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Article

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Posted Date: July 29th, 2026

DOI: <https://doi.org/10.21203/rs.3.rs-10370684/v1>

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Additional Declarations: No competing interests reported.

Numerical Simulation of Microscopic Oil-Water Two-Phase Flow Mechanisms in Porous Media Using the Volume of Fluid (VOF) Method

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Abstract: The microscopic seepage law of oil-water two-phase flow in porous media can directly reflect the formation process of residual oil. However, existing physical simulation methods are unable to accurately quantify the oil-water flow patterns under varying external conditions. To systematically investigate the pore-scale displacement behavior of oil – water two-phase flow under different controlling factors, matrix and matrix-fracture porous-media models were developed using the algebraic Volume of Fluid (VOF) method coupled with the incompressible Navier-Stokes equations. The results show that: ①Injection velocity affects water-phase migration pathways by regulating the relative contributions of viscous and capillary effects, and this influence is controlled by the specific pore structure. ②Wettability, pore-throat structure, and injection velocity jointly control fracture-matrix fluid exchange. When the injection velocity increased to 0.015 m/s, the oil recovery factor of the MWS mode decreased to 63.7%, indicating that an excessively high injection velocity may weaken matrix imbibition. ③Different water-injection schedules exhibit distinct advantages in terms of final oil recovery and oil recovery per unit injected-water volume. The oil recovery factors obtained using periodic intermittent, periodic variable-rate, and constant-rate injection were 36%, 40%, and 37%, respectively. Linear interpolation showed that, to achieve an oil recovery factor of approximately 35%, the required normalized cumulative injected volumes, N_{inj} , were approximately 2.93, 3.61, and 5.25, respectively. Under the injection cycles and simulation conditions considered in this study, periodic intermittent and periodic variable-rate injection reduced the cumulative injected-water requirement by approximately 44% and 31%, respectively, compared with constant-rate injection.

Key words: Volume of Fluid (VOF); Oil-water two-phase flow; Microscopic model; Numerical simulation; Mixed-wettability mode

1 Introduction

Tight oil reservoirs, recognized as one of the crucial unconventional oil and gas resources, currently stand as the focal point of exploration and development in the petroleum industry [1-2]. Tight sandstone reservoirs are characterized by low porosity, low permeability, and significant heterogeneity. Controlled by the micro-nano pore structure, the flow ability of crude oil in the pores is weak, resulting in a low degree of utilization of crude oil in tight reservoirs [3]. The method combining displacement and imbibition has been extensively studied and widely applied in the field as an important stimulation measure to mobilize crude oil in tight reservoirs. Driven by capillary pressure, the solution displaces the crude oil in tight pore throats into the main channels with high permeability through the combination of external displacement force and the oil-water replacement by imbibition capillary force, enhancing the oil washing efficiency of the injected water and thus becoming the main oil displacement force in tight reservoirs [4-5]. Therefore, in-depth research on the microscopic interaction mechanism of oil-water two-phase seepage during the displacement and imbibition process in tight reservoirs is of great engineering application significance for the large-scale and efficient development of tight oil reservoirs.

Tight oil reservoirs can be equivalent to a porous medium system composed of complex pore structures. The front edge of water flooding for oil displacement is jointly composed of a large number of menisci in pores, and its evolution process is jointly controlled by various pore filling mechanisms and physical properties [6]. However, in real core displacement experiments, limited by the scale effect of micro-nano pore-throat structures and the experimental resolution, it is difficult to accurately characterize and quantitatively describe the interface evolution process at the micron-scale pore throats [7]. In contrast, numerical simulation methods can obtain physical quantities such as velocity, pressure, and fluid distribution within porous media, thereby enhancing the understanding of the displacement and imbibition process in tight reservoirs [8]. Therefore, many scholars have adopted different mathematical methods to establish numerical simulation models of porous

media and carried out research on the seepage mechanism of oil-water two-phase flow within porous media at the microscopic pore scale. Among them, Li et al. [9] extracted the structural characteristics of the bedded shale reservoir based on scanning electron microscopy, and established a multi-component, multi-phase, and multi-relaxation time lattice Boltzmann model considering the nano-scale effect. They studied the occurrence state, flow behavior, and relative permeability characteristics of crude oil in bedded shale at different water saturation stages. Chai et al. [10] proposed a method for identifying the evolution of flow paths during the two-phase displacement process in porous media based on the results obtained by the direct numerical simulation (DNS) method, aiming to study the changes in flow paths and the dynamic distribution characteristics of oil-water two-phase during the two-phase displacement process in porous media. Sedghi et al. [11] developed a coupled dynamic pore-network modeling platform (LCD-PNM) and validated its reliability under both water-wet and mixed-wettability conditions. Furthermore, under various wettability and flow conditions, they carried out a pore-scale numerical simulation integrating physical principles for the oil-water two-phase flow in large-scale disordered pore networks. The simulation results revealed the complex coupling mechanism between viscous force and capillary force.

Real reservoirs often have mixed wettability [12]. Due to the complex and randomly distributed mineral components in tight reservoirs, the wettability distribution on the surface of rock pores is non-uniform [13], which makes the seepage behavior of oil-water two-phase complex and diverse. As one of the key parameters of capillary pressure, wettability directly affects the evolution characteristics of the imbibition front in porous media. Bakhshian S et al. [14] used a multiphase lattice Boltzmann model to clarify how wettability affects the recovery efficiency of the displaced phase in homogeneous and heterogeneous porous media. The results showed that as the wetting condition changes from strong drainage to imbibition, the displacement mode changes from breakthrough flow to corner flow mode. Ambekar A S et al. [15] used a pore-scale three-dimensional model and the Volume of Fluid (VOF) simulation method. The simulation results showed that in oil-wet media, the two-phase flow is mainly controlled by the physical properties of pore filling. Yan et al. [16] used the multi-component and multi-phase flow LBM model to simulate the transient two-phase flow in porous media. The results show that after injecting the non-wetting phase fluid, a liquid-phase dominant flow channel will be formed inside the porous media. Zhang et al. [17] used the VOF method to conduct a microscopic visual numerical simulation of the oil-water two-phase flow in porous media. Under different conditions such as wettability, displacement pressure, and oil-water viscosity ratio, the test results of breakthrough time, residual oil distribution, and residual oil saturation were compared and analyzed, revealing the dynamic flow characteristics of the oil-water two-phase during the water flooding process in different types of pores. Peng et al. [18] carried out in-situ wettability characterization in pore-scale two-phase flow based on the automatic measurement results of in-situ contact angles. On this basis, combined with the measured contact angles and the VOF method, an in-situ wettability modeling method for pore-scale two-phase flow was constructed.

In conclusion, in the existing microscopic numerical simulation models, most of them adopt porous media models with regular shapes, and the influence of the existence of fractures on the seepage laws of oil-water two-phase flow during the displacement and imbibition process is not considered. In addition, when considering the influence of various factors on the effect of displacement and imbibition, the research mainly focuses on the dominant water flooding channels and the remaining oil formation laws, and the microscopic action mechanism of the water flooding sweep efficiency under different injection modes is not considered. To address these issues, a pore-scale oil – water two-phase flow model was established by coupling the algebraic VOF formulation with the incompressible Navier – Stokes equations. Porous media models and matrix-fracture dual-medium pore-throat structure models are constructed. Three key factors are considered, including displacement velocity, contact angle, and mixed-wettability systems. A comprehensive analysis is carried out on water-phase flow path selection, the evolution of the water flooding front, and the oil-water flow behavior under matrix-fracture synergistic effects during the displacement and imbibition process. Moreover, the actual reservoir core slices are scanned. The grid medial axis extraction method and the maximum covering sphere method are adopted to digitally identify and characterize the flow paths in complex pore channels. Combined with the production and development characteristics of the high water-cut period of the oil reservoir, a microscopic numerical model of core thin sections with initial oil-water distribution was established. The influence of different injection methods on the water flooding sweep effect was explored. The technical route is shown in Figure 1. The research results of this paper provide theoretical support for the effective utilization and efficient development of tight oil reservoirs.

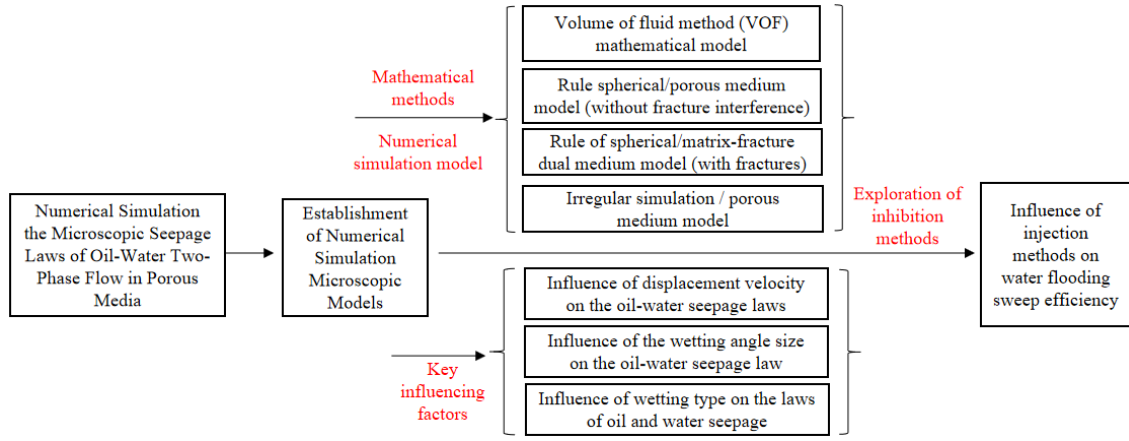


Figure 1. Technical route

2 Establishment of VOF Mathematical Method

The VOF method is a flow simulation method based on computational fluid dynamics, which is discretized by the finite volume method [19-20]. The VOF method characterizes the change process of two-phase flow field parameters by constructing a series of partial differential equations, calculates the numerical solution based on the constructed grid structure, and simulates the flow process of multiphase fluids. The VOF method solves the pressure and velocity variations of incompressible Newtonian fluid two-phase flow by coupling the continuity equation and the Navier-Stokes equation. The governing equation is:

$$\nabla \cdot \mathbf{u} = 0 \quad (1)$$

$$\frac{\partial(\rho \mathbf{u})}{\partial t} + \nabla \cdot (\rho \mathbf{u} \mathbf{u}) = -\nabla p + \rho \mathbf{g} + \nabla \cdot [\mu (\nabla \mathbf{u} + \nabla^T \mathbf{u})] + \mathbf{F}_s \quad (2)$$

Where, $\mathbf{u}$ is velocity vector, m/s; t is time, s; p is pressure, N/m²; ρ is density, kg/m³; $\mathbf{g}$ is gravitational acceleration, m/s²; μ is viscosity, mPa·s; $\mathbf{F}_s$ is the interfacial force acting on the phase surface, N/m³.

The viscous force ($\mathbf{F}_n$) expression is:

$$\mathbf{F}_n = \nabla \cdot [\mu (\nabla \mathbf{u} + \nabla^T \mathbf{u})] \quad (3)$$

Where, $\mathbf{F}_n$ is viscous force, N; μ is dynamic viscosity, mPa·s; $\mathbf{u}$ is velocity vector, m/s.

Based on the calculated the fluid volume fraction in each grid, the VOF method constructs the interface by using the principle of volume transport to track the fluid interface [21]. The fluid volume fraction (α) is defined as the percentage of the volume of each phase of the fluid in the grid volume, with a value ranging from 0 to 1. The expression of the phase transport equation for α is:

$$\frac{\partial \alpha}{\partial t} + \nabla \cdot (\alpha \mathbf{u}) + \nabla \cdot [\alpha (1 - \alpha) \mathbf{u}_c] = 0 \quad (4)$$

Where, α is the water-phase volume fraction; $\mathbf{u}_c$ is compression velocity, m/s; α is the fluid volume fraction; $\mathbf{u}$ is the fluid velocity, m/s,

$$\mathbf{u}_c = C_a |\mathbf{u}| \mathbf{n}_a \quad (5)$$

$$\mathbf{n}_a = \frac{\nabla \alpha}{|\nabla \alpha| + E} \quad (6)$$

Where, C_a is the dimensionless interface-compression coefficient; $\mathbf{n}_a$ is the unit normal vector of the oil-water interface, E is a small positive value introduced to avoid division by zero. In the face-based OpenFOAM discretization, the magnitude of the compression velocity is evaluated from $C_a |\phi_f| / |S_f|$, where ϕ_f is the volumetric face flux and $|S_f|$ is the face area.

The phase-fraction equation was solved using the algebraic VOF method implemented in OpenFOAM with the multidimensional universal limiter for explicit solution (MULES) to preserve a bounded volume fraction ($0 \leq \alpha \leq 1$).

In order to maintain the balance of mass and momentum in each phase, the density ρ and viscosity μ at the two-phase interface are calculated through the volume fraction α . The expressions are as follows:

$$\begin{cases} \rho = \alpha \rho_1 + (1 - \alpha) \rho_2 \\ \mu = \alpha \mu_1 + (1 - \alpha) \mu_2 \end{cases} \quad (7)$$

Where, ρ_1 、 ρ_2 are the densities of the two-phase fluid respectively, kg/m³; μ_1 、 μ_2 are the viscosities of the two fluid

phases, respectively, mPa·s.

The interfacial force F_s on the phase interface is generated by the interfacial tension, and its expression is:

$$F_s = \sigma \kappa n \quad (8)$$

Where, F_s is the interfacial tension, N/m³; σ is two-phase interfacial tension, N/m; κ is interface curvature; n is a unit vector perpendicular to the interface between two phases. The VOF method can be implemented in the CFD open-source software OpenFOAM. It mainly uses the SIMPLER algorithm to perform coupled solutions for velocity and pressure, as well as stress and velocity.

The solid-surface wettability was represented by a prescribed equilibrium contact angle. According to Young's equation:

$$\sigma_{so} - \sigma_{sw} = \sigma_{ow} \cos \theta_e \quad (9)$$

Where, σ_{so} is the solid–oil interfacial tension, N/m; σ_{sw} is the solid–water interfacial tension, N/m; σ_{ow} is the oil–water interfacial tension, N/m; θ_e is the equilibrium contact angle measured through the water phase, °.

In the VOF model, the interface normal adjacent to the solid wall was corrected as:

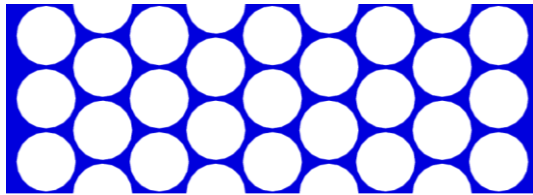
$$n_\theta = n_s \cos \theta_e + t_s \sin \theta_e \quad (10)$$

Where, n_θ is the corrected unit normal vector of the oil–water interface; n_s is the unit normal vector of the solid wall; t_s is the unit tangential vector of the solid wall; The corrected normal was used to calculate the interface curvature and surface-tension force.

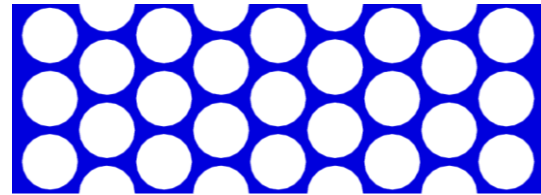
3 Establishment of a microscopic mathematical model for oil-water two-phase seepage and verification of its rationality

3.1 Establishment of microscopic porous medium simulation model

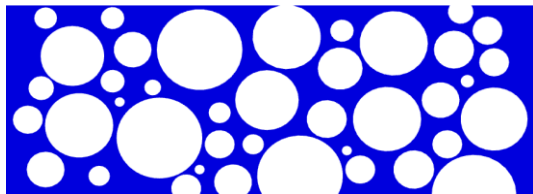
In this section, two types of models, namely homogeneous porous media and heterogeneous porous media models, are established respectively (as shown in Figure 2). They are numbered A, B, C, and D respectively, and the dimensions of all models are 80×30 μm. Among them, models numbered A and B are micro-homogeneous models, while models numbered C and D are micro-heterogeneous models. It should be noted that all pore-scale numerical simulations were conducted using two-dimensional geometries. These models can capture the main in-plane evolution of the oil – water interface and enable comparison of the relative effects of factors such as injection velocity at a relatively low computational cost. Therefore, the results are mainly intended to reflect relative trends under different conditions. However, real pore structures are inherently three-dimensional, and the two-dimensional simplification may affect the prediction of behaviors such as fluid trapping and breakthrough time.



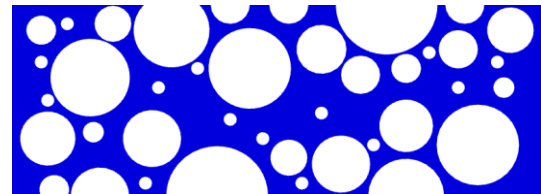
No. A: Homogeneous porous medium - minimum throat width 5 μm



No. B: Homogeneous porous medium - minimum throat width 6 μm



No. C: Heterogeneous porous media - porosity is 36.4%



No. D: Heterogeneous porous media - porosity is 49.1%

Figure 2. Microscopic numerical simulation models of different types of porous media
(white spheres represent rock skeleton particles, and blue represents flowing pore channels)

The porous media permeability of the particle packing is estimated based on the Kozeny-Carman equation for spherical particles [22-23], as shown in Table 1. The permeability values listed in Table 1 were estimated using the Kozeny – Carman relation and are mainly used to compare the relative flow capacities of different pore models. This relation is based on simplified assumptions concerning the equivalent pore diameter, porosity, and homogeneous pore structure; therefore, the estimated values are not regarded as exact intrinsic permeabilities. Among the above four models, the boundary conditions

are respectively defined as symmetric boundaries and no-slip boundaries for the model boundaries and the particle walls of the skeleton. In the numerical simulation of oil-water two-phase flow, the density of oil is $\rho_o = 967.3\text{kg/m}^3$, and its viscosity is $\mu_o = 12.1\text{ mPa}\cdot\text{s}$; the density of water is $\rho_w = 1000\text{kg/m}^3$, and its viscosity is $\mu_w = 1\text{ mPa}\cdot\text{s}$; the interfacial tension between oil and water is $\sigma = 0.0723\text{ N/m}$.

Table 1. Basic physical parameters of porous media model

No.	Skeleton particle radius / μm	Minimum throat width / μm	Porosity / %	Kozeny – Carman estimated permeability / mD
A	47.5	5	13.7	4.1
B	46	6	17.8	10.9
C	/	4	36.4	48.2
D	/	4	49.1	64.8

3.2 Establishment of the matrix-fracture dual medium model

In the dual-medium model composed of fractures and matrix, the existence of fractures helps to improve the communication intensity between the oil and water phases [24]. The numerical simulation model of the matrix - fracture porous medium is shown in Figure 3(a). The geometric dimensions of this model are $90\text{ }\mu\text{m} \times 90\text{ }\mu\text{m}$, the rock matrix domain is composed of homogeneous particles with different wettability, and the average diameter of the solid phase particles is $3.8\text{ }\mu\text{m}$. The yellow circles represent oil-wetting particles, with a corresponding contact angle of 135° , and the black circles represent water-wetting particles, with a corresponding contact angle of 45° . The fracture system embedded in the matrix consists of a main fracture and branch fractures. The horizontal main fracture has a width of $6\text{ }\mu\text{m}$, and the branch fractures, which intersect the main fracture at an angle of 60° , have a width of $5\text{ }\mu\text{m}$. The boundary conditions are set as follows: the left side of the horizontal main fracture is the velocity inlet, and the ends of fractures at all levels are the pressure outlets.

Mixed-wettability systems are commonly classified into four types [13,25]: (1) Macropore oil-wet (MWL) mode, in which large pores are oil-wet while small pores remain water-wet. (2) Micropore oil-wet (MWS) mode, in which small pores are oil-wet while large pores are water-wet. (3) Fractional wettability (FW) mode, in which pores across the entire pore-size distribution simultaneously exhibit both water-wet and oil-wet characteristics, and (4) overall oil-wet (OW) mode, in which the entire pore surface is oil-wet. The four mixed-wettability models are illustrated in Figure 3(b). Initially, the mixed-wettability porous media are fully saturated with oil. Once water enters the fracture system through the main fracture inlet, it progressively displaces the initially trapped oil from the porous medium under the combined effects of displacement and imbibition.

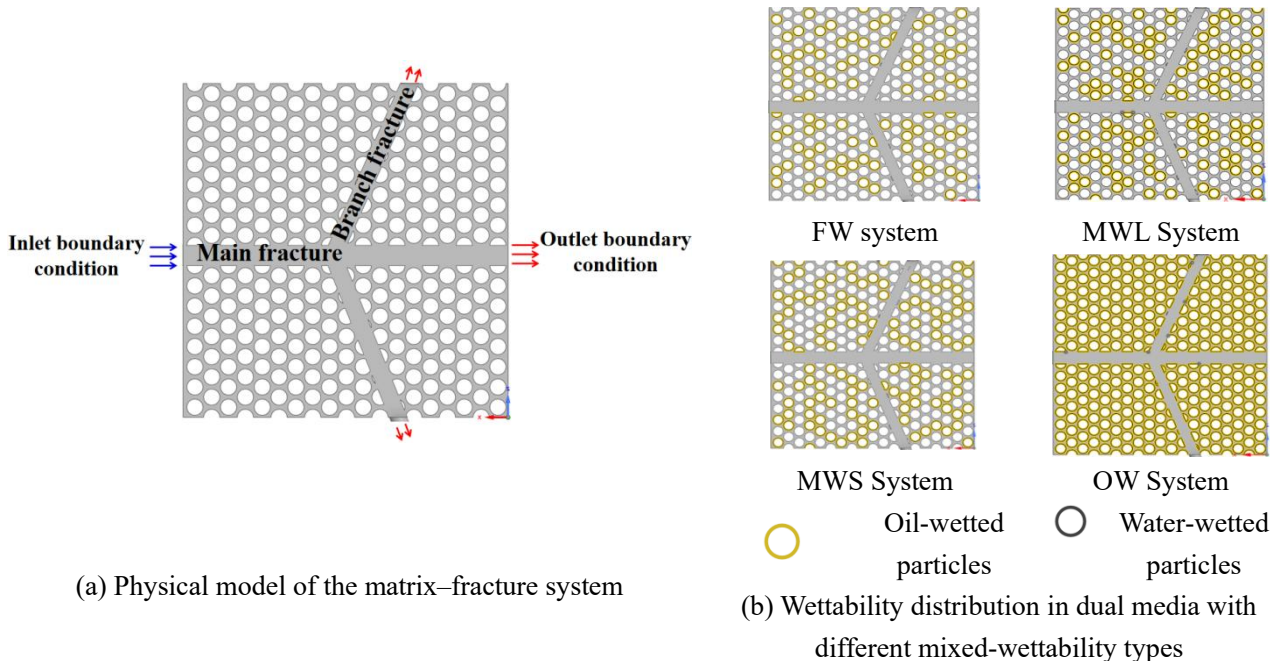


Figure 3. Schematic diagram of the pore-scale matrix-fracture system and wettability distribution under different mixed-wettability types in tight oil reservoirs

3.3 Establishment of numerical simulation model for real core slices of reservoir

The porous media model usually ignores the real geometric shape and connectivity of the pore structure of reservoir rocks. However, the oil-water flow is often significantly affected by the pore-throat structure [26-27]. The process of establishing the numerical simulation model for real core slices of the reservoir refers to "Appendix 1". The initial oil-water distribution state of the numerical simulation model of real core slices of the reservoir is shown in Figure 4. Among them, taking the fluid properties of the W reservoir as an example, in the numerical simulation setup, the density of oil is set as $\rho_o = 848.7 \text{ kg/m}^3$ and the viscosity of oil is $\mu_o = 14.1 \text{ mPa}\cdot\text{s}$, the density of water is $\rho_w = 1000 \text{ kg/m}^3$ and the viscosity of water is $\mu_w = 1 \text{ mPa}\cdot\text{s}$; the oil - water interfacial tension is $\sigma = 0.0723 \text{ N/m}$, and the wetting angle is $\theta = 60^\circ$.

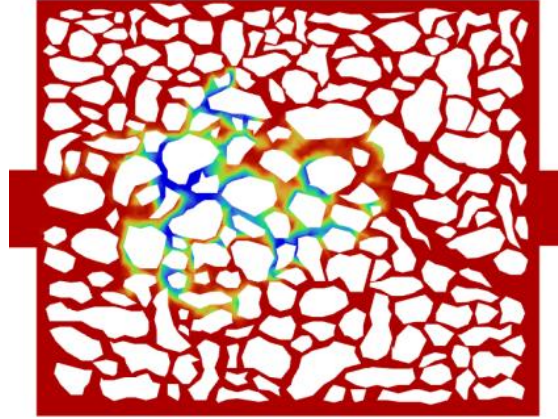


Figure 4. Schematic diagram of the initial oil–water distribution in the core

(White represents rock grains, red represents the oil phase, and blue represents the water phase.)

Given that the W oil reservoir is in the high water cut period (with a comprehensive water cut rate of 68.4%), the differences among oil reservoirs in different water cut periods at the core scale mainly lie in the distribution of remaining oil space and the changes in pore-throat connectivity. The characteristics of remaining oil in the high water cut period are extremely complex and difficult to mobilize. Therefore, the models in Figure 4 respectively constructed the initial states of oil and water distribution in the core with different remaining oil occurrence forms such as continuous sheet-like, multi-pore-like, oil column, oil droplet, and oil film[28].

3.4 Mesh-independence verification

Compared with pore-network modeling, the VOF method directly solves the mass and momentum conservation equations on the resolved pore geometry and retains detailed information on the local velocity, pressure, and fluid distribution. It can explicitly capture the transient oil–water interface and is therefore suitable for analyzing interface deformation, pore filling, fluid trapping, preferential channeling, and rapid interface rearrangement in irregular matrix and matrix–fracture pore structures. Compared with the lattice Boltzmann method, the VOF method can be readily implemented within a finite-volume CFD framework and conveniently coupled with pressure–velocity solution algorithms, surface-tension models, and wall-contact-angle boundary conditions. These characteristics make it suitable for the pore-scale displacement problems considered in this study.

However, the VOF method also has certain limitations. Its numerical results are sensitive to mesh resolution, interface-compression treatment, interface-curvature calculation, and the contact-angle boundary condition. Moreover, resolving micrometer-scale pore throats requires a large number of computational cells, resulting in a relatively high computational cost. Therefore, a mesh-independence test was conducted using triangular meshes. Three characteristic mesh sizes of 0.50, 0.35, and 0.20 μm were considered, corresponding to approximately 19,456, 39,184, and 127,863 triangular elements, respectively. The difference in the total number of elements between two successive mesh levels exceeded 75%. Figure 5 presents the variation in water saturation with time for different mesh sizes. The saturation curves obtained using the 0.20 and 0.35 μm meshes show nearly identical trends. The average relative deviation over the entire displacement process was approximately 2.6%, while the deviation at the final stage was only about 1%-2%. In contrast, the average relative deviation between the 0.50 μm coarse mesh and the 0.20 μm fine mesh was approximately 9.7%, with a maximum deviation of about 18.4% during the rapid interface-advancement stage. Therefore, the results obtained using the 0.35 μm mesh were considered essentially mesh-independent, and this mesh size was adopted in the subsequent simulations.

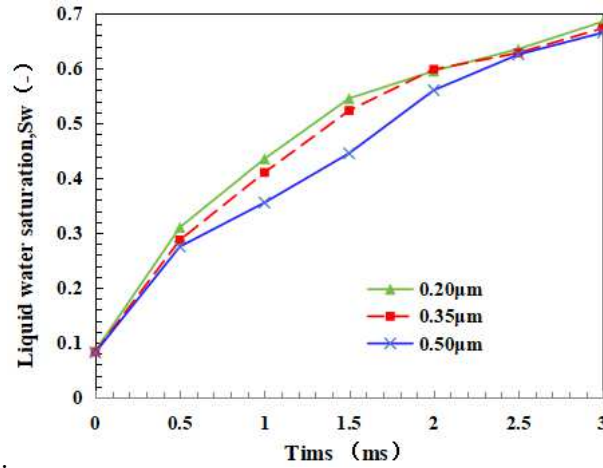


Figure 5. Variation of liquid-water saturation with time for different mesh sizes

For the subsequently developed large-scale heterogeneous pore model with dimensions of $500 \mu\text{m} \times 400 \mu\text{m}$, retaining a uniform mesh size of $0.35 \mu\text{m}$ would substantially increase the number of computational elements and the associated computational cost. To balance numerical accuracy and computational efficiency, mesh-independence tests were performed using three global characteristic mesh sizes of 1.0, 0.8, and $0.6 \mu\text{m}$. The results showed that the differences in average water saturation, total pressure drop, and oil recovery factor between the 0.8 and $0.6 \mu\text{m}$ meshes were within approximately 3%-5%, indicating that the $0.8 \mu\text{m}$ mesh essentially satisfied the mesh-independence requirement. Therefore, a global characteristic mesh size of $0.8 \mu\text{m}$ was adopted for the subsequent simulations, with local refinement to $0.4\text{-}0.5 \mu\text{m}$ in narrow pore throats and regions exhibiting pronounced oil-water interfacial variations. This mesh strategy effectively reduces the computational cost while maintaining sufficient resolution of the pore-throat geometry and the oil-water interface.

4 Numerical simulation study on the microscopic seepage law of oil-water two-phase flow

Taking the mixed-wettability tight oil reservoir as the research object, this section conducts a study on the influence of displacement and imbibition velocity and wettability on the seepage laws of oil-water two-phase flow based on the established microscopic numerical simulation models of porous media, matrix-fracture dual media, and real cores. To reduce the dependence of the comparison on absolute length and time scales, the displacement process can be characterized using the dimensionless time:

$$t^* = \frac{tU}{L_c}$$

Where, t is the simulation time; U is the mean inlet velocity; and L_c is the characteristic model length.

4.1 Influence of water-phase seepage velocity on oil-water two-phase flow

Under the condition of low water phase seepage velocity, in the low-permeability porous media dominated by the microscale, the fluid displacement process is more sensitive to local structural heterogeneity. The oil-water distribution under neutrally wetting pore throats at $v = 0.005 \text{ m/s}$ is shown in Figure 6(a). In the low-permeability porous media models numbered A (4.1 mD) and B (10.5 mD), since the pore-throat diameter is only 5-10 micrometers, when the displacement front encounters smaller pore throats, it is hindered by a relatively large capillary resistance, which impedes its further flow. As a result, the displacement fluid begins to flow laterally and may even produce a backflow effect. When the backflow of the reverse displacement encounters greater resistance, the front edge of the displacing phase continues to flow forward. The process is repeated continuously until a breakthrough is achieved. In this case, capillary forces dominate, making the side-channel capture effect more likely to occur: the displacement front advances slowly. The displacing phase (water) preferentially flows through low-resistance pore throats along bypass pathways, while the defending phase (oil) becomes trapped in pore bodies, forming large clusters. For the heterogeneous porous media numbered C and D, there are relatively large and small pore throats locally. Overall, it is characterized by the locking of local low - resistance channels and the concentration of flow paths, thus forming preferential water flow channels.

Under high water-phase seepage velocity conditions, the capillary number increases significantly, and the restraining effect of capillary forces at the micrometer scale on water flow is markedly reduced, while the relative contribution of viscous forces becomes more pronounced. The oil-water distribution in neutrally wetting pores and throats at $v=0.01 \text{ m/s}$ is

shown in Figure 6(b). With the enhanced relative effect of viscous forces, the fluid advances rapidly along paths of least resistance. For homogeneous porous media (No.s A and B), when the dimensionless time reaches $t^*=18.75$, uniform displacement is disrupted, and the overall displacement process exhibits a slight flow bias toward locally well-connected pore channels (low-resistance directions). The injected water can overcome the capillary resistance within the small pore throats and form a rapid through-flow channel from the injection end to the outlet under the overall pressure-difference drive. At this point, the displacement path is mainly controlled by the pressure-drop distribution and the principle of minimizing flow resistance. The influence of pore-structure heterogeneity is relatively smoothed, but the existing highly connected structures (porous media models No.s C and D) are further strengthened by the enhanced viscous effect, thereby accelerating the formation of preferential seepage channels.

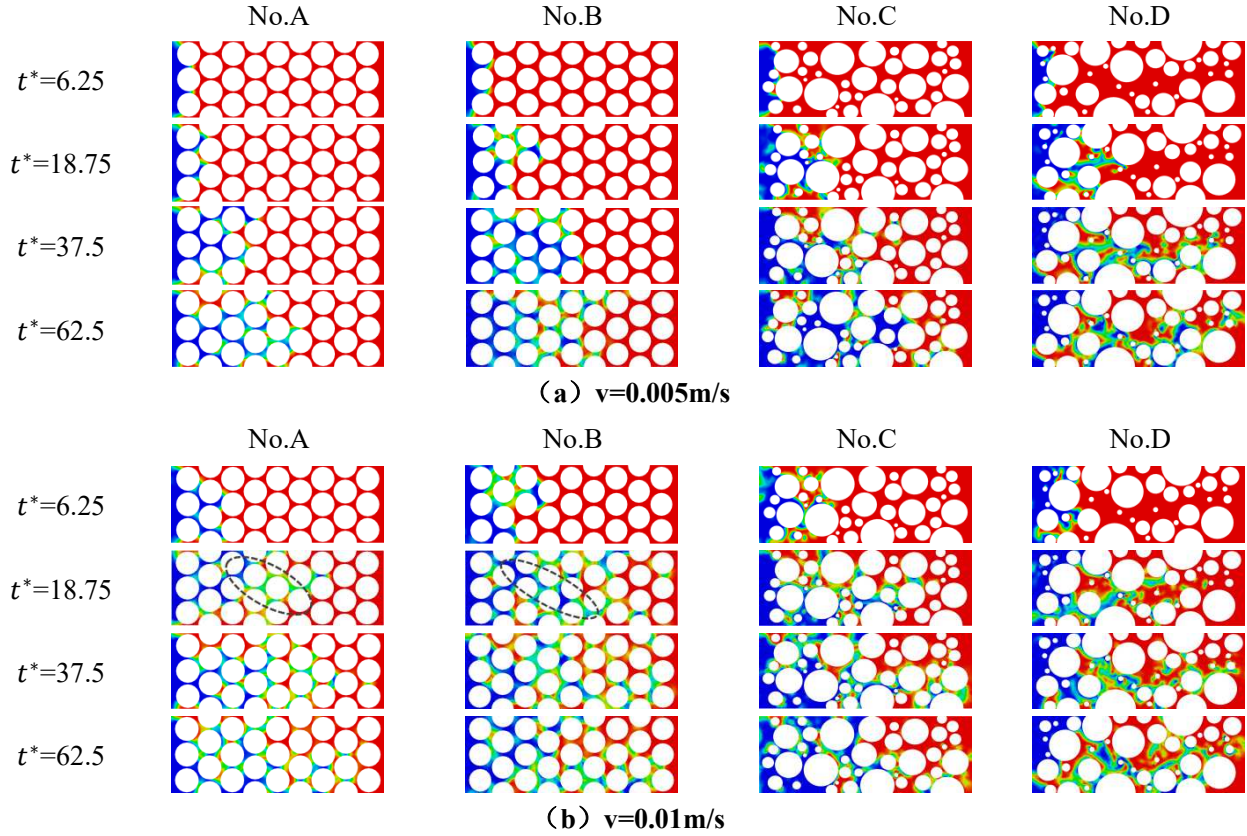
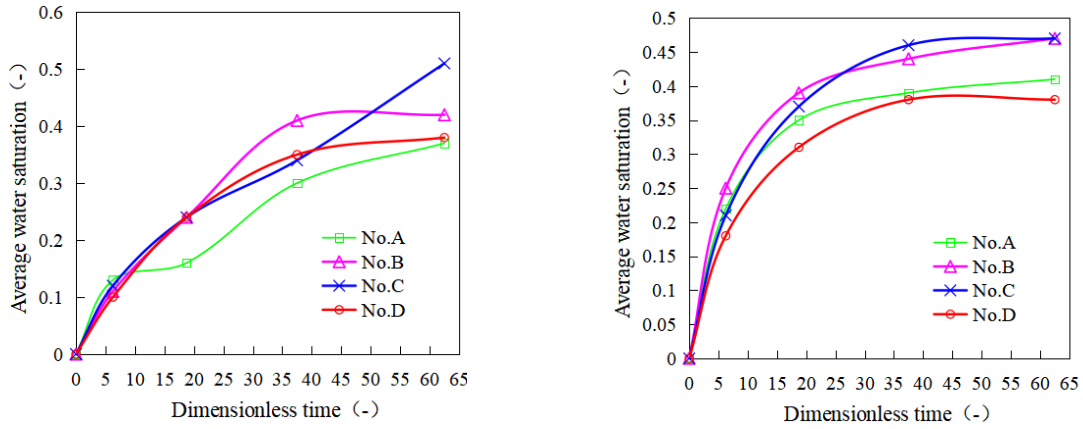


Figure 6. Oil-water distribution in neutrally wetting pores and throats(white represents rock grains, red represents the oil phase, and blue represents the water phase)

The local pore-throat size and connectivity characteristics significantly affect the formation of preferential water-flow pathways and the spatial distribution of residual oil. Accordingly, the average water saturation, dimensionless breakthrough time, and oil recovery factor are employed to quantitatively evaluate water-front propagation, sweep extent, and residual-oil mobilization under different pore-structure conditions. It should be noted that the dimensionless breakthrough times and characteristic displacement stages reported in this study are based on micrometer-scale two-dimensional pore models. The average water saturation was calculated by area-weighted averaging of the water-phase volume fraction over the pore domain. The dimensionless breakthrough time was defined as the dimensionless time at which the area-averaged water-phase volume fraction at the outlet first reached 0.01. The oil recovery factor was determined from the decrease in the oil-phase area relative to its initial value. The results presented in Figure 7 and Table 2 show that, at the same dimensionless time of $t^*=62.5$ the average water saturations of Models A, B, C, and D were approximately 0.37, 0.42, 0.51, and 0.38, respectively, at an injection velocity of 0.005 m/s. When the injection velocity was increased to 0.01 m/s, the corresponding values at $t^*=62.5$ were approximately 0.41, 0.47, 0.47, and 0.38. Models C and D reached water breakthrough at a dimensionless time of approximately $t^*=62.5$ under both injection-velocity conditions, indicating that the breakthrough occurred at a similar dimensionless displacement stage. At the same dimensionless time, the oil recovery factor of Model C decreased from approximately 51.2% to 47.0% as the injection velocity increased. This result indicates that the increased relative contribution of viscous effects altered the water-flow distribution and intensified preferential channeling and viscous fingering, thereby limiting the effective mobilization of residual oil in regions adjacent to the dominant flow pathways.

Table 2. Comparison of oil recovery factors for different porous-media models at $t^*=62.5$ under different injection velocities.

Flow velocity	NO.A	NO.B	NO.C	NO.D
0.005 m/s	36.5%	41.8%	51.2%	37.9%
0.01 m/s	41.4%	46.8%	47%	38%



(a) Evolution of average water saturation at a low injection velocity ($v=0.005$ m/s) (b) Evolution of average water saturation at a high injection velocity ($v=0.01$ m/s)

Figure 7. Evolution of average water saturation in different porous-media models at low and high injection velocities.

4.1.3 Analysis of the variation in total pressure drop across the model

(1) Analysis of the variation law of total pressure drop in homogeneous porous media

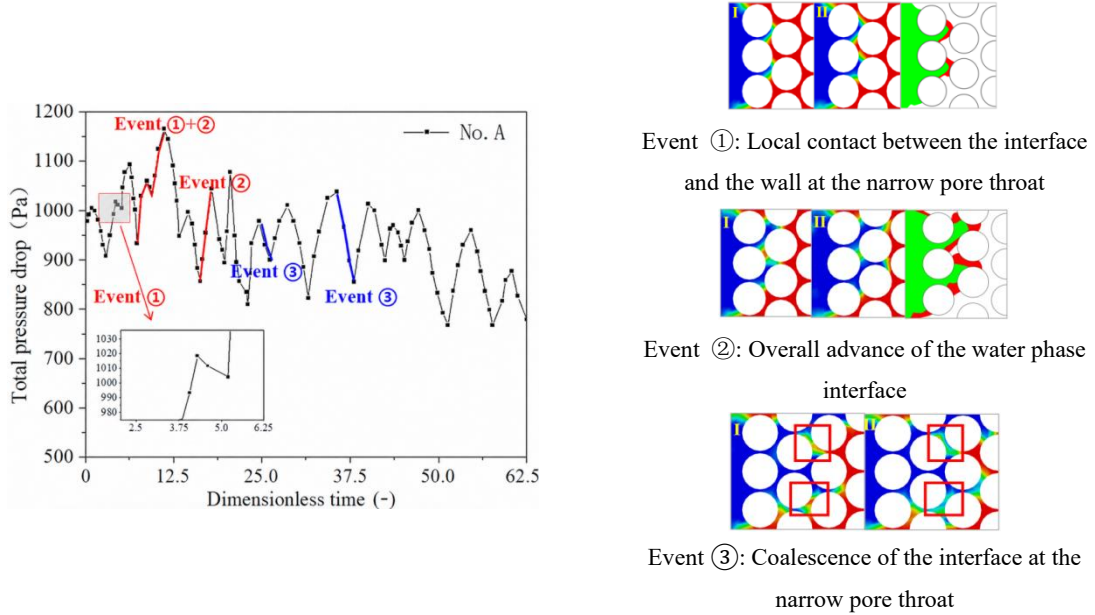
As shown in Figure 8(a), in low-permeability (4.1-10.9 mD) homogeneous porous media, the increase in total pressure drop is primarily caused by event ① or the combined occurrence of events ① and ②. Event ① refers to a local contact mechanism: when the water-phase interface comes into contact with the rock particle surface, a localized pressure release occurs, leading to a temporary reduction in total pressure drop. However, this pressure release is confined to pore-throat regions and is transient, so the overall curve exhibits a "slight sawtooth-like" increasing trend in pressure drop. Event ② corresponds to the overall advancement of the water-phase interface, indicating outward expansion of the fluid front. Due to the constraint imposed by the minimum pore-throat radius, an increasing number of narrow pore throats are simultaneously occupied by the oil-water interface and become subject to high capillary-entry pressure limitations. As a result, the number of effective flow channels is significantly reduced, and the equivalent permeability decreases sharply. To maintain the imposed flow rate, the system must increase the applied pressure gradient, which consequently leads to a pronounced rise in the total pressure drop.

The mechanism responsible for the decrease in total pressure drop is event ③, referred to as the interface coalescence effect. Within narrow pore throats, interface coalescence causes multiple high-curvature capillary interfaces, originally distributed across different throats, to merge into a single continuous interface with reduced curvature. This significantly lowers the capillary resistance that must be overcome by the water phase and improves the connectivity of flow pathways, thereby resulting in a sudden drop in the total pressure drop. Although low-permeability homogeneous porous media still satisfy the physical conditions for Haines jumps at the pore-throat scale, the phenomenon is generally weak due to limited geometric variability of pore throats and a relatively narrow distribution of capillary entry pressures. As a result, such jump events are typically smoothed out in the macroscopic pressure-drop response.

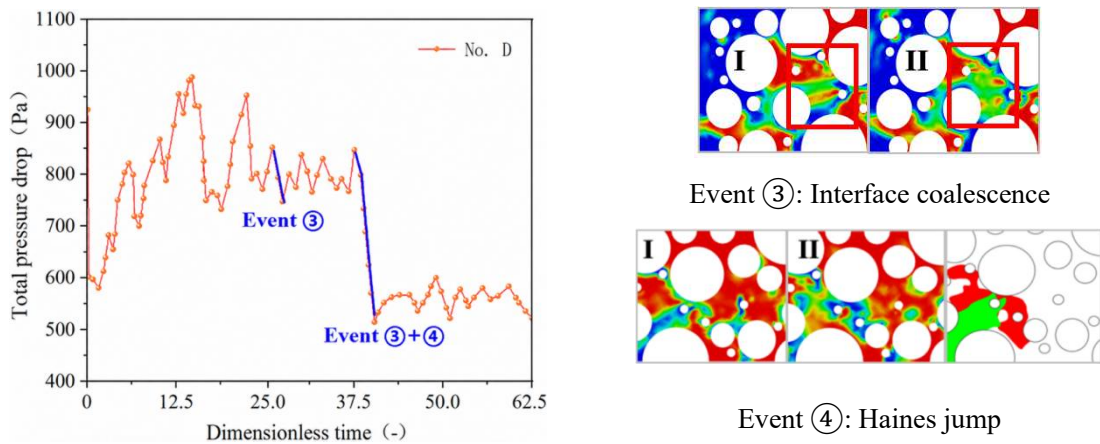
(2) Analysis of the variation law of total pressure drop in heterogeneous porous media

For heterogeneous porous media with preferential flow channels, the mechanisms responsible for the increase in total pressure drop remain the same, namely the overall advancement and contact of the oil-water interface. However, the mechanisms leading to a decrease in total pressure drop differ from those in homogeneous media. As shown in Figure 8(b), in heterogeneous porous media, it is associated with Interface coalescence (Event ③) and Haines jumps (Event ④). The Haines jump is a transient process characterized by a shift from capillary-force-dominated flow to viscous-force-dominated flow [29]. It is associated with instantaneous capillary pressure release, which progressively unlocks potential low-resistance flow paths and typically occurs when the interface traverses narrow pore throats. At the early stage of displacement, multiple

potential flow paths coexist, and sporadic Haines jumps occur in local pore throats, leading to small, frequent sawtooth-like fluctuations in total pressure drop without a clear decreasing trend (Event ③). When Haines jumps repeatedly occur along a geometrically preferential channel (e.g., a large pore-throat, low-resistance direction), the effective capillary resistance of that channel is gradually reduced, and flow begins to concentrate within it. As key pore throats are successively invaded by the water phase, a stable preferential channel is established. At this stage, the total pressure drop exhibits a marked reduction in fluctuation frequency, transitioning from a sawtooth-like response to a smoother and lower-level behavior, ultimately leading to a significant decrease in the overall pressure drop of the system (Event ③+④).



(a) Total pressure-drop evolution and interfacial events in homogeneous porous medium Model A



(b) Total pressure-drop evolution and interfacial events in heterogeneous porous medium Model D

Figure 8. Evolution of total pressure drop and associated interfacial mechanisms in homogeneous and heterogeneous porous-media models

4.2 Influence of wetting angle on the evolution of water-phase seepage path

Early studies suggested that the wettability of hydrocarbon reservoirs is uniformly distributed (i.e., uniformly water-wet or oil-wet). With advances in experimental and imaging techniques [30], researchers have gradually recognized that reservoir wettability is actually heterogeneous, exhibiting mixed-wettability behavior. Taking porous media model B as an example, the evolution of water-phase flow pathways under different contact angles is investigated, and the results are shown in Figure 9. It should be noted that a constant static contact angle was used in this study to represent solid-surface wettability; that is, the contact angle was assumed to be independent of the velocity of the three-phase contact line. During actual pore-scale displacement, the apparent contact angle may be affected by the direction of contact-line motion and the local capillary number, exhibiting hysteresis between the advancing and receding contact angles[31]. Therefore, the static contact-angle model may influence the transient capillary pressure and interfacial propagation time during rapid interfacial

rearrangement and Haines-jump events.

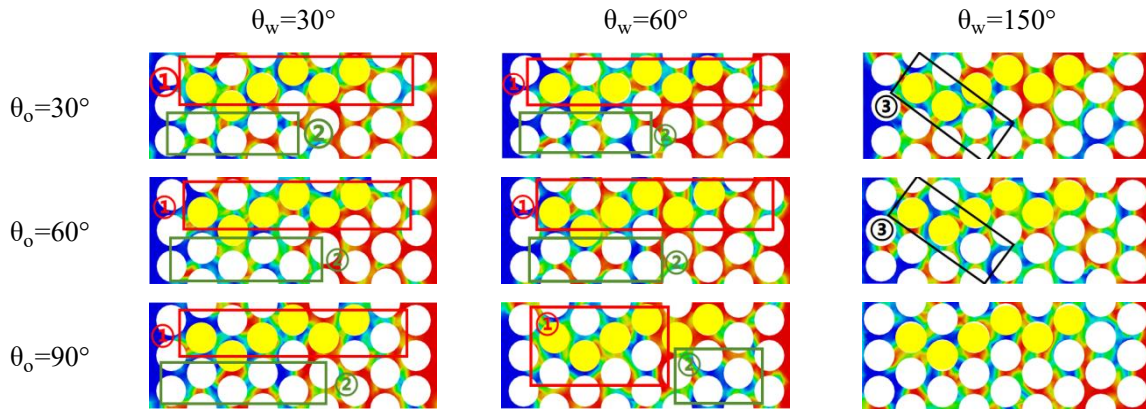


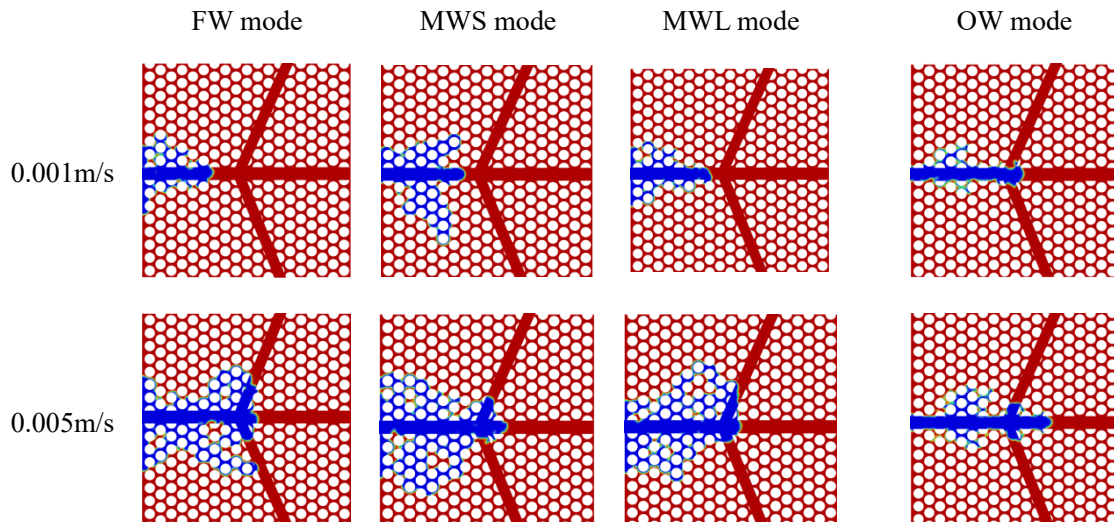
Figure 9. Oil-water distribution at $t^*=62.5$ and $v=0.005\text{m/s}$ under different mixed-wettability contact angles (red represents the oil phase, and blue represents the water phase)

As shown in Figure 9, under low water-phase velocity conditions, the water-phase flow pathways exhibit significant differences under different contact angles. When $\theta_w=30^\circ$, pronounced fingering behavior develops along water-wet particles, and rapid breakthrough occurs along pathway ①. In this case, the oil-water distribution is primarily governed by θ_w . When $\theta_w=60^\circ$, the increase in θ_o suppresses the degree of water fingering along pathway ①. For $\theta_o \leq 60^\circ$, the displacement front still preferentially breaks through along pathway ①. However, when $\theta_o > 60^\circ$, the capillary advantage of pathway ① is weakened, and the water-phase flow transitions from a single dominant pathway to a combined mode involving pathways ① and ②. When $\theta_w=150^\circ$, the corresponding water-wet particles exhibit strong oil-wet characteristics in terms of physical behavior. At this stage, the influence of wettability on the water-phase flow path is significantly reduced, and the flow is primarily governed by pore structure and local flow resistance. Consequently, the water phase preferentially advances along low-resistance directions between particles, where hydraulic resistance is minimized. At $t^*=62.5$, the average water saturation ranges from approximately 0.34 to 0.61. The combination of $\theta_o=60^\circ$ and $\theta_w=150^\circ$ an oil recovery factor of approximately 60.3%, whereas the combination of $\theta_o=60^\circ$ and $\theta_w=60^\circ$ gives the highest average water saturation of approximately 0.61. No distinct water breakthrough is observed at the outlet within 1.0 s for the conditions shown in Figure 9. Therefore, the corresponding breakthrough times are recorded as greater than 1.0 s.

4.3 Evolution law of water phase seepage path in mixed-wettability models

4.3.1 Evolution law of water phase seepage path under different seepage velocities

Mixed-wettability systems are mainly classified into four types: MWL, MWS, FW, and OW modes[32]. In the dual-medium model composed of fractures and matrix, the existence of fractures is conducive to improving the effect of imbibition oil recovery. The matrix-fracture dual-media models established in Figures 3 are selected, and four injection velocities are set: 0.001, 0.005, 0.01, and 0.015 m/s.



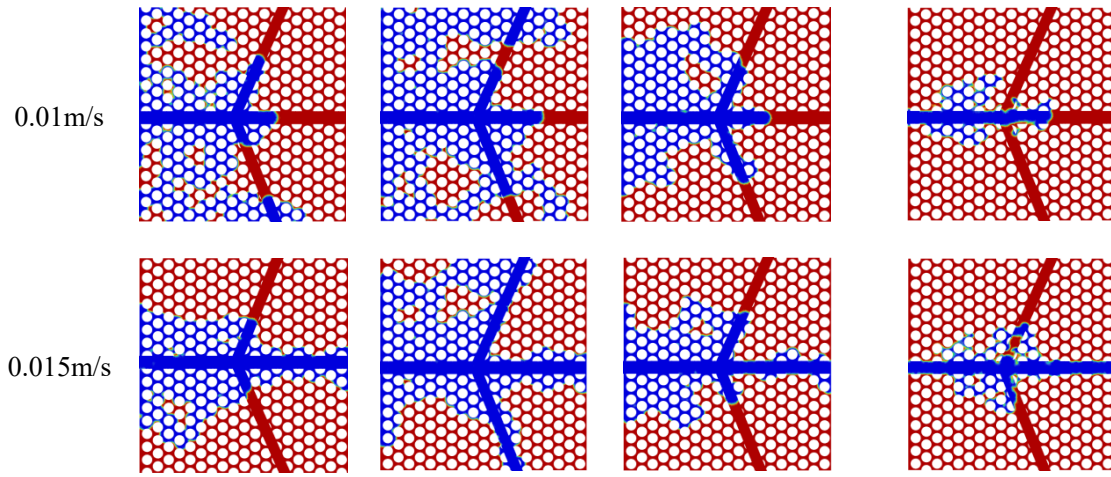


Figure 10. Variation of imbibition performance and oil-water distribution with injection velocity under different wettability systems

(red represents the oil phase, and blue represents the water phase)

Because the pore space was initially fully saturated with oil and both the oil and water phases were assumed to be incompressible, the oil recovery factor calculated from the reduction in the oil volume remaining within the model is theoretically equal to the average water saturation according to volume conservation. To avoid redundancy among the evaluation metrics, the oil recovery factor and dimensionless breakthrough time were employed to characterize the overall oil-displacement performance under different wettability modes and injection velocities.

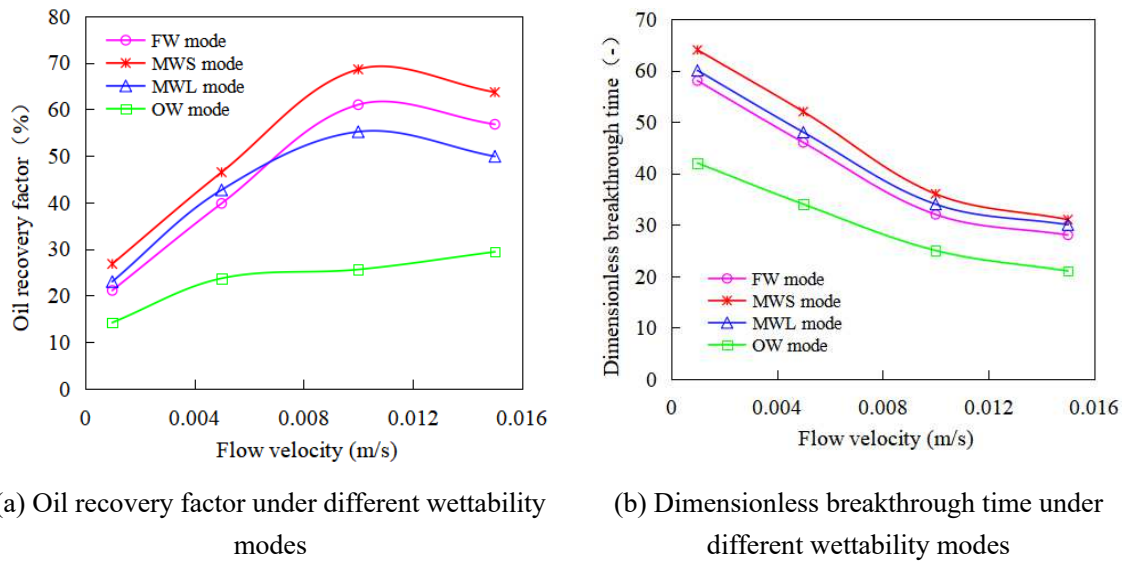


Figure 11. Effects of flow velocity on oil recovery factor and dimensionless breakthrough time under different wettability modes.

As shown in Figures 10 and 11, within the model geometries and parameter range considered in this study, injection velocity and wettability jointly affect water migration and oil mobilization in the fracture – matrix system. As the injection velocity increases from 0.001 to 0.01 m/s, water penetrates more extensively into the matrix in the FW, MWS, and MWL modes, resulting in an overall increase in oil recovery. Owing to the favorable connectivity of water-wet pores, the MWS mode promotes water transfer from the fracture into the matrix and achieves the highest oil recovery factor of approximately 69% at 0.01 m/s. The corresponding recovery factors of the FW and MWL modes are approximately 61% and 55%, respectively. In contrast, the continuous oil-wet pore throats in the OW mode restrict water penetration into the matrix, and the recovery factor remains only about 26%, indicating that most of the injected water migrates mainly through the fracture and locally low-resistance pathways.

The dimensionless breakthrough time decreases with increasing injection velocity, indicating faster water propagation through the fracture-matrix system. At 0.01 m/s, the dimensionless breakthrough times of the FW, MWS, and MWL modes are approximately 33-36, whereas that of the OW mode is about 25. This earlier breakthrough in the OW mode does not correspond to improved matrix sweep or higher oil recovery. Therefore, an earlier breakthrough primarily reflects

accelerated water transport and should not be used alone to evaluate displacement performance.

When the injection velocity is further increased to 0.015 m/s, the recovery factors of the FW, MWS, and MWL modes decrease by approximately 4 – 6 percentage points compared with those at 0.01 m/s, while their dimensionless breakthrough times are further reduced to approximately 28 – 31. This indicates that although a higher injection velocity facilitates the displacement of oil retained in the fractures, it also strengthens preferential flow through the fracture network, leading to earlier breakthrough and reduced effective matrix sweep. Considering both oil recovery factor and dimensionless breakthrough time, an injection velocity of approximately 0.01 m/s provides a relatively favorable balance between imbibition and displacement under the present simulation conditions, with the MWS mode exhibiting the best overall performance.

4.4 Influence of water injection mode on sweep efficiency in water flooding

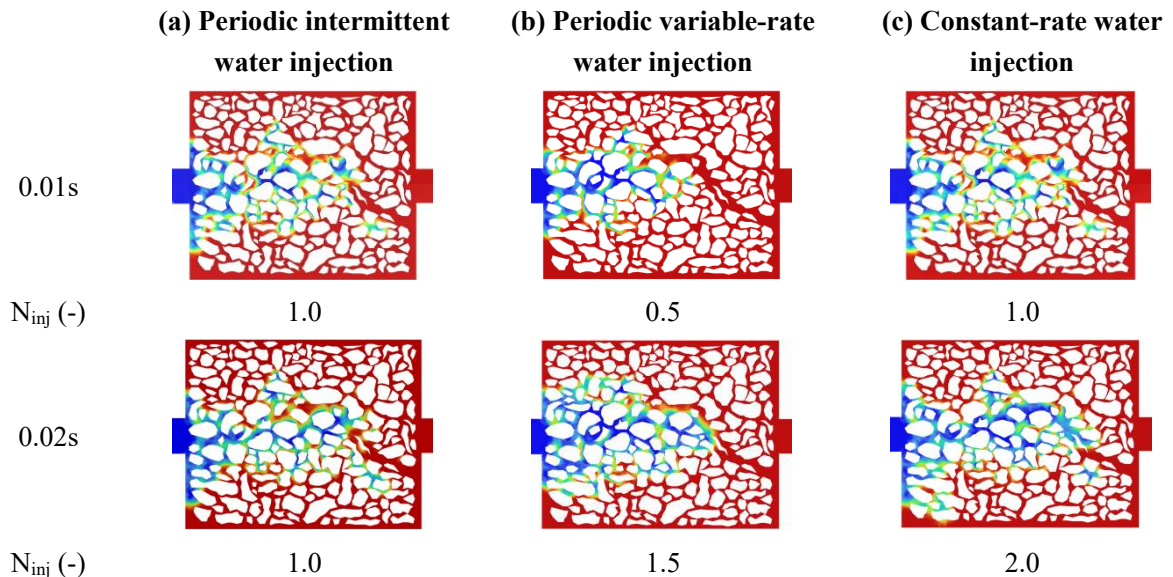
Well X in the W reservoir is a water injection well, and its daily injection rate exhibits three typical time-dependent injection patterns: periodic intermittent injection, periodic variable-rate injection, and constant-rate injection. To investigate the influence of injection mode on the oil-water two-phase flow mechanism, a comparative analysis is conducted among constant-rate injection, periodic intermittent injection, and periodic variable-rate injection.

To quantitatively evaluate the oil-displacement performance and water-use efficiency under different water-injection modes, the oil recovery factor, water-injection efficiency, and normalized cumulative injected volume were employed as evaluation metrics. The oil recovery factor was defined as the ratio of the volume of oil produced during the simulation to the initial oil volume, while the water-injection efficiency was defined as the oil recovery factor obtained per unit normalized cumulative injected volume. To eliminate the effects of differences in instantaneous injection rate and shut-in duration among the various injection schemes, the normalized cumulative injected volume was further defined as follows:

$$N_{inj}(t) = \frac{V_{inj}(t)}{\Delta V_0} = \frac{\int_0^t Q_{in}(\tau) d\tau}{\Delta V_0}$$

Where, $N_{inj}(t)$ is the normalized cumulative injected volume at time t , which represents the ratio of the actual cumulative injected-water volume to the reference injected volume; $V_{inj}(t)$ is the reference injected-water volume, m^3 ; ΔV_0 is the instantaneous water-injection rate at time τ , m^3/s ; t is the current simulation time, s ; and τ is the integration variable of time.

The volume of water injected at 0.01 m/s for 0.01 s was taken as the reference injected volume, ΔV_0 , and the normalized cumulative injected volume was defined as $N_{inj}=V_{inj}/\Delta V_0$. Periodic intermittent water injection followed a cyclic scheme consisting of injection at 0.01 m/s for 0.01 s, followed by a shut-in period of 0.01 s. During the injection stage, N_{inj} increased by 1.0, whereas it remained unchanged during the shut-in stage; therefore, each complete cycle produced an increment of 1.0 in N_{inj} . Periodic variable-rate water injection followed a cyclic scheme consisting of injection at 0.005 m/s for 0.01 s, followed by injection at 0.01 m/s for 0.01 s. The corresponding increments in N_{inj} were 0.5 and 1.0, respectively, giving a total increment of 1.5 per cycle. Constant-rate water injection was performed continuously at 0.01 m/s, for which N_{inj} increased by 1.0 every 0.01 s. The oil–water distributions under the three injection modes at different normalized cumulative injected volumes are shown in Figure 12.



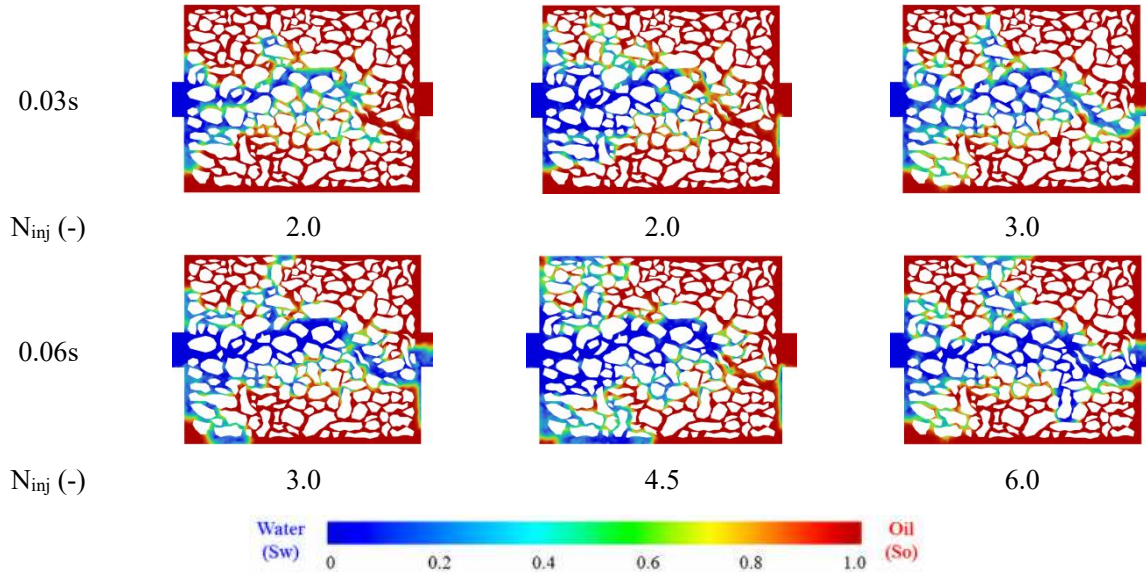


Figure 12. Oil-water two-phase distribution characteristics at different times under various water injection modes

To compare the oil-displacement efficiencies of the three water-injection modes, the normalized cumulative injected volume, N_{inj} , was used as the horizontal coordinate, and the oil recovery factor, RF, was used as the vertical coordinate. The relationship between oil recovery factor and normalized cumulative injected volume is shown in Figure 13.

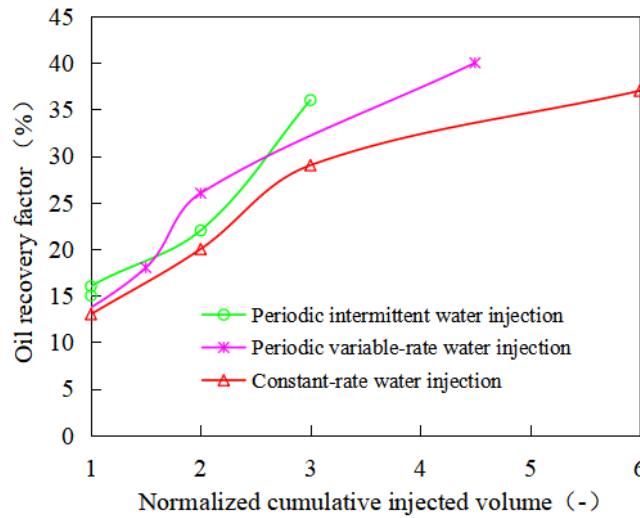


Figure 13. Oil recovery factor as a function of normalized cumulative injected volume under different water-injection modes

As shown in Figures 12 and 13, the three water-injection modes exhibit distinct oil-displacement behaviors because of their different cumulative injected volumes and injection schedules. At $t=0.01$ s, periodic intermittent injection and constant-rate injection have the same injection velocity and normalized cumulative injected volume, $N_{inj}=1.0$, and therefore show similar oil–water distributions. Their oil recovery factors are approximately 15% and 13%, respectively. In comparison, periodic variable-rate injection corresponds to only $N_{inj}=0.5$ at this time, resulting in a lower oil recovery factor of approximately 10% and a smaller swept region. The lower cumulative injected volume and pressure gradient reduce the contribution of viscous displacement, making capillary effects relatively more pronounced.

During $t=0.01$ – 0.02 s, periodic intermittent injection enters the shut-in stage. Although N_{inj} remains unchanged at 1.0, the oil recovery factor increases slightly from approximately 15% to 16%, indicating that capillary-driven redistribution and lateral imbibition continue during the shut-in period. However, as the oil–water interface advances and the local capillary-pressure difference decreases, the subsequent displacement rate gradually declines. In contrast, constant-rate injection continuously maintains the injection pressure gradient. As N_{inj} increases from 1.0 to 2.0, the oil recovery factor increases from approximately 13% to 20%, while the injected water preferentially propagates through relatively low-resistance flow paths. For periodic variable-rate injection, this interval corresponds to the high-velocity stage at 0.01 m/s. Consequently, N_{inj} increases from 0.5 to 1.5, and the oil recovery factor increases from approximately 10% to 18%.

The variation in the injection velocity dynamically modifies the pressure gradient and promotes a broader and more continuous advancement of the displacement front.

When the injection time is extended to 0.03–0.06 s, the differences among the three injection modes become more evident. For periodic intermittent injection, N_{inj} increases from 2.0 to 3.0, while the oil recovery factor increases from approximately 22% to 36%. The repeated injection and shut-in stages periodically weaken the dominant preferential flow paths, promote lateral redistribution of the injected water, and reduce the continuity of water fingers. As a result, residual oil gradually changes from continuous oil-rich regions to isolated trapped clusters. For periodic variable-rate injection, the oil recovery factor increases from approximately 26% at $N_{inj}=2.0$ to approximately 40% at $N_{inj}=4.5$. By comparison, constant-rate injection increases the oil recovery factor from approximately 29% at $N_{inj}=3.0$ to approximately 37% at $N_{inj}=6.0$. Although continuous injection maintains a relatively stable displacement front, the injected water remains concentrated within the dominant central flow paths, leaving part of the lateral pore space insufficiently swept.

At $t=0.06$ s, the water-injection efficiencies, defined as $E_w=RF/N_{inj}$, are approximately 12.0, 8.9, and 6.2 percentage points per unit normalized cumulative injected volume for periodic intermittent injection, periodic variable-rate injection, and constant-rate injection, respectively. Periodic intermittent injection therefore provides the highest water-injection efficiency. In addition, linear interpolation of the $RF-N_{inj}$ curves indicates that an oil recovery factor of approximately 35% requires N_{inj} values of approximately 2.93 and 5.25 for periodic intermittent injection and constant-rate injection, respectively. Thus, periodic intermittent injection reduces the required injected-water volume by approximately 44% compared with constant-rate injection at the same oil recovery factor. Overall, periodic intermittent injection exhibits the greatest water-saving potential, whereas periodic variable-rate injection achieves the highest final oil recovery factor.

5 Conclusions and recommendations

This study investigates, at the pore scale, the coupled effects of pore structure, wettability, and injection strategy on oil-water two-phase transport and residual-oil mobilization, and elucidates the mechanisms governing preferential-channel formation, fracture-matrix fluid exchange, and local interfacial rearrangement under different conditions. The results provide pore-scale mechanistic insights for optimizing injection velocity, wettability control, and periodic water-injection schemes in tight and fractured reservoirs, and establish a basis for upscaling pore-scale results to relative-permeability and capillary-pressure parameters. It should be noted that the present results mainly represent relative trends within the developed two-dimensional pore models and the investigated parameter ranges. Their engineering applicability requires further validation using three-dimensional pore models, core-flooding experiments, and field-specific injection – production conditions. The main conclusions are as follows:

(1) Injection velocity affects water-flow pathway selection and residual-oil distribution by altering the relative contributions of viscous and capillary effects, although its influence depends on the specific pore structure. At relatively low injection velocities, water-front propagation is more sensitive to local pore-throat dimensions, capillary-pressure barriers, and variations in connectivity. As the injection velocity increases, the relative contributions of the pressure gradient and viscous effects become more pronounced, and the water phase tends to migrate through low-resistance and highly connected pathways. Among the four pore models developed in this study, Model C is characterized by relatively pronounced pore-throat size variations and nonuniform local connectivity. At $t^*=62.5$, when the injection velocity was increased from 0.005 m/s to 0.01 m/s, the oil recovery factor decreased from approximately 51.2% to 47.0%. This result indicates that increasing the injection velocity may reinforce pre-existing preferential pathways and reduce oil mobilization in regions adjacent to these pathways

(2) Wettability and injection velocity jointly control water-phase migration and fracture–matrix fluid exchange. Variations in the prescribed contact angle on particle surfaces modify local capillary-pressure barriers and interfacial stability and, together with pore-throat geometry and connectivity, affect water transfer from the fractures into the matrix. At $v=0.01$ m/s, the oil recovery factors of the MWS, FW, MWL, and OW modes were approximately 68.6%, 61.0%, 55.2%, and 25.6%, respectively. The recovery factor of the MWS mode was approximately 43.0 percentage points higher than that of the OW mode, while the dimensionless breakthrough time increased from 25 to 36. When the injection velocity was further increased to 0.015 m/s, the oil recovery factor of the MWS mode decreased to approximately 63.7%, indicating that an excessively high injection velocity may reinforce fracture-dominated preferential flow and weaken matrix imbibition. Therefore, within the two-dimensional pore geometries and parameter ranges considered in this study, the MWS mode at an intermediate injection velocity exhibited relatively effective matrix-oil mobilization; however, this trend depends on the

specific pore structure and wettability distribution.

(3) The different water-injection schedules exhibit distinct advantages in terms of final oil recovery and oil recovery per unit injected-water volume. Under the two-dimensional pore geometry and injection cycles considered in this study, constant-rate injection causes the injected water to continuously migrate through pre-existing low-resistance pathways, thereby gradually reducing the incremental oil-displacement contribution of additional injected water at the later stage. Periodic intermittent injection promotes fluid redistribution and lateral imbibition during shut-in periods, weakening the persistent control of preferential pathways, whereas periodic variable-rate injection expands the swept region by dynamically adjusting the pressure gradient. At $t=0.06$ s, the oil recovery factors obtained using periodic intermittent, periodic variable-rate, and constant-rate injection were approximately 36%, 40%, and 37%, respectively. To achieve an oil recovery factor of approximately 35%, the required normalized cumulative injected volumes, N_{inj} , were approximately 2.93, 3.61, and 5.25, respectively. Compared with constant-rate injection, periodic intermittent and periodic variable-rate injection reduced the cumulative injected-water requirement by approximately 44% and 31%, respectively. Therefore, under the present simulation conditions, periodic intermittent injection exhibited relatively high water-injection efficiency and water-saving potential. However, the field implementation of periodic injection may also involve pump start–stop operations, pressure fluctuations, fines migration, and formation damage. Accordingly, the present results are primarily intended to compare relative trends under the investigated conditions.

Author contributions

Hualei Xu: Writing – Original Draft, Conceptualization. **Hualei Xu & Ziqi Chen:** Methodology, Conducting experiments.

Jie Wang & Houshun Jiang: Supervision, Data analysis, Visualization, Writing – Review & Editing. **Jianyu Li & Yong Cheng:** Visualization, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

Funding

Supported by Open Fund of Hubei Key Laboratory of Oil and Gas Drilling and Production Engineering (Yangtze University) (NO. YQZC202401), & National Science and Technology Major Project of China (No. 2025ZD1404305, 2025ZD1406103, and 2025ZD1406402).

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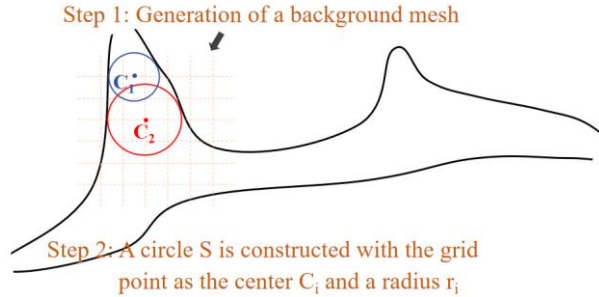
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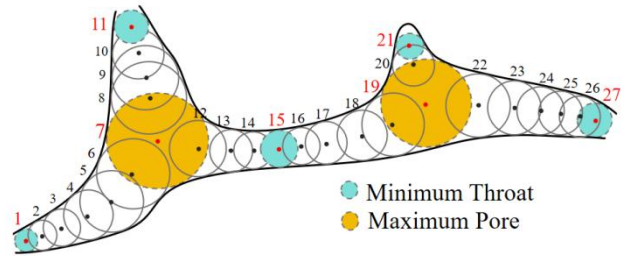
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Appendix 1: Construction Process of a Numerical Simulation Model Based on Real Reservoir Core Sections

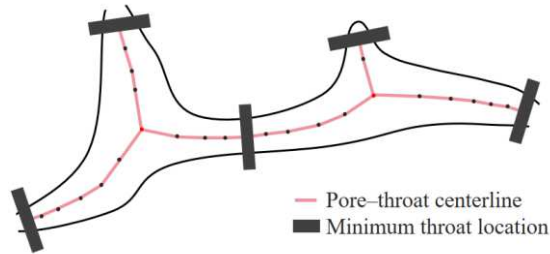
To investigate the evolution of oil-water two-phase flow pathways, the microscopic physical experimental images from Well X in the W reservoir were discretized into minimum pore units based on the maximal inscribed sphere (MIS) method. The processing procedure is illustrated in Figure 1.1 (a-d). First, the core images under oil-saturated conditions were binarized to separate the fluid phase (oil/water) from the rock matrix, thereby extracting the rock skeleton. Second, while preserving the overall pore-network topology, geometric smoothing was applied to the pore-throat structures of the real core sections. The resulting heterogeneous pore structure model is shown in Figure 1.1 (d-e).



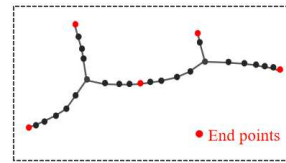
(a) Determination of the maximal inscribed sphere



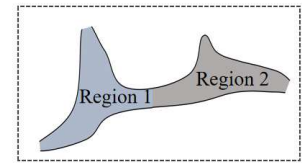
(b) Identification of pore-throat locations



(c) Determination of the pore-throat centerline

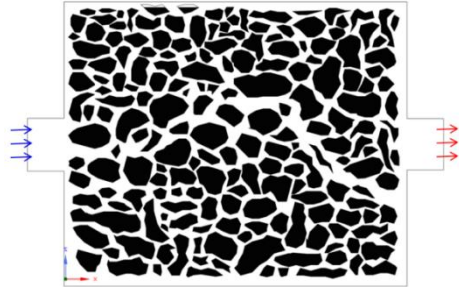


I. Topological pore-throat structure

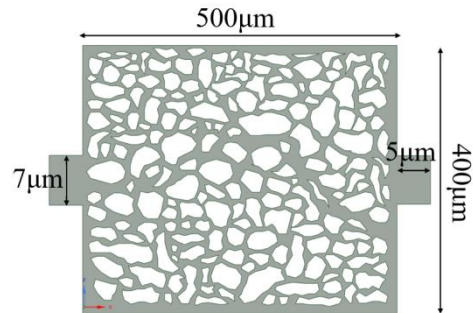


II. Partitioning of pore-throat units

(d) Construction of the endpoint mapping matrix



(e) 2D pore-throat structural model of core samples from Well X in the W reservoir. (black represents rock grains, and white represents flow channels)



(f) Microscopic heterogeneous numerical model of waterflood flow (white represents rock grains, and gray represents flow channels)

Figure 1.1. Pore-throat segmentation process of core slices from Well X in the W reservoir based on the maximal inscribed sphere method