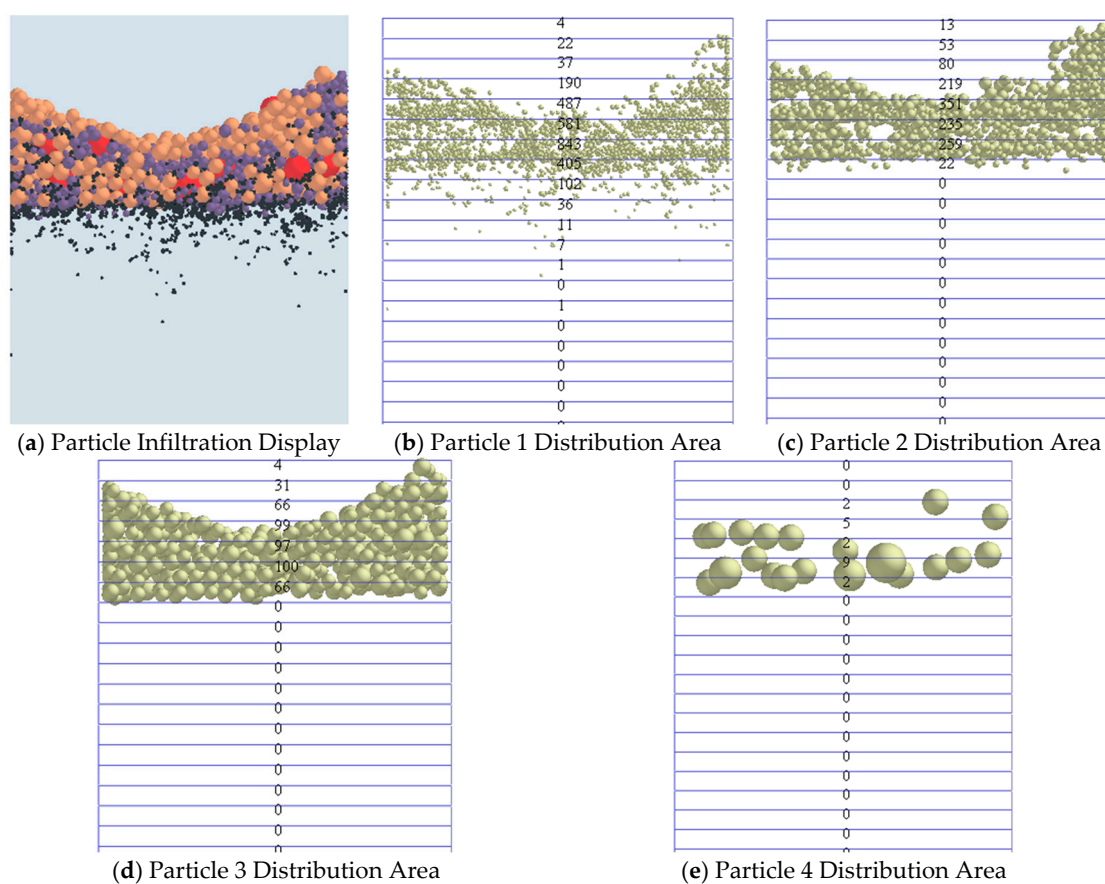


Figure 7. CFD-DEM simulation results based on Vickers criterion.

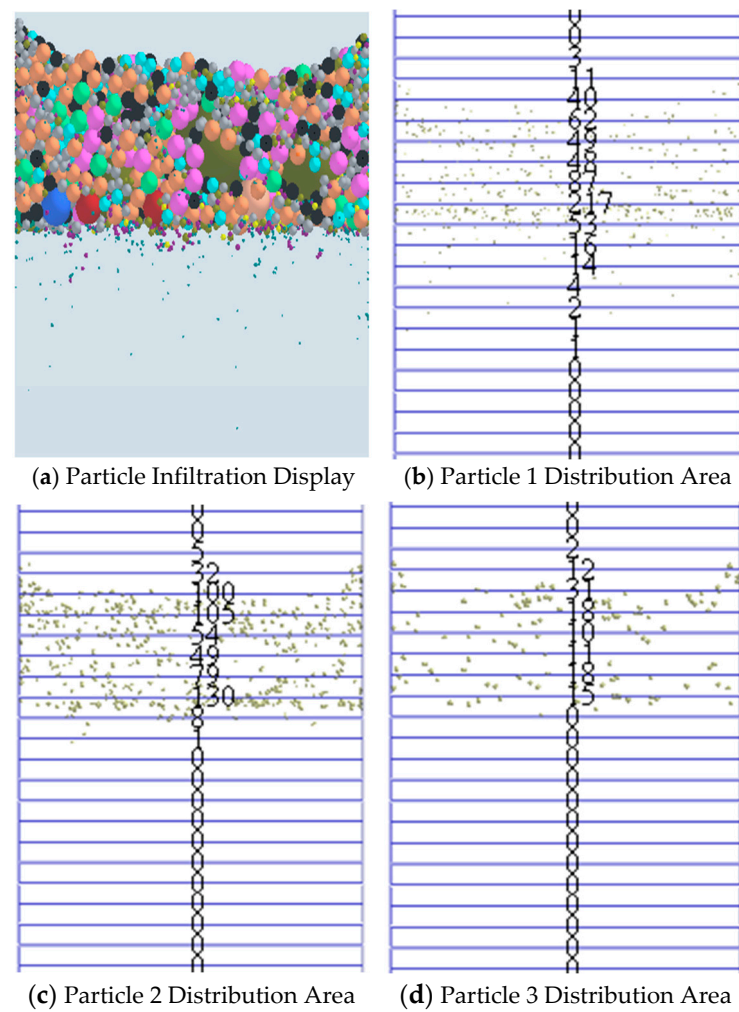


Figure 8. CFD-DEM simulation results based on Ideal Packing Theory.

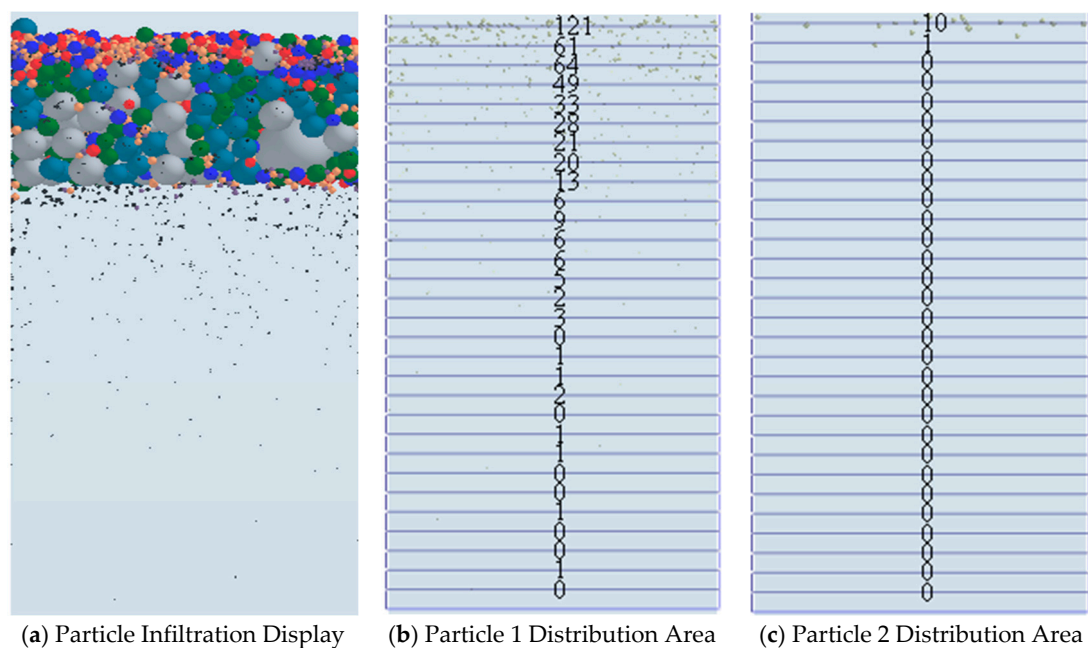


Figure 9. CFD-DEM simulation results based on D90 rule.

The simulation results based on the Vickers criterion are shown in Figure 7, revealing significant differences in particle infiltration and distribution characteristics. Figure 6a

illustrates the distribution changes in particles during the infiltration process, where the upper layer shows dense particle accumulation, while the lower layer appears relatively sparse. This reflects the gradual reduction in particles during infiltration under fluid impact. The numerical values in the figure represent particle aggregation density. Starting from the eighth horizontal line downward, each line represents a depth increment of 1 mm. On this depth scale, Particle 1 demonstrates certain infiltration capability, reaching a depth of 8 mm, indicating that its size characteristics grant it relatively strong mobility within the medium. Particle 2 infiltrates only 1 mm, showing weak infiltration capability and a tendency to accumulate at shallower depths. Particles 3 and 4 show almost no infiltration, indicating that their movement within the medium is significantly hindered, which relates to their larger particle sizes. Combined with the proportional settings of different particle size intervals in the Vickers criterion, the simulation results reveal significant behavioral differences among particles of varying sizes within the medium. By rationally configuring the proportions of particles in different size intervals, the differential infiltration characteristics can be utilized to form an effective plugging structure in the medium. Larger particles preferentially block at shallow depths, while smaller particles partially infiltrate to fill voids, thereby achieving effective medium plugging. This validates the rationality and effectiveness of the Vickers criterion in configuring plugging material particle sizes, providing a theoretical basis for particle size selection and proportioning in practical plugging operations.

Figure 8 presents the simulation results based on the Ideal Packing Theory. From the particle infiltration display and the respective particle distribution area diagrams, starting from the 10th horizontal line downward, each line represents a 1 mm depth. In this simulation, Particle 1 exhibits strong infiltration capability, reaching a depth of 8 mm; Particle 2 infiltrates to a depth of 2 mm, showing significantly weaker infiltration capability than Particle 1 and tending to accumulate more in shallower regions; Particle 3 infiltrates 1 mm, with further reduced infiltration capability, preferring to accumulate in shallow layers.

The simulation results reflect significant differences in the infiltration behavior of particles with different sizes within the medium. Larger particles have weak infiltration capability and preferentially block at shallow depths, while smaller particles infiltrate relatively deeper. These characteristic differences help form a multi-layered plugging structure within the medium, where particles of different sizes function at various depths, collectively enhancing the plugging effectiveness.

Figure 9 presents the simulation results based on the D90 rule. Starting from the first horizontal line downward in the figure, each line represents a depth of 1 mm. The results show that Particle 1 reached an infiltration depth of 29 mm, while Particle 2 only infiltrated 2 mm. This indicates unreasonable particle size settings in the D90 rule, where particles of different sizes fail to cooperate effectively, resulting in unstable accumulations.

From the simulation results of the Vickers criterion, Ideal Packing Theory, and D90 rule, significant differences in particle invasion characteristics among the different plugging theories can be observed. Taking the D90 rule as an example, when the invasion depth of its Particle 1 reaches 9 mm, the particle count still exceeds 10, indicating that a substantial number of particles can penetrate to relatively deep positions. This situation may lead to inadequate plugging effectiveness, as more particles penetrate deep into the formation, failing to form an effective plugging layer in the near-wellbore zone. This increases the risk of continued fluid invasion, potentially causing unnecessary formation damage and affecting subsequent production or operations. In contrast, under the Vickers criterion, the particle count of Particle 1 only exceeds 10 when the invasion depth reaches 4 mm. Moreover, within the first two millimeters of invasion depth, the particle count rapidly decreases from 405 to 102. This trend indicates that Particle 1 under the Vickers criterion can

rapidly accumulate in shallow layers, forming areas with high particle aggregation density. This facilitates the quick establishment of an effective plugging layer in the near-wellbore zone, promptly preventing further fluid invasion, thereby better protecting the formation and reducing the likelihood of formation damage. This also highlights the advantage of the Vickers criterion in controlling particle invasion depth and forming effective plugs. Compared to the Ideal Packing Theory and D90 rule, it allows more precise regulation of particle distribution to meet the requirements of plugging operations.

3.3. Permeability Experiment Optimization Results

Sand-packed-tube displacement experiments were conducted with four test groups: a blank sample, and the D90 rule, Ideal Packing Theory, and Vickers criterion. The respective samples consisted of 50% quartz sand + 50% well cleaning fluid; 50% quartz sand + 50% D90 rule-based well cleaning fluid system; 50% quartz sand + 50% Ideal Packing Theory-based well cleaning fluid system; 50% quartz sand + 50% Vickers criterion-based well cleaning fluid system. The experimental results are shown in Figures 10 and 11.

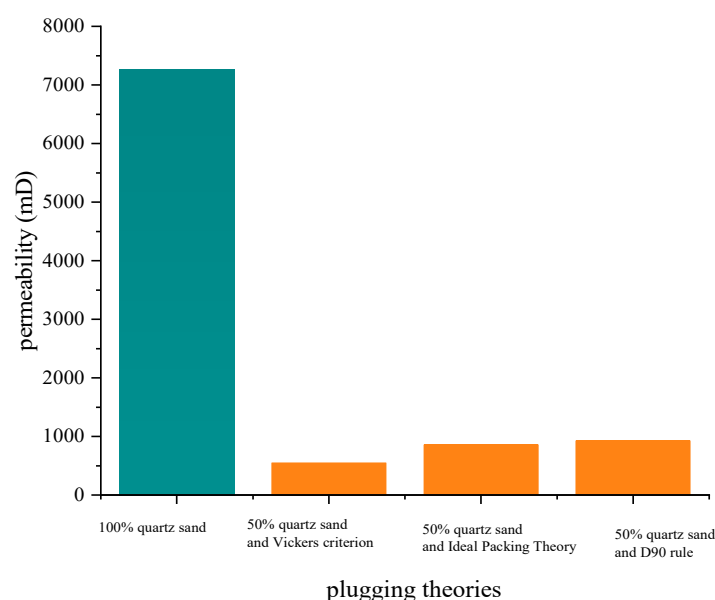


Figure 10. Permeability test results.

As shown in Figure 10, when using 50% quartz sand + 50% well cleaning fluid, the permeability is 7256 mD, indicating large pores between quartz sand particles and low flow resistance of the cleaning fluid. When different theoretical temporary plugging agents were added to the cleaning fluid and mixed with 50% quartz sand, the permeability decreased significantly. Specifically, with 50% quartz sand + Vickers criterion-based temporary plugging agent, permeability dropped to 548 mD; with 50% quartz sand + Ideal Packing Theory-based temporary plugging agent, permeability was 854 mD; and with 50% quartz sand + D90 rule-based temporary plugging agent, permeability was 923 mD. It can be seen from Figure 11 that the different well cleaning fluid systems based on various plugging theories exhibit varying reduction rates in flow capacity. The most significant reduction is observed with the “50% quartz sand + Vickers criterion” system, achieving a 92.4% decrease. This is followed by the “50% quartz sand + 50% Ideal Packing Theory” system, with an 88.2% reduction, while the least effective is the “50% quartz sand + 50% D90 rule” system, showing an 87.3% reduction.

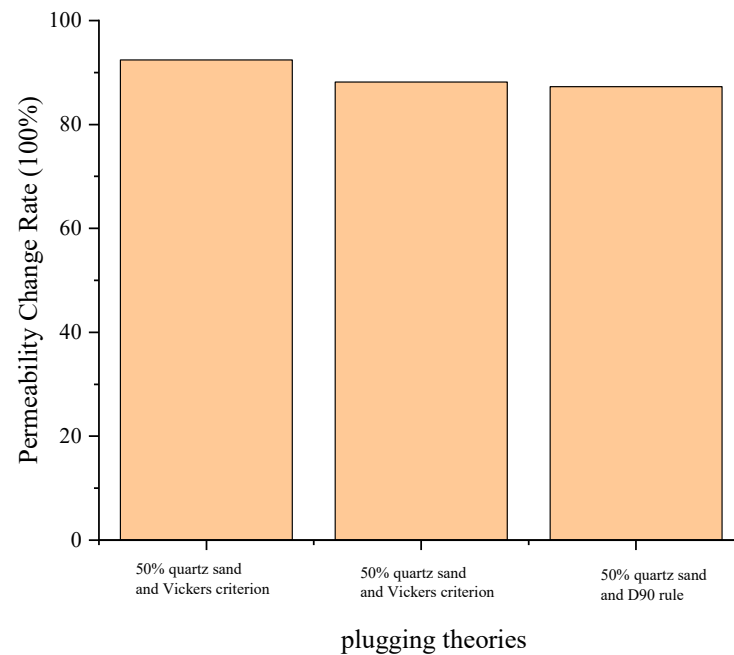


Figure 11. Permeability change rate results.

By comparing the permeability test results of the three plugging theories, it was found that the plugging layer formed using the Vickers criterion-based temporary plugging agent exhibited the lowest permeability. Lower permeability indicates a denser plugging layer, creating greater resistance to fluid passage and more effectively preventing fluid penetration and flow. The Vickers criterion, through rational configuration of particle size ranges and their proportions, enables the temporary plugging particles to be more tightly arranged and compacted within the sand-packed tube, resulting in smaller interparticle voids and a denser plugging structure. This compact sealing layer better meets the requirements of plugging operations, providing more reliable barrier protection in near-wellbore zones or other areas requiring sealing, thereby reducing formation damage caused by fluid invasion. Based on the comprehensive sand-packed-tube experimental results, the Vickers criterion-based temporary plugging agent demonstrated excellent performance in reducing permeability and forming a dense sealing layer. Therefore, the Vickers criterion was selected as the theoretical basis for particle size configuration in plugging operations to achieve more efficient and reliable plugging effects.

Based on the analysis of the plugging test results, CFD-DEM simulation data, and sand-packed-tube permeability measurements, the Vickers criterion demonstrates superior plugging performance compared to the Ideal Packing Theory and D90 rule. The particle size distribution defined by the Vickers criterion demonstrates excellent compatibility with the target formation, providing effective guidance for well cleaning operations in the designated reservoir.

4. Conclusions

This study takes the formation of the Ordos Basin as the research object. After completing the propping operation using quartz sand, the Vickers criterion, Ideal Packing Theory, and D90 rule are optimized for plugging theory based on the plugging effect of well washing fluid on the operation area. Through a combined experimental and numerical simulation approach, the plugging effectiveness of the three plugging theories is evaluated, revealing their operational mechanisms during wellbore sealing processes. The optimal

plugging theory demonstrating the strongest compatibility with the target formation is identified, leading to the following conclusions:

- (1) The plugging test results indicate that the Vickers criterion achieves the best sealing performance. The Vickers criterion ensures uniform distribution of plugging particles within the 8–200 mesh range. This relatively uniform particle size distribution design contributes to improved sealing performance. Smaller particles can fill the voids between larger particles, forming a denser sealing layer that effectively prevents fluid invasion and reduces penetration depth. This approach demonstrates significant advantages in controlling particle invasion and establishing effective plugging barriers.
- (2) Based on the CFD-DEM model, the particle migration, bridging, and accumulation sealing processes guided by the three theories were simulated and analyzed. The Vickers criterion demonstrated superior plugging performance, enabling rapid formation of effective sealing in shallow regions.
- (3) The sand-packed-tube displacement experiment results indicate that the temporary plugging agent based on the Vickers criterion formed a plugging layer with the lowest permeability (reduced to 548 mD), significantly outperforming both the Ideal Packing Theory and the D90 rule. Its uniformly distributed particle size range (8–200 mesh) creates a densely packed structure through particle gradation, effectively preventing fluid invasion. This validates the scientific basis and practical rationality of the Vickers criterion in designing particle size matching for plugging materials.
- (4) The superiority of the Vickers criterion in the plugging of shale oil horizontal wells was verified by combining experimental and numerical simulation methods. However, there are still some limitations, mainly including that the difference between the experimental conditions and actual formation environment may lead to result deviations, and the simplification of some parameter assumptions in the numerical simulation may affect the simulation accuracy. Future research needs to employ conditions closer to on-site actual working conditions, refine the experimental design and simulation parameters, and explore more new plugging materials and their interaction mechanisms with formations, as well as their impact on subsequent plugging removal and flowback operations.

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